Power Distribution Productivity and Benchmarking Study

June 1, 2023 Revised

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Executive Summary

The Alberta Utilities Commission (“AUC” or “the Commission”) has established a proceeding to determine key provisions of a third generation of generic performance-based regulation --- dubbed “PBR3”--- for gas and electric power distributors. As in the prior two generations, the third generation is expected to feature multiyear rate plans. Each plan will include a rate or revenue cap index with an X factor that reflects industry productivity trends and possibly also a stretch factor. The AUC has retained National Economic Research Associates (“NERA”) to update a study it previously prepared for the Commission on the trend in the productivity of U.S. power distributors. The efficiency of Alberta utilities is also an issue in the proceeding, and studies of their efficiency may inform the design of stretch factors and efficiency carryover mechanisms.

The Consumers’ Coalition of Alberta (“CCA”) has retained Pacific Economics Group Research LLC ("PEG") to appraise the evidence of NERA and the distributors on X factors and efficiency measurement and to prepare our own studies of U.S. power distributor industry productivity trends and of the productivity trends and cost performances of Alberta power distributors. On the basis of this research, we were asked to make recommendations concerning the X factors for Alberta power and natural gas distributors. This is our report on this work. The report also includes general discussions of principles and methods used in statistical benchmarking and the design of rate and revenue cap indexes. We acknowledge we have a duty to provide opinion evidence to the Commission that is fair, objective and non-partisan.

Design of Rate and Revenue Cap Indexes

Rate and revenue cap indexes used in North American PBR are frequently designed with the aid of statistical research on the input price and productivity trends of utilities. This approach has a solid foundation in cost theory and established empirical research methods. Its use in North America has been aided by the extensive standardized data that have been available for many years on the operations of numerous gas and electric utilities in the United States (“U.S.”)

Productivity indexes are influenced by external business conditions and are useful but not pure measures of cost efficiency. Productivity growth can, for example, be slowed by an increased need for replacement capital expenditures and can accelerate after the expenditure surge. Utilities are more capable of brisk productivity growth to the extent that they are currently inefficient.

Several "hot-button" issues have arisen concerning productivity research methods in recent North American PBR proceedings. One is the best sample period for these studies. Another is the best capital cost specification. A third is how productivity research should be adjusted when certain costs are tracked. A fourth is whether productivity research should be customized to reflect local productivity drivers.

Statistical Benchmarking

Statistical benchmarking has growing use in utility ratemaking and is now used in several Canadian jurisdictions. It is useful for rate rebasings and for choosing the stretch factor terms of rate and revenue cap index formulas. Stretch factors linked to benchmarking strengthen cost performance incentives and can function like efficiency carryover mechanisms.

Established approaches to benchmarking include unit cost indexing and econometric modelling. The econometric approach to benchmarking has been favored by regulators in Ontario and several other jurisdictions in the English-speaking world. It generally yields more accurate measures of efficiency levels and trends than productivity indexes. The practice of econometric benchmarking has matured with accumulated experience. For example, the variables that belong in a cost model are better understood.

X Factor Issues

Concerns About NERA's Methodology

In a 2018 Ontario proceeding NERA updated the study of the total factor productivity ("TFP") trends of U.S. power distributors which it had prepared for the AUC in its first generic PBR ("PBR1") proceeding. NERA once again recommended use of power distributor productivity trend research to set the productivity growth target for gas distributors. PEG provided a critique of this study in work for Ontario Energy Board staff.

The volumetric output index that NERA used is inappropriate for a study intended to calibrate the X factor of a revenue per customer index or of a price cap index for utilities with high fixed charges. The one hoss shay method that NERA used to measure capital quantities has several disadvantages, including its sensitivity to the assumption of a constant and low average service life ("ASL") of assets. These problems combine to make the TFP trend of U.S. distributors markedly negative in the later years of the sample period.

NERA recommended a 0.00% base TFP trend for their Ontario gas utility client on the basis of their research. PEG made some corrections for key deficiencies in NERA's productivity research. With improved methods, we reported that the TFP trends of U.S. power distributors averaged **0.49%** growth during the fifteen years from 2001 to 2016.

Empirical Research for the CCA

Data

The primary source of the U.S. data used in our studies for the CCA in this proceeding was reports of electric utilities to the federal government which are in the public domain. There were 90 U.S. utilities in the sample for our productivity research and 88 in the sample for the econometric research. The primary source of our data on the operations of Alberta power distributors was their Rule 005 filings and rebasing applications to the AUC. The distributors provided useful additional information in response to our preliminary information requests.

Power Distribution Productivity Trends of U.S. Utilities

We calculated trends in the partial factor productivity of capital and operation and maintenance ("O&M") inputs as well as in the total factor productivity of sampled U.S. electric utilities in the provision of power distributor services. Capital costs and quantities were measured using a geometric decay specification.

Using equal weights for each sampled distributor, we found that the growth in the distribution TFP of sampled U.S. utilities averaged 0.31% annual growth over our full 26-year 1996-2021 sample period and 0.08% average annual growth over the most recent fifteen years. O&M productivity averaged 0.82% annual growth over the full sample period and 0.66% annual growth over the last fifteen years. Capital productivity averaged 0.13% annual growth over the full sample period and a slight 0.07% annual decline over the last fifteen years. The TFP growth of our Western Peer Group averaged 0.75% over our full sample period and a similar 0.71% over the last fifteen years.

Alberta Productivity Trends

We calculated the O&M, capital, and multifactor productivity trends of the four Alberta power distributors that will be subject to PBR3. The sample period was the fifteen historical years from 2007 to 2021 and two forecasted years: 2022 and 2023. We generally found that the O&M, capital, and total factor productivity growth of the DFOs was well below the U.S. norm in the years before the start of generic PBR. TFP growth declined by 1.7% annually. During PBR1, O&M productivity growth accelerated markedly, averaging 4.7% annually, but capital productivity growth did not. TFP growth nonetheless accelerated but was still modestly below the 15-year U.S. trend, averaging -0.6% annually. During the second generic PBR plan ("PBR2"), O&M productivity growth slowed but was still brisk while capital productivity growth accelerated markedly. TFP growth averaged -0.5% annually.

Alberta Benchmarking Results

Our benchmarking work was complicated by differences in the ways that Alberta DFOs and sampled U.S. electric utilities report their costs. PEG lodged preliminary information requests to better understand the cost accounting of the DFOs. Having developed cost calculations that we hope permit "apples to apples" comparisons, we developed econometric benchmarking models of power distributor O&M expenses, capital cost, and total cost.

In all three of our econometric models, all of the parameter estimates for the first-order terms of the business condition variables were statistically significant and plausible as to sign and magnitude. The total cost and capital cost models had considerably more explanatory power than the O&M cost model. We compared each power distributor's O&M expenses, capital cost, and total cost to the cost projected by our corresponding econometric benchmarking model.

ENMAX In 2023 the forecasted O&M cost of ENMAX is 20% below our econometric benchmark value.[1] ENMAX's capital cost was 2% below our benchmark. ENMAX's total cost was 17% below our benchmark value.

EPCOR In 2023 the forecasted O&M cost of EPCOR is 35% below our econometric benchmark for that year. EPCOR's capital cost was 10% below our benchmark. EPCOR's total cost was about 25% below our benchmark and the best in Alberta.

ATCO Electric In 2023 the forecasted O&M cost of ATCO Electric is 70% above our benchmark value on average. ATCO Electric's capital cost exceeded our benchmark by 68%. ATCO Electric's total cost was 56% above the benchmark values and the worst in Alberta. We acknowledge that these are outlier values.

[1] All percentages are stated in logarithmic terms.

FortisAlberta In 2023 the forecasted O&M cost of FortisAlberta is 8% below our econometric benchmark value. FortisAlberta's forecasted capital cost was 13% below our benchmark. FortisAlberta's total cost was 23% below our benchmark.

Implications for the MRPs

Base TFP Growth Trend

The AUC previously resolved to base the TFP growth target for gas and electric power distributors alike on the TFP trends of U.S. power distributors. If the AUC wishes to base the TFP growth target on national productivity trends, we recommend the 0.08% average annual TFP growth of the power distributors in PEG's productivity study over the most recent 15 years of the sample period. The corresponding O&M productivity growth target is 0.66%. If the Commission wishes to prioritize a sharing of plan benefits, the TFP growth of our Western Peer Group averaged 0.71% during these fifteen years and 0.75% over PEG's full sample period. The 0.31% average annual productivity growth rate of U.S. power distributors over PEG's full sample period is another option.

Stretch Factors

The stretch factor term of a rate or revenue cap index formula should reflect an expectation of how the productivity growth of the subject utility will differ from the base productivity growth target. This depends in part on the utility's operating efficiency at the start of the PBR plan. It should also depend on how the performance incentives generated by the plan compare to those in the regulatory systems of utilities in productivity studies that are used to set the base productivity trend.

Statistical benchmarking has been used to inform the choice of stretch factors in several jurisdictions. Regulators in Ontario and Massachusetts use benchmarking to set stretch factors routinely. Benchmarking scores in certain ranges yield certain stretch factors. Incentive power research by PEG shows that utilities under PBR should achieve superior productivity growth even after two PBR plans.

We believe that we have made a strong case for the AUC to reconsider its approach to setting stretch factors. Superior productivity growth does not just occur during the early years of multiyear rate plans. Stretch factors linked to statistical benchmarking strengthen performance incentives. We have provided benchmarking studies that are similar to those provided in other jurisdictions that practice PBR.

In a summary format we have provided the following table that shows the stretch factors that we indicated for the four electric DFOs given our 2023 total cost benchmarking results.

Utility	Total Cost Benchmarking Score, 2023	Ontario Energy Board	Massachusetts DPU	PEG Incentive Power Research	
				Customers get half of expected performance gains	Customers get all of expected performance gains
ATCO Electric	56%	0.60	0.55	0.30	0.60
ENMAX	-17%	0.15	0.33	0.20	0.39
EPCOR	-25%	0.15	0.25	0.20	0.39
FortisAlberta	-23%	0.15	0.25	0.20	0.39

1. Introduction

The Alberta Utilities Commission has established a proceeding to determine key provisions of a third generation of performance-based regulation (dubbed "PBR3") for jurisdictional gas and electric power distribution facility owners ("DFOs"). PBR3 will likely take the form of multiyear rate plans ("MRPs") that feature rate or revenue per customer indexes with formulas that contain an X factor that reflects a stretch factor and a productivity growth target based on industry productivity trends.[2] The issues list includes consideration of the appropriate productivity growth target and stretch factor. It also includes consideration of techniques for measuring the efficiency of Alberta DFOs. The AUC has retained National Economic Research Associates to update a study of U.S. power distributor productivity trends that it prepared for the Commission in the PBR1 proceeding.

PEG is North America's leading energy utility productivity and statistical benchmarking consultancy. We have done numerous power distribution productivity and benchmarking studies, including several studies for Ontario Energy Board ("OEB") staff. The CCA has asked PEG to study the productivity trends of U.S. power distributors and to measure the productivity trends and cost performances of the four Alberta power DFOs that will be subject to PBR3. We acknowledge we have a duty to provide opinion evidence to the Commission that is fair, objective and non-partisan.

This is our report on this work. Section 2 discusses the use of statistical cost research in benchmarking and the design of rate and revenue cap indexes. Section 3 discusses stretch factors. Section 4 provides a brief history of Alberta X factors. Our concerns about NERA's X factor research methodology are discussed in Section 5. PEG's independent statistical cost research for the CCA in this proceeding is detailed in Section 6. We provide in Section 7 our stretch factor and X factor recommendations. Appendix A discusses various methodological topics in the study in more detail, while a brief discussion of PEG's credentials is provided in Appendix B.

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[2] We prefer to use the term "multiyear rate plan" instead of PBR to describe the regulatory systems of Alberta DFOs since PBR encompasses many other kinds of mechanisms that are not used in Alberta. These mechanisms include revenue decoupling, targeted performance incentive mechanisms, and special incentives for underused practices. For further discussion of the various approaches to PBR see Lowry, M.N., Makos, M., and Kavan, R., *Performance-Based Regulation: Basic Features and Possible Applications to BC Hydro*, prepared for the British Columbia Utilities Commission, 28 February 2020.

2. Use of Statistical Cost Research in Utility Ratemaking

In this section of the report we discuss how statistical cost research can be used in utility ratemaking. We begin by discussing basic indexing concepts. There follow discussions of the use of indexing and statistical benchmarking research in ratemaking. The capital cost specifications that are used in both kinds of research are an important focus.

2.1. Basic Indexing Concepts

Input Price and Quantity Indexes

The cost of each input that a company uses is the product of its price and quantity. The aggregate cost of many inputs is, analogously, the product of a cost-weighted input price index ("*Input Prices*") and input quantity index ("*Inputs*").

Cost = *Input Prices* x *Inputs.* [1]

These indexes can provide summary comparisons of the prices and quantities of the various inputs that a company uses. Depending on their design, these indexes can compare the *levels* of prices (and quantities) of different utilities in a given year, the *trends* in the prices (and quantities) over time, or both.

Indexes designed to measure only the trends of prices or quantities may be called trend indexes. Indexes designed only to compare the levels of prices at a point in time are said to be bilateral. Indexes designed both to measure trends and compare levels are said to be multilateral.

Capital, labor, and miscellaneous materials and services are the major classes of inputs that are typically addressed by the base rates of gas and electric utilities. These are capital-intensive businesses, so heavy weights are placed on the capital subindexes.

The growth rate of a company's cost can be shown to be the sum of the growth in (properly designed) input price and quantity indexes.[3]

growth Cost = *growth Input Prices* + *growth Inputs.* [2]

[3] This result, which is credited to the French economist François Divisia, holds for particular kinds of growth rates.

Rearranging terms, it follows that input quantity trends can be measured by taking the difference between cost and input price trends.

$$\textit{growth Inputs} = \textit{growth Cost} - \textit{growth Input Prices.} \qquad [3]$$

This greatly simplifies input quantity measurement.

Productivity Indexes

The Basic Idea

A productivity index is the ratio of an output quantity (or scale) index ("*Outputs*") to an input quantity index.

$$\textit{Productivity} = \frac{\textit{Outputs}}{\textit{Inputs}}. \qquad [4]$$

Indexes of this kind are used to measure the efficiency with which firms convert production inputs into the goods and services that they provide. Productivity indexes can be designed to compare productivity levels of different companies in a given year, to measure productivity *trends*, or to do both.

The growth of a productivity trend index can be shown to be the difference between the growth of the output and input quantity indexes.[4]

$$\textit{growth Productivity} = \textit{growth Outputs} - \textit{growth Inputs.} \qquad [5]$$

Productivity grows when the output index rises more rapidly (or falls less rapidly) than the input index. Productivity can be volatile for various reasons that include fluctuations in outputs and/or the uneven timing of certain expenditures. The volatility of productivity growth tends to be greater for individual companies than the average growth of a group of companies.

The scope of a productivity index depends on the array of inputs that are addressed by the input quantity index. A *multifactor* productivity index measures productivity in the use of multiple inputs. These are sometimes called *total* factor productivity ("TFP") indexes even though they rarely address all inputs that companies use.[5] Some indexes measure productivity in the use of a subset of all inputs (e.g., O&M or capital inputs). These indexes are sometimes called *partial* factor productivity indexes.

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[4] This result also holds true for particular kinds of growth rates.

[5] The TFP term is popular in Alberta proceedings and will be used in this report.

Output Indexes

The output quantity (trend) index of a firm summarizes growth in its outputs or operating scale. If output is multidimensional, its trend can be measured by a multidimensional output index. Growth in each output dimension that is itemized is measured by a subindex, and growth in the summary index is a weighted average of the growth in the subindexes.

In designing an output index, choices concerning subindexes and weights should depend on the way the index is to be used. In utility industry research one possible objective is to measure the impact of output growth on a company's *revenue*. In that event, the subindexes should measure trends in company *billing determinants* (e.g., delivery volumes) and the weight for each itemized determinant should reflect its share of revenue.[6] A productivity index calculated using a revenue-weighted output index ("$Outputs^R$") will be denoted as $Productivity^R$.

$$growth\ Productivity^R = growth\ Outputs^R - growth\ Inputs. \qquad [6a]$$

Another possible objective of output research is to measure the impact of output growth on the *cost* of a utility. In that event, the index should be constructed from one or more output variables that measure dimensions of "workload" that drive cost. If there is more than one output variable, the weights for these variables should reflect their relative cost impacts. The sensitivity of cost to a small change in the value of a business condition variable is commonly measured by its cost "elasticity." Cost elasticities can be estimated econometrically using data on the costs of utilities and variables measuring the business conditions that drive these costs. Such estimates provide the basis for elasticity-weighted output indexes.[7] A productivity index calculated using a cost-based output index ("$Outputs^C$") will be denoted as $Productivity^C$.

$$growth\ Productivity^C = growth\ Outputs^C - growth\ Inputs. \qquad [6b]$$

If the goal of productivity research is to measure the change in cost efficiency an elasticity-weighted index is generally more useful than a revenue-weighted index.

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[6] This approach to output quantity indexation is also credited to Francois Divisia.

[7] An early discussion of elasticity-weighted output indexes is found in Denny, Michael, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

Sources of Productivity Growth

Economists have studied the drivers of productivity growth using mathematical theory and empirical methods.[8] This research has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit firms to produce given output quantities with fewer inputs.

A second important source of productivity growth is output growth. In the short run, output growth can spur the productivity growth of a company to the extent that it has excess capacity. In the longer run, economies of scale can be realized even if capacity additions are required provided that output growth exceeds its impact on cost. Scale economies will typically be lower the slower is output growth. Incremental scale economies from further output growth may also depend on the current scale of an enterprise. For example, larger utilities may be less able to achieve incremental scale economies.

Productivity growth is also driven by changes in X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum possible efficiency. Productivity growth will increase to the extent that X inefficiency diminishes. A company's potential for future productivity growth from this source is greater the lower is its current efficiency.

Technological change, scale economies, and X inefficiency are generally considered to be dimensions of operating efficiency. This has encouraged the use of productivity indexes to measure operating efficiency. However, theoretical and empirical research reveals that productivity index growth also depends on changes in miscellaneous external business conditions, other than input price inflation and output growth, which also drive cost. One example for a power distributor is the extent of forestation in its service territory. If increased forestation causes more vegetation management due, for example, to the maturation of suburban trees, productivity growth may thereby be slowed.

System age is another business condition that affects productivity. Productivity growth tends to be greater to the extent that the current capital stock is large relative to the need to refurbish or replace aging plant. If on the other hand a utility requires unusually high replacement capital expenditures (sometimes called "repex"), cost growth surges and productivity growth can be unusually slow and even decline. Highly depreciated facilities are typically replaced by facilities that are designed to last for

[8] The seminal paper on this topic is Denny, Fuss and Waverman, ibid.

decades and may need to comply with higher performance standards than the assets they replace. On the other hand, cost growth tends to slacken and productivity growth to accelerate after a period of unusually high capex.

A TFP index with a *revenue*-weighted output index (“TFP^R”) has an important driver that doesn’t affect a cost efficiency index. This is true since:

$$\begin{aligned} \textit{growth } TFP^R &= \textit{growth Outputs}^R - \textit{growth Inputs} + (\textit{growth Outputs}^C - \textit{growth Outputs}^C) \\ &= (\textit{growth Outputs}^C - \textit{growth Inputs}) + (\textit{growth Outputs}^R - \textit{growth Outputs}^C) \\ &= \textit{growth } TFP^C + (\textit{growth Outputs}^R - \textit{growth Outputs}^C). \qquad [7] \end{aligned}$$

Relation [7] shows that the growth in TFP^R can be decomposed into the trend in a cost efficiency index and an “output differential” that measures the difference between the impact that trends in outputs have on revenue and cost.

The output differential is sensitive to changes in external business conditions such as those that drive system use. For example, if a power distributor obtains a sizable share of its base rate revenue from usage charges, its revenue may depend chiefly on system use, while its cost depends chiefly on system capacity. In that event, demand-side management can depress revenue more than cost, reducing the output differential and slowing growth in TFP^R.

This analysis has some noteworthy implications. One is that productivity indexes are imperfect measures of operating efficiency. Productivity can fall (or rise) for reasons other than deteriorating (improving) efficiency. Our analysis also suggests that productivity growth can differ between utilities, and over time for the same utility, for reasons that are beyond their control. For example, a utility with unusually slow output growth and an unusually high number of assets needing replacement can have unusually slow productivity growth.

2.2. Use of Indexing in Price and Revenue Cap Index Design

Price Cap Indexes

Index Logic

Index logic supports the use of index research in the design of price cap indexes (“PCIs”). We begin our demonstration by considering the growth in the prices charged by an industry that earns, in the long run, a competitive rate of return.[9] In such an industry, the trend in revenue equals the long-run trend in cost.

$$trend\ Revenue = trend\ Cost. \quad [8]$$

The trend in the revenue of any firm or industry can be shown to be the sum of the trends in revenue-weighted indexes of its output prices ("*Output Prices^R*") and billing determinants ("*Outputs^R*")

$$trend\ Revenue = trend\ Outputs^R + trend\ Output\ Prices^R. \quad [9]$$

Relation [2] implies that the trend in cost is analogously the sum of the trends in cost-weighted input price and quantity indexes.

$$trend\ Cost = trend\ Input\ Prices + trend\ Inputs \quad [10]$$

Relations [8-10] imply that the trend in output prices that permits revenue to track cost is the difference between the trends in the input price index and in a total factor productivity index of TFP^R form.

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

The result in equation [11] provides a conceptual framework for the design of price cap indexes that are useful in MRPs. These indexes have the general form

$$growth\ Rates = growth\ Input\ Prices - (\overline{TFP}^R + Stretch). \quad [12a]$$

Here $\overline{TFP}^R$ is a base TFP growth target that is typically the trend in the TFP^R of a utility peer group. A "stretch factor" is often added to the formula which slows PCI growth in a manner that shares with customers the financial benefits of performance improvements that are expected under the MRP.

In Alberta and some other jurisdictions, the sum of $\overline{TFP}$ and *Stretch* is called the X factor.[10]

$$X = \overline{TFP^R} + Stretch \quad [12b]$$

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

[10] The X factor term applies only to $\overline{TFP}$ in other jurisdictions.

The index research then has the goal of "calibrating" (rather than solely determining) X.

Revenue Cap Indexes

Theoretical Foundation

Cost theory and index logic also support the design of revenue cap indexes ("RCIs"). Consider first the following basic result of cost theory:

growth Cost = growth Input Prices – growth Productivity^C + growth Outputs^C.[11] [13]

The growth in the cost of a company is the difference between the growth in its input price and *Productivity^C* indexes plus the growth in a consistent cost-based output index. This result provides the basis for a revenue cap index of general form:

growth Allowed Revenue^{Utility} = growth Input Prices – $\left(\overline{TFP^C} + Stretch\right)$ + *growth Scale^{Utility}* [14]

Here $\overline{TFP^C}$ is a TFP^C growth target that will typically be determined using peer group productivity research. Once again, the X factor term in an RCI may equal the sum of the productivity growth target and stretch or only the productivity growth target.

An alternative rationale for a revenue cap index can be found in index logic. Recall from [2] that growth in the cost of an enterprise is the sum of the growth in an appropriately-designed input price index and input quantity index.[12] It then follows that

growth Cost = growth Input Prices + growth Outputs^C
- (*growth Outputs^C – growth Input Quantities*)
= *growth Input Prices – growth Productivity^C + growth Outputs^C.* [15]

This derivation permits the use of index research to calibrate X factors that are applicable to various cost categories using various input quantity specifications.

Revenue per Customer Index

Relation [13] raises the issue of the appropriate scale escalator for a revenue cap index. For example, the capital quantity need not measure the "service flow" from capital assets. For gas and electric power distributors, the number of customers served is a sensible RCI scale escalator. The

[11] See Denny, Fuss, and Waverman, *op. cit.*

[12] This result is also due to François Divisia.

customers variable typically has the highest estimated cost elasticity amongst the scale variables modelled in econometric research on energy distributor cost. The number of customers drives the cost of customer services, service lines, and line transformers and is highly correlated with system peak load. An RCI scale escalator that includes volumes and/or peak demand as output variables diminishes a utility's incentive to promote DSM.

Relation [~~13~~10] can then be revised to obtain the following result:

growth Cost = *growth Input Prices* + *growth Input Quantities* + (*growth Customers* – *growth Customers*)

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

= *growth Input Prices* – *growth* TFP^N + *growth Customers*

where TFP^N is a TFP index that uses the number of customers to measure output. This result provides the rationale for the following revenue cap index formula

growth Revenue = *growth Input Prices* – ($\overline{TFP^N}$ + *Stretch*) + *growth Customers* [16a]

Here $\overline{TFP^N}$ is a productivity growth target using the number of customers to measure output. An equivalent formula is:

growth Revenue – *growth Customers*

= *growth* (*Revenue/Customer*) = *growth Input Prices* – ($\overline{TFP^N}$ + *Stretch*). [16b]

This is sometimes called a "revenue per customer" index and, for convenience, this expression will be used to refer to RCIs which conform to either [16a] or [16b].

Suppose now, that a revenue-weighted output index is used in the TFP research used to calibrate the X factor of a revenue per customer index. Relation [7] then implies that it is appropriate to include an output differential in the revenue cap index formula.

growth Revenue = *growth Input Prices* – *X* + *growth Customers* [17a]

X = $\overline{TFP^N}$ + (*trend Customers* – *trend* $Outputs^R$) + *Stretch* [17b]

Sample Period

The sample period for productivity research has been a controversial issue in several PBR proceedings. In the early days of PBR, there was some consensus that the sample period was one that captured the "long-term" productivity trend of the industry. This might be viewed as the trend for a period long enough to be insensitive to any industry repex cycle.

Since 2000, the productivity trends of energy utilities have tended to decline for various reasons. This has prompted expert witnesses for utilities to advocate for a sample period that is more "forward looking" while being long enough to smooth out some of the year-to-year oscillations. In Massachusetts, a fifteen-year productivity trend has been embraced as one that strikes a reasonable balance between these goals. If a fifteen-year period is applied in repeated plans, the X factor will be more forward looking at the same time as it tracks the industry productivity trend over multiple plans. However, it should be recognized that fifteen years provides an estimate of the recent rather than the long-term productivity trend.

Simple vs. Size-Weighted Averages

In calculating industry productivity trends, a choice must be made between simple and size-weighted averages of results for individual utilities. The arguments for size-weighted averages include the following.

- This is a better measure of the *industry* productivity trend since larger utilities account for a larger share of industry experience. For example, Pacific Gas and Electric distributes power to more customers than several Northeast distributors combined.

We have noted that scale economies are an important driver of productivity growth.

- To the extent that scale economies vary with a utility's size, size-weighted results are more pertinent in X factor studies for larger utilities.

Arguments for even-weighted averages include the following.

- Size-weighted averages can be unduly sensitive to results for a few large utilities that may face unusual operating conditions or have unusual management talent. For example, Pacific Gas and Electric and Southern California Edison, the two largest power distributors in the United States, have both contended with severe wildfires in recent years that raised their cost substantially.
- Insofar as size does affect productivity trends, even-weighted averages are more pertinent in X factor studies for smaller utilities.

- Econometric cost research typically assigns the same weight to every utility, regardless of their size.

PEG typically uses size-weighted averages in X factor studies applicable to large utilities and even-weighted averages in X factor studies applicable to utilities of small or average size.

Dealing with Cost Exclusions

General Considerations

It is important to note that relation [15] applies to *subsets* of cost as well as to *total* cost. Thus, a revenue cap index designed to escalate only O&M revenue can reasonably take the form

$$growth\ Revenue_{O\&M} = Inflation_{O\&M} - (Productivity_{O\&M} + Stretch) + growth\ Customers. \qquad [18]$$

Here $Productivity_{O\&M}$ is the trend in the productivity of a group of utilities in the management of O&M inputs. The scale escalator ("$Scale_{O\&M}$") involves one or more variables that drive O&M.

If the MRP provides for certain costs to be addressed by variance accounts, relation [15] similarly provides the rationale for excluding these costs from the X factor research. This principle is widely (if not unanimously) accepted, and when costs are accorded variance account treatment in MRPs [e.g., costs of energy, demand-side management ("DSM"), and pension programs] they are frequently excluded from the supportive X factor studies.

Capital Cost Exclusions

This reasoning is important when considering how to design a rate or revenue cap index with MRP provisions that provide extra funding for capex.[13] Most of the capex addressed by supplemental capex funding mechanisms may be similar in kind to that incurred by utilities sampled in past and future productivity studies that are used to calculate the company's X factors.[14] The company can then be compensated twice for the same capex: once via supplemental capex funding and then again by low X factors in past, present, and future MRPs. This raises the question of whether the productivity research used to determine the X factor should take account of supplemental capex funding.

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[13] Notable hearings where this controversy has arisen are discussed below.

[14] This is also true of Z factors.

Salient Precedents

The "double counting" issue has been debated in several MRP proceedings and no consensus has been established. Most regulators have eschewed X factor adjustments for supplemental capex funding and based X factors on unadjusted TFP trends. However, Hawaii's Public Utilities Commission ruled, in a recent MRP proceeding, that X factors in revenue cap indexes for the three Hawaiian Electric companies should be set at zero, despite evidence that they should be materially negative, due in part to the fact that some plant additions will be eligible for cost tracking.[15] Addressing the companies' concerns that a 0% X factor would lead to systematic underearning, the Hawaiian Commission noted several examples where the companies would have increased opportunities to enhance their earnings including:

> the new [Exceptional Project Recovery Mechanism ("EPRM") Guidelines explicitly include project expenses, in addition to capital expenditures, as eligible for recovery under the new EPRM, which may offer greater cost recovery for exceptional projects.[16]

Inflation Issues

Suppose now that a macroeconomic inflation index such as the U.S. gross domestic product price index ("GDPPI") is the sole inflation measure in a revenue cap index. Relation [15] can be restated as:

$$\begin{aligned} \textit{growth Cost} &= \textit{growth Input Prices} - \textit{growth Productivity}^C + \textit{growth Outputs}^C \\ &\quad + \textit{growth GDPPI} - \textit{growth GDPPI} \\ &= \textit{growth GDPPI} - [\textit{growth Productivity}^C + (\textit{growth GDPPI - growth Input Prices})]. \\ &\quad + \textit{growth Outputs}^C. \qquad [19] \end{aligned}$$

Relation [19] shows that cost growth depends on GDPPI inflation, growth in operating scale and productivity, and on the difference between GDPPI and utility input price inflation. A revenue cap index may then have the formula

$$\textit{growth Allowed Revenue}^{Utility} = \textit{growth GDPPI} - \overline{TFP^C} - Stretch - \left(\overline{GDPPI} - \overline{Input\ Prices^{Industry}}\right) + \textit{growth Scale}^{Utility}. \qquad [20]$$

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[15] Hawaii Public Utilities Commission (2020), Decision and Order No. 37507, Docket No. 2018-0088.

[16] Hawaii Public Utilities Commission (2020), ibid., p. 54.

The term in parentheses may be called the inflation differential and is the difference between the GDPPI and industry input price trends.

The GDPPI is the U.S. government's featured index of inflation in the prices of the economy's final goods and services.[17] It can then be shown that the trend in the GDPPI is the difference between the trends in the economy's input price and (multifactor) productivity indexes.

$$\textit{trend GDPPI} = \textit{trend Input Prices}^{Economy} - \textit{growth TFP}^{Economy}. \qquad [21]$$

A revenue cap index may then have the formula

$$\textit{growth Allowed Revenue}^{Utility} = \textit{growth GDPPI} - \{[(\overline{\textit{TFP Industry}}^{C} - \overline{TFP}^{Economy}) + (\overline{\textit{Input Prices}}^{Economy} - \overline{\textit{Input Prices}}^{Industry})] + \textit{Stretch}\} + \textit{growth Outputs}^{C}. \qquad [22]$$

Here, the first term in brackets is called the "productivity differential." It is the difference between the productivity trends of the industry and the economy. The second term in parentheses is called the "input price differential." It is the difference between the input price trends of the economy and the industry.

Relation [22] has been the basis for the design of several approved X factors in MRPs in the United States.[18] This approach has, for example, been approved in Massachusetts on several occasions. Since the multifactor productivity growth of the U.S. economy has tended to be brisk it has resulted in substantially negative X factors in several American MRPs for energy distributors. TFP growth has historically been slower in Canada's economy, and macroeconomic price indexes are rarely the sole inflation measures in approved rate or revenue cap indexes. X factors in many approved U.S. rate and revenue cap indexes are therefore not readily comparable to those in Canada.

2.3. Statistical Benchmarking

What is Benchmarking?

The word benchmark originally comes from the field of surveying. The *Oxford English Dictionary* defines a benchmark as:

[17] Final goods and services include consumer products, government services, and exports.

[18] See, for example, D.P.U. 96-50, D.T.E. 03-40, D.T.E. 05-27, D.P.U. 17-05, and D.P.U. 18-150.

> A fixed point (esp. a cut or mark in a wall, building, etc.), used by a surveyor as a reference in measuring elevations.[19]

The term has subsequently been used more generally to indicate something that can be used as a point of comparison in performance appraisals.

A quantitative benchmarking exercise involves one or more activity measures. These are sometimes called key performance indicators. The value of each indicator achieved by an entity under scrutiny is compared to a benchmark value that reflects a performance standard. Given data on the cost of a utility called Western Power Distribution, and a certain cost benchmark we might, for instance, measure its cost performance by taking the ratio of the two values:

$$\textit{Cost Performance} = \textit{Cost}^{\textit{Western}}/\textit{Cost}^{\textit{Benchmark}}.$$

Benchmarks are often developed statistically using data on agents engaged in the same activity. Various performance standards can be used in benchmarking, and these often reflect statistical concepts. One sensible standard is the average performance of the agents in the sample. An alternative standard is the performance that would define the margin of the top quartile of performers. An approach to benchmarking that uses statistical methods is called statistical benchmarking.

These concepts are usefully illustrated by the process through which decisions are made to elect athletes to the Hockey Hall of Fame. Statistical benchmarking plays a major (if informal) role in player selection. Players, for example, are evaluated using multiple performance indicators. The values typically achieved by Hall of Fame members are useful benchmarks. These values reflect a Hall of Fame performance standard.

External Business Conditions

When appraising the relative performance of two sprinters, comparing their times in the 100-meter dash when one runs uphill and the other runs on a level surface is not ideal since runner speed is influenced by the slope of the surface. In comparing the costs of utilities, it is similarly recognized that differences in their costs depend in part on differences in the external business conditions they face. These conditions are sometimes called cost “drivers.” The cost performance of a company depends on the cost it achieves (or, in the case of a forward test year, *proposes*) given the business conditions it

[19] "benchmark, n. and adj." OED Online. Oxford University Press.

faces. Cost benchmarks should, therefore, accurately reflect external business conditions and their impact on cost.

Economic theory is useful in identifying cost drivers and controlling for their influence in benchmarking. Under certain reasonable assumptions, cost "functions" exist that relate the cost of a utility to the business conditions in its service territory. Economic theory reveals that the business conditions that drive cost include the prices of inputs to its production process and the operating scale of the company. Miscellaneous other business conditions may also drive cost.

Economic theory allows for the existence of multiple output variables in cost functions. The cost of a power distributor depends, for instance, on its peak load and the number and dispersion of customers that it serves.

Benchmarking Methods

In this section, two benchmarking methods commonly used in North American ratemaking proceedings are discussed. These methods are econometric modelling and indexing.

Econometric Modeling

We noted above that simply comparing the results of a sprinter racing 100 meters uphill to a runner racing on a level course is not ideal for measuring the relative performance of the athletes. Statistics can sharpen our understanding of each runner's performance. For example, a mathematical model could be developed in which time in the 100-meter dash is a function of track conditions like wind speed, racing surface, and gradient. The parameters in the model that correspond to each track condition would quantify their impact on times. A sample of times turned in by runners, under the varying track conditions, could be used to estimate model parameters. The resultant run time model could then be used to predict the typical performance of the runners given the track conditions they faced.

The relationship between the cost of utilities and the business conditions they face (sometimes called the "structure" of cost) can also be estimated statistically. A branch of statistics called econometrics has developed procedures for estimating economic model parameters using historical data on the variables.[20] The parameters of a utility cost function can be estimated using historical data

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[20] The estimation of model parameters is sometimes called regression.

on the costs incurred by a group of utilities and the business conditions they faced. The sample used in model estimation can be a time series consisting of data over several years for a single company, a cross section consisting of one observation for each of several companies, or a "panel" data set that pools time series data for several companies.

Economic theory can guide the specification of cost models. As noted above, cost is a function of input prices and output quantities. Multiple scale variables may be pertinent. If panel data are used in model estimation, the input price indexes in such a study should accurately compare price levels at each point in time as well as price trends over time.

Basic Assumptions Econometric research involves certain critical assumptions. The most important assumption, perhaps, is that the values of some economic variables (called dependent or left-hand side variables) are functions of certain other variables (called explanatory or right-hand side variables) and error terms. In an econometric cost model, cost is the dependent variable and the cost drivers are the explanatory variables. The explanatory variables are generally assumed to be independent in the sense that their values are not influenced by the values of dependent variables.

The error term in an econometric cost model is the difference between actual cost and the cost predicted by the model. Error terms are a means of modelling the reality that the cost model is unlikely to provide a full explanation of the variation in the costs of sampled utilities. The limitations of the model may include mismeasurement of cost and the external business conditions, the exclusion from the model of relevant business conditions, and the failure of the model to capture the true form of the underlying functional relationship. It is customary to assume that error terms are random variables drawn from probability distributions with measurable parameters.

Statistical theory is useful for selecting the business conditions used in cost models. Tests can be constructed for the hypothesis that the parameter for a business condition variable under consideration equals zero. A variable can be deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence.

Cost Predictions and Performance Appraisals A cost function fitted with econometric parameter estimates is called an econometric cost model. Such models can be used to predict a company's cost given local values for the business condition variables.[21] These predictions are econometric cost benchmarks. Cost performance is measured by comparing a company's cost in year *t* to the cost projected for that year by the econometric model. The year in question can be in the past or the future.

Accuracy of Benchmarking Results A cost prediction like that generated in the manner just described is our best single guess of the company's cost given the business conditions that it faces. This is an example of a point prediction. This prediction is apt to differ from the true expectation of cost due, for example, to the exclusion from the model of relevant business conditions.

Statistical theory provides useful guidance regarding the accuracy of such benchmarks. One important result is that an econometric model can yield biased predictions if relevant business condition variables are excluded from the cost model. A model used to benchmark the cost of a power distributor serving an area of high forestation, for example, yields biased cost predictions if it excludes a good variable for this condition. It is therefore desirable to include in the model all cost drivers for which data are available at reasonable cost, are believed to be relevant, and which have plausible and statistically significant parameter estimates. Cost models used in benchmarking therefore have several business condition variables.

In addition, statistical theory provides the foundation for the construction of confidence intervals that represent the full range of possible cost model predictions that are consistent with the data at a given level of confidence. Wider confidence intervals suggesting reduced benchmarking precision are likely to the extent that:

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[21] Suppose, for example, that you want to benchmark the cost of Western Power Distribution. You could predict the cost of Western in period *t* using the following model:

$$\hat{C}_{Western,t} = \hat{a}_0 + \hat{a}_1 \cdot N_{Western,t} + \hat{a}_2 \cdot L_{Western,t}.$$

Here, $\hat{C}_{Western,t}$ denotes the predicted cost of the company, $N_{Western,t}$ is the number of customers that Western serves, and $L_{Western,t}$ is the length of its distribution line. The $\hat{a}_0$, $\hat{a}_1$, and $\hat{a}_2$ terms are parameter estimates. Cost performance might then be measured using a formula such as:

$$Cost\ Performance = ln\left({C_{Western,t}}/{\hat{C}_{Western,t}}\right)$$

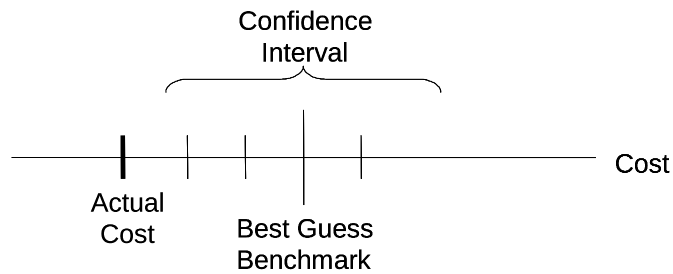
where ln indicates a natural logarithm. Good scores would have negative values while inferior scores would have positive values.

- the model is less successful in explaining the variation in the historical cost data used to estimate the model's parameters;
- the sample of data used in model estimation is smaller;
- the number of business condition variables included in the model is larger;
- the business conditions of sample companies are less varied; and
- the business conditions of the subject utility are less similar to those of the typical firm in the sample.

These results have important implications for benchmarking. For example, the results suggest that we can often improve the precision of an econometric benchmarking model by pooling data for sampled companies over multiple years rather than using only a cross-section of data for a single year. The results also suggest that the precision of an econometric benchmarking exercise is generally *enhanced* by using data from companies with diverse operating conditions. For example, to capture the impact of variables that measure the ruralization of a service territory it is useful to have data for utilities that operate under urban as well as rural conditions.

Testing Efficiency Hypotheses Confidence intervals developed from econometric results not only provide us with indications of the accuracy of a benchmarking exercise but also permit us to test hypotheses regarding cost efficiency. Suppose, for example, that we use a sample average efficiency standard and compute the confidence interval for the benchmark that corresponds to the 90 percent confidence level. It is possible to test the hypothesis that the company has not attained the benchmark standard of efficiency. If, for example, the company's actual cost is below the best guess benchmark generated by the model, but nonetheless lies within the confidence interval, the aforementioned hypothesis cannot be rejected. In other words, the company is not a *significantly* superior cost performer.

An important advantage of efficiency hypothesis tests is that they take into account the accuracy of the benchmarking exercise. There is uncertainty involved in the prediction of benchmarks. These uncertainties are properly reflected in the confidence interval that surrounds the point estimate (best single guess) of the benchmark value. The confidence interval will be greater the greater the uncertainty is regarding the true benchmark value. If uncertainty is great, our ability to draw conclusions about operating efficiency is hampered.



Econometric Benchmarking Precedents Econometric benchmarking has been used in Ontario, Québec, and Massachusetts to set the stretch factor terms of rate or revenue cap indexes. It has also been used by regulators in Australia and Great Britain.[22]

PEG personnel have also provided econometric benchmarking evidence in several North American proceedings. In Ontario, we have performed benchmarking studies for Enbridge Gas Distribution and the Ontario Energy Board. In Massachusetts, we have used it to support stretch factor proposals in PBR proceedings for Bay State Gas, Boston Gas, and NSTAR Gas.[23] We have filed testimony on the cost performance of San Diego Gas & Electric and Southern California Gas on several occasions.[24] In some Colorado PUC proceedings, we used econometric benchmarking to appraise the forward test year cost proposals for the gas and electric services of Public Service of Colorado.[25] In Vermont, PEG benchmarked the cost performance of Central Vermont Public Service in the provision of power distributor services. This study provided the basis for an article in *The Energy Journal.*[26]

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[22] See for example, Ofgem, RIIO-ED1 Final determinations for the slow-track electricity distribution companies Business Plan expenditure assessment (2014) and Australian Energy Regulator, Final Decision EvoEnergy Distribution Determination 2019 to 2024 Attachment 6 Operating Expenditure (2019).

[23] See Massachusetts D.P.U. proceedings 96-50 and 03-40 (Boston Gas); 05-27 (Bay State Gas); and 19-120 (NSTAR Gas).

[24] See for example, California Public Utilities Commission Application Nos. 02-12-027, 02-12-028 and 06-12-009, and 06-12-010.

[25] See for example, Colorado Public Utilities Commission Proceedings 09AL-299E, 10AL-963G, 17AL-0363G, and 17AL-0649E.

[26] Mark N. Lowry, Lullit Getachew, and David Hovde. *Econometric Benchmarking of Cost Performance: The Case of U.S. Power Distributors*, THE ENERGY JOURNAL 26 (3), at 75-92 (2005).

Indexing

In their internal reviews of operating performance utilities tend to employ index approaches to benchmarking rather than the econometric approach just described. Benchmarking indexes are also used occasionally in regulatory submissions. We begin our discussion with a review of index basics and then consider unit cost and productivity indexes.

Index Basics An index is defined in one dictionary as "a ratio or other number derived from a series of observations and used as an indicator or measure (as of a condition, property, or phenomenon)."[27] In utility-performance benchmarking, indexing typically involves the calculation of ratios of the values of performance metrics for a subject utility to the corresponding values for a sample of utilities. The companies for which sample data have been drawn are sometimes called a peer group.

We have noted that a simple comparison of the costs of utilities reveals little about their cost performances to the extent that there are large differences in the cost drivers they face. In index-based benchmarking, it is therefore common to use as cost metrics the ratios of their cost to one or more important cost drivers. The operating scale of utilities is typically the greatest source of difference in their cost. It makes sense then to compare ratios of cost to operating scale. Such a ratio is the cost per unit of operating scale or unit cost. In comparing the unit cost of a utility to the average for a peer group, we introduce an automatic control for differences between the companies in their operating scale. This permits us to include companies with more varied operating scales in the peer group.

A unit cost index is the ratio of a cost index to a scale index.

$$Unit\ Cost = Cost/Scale. \quad [23]$$

Each index compares the value of the metric to the average for a peer group.[28] The scale index can be multidimensional if it is desirable to measure operating scale using multiple scale variables.

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[27] Webster's Third New International Dictionary of the English Language Unabridged, Volume 2, p. 1148. (Chicago: G. and C. Merriam and Co. 1966).

[28] A unit cost index for Western Distribution, for instance, would have the general form

$$Unit\ Cost_t^{Western} = \frac{(Cost_t^{Western}/Cost_t^{Peers})}{(Scale^{Western}/\ Scale_t^{Peers})}.$$

Unit cost indexes do not control for differences in the other cost drivers that are known to vary between utilities. We have noted that cost depends on input prices and miscellaneous other business conditions in addition to operating scale. The accuracy of unit cost benchmarking thus depends on the extent to which the cost pressures placed on the peer group by these additional business conditions are similar on balance to those facing the subject utility.

One sensible upgrade to unit cost indexes is to adjust them for differences in the input prices that utilities face. The formula for real (inflation-adjusted) unit cost is

$$Unit\ Cost^{Real} = \frac{Cost\ /\ Input\ Prices}{Scale}. \qquad [24]$$

Recollecting that cost is the product of properly-designed input price and quantity indexes

Cost = Input Prices · Input Quantities

it follows that

$$Unit\ Cost^{Real} = \frac{Input\ Quantities}{Scale} = 1/Productivity \qquad [25]$$

Thus, a real unit cost index will yield the same benchmarking results as the corresponding productivity index.

2.4. Custom Productivity Growth Targets

Econometric research can also be used to develop custom productivity growth targets. Consider by way of example the following econometric cost model.

$$\ln Cost^{Real} = \hat{\beta}_0 + \hat{\beta}_1 \times \ln Output_1 + \hat{\beta}_2 \times \ln Output_2$$
$$+ \hat{\beta}_3 \times \ln Other_1 + \hat{\beta}_4 \times \ln Other_2 + \hat{\beta}_T \times Trend \qquad [26]$$

Here, $Cost^{Real}$ is real cost, the ratio of cost to an input price index. The $\hat{\beta}$ terms are econometric estimates of model parameters. This model has a double log functional form in which cost and the values of business condition variables are logged. With this form, parameters $\hat{\beta}_1$ to $\hat{\beta}_4$ are also estimates of the elasticities of cost with respect to the four business condition variables. The term $\hat{\beta}_T$ is an estimate of the parameter for the trend variable in the model.

Denny, Fuss, and Waverman provided the additional useful result that, for a cost model like [26], growth in a company's *productivity* can be decomposed as follows. [29]

$$\textit{growth Productivity} = [1 - (\hat{\beta}_1 + \hat{\beta}_2)] \times \textit{growth Outputs} \cancel{+}- \hat{\beta}_3 \times \textit{growth Other}_1$$

$$\cancel{+}- \hat{\beta}_3 \times \textit{growth Other}_2 - \hat{\beta}_T. \qquad [27]$$

The first term in [27] represents the component of productivity growth that is realized due to economies of scale when output grows. These economies are greater the smaller is the sum of the cost elasticities with respect to output ($\hat{\beta}_1 + \hat{\beta}_2$) and the greater is output index growth. Relation [27] also shows that if a *change* in the value of a business condition variable like $Other_1$ raises cost it also slows productivity growth. If the trend variable parameter estimate has a negative (positive) value it would to that extent raise (lower) productivity growth. Formulas like [27] can be generalized to models with additional (or fewer) outputs and other business condition variables.

Econometric cost research and an equation like [27] can be used to identify productivity growth drivers and estimate their impact. Given forecasts of the change in output and other business conditions, an equation like [27] can also provide the basis for productivity growth benchmarks that are specific to the business conditions of a utility that will be operating under an MRP. These are effectively projections of the productivity growth of typical utility managers if faced with expected changes in the business conditions of the subject utility.

For the simple model detailed in relation [26] a productivity growth projection formula for ATCO would be

$$trend\ \widehat{Productivity}^{C}_{ATCO} = [1 - (\hat{\beta}_1 + \hat{\beta}_2)] \times trend\ \widehat{Outputs}_{ATCO}$$

$$\cancel{+}- \hat{\beta}_3 \times trend\ \widehat{Other}_{1,ATCO} \cancel{+}- \hat{\beta}_4 \times trend\ \widehat{Other}_{2,ATCO}) - \hat{\beta}_T. \qquad [28]$$

[30]

[29] Denny, Fuss, and Waverman, *op. cit*.

[30] Here is a more general formula.

$$trend\ Productivity^{C}_{ATCO} = \left(1 - \sum_i \hat{\beta}_i\right) \cdot E\left(trend\ \widehat{Outputs^{C}_{ATCO}}\right) - \sum_l \hat{\beta}_l \cdot \mathrm{E}\left(trend\ \widehat{Others_{l,ATCO}}\right) - \hat{\beta}_T$$

Here $\hat{\beta}_i$ is the econometric parameter estimate for each output variable i while $\hat{\beta}_l$ is the parameter estimate for each other business condition l that is included in the model.

Here $trend\ \widehat{Productivity}^{C}_{ATCO}$ is the projected annual productivity growth trend (average annual growth rate) for ATCO during the final four years of its next MRP. The variable $trend\ \widehat{Outputs}_{ATCO}$ is the expected trend in ATCO's output index. $trend\ \widehat{Other}_{l,ATCO}$ is the expected trend for ATCO in each external business condition l that is included in the model.

In an application to Canadian telecommunications Denny, Fuss, and Waverman, were the first to use econometric research and a formula like [27] to decompose TFP growth. The method was also used several times in California proceedings.[31] In work for the Ontario Energy Board, PEG used this method in an Ontario gas MRP proceeding to project the TFP trends of two large gas utilities and published a paper on the work in the *Review of Network Economics.*[32] These projections were useful because the productivity drivers facing these utilities (e.g., rapid growth in Toronto and Ottawa) were very different from those facing gas utilities in adjacent American states.

Productivity growth projections have several advantages in the design of an X factor. They are useful for ascertaining the reasonableness of an X factor which is based on more conventional industry cost trend research. Moreover, the projection can pertain to the specific costs that the revenue cap index will address. Despite being customized to a utility's business conditions, the use of these projections would not weaken the utility's cost containment incentives since they reflect only the estimated cost impact of these external conditions.

2.5. Capital Cost Issues

Capital Cost, Prices, and Quantities

Since the technologies of energy distributors are capital-intensive, the capital cost specification is important in benchmarking and productivity studies. A discussion of sensible specifications might begin by noting that the annual cost of capital that a utility incurs includes depreciation expenses, a return on investment, and certain taxes. If the price (unit value) of older assets changes over time, the annual cost may also be net of any capital gains or losses. Annual capital cost is not the same as the additions made each year to the rate base.

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[31] See, for example, California Public Utilities Commission A.98-01-014.

[32] See Lowry, M.N., and Getachew, L., *Review of Network Economics*, "Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry" Vol. 8, Issue 4, December 2009.

The quantity of capital has several dimensions. These include the service flow that the assets provide, their capacity or potential service flow (which is often higher), and the stock of present and future capacity/service flows that are possible. Each of these notions of quantity has a corresponding price. Rental prices are prices for the use of capacity (e.g., the use of a car or hotel room for a day). There are also prices to gain ownership of capital assets (e.g., new and used automobiles).

Potential and actual service flows from assets may decay as they age and these flows eventually end. This causes the values of assets to depreciate over time. Depreciation occurs even if the annual capacity/service flow is constant until retirement.

Depreciation and service lives matter, especially in capital-intensive industries. One reason that depreciation matters is that opportunity cost accounts for a sizable share of the cost of asset ownership. Money tied up in ownership typically has other valuable uses. Depreciation reduces opportunity cost over time and can be an important driver of cost trends. Following a capex surge, for instance, depreciation in the value of a utility's assets may materially slow a utility's cost growth.

The service lives of assets can be an important consideration in the choice between assets. For example, utilities have some ability to extend the service lives of aging assets by increasing O&M. This is tantamount to choosing between an old asset with a low opportunity cost of ownership and a new asset that contains a large stock of future service flows but also has a high opportunity cost. Buyers also choose between assets with different service lives in other markets (e.g., those for consumer durables). The new assets (e.g., automobiles) offered for sale have varied service lives, and there are markets for used assets. Asset prices and opportunity costs vary with expected service lives.

Monetary Capital Cost Specifications

<u>The Basic Idea</u>

Monetary approaches to the measurement of capital prices and quantities are conventionally used in statistical research on the productivity and cost performance of North American utilities. In these approaches, capital cost ("*CK*") is the product of a consistent capital price index ("*WK*") and capital quantity index ("*XK*").

$$CK = WK \times XK. \quad [29]$$

The growth rate of capital cost can then be shown to be the sum of the growth rates of these indexes.[33] This decomposition facilitates productivity and econometric cost research.

In utility cost and productivity research, construction of capital quantity indexes involves deflation, using asset price indexes, of reported values of gross plant additions. These quantities are then subjected to a standardized decay specification. Utilities have various methods for calculating depreciation expenses that they report to regulators and retire their assets at different times. Consequently, when calculating capital quantities using a monetary method, it is desirable to rely on the reporting companies chiefly for the values of their gross plant additions and to use a standardized decay specification for all companies.

In research on the productivity and cost performances of U.S. energy utilities, Handy Whitman utility construction cost indexes ("HWIs") have traditionally been used as the asset price indexes. Statistics Canada used to compute credible electric utility construction cost indexes but these have been discontinued.

Since some of the plant a utility owns may be 40-60 years old, it is desirable in these calculations to have gross plant addition data for many years into the past. For earlier years, however, the desired gross plant addition data are frequently unavailable. Consequently, it is customary to begin the calculation of a capital quantity index by finding the reported value of plant at the end of the limited-data period and then to estimate the quantity of capital that it reflects using data on asset prices in earlier years. This initial year of the capital quantity index is sometimes called the "benchmark year."

Since the estimate of the capital quantity in the benchmark year is inexact, it is preferable to base capital and total cost research on a sample period that begins many years after the benchmark year. If this is not done, research on capital and total cost will be less accurate, especially in the early years of the sample period.

Capital Service Flows and Service Prices

A capital good has the capacity to provide a stream of services over some period of time. In rigorous statistical cost research, it is often assumed that the capital quantity index measures the annual service flow. A companion capital price index is then chosen that measures the hypothetical price of a

[33] This result is specific to certain growth rate measures.

unit of capital service. This is sometimes called a "service" or "rental" price. The design of capital service price indexes should be consistent with the assumption about the decay in the service flow. The product of the capital service price index and the capital quantity index is interpreted as the annual cost of using the flow of services. This is sometimes called the user cost of capital.

Popular Monetary Capital Cost Specifications

Several monetary methods have been established for measuring capital price and quantity trends. A key issue in the choice between these methods is the pattern of decay in the quantity from each year's plant additions. This pattern is sometimes called the age-efficiency profile.

Another issue in the choice between monetary methods is whether plant is valued in historical or replacement (i.e., current) dollars. Historical valuations (sometimes called "book" valuations) are commonly used in North American utility cost accounting. When plant is instead valued in current (aka replacement) dollars, utilities experience capital gains if the value of older plant appreciates, and this reduces the cost of capital.

Three monetary methods for calculating capital cost have been used extensively in utility X factor research: geometric decay, one-hoss shay, and cost of service. We discuss these methods in turn.

1. Geometric Decay Under this method, the quantity of capital from each group of plant additions to which it is applied declines at a constant rate ("*d*") over time. The capital quantity at the end of each period *t* ("XK_t") is related to the quantity at the end of the *last* period and the quantity of gross plant additions ("XKA_t") by the following equation:[34]

$$XK_t = XK_{t-1} \cdot (1\text{-}d) + XKA_t \qquad [30a]$$

$$= XK_{t-1} \cdot (1\text{-}d) + \frac{VKA_t}{WKA_t}. \qquad [30b]$$

This pattern of decay gives rise to a constant rate of asset depreciation. A constant rate of depreciation is accelerated relative to straight-line depreciation in the early years of an asset's service life but is less rapid in later years. Note that the quantity of gross plant additions is

[34] Equations of this kind are sometimes called "perpetual inventory equations."

calculated as the ratio of the value of the additions ("VKA") to the value of an asset price index ("WKA") in the same year.

The standard geometric decay method assumes a replacement valuation of plant. Cost is thus computed net of capital gains. The companion capital price is a service price.

2. <u>One-Hoss-Shay</u>[35] Under the one hoss shay method, the service flow from each asset is assumed to be constant until the end of its service life, when it abruptly falls to zero. This decay pattern is typical of an incandescent light bulb. However, in utility cost research this constant-flow assumption is usually applied to the *total* plant additions each year.

The quantity of capital at the end of year *t* is the sum of the quantity at the end of the prior year plus the quantity of gross plant additions less the quantity of plant retirements ("XKR_t"):

$$XK_t = XK_{t-1} + XKA_t - XKR_t \tag{31a}$$

$$= XK_{t-1} + \frac{VKA_t}{WKA_t} - \frac{VKR_t}{WKA_{t-s}}. \tag{31b}$$

Since reported utility retirements are valued in historical dollars, the quantity of retirements in year *t* is calculated by dividing the reported value of retirements ("*VKR*") by the value of the asset price index for the best guess of the year when the retired assets were added.

[35] Wikipedia provides a succinct narrative of the origin of this term (https://en.wikipedia.org/wiki/One-horse_shay),

> A **one-horse shay** is a light, covered, two-wheeled carriage for two persons, drawn by a single horse. The body is chairlike in shape and has one seat for passengers positioned above the axle which is hung by leather braces from wooden springs connected to the shafts. "One-horse shay" is an American adaptation, originating in Union, Maine, of the French *chaise*. The one-horse shay is colloquially known in the U.S. as a 'one-hoss shay'.
>
> American writer Oliver Wendell Holmes Sr. memorialized the shay in his satirical poem "The Deacon's Masterpiece *or* The Wonderful One-Hoss Shay". In the poem, a fictional deacon crafts the titular wonderful one-hoss shay in such a logical way that it could not break down. The shay is constructed from the very best of materials so that each part is as strong as every other part. In Holmes' humorous, yet "logical", twist, the shay endures for a hundred years (amazingly to the precise moment of the 100th anniversary of the Lisbon earthquake shock) then it "went to pieces all at once, and nothing first, — just as bubbles do when they burst". It was built in such a "logical way" that it ran for exactly one hundred years to the day.
>
> In economics, the term "one-hoss shay" is used, following the scenario in Holmes' poem, to describe a model of depreciation, in which a durable product delivers the same services throughout its lifetime before failing with zero scrap value. A chair is a common example of such a product.

Plant is once again valued at replacement cost. The annual cost of capital is then computed net of capital gains. The companion capital price is once again a capital service price.

3. Cost of Service ("COS"). The geometric decay and one hoss shay approaches for calculating capital cost use assumptions that differ from those used to calculate capital cost in traditional cost of service ratemaking.[36] With both approaches, we have seen that the trend in capital cost is a simulation of the trend in cost incurred for purchasing capital services in a competitive rental market. However, we showed in Section 2.2 that the derivation of a revenue cap index using index logic does not require a service price/service flow treatment of capital cost. It can in principle use more familiar capital cost accounting provided that capital cost can still be decomposed into price and quantity indexes.

   The alternative COS approach to measuring capital cost achieves this decomposition and uses a simplified version of COS accounting. Plant is valued in historical dollars and straight-line depreciation of asset values is assumed. Capital cost is not intended to simulate the cost of purchasing capital services in a competitive rental market, and the capital price is not a simulation of a capital service price. The formulae are complicated, however, making them more difficult to code and review.

Two other methods for calculating capital cost also warrant discussion – hyperbolic decay and the Kahn method:

4. Hyperbolic Decay Hyperbolic decay has rarely been used in North American X factor or utility benchmarking studies but merits consideration in these applications. Under this approach the service flow from groups of assets to which it is applied is assumed to decline at a rate that may vary as they age. This is appealing because the service flows from many utility assets seem to decline more rapidly as they age.

   Like one-hoss shay and geometric decay, a hyperbolic decay specification typically entails a replacement valuation of plant. The annual cost of capital is therefore computed net of capital gains. The capital price is a service price which reflects these assumptions.

[36] The OHS assumptions are more markedly different.

5. Kahn Method An X factor can also be calculated using the simpler Kahn Method. This general approach was developed by Alfred Kahn, the distinguished regulatory economist who was a professor at Cornell University. It has been used by the FERC to set the X factors in MRPs for interstate oil pipelines. PEG has upgraded the method that Dr. Kahn used to better approximate cost of service capital cost accounting. PEG used this method in recent Massachusetts and Hawaii MRP proceedings.[37]

   In a U.S. proceeding, the Kahn Method might involve calculating trends in the cost of base rate inputs of a sample of U.S. power distributors using an approximation to traditional capital cost accounting and then solving for the value of X which would cause the trend in distributor cost to equal the trend in a revenue cap index with a formula like:

$$\textit{growth Allowed Base Revenue}^{Utility} = \textit{growth GDPPI} - X + \textit{growth Outputs}^{C}. \qquad [32]$$

   The X factor resulting from such a calculation reflects the inflation differential that we discussed in Section 2.2 above as well as the productivity trends of sampled utilities. This is a problem in an application to Alberta since the inflation differential for a U.S. utility may differ considerably from that which is pertinent in a Canadian proceeding.

Choosing the Right Monetary Approach

The relative merits of alternative monetary approaches to measuring capital cost have been debated in several PBR proceedings. Based on PEG's experience in debates of this nature we believe that the following considerations are particularly relevant.

The Goal of X Factor Research is to Find a Just and Reasonable Method for Adjusting Rates Between Rate Cases.

Statistical cost research has many uses, and the best capital cost specification for one application may not be best for another. One use of such research is to measure a utility's operating efficiency. Another use is to determine the X factor in a rate or revenue cap index.

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[37] See Massachusetts DPU 18-150, Exhibits. AG-MNL, pp. 15-16 and AG-MNL-2, pp. 39-40, and Hawaii PUC 2018-0088, Initial Comprehensive Proposal of the Hawaiian Electric Companies, Exhibit A, *Designing Revenue Adjustment Indexes for Hawaiian Electric Companies*, August 14, 2019, pp. 19-20.

Revenue cap indexes used in PBR are intended to adjust allowed revenue between general rate cases that employ a cost-of-service approach to capital cost measurement. In North America, the calculation of capital cost in rate cases typically involves an historical valuation of plant and straight-line depreciation. Absent a rise in the target rate of return, the cost of the assets that sampled utilities add in a given year shrinks over time as depreciation reduces their net plant value and thereby the return on rate base. Capital cost can rise rapidly in a period of high repex. In view of these realities, we do not necessarily want the X factor to reflect the trend in an ideal measure of cost efficiency.

Consider also that when a macroeconomic inflation measure like the GDP-IPI is the revenue (or price) cap index inflation measure, the input price trend of utilities becomes an issue as well as the productivity trend in X factor determination. The capital price index then becomes a criterion in the choice of the capital cost specification as well as the productivity index since an input price differential must be chosen. The capital service prices used in OHS, GD, and HD are volatile. X factor witnesses often try to downplay this volatility, but more recently the X factor witnesses for energy distributors in Massachusetts have touted the appropriateness of a large negative input price differential that benefitted their clients, and the Massachusetts regulator embraced their analysis. Large input price differentials do not always favor utilities. In a proceeding to approve a price cap index for Central Maine Power, a witness for consumer interests asked for a large *positive* input price differential.[38]

<u>One Hoss Shay Pros and Cons</u>

One Hoss Shay Advantages The one hoss shay specification is sometimes argued to better fit the service flows of individual utility assets than geometric decay. The argument is that many assets, once installed, provide a fairly constant service flow for many years. One hoss shay has for this reason been used in some productivity studies filed in proceedings to determine X factors.

Another advantage of one hoss shay is that the data are unavailable in some jurisdictions to accurately calculate capital quantities using monetary methods. In these jurisdictions, the assumption of a one hoss shay service flow legitimizes using available data on capacity (e.g., line miles) to measure capital quantities.[39]

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[38] Maine PUC Docket 1999-00666

[39] However, capacity data are then unavailable as measures of output.

One Hoss Shay Disadvantages Other considerations suggest that the one hoss shay specification is disadvantageous. Notable problems include the following.

- Individual utility assets frequently do not exhibit a constant service flow until their retirement. For example, many assets tend to have diminished reliability, are less safe or environmentally benign, and thereby require more maintenance and inspections as they age. For example, in a recent Quebec proceeding Hydro-Quebec Transmission stated in response to an information request from PEG that

  > **Dans le dossier tarifaire 2013 et 2014**, **le Transporteur a expliqué que le vieillissement de son parc d'actifs entraîne des pressions à la hausse sur ses charges. D'une part, il a précisé que les activités de maintenance corrective ou préventive requises sont par nature plus significatives et augmentent ainsi les coûts de maintenance. D'autre part, le Transporteur a indiqué qu'il procède à des interventions ciblées et de réhabilitation ayant pour but de diminuer le risque de défaillance majeure d'équipements et d'éviter d'importants investissements pour les remplacer. Il a également expliqué que la forte sollicitation du réseau entraîne également une pression accrue sur le coût des interventions.**
  >
  > **Dans le dossier tarifaire 2016, le Transporteur a indiqué que les analyses sur ses travaux de maintenance passées démontrent que plus l'âge d'un actif augmente, plus le risque de bris et de défaillance augmente. Finalement, dans le dossier tarifaire 2017, le Transporteur a démontré que l`âge moyen du parc entraîne des effets importants sur la maintenance en précisant que l'effort de maintenance augmente de manière significative une fois passé le 50 % de la durée de vie utile d'un équipement.**[40]

- In productivity studies, capital quantity trends are rarely calculated for *individual* assets. Instead, they are typically calculated from data on the total value of *all* of the additions to (and, in the case of one hoss shay, retirements of) the various kinds of assets that a utility uses. Even if each individual asset did have a constant service flow, the flow from total plant additions could be poorly approximated by one-hoss shay[41] for several reasons.

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[40] B-0265 (HQT-16, Document 1), p. 9.

[41] Consistent with these remarks, the authors of a capital research manual for the Organization of Economic Cooperation and Development stated in the Executive Summary that:

a. Different kinds of assets can have markedly different service lives.

b. Assets of the same kind have varied service lives. Identical light bulbs installed by Alberta homeowners in January of a given year, for instance, will burn out at different times. In power distribution, the service lives of assets vary due to casualty losses (e.g., due to severe storms).

c. Individual assets sometimes have components with different service lives. The fixtures on a distribution pole, for example, might need replacement before the pole itself.

- The value of assets with one hoss shay service flows depreciate as they age because of diminution in their expected future service flows. However, the simple one hoss shay approach abstracts from asset value depreciation since the service flow from the asset is assumed constant and the price of capital services is one that is commensurate with a competitive rental market. This matters for several reasons.

  a. We have noted that depreciation reduces the opportunity cost of owning assets, and this is a material consideration when benchmarking utility cost. Using a simple one hoss shay approach in a cost benchmarking study, a utility's effort to delay replacement of assets will not be recognized.[42]

  b. Depreciation can materially affect utility cost trends in the short and medium term, and its effect merits consideration in X factor selection. For example, we might want X to be less (more) positive if the subject utility and utility industry are both in a period of high (low) repex.

> In practice, cohorts of assets are considered for measurement, not single assets. Also, asset groups are never truly homogenous but combine similar types of assets. When dealing with cohorts, retirement distributions must be invoked because it is implausible that all capital goods of the same cohort retire at the same moment in time. Thus, it is not enough to reason in terms of a single asset but age efficiency and age-price profiles have to be combined with retirement patterns to measure productive and wealth stocks and depreciation for cohorts of asset classes.

OECD, *Measuring Capital OECD Manual 2009*, 2nd ed., at 12.

[42] On the other hand, a capital cost specification that is more sensitive to age complicates modelling by raising the need for an appropriate age variable.

c. Depreciation is another reason why the quantity of a group of assets declines as they age. For example, as the asset ages, the utility obtains a constant service flow from a 33-year-old asset one year and from a cheaper 34-year-old asset the next. This is arguably a quantity decline just as the quantity of labor could decline if a utility found a way to get work done with cheaper kinds of labor.

- One hoss shay is more difficult to implement accurately than other capital cost specifications. To understand why, consider first that all monetary methods require deflation of gross plant *additions*. These calculations are facilitated by the fact that the years in which given additions are made are known exactly, so that it is easy to choose the matching value of the asset price deflator. The challenge with one hoss shay is that it also requires deflation of plant *retirements*, and the vintages of reported retirements are not readily available for a large number of utilities. One hoss shay practitioners commonly address this challenge by deflating the value of retirements by the value of an asset price index for a year in the past which reflects the assumed average service life ("ASL") of the assets. Deflations by this means can be well off the mark.
- One hoss shay has given rise to methodological controversies in PBR proceedings. The biggest controversy has involved the ASL. Another is the appropriate method for calculating the capital quantity in the first year. PEG's empirical research suggests that productivity results using one hoss shay are quite sensitive to the ASL assumption. Since the ASL is used to match a value for the asset price index to the retirements value, and retirements reduce the capital quantity, a higher ASL tends to slow measured capital quantity growth and thereby accelerate TFP growth. The ASL can then be a "fudge factor" in an X factor study.

In many proceedings where OHS has been used, controversy has also arisen as to whether the first year of the capital quantity index should be calculated by deflating *gross* or *net* plant value by an average of past values of construction cost indexes. Since OHS partisans typically rely on the NERA data set, and NERA used *net* plant value, there has been a tendency for utility witnesses to claim that there is "no established rule" about this in the literature rather than putting on their economist thinking caps. However, in a recent Massachusetts proceeding LEI, working for a utility, used OHS in a productivity study and deflated gross rather than net plant value to start the capital quantity index.

- For various reasons, one hoss shay studies sometimes produce negative capital quantities. In the second generic PBR proceeding in Alberta, for instance, Christensen reported in response to an information request that if they raised the ASL to a level more similar to that actually reported by utilities during their chosen sample period it produced negative capital quantities for some utilities. A possible reason for this problem was the use of an inappropriate means of estimating the capital quantity in the first year. Christensen and LEI encountered the same problem of negative capital quantities when they tried to use Handy Whitman gas utility construction cost indexes as asset price deflators in recent Massachusetts X factor studies. Both consultants instead used a producer price index to deflate asset values.

<u>Geometric Decay Pros and Cons</u>

Geometric Decay Advantages

- Geometric decay takes some account of the depreciation in asset value and the decline in capital quantities that result over time from a cohort of diverse assets.
- In an X factor study, geometric decay is therefore more sensitive to any capex cycle that a utility or utility industry might display. It is also more sensitive to system age in a benchmarking study. A remarkable effort by a utility to extend asset life can be recognized.
- The price and quantity formulas are particularly simple and intuitively appealing.
- Calculation of retirement quantities is not required.
- Results are less sensitive to the ASL assumption.

Geometric Decay Disadvantages

- The assumption of constant decay means that initial decay is somewhat greater than that which actually occurs.
- Some practitioners seek TFP trends that are relatively insensitive to capex surges.

<u>Popularity of Alternative Capital Cost Specifications</u>

Here is some evidence on the popularity of alternative capital cost specifications in productivity research.

- The U.S. Bureau of Labor Statistics, Australian Bureau of Statistics, and Statistics New Zealand all use hyperbolic decay in their multifactor productivity studies of the economy and important sectors thereof.[43] We understand that Statistics Canada uses geometric decay in such studies.

- Table 1 reports capital cost specifications that have been used in North American energy utility productivity studies. It shows that geometric decay has been by far the most common method used in these studies. In Ontario, for example, geometric decay has been routinely used in productivity and benchmarking studies that are filed by OEB staff and utility witnesses. PEG's 2017 study of power distributor productivity for Lawrence Berkeley National Laboratory also used geometric decay.[44]

  It is also notable that Christensen Associates used geometric decay in virtually all of their numerous studies of telecommunications and cable television productivity, as well as in energy distribution productivity studies that they prepared before their Alberta and Massachusetts engagements. Concentric Energy Advisors used the Kahn method in productivity research and testimony for Hydro-Québec and used geometric decay in gas utility productivity research and testimony for Enbridge Gas Distribution in Ontario.[45] Table 1 also shows that the cost of service and Kahn methods have both been used more frequently than one hoss shay.

- However, there has been an uptick in recent years in (utility-funded) studies using one hoss shay. In addition to two Massachusetts *gas* distributor studies, there have been two Massachusetts *power* distributor studies. Furthermore, the Massachusetts Department of Public Utilities ("DPU") has explicitly embraced the one hoss shay specification for X factor studies. PEG used one hoss shay in its recent Massachusetts gas distributor productivity

[43] See for example, Bureau of Labor Statistics, Multifactor Productivity, *Technical Information About the BLS Multifactor Productivity Measures,* at 3 (September 26, 2007).

[44] Mark N. Lowry, Jeff Deason, and Matt Makos (2017), *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, LAWRENCE BERKELEY NATIONAL LABORATORY, at B. 19-20 (July 2017).

[45] James Coyne, James Simpson, and Melissa Bartos, *Incentive Ratemaking Report* (prepared for Enbridge Gas Distribution), OEB Proceeding EB-2012-0459, Exh. A2, Tab 9, Sch. 1, p. B-11 (June 28, 2013).

Table 1

Capital Cost Specifications Used in North American Energy Utility Productivity Evidence

Power Industry Studies					
Year	**Jurisdiction**	**Author**	**Client**	**Industry Studied**	**Capital Cost Specification**
1994	Maine	PEG personnel[1]	Utility	Northeast Bundled Power Service	Geometric Decay
1995	New York	PEG personnel[1]	Utility	US Bundled Power Service	Geometric Decay
1998	California	PEG personnel[1]	Utility	US Power Distributors	Geometric Decay
1999	Hawaii	PEG	Utility	US Bundled Power Service	Geometric Decay
1999	Maine	NERA	Utility	Northeast Power Distributors	One Hoss Shay
2000	Alberta	NERA	Utility	Western Power Distributors	One Hoss Shay
2001	Maine	PEG	Utility	Northeast Power Distributors	Geometric Decay
2002	California	PEG	Utility	US Power Distributors	Geometric Decay
2004	California	PEG	Utility	US Power Distributors	Geometric Decay
2005	Massachusetts	PEG	Utility	Northeast Power Distributors	Geometric Decay
2006	California	PEG	Utility	US Power Distributors	Geometric Decay
2006	Kansas	Christensen Associates	Utility	US Power Distributors	Geometric Decay
2006	Kansas	Christensen Associates	Utility	US Bundled Power Service	Geometric Decay
2006	Kansas	Christensen Associates	Utility	US Power Generation	Geometric Decay
2006	Kansas	Christensen Associates	Utility	US Power Transmission	Geometric Decay
2007	Maine	PEG	Utility	Northeast Power Distributors	Cost of Service
2008	Maine	Christensen Associates	Regulator	Northeast Power Distributors	Geometric Decay
2008	Vermont	PEG	Utility	US Power Distributors	Cost of Service
2008	Ontario	PEG	Commission	Ontario Power Distributors	Cost of Service
2008	Ontario	LEI	Utility	Ontario Power Distributors	One Hoss Shay (Physical Asset)
2010	California	PEG	Utility	US Power Distributors	Geometric Decay
2010	Alberta	NERA	Commission	US Power Distributors	One Hoss Shay
2011	District of Columbia	PEG	Utility	Northeast Power Distributors	Cost of Service
2011	Maryland	PEG	Utility	Northeast Power Distributors	Cost of Service
2011	Maryland	PEG	Utility	Northeast Power Distributors	Cost of Service
2011	New Jersey	PEG	Utility	Northeast Power Distributors	Cost of Service
2011	Alberta	LEI	Utility	Ontario Power Distributors	One Hoss Shay (Physical Asset)
2012	Delaware	PEG	Utility	Northeast Power Distributors	Cost of Service
2013	British Columbia	Black & Veatch	Utility	US Power Distributors	Kahn Variant
2013	British Columbia	PEG	Consumer Advocate	US Power Distributors	Cost of Service
2013	Massachusetts	PEG	Utility	Northeast Power Distributors	Cost of Service
2013	Massachusetts	Acadian Consulting	Consumer Advocate	Northeast Power Distributors	Cost of Service
2013	Maine	PEG	CMP	Northeast Power Distributors	Cost of Service
2013	Ontario	PEG	Regulator	Ontario Power Distributors	Geometric Decay
2015	Alberta	Brattle Group	Utility	US Power Distributors	One Hoss Shay
2015	Alberta	PEG	Consumer Advocate	US Power Distributors	Geometric Decay
2015	Alberta	Christensen Associates	Utility	US Power Distributors	One Hoss Shay
2016	Ontario	LEI	Utility	US Hydro-electric Generation	One Hoss Shay (Physical Asset)
2016	Ontario	PEG	Regulator	US Hydro-electric Generation	Geometric Decay
2017	Massachusetts	Christensen Associates	Utility	US Power Distributors	One Hoss Shay
2018	Massachusetts	Acadian Consulting	Consumer Advocate	US Power Distributors	Geometric Decay
2017	US	PEG	Government	US Power Distributors	Geometric Decay
2017	Ontario	NERA	Utility	US Power Distribution	One Hoss Shay
2018	Massachusetts	Christensen Associates	Utility	US Power Distributors	One Hoss Shay
2019	Massachusetts	PEG	Attorney General	US Power Distributors	Geometric Decay and Kahn Variant
2018	Ontario	Power Systems Engineering	Utility	US Power Transmitters	Geometric Decay
2019	Ontario	PEG	Regulator	US Power Transmitters	Geometric Decay
2019	Ontario	Power Systems Engineering	Utility	US Power Transmitters	Geometric Decay
2019	Ontario	PEG	Regulator	US Power Transmitters	Geometric Decay
2019	Hawaii	PEG	Utility	US Bundled Power Service	Kahn Variant
2020	Hawaii	Ronald Binz	Environmentalist	US Bundled Power Service	Kahn Variant
2021	Quebec	Brattle Group	Utility	US Power Transmitters	One Hoss Shay
2021	Quebec	PEG	Industrial	US Power Transmitters	Geometric Decay
2022	Ontario	Clearspring Energy Advisors	Utility	US Power Transmitters	Geometric Decay
2022	Ontario	PEG	Regulator	US Power Transmitters	Geometric Decay
2022	Massachusetts	Christensen Associates	Utility	US Power Distributors	Hyperbolic Decay

Table 1 (continued)

Capital Cost Specifications Used in North American Energy Utility Productivity Evidence

Gas Industry Studies

Year	Jurisdiction	Author	Client	Industry Studied	Capital Cost Specification
1995	California	PEG personnel[1]	Utility	US Gas Utilities	Geometric Decay
1996	Massachusetts	PEG personnel[1]	Utility	US Gas Utilities	Geometric Decay
1997	British Columbia	PEG personnel[1]	Utility	US Gas Utilities	Geometric Decay
1997	Georgia	PEG personnel[1]	Utility	US Gas Utilities	Geometric Decay
1998	California	PEG personnel[1]	Utility	US Gas Utilities	Geometric Decay
1999	Ontario	Christensen Associates	Utility	Company-specific	Geometric Decay
2002	California	PEG	Utility	US Gas Utilities	Geometric Decay
2003	Massachusetts	PEG	Utility	Northeast Gas Distributors	Geometric Decay
2004	California	PEG	Utility	US Gas Utilities	Geometric Decay
2006	California	PEG	Utility	US Gas Utilities	Geometric Decay
2007	Ontario	PEG	Regulator	US Gas Utilities	Cost of Service & Geometric Decay
2010	California	PEG	Utility	US Gas Utilities	Geometric Decay
2011	Quebec	PEG	Utility and Consumer Adv	US Gas Utilities	Cost of Service
2011	Ontario	PEG	Regulator	Gas Utilities	Cost of Service
2012	Quebec	PEG	Utility	US Gas Utilities	Cost of Service
2013	British Columbia	PEG	Consumer Advocate	US Gas Utilities	Cost of Service
2013	British Columbia	Black & Veatch	Utility	US Gas Utilities	Kahn Variant
2013	Ontario	Concentric Energy Advisors	Utility	US Gas Utilities	Geometric Decay
2018	Ontario	PEG	Regulator	US Gas Utilities	Geometric Decay
2019	Massachusetts	LEI	Utility	US Gas Distributors	One Hoss Shay
2020	Massachusetts	PEG	Attorney General	US Gas Distributors	One Hoss Shay
2020	Massachusetts	Christensen Associates	Utility	US Gas Distributors	One Hoss Shay
2022	Ontario	Black & Veatch	Utility	US Gas Distributors	Hyperbolic Decay

Oil Pipeline Industry Studies

Year	Jurisdiction	Author	Client	Industry Studied	Capital Cost Specification
1993	US	Klick	Utility	US Oil Pipelines	Kahn Method
1993	US	NERA	Consumers	US Oil Pipelines	Kahn Method
2000	US	FERC Staff	Regulator	US Oil Pipelines	Kahn Method
2000	US	NERA	Utility	US Oil Pipelines	Kahn Method
2000	US	Shippers	Consumers	US Oil Pipelines	Kahn Method
2005	US	Innovation and Information Consultants	Consumers	US Oil Pipelines	Kahn Method
2005	US	NERA	Utility	US Oil Pipelines	Kahn Method
2010	US	NERA	Utility	US Oil Pipelines	Kahn Method
2010	US	Brattle	Consumers	US Oil Pipelines	Kahn Method
2015	US	FERC Staff	Regulator	US Oil Pipelines	Kahn Method
2015	US	NERA	Utility	US Oil Pipelines	Kahn Method
2015	US	Brattle	Consumers	US Oil Pipelines	Kahn Method
2020	US	FERC Staff	Regulator	US Oil Pipelines	Kahn Method
2020	US	NERA	Utilities	US Oil Pipelines	Kahn Method
2020	US	Brattle	Consumers	US Oil Pipelines	Kahn Method

[1] Economists now affiliated with PEG prepared these studies when they worked for Christensen Associates.

research and testimony due in part to the DPU's stance and in part due to budgetary limitations.

Conclusions

The cost-of-service capital cost specification has many advantages in X factor studies. However, the math is complicated, and the assumption of historical plant valuations is not ideal for a benchmarking study. Hyperbolic decay may make the most sense for benchmarking, but its use in utility applications has not been widespread. Geometric decay is a serviceable alternative for both X factor research and benchmarking, especially in Canada where inflation differentials have not been a major issue.

3. Stretch Factors

3.1. Rationale

The stretch factor term of a rate or revenue cap index should reflect an expectation of how the productivity growth of the utility that will be operating under PBR (the "subject utility") will differ from the productivity trend of the peer group. This depends in part on how the performance incentives generated by PBR --- its incentive "power" --- differ from that generated by the regulatory systems of utilities in the productivity research sample.

The difference between the productivity trend of the peer group and subject utility also depends on the utility's operating efficiency at the start of the MRP. Prior operation under one or more MRPs with strong incentive power encourages the elimination of inefficiencies. However, the productivity trend of the utility is likely to remain elevated compared to that of the industry after one or two plans. To understand why, consider first that there is no guarantee that a utility will, after operating under one or two MRPs, exhaust the inefficiencies that they can *immediately* address, for several reasons.

- The extent of inefficiencies that can be immediately addressed at the start of PBR varies between utilities. It is harder to eliminate all of them in one or two plans the larger was the initial inefficiency.
- The Alberta DFOs have only experienced one term of relatively strong capex containment incentives.
- While large efficiency gains are sometimes observed in a short period of time in businesses operating in unregulated markets, it should be remembered that the incentives generated by an MRP are typically much weaker than those in unregulated markets. Even if an MRP has no earnings sharing, for example, the full benefits of any lasting efficiency gains that are achieved are likely to be passed through to customers at the next rebasing. The incentive to improve efficiency is especially weak in the later years of the plan. Since performance improvements often entail up-front costs, these costs may not be fully recovered if undertaken in later plan years. Thus, many efficiency improvement projects become uneconomic these years.

Consider next that some of the inefficiencies a utility has cannot be addressed immediately. Here are some examples.

- Utility plant that is excessively costly may not merit replacement for many years.
- After two terms of PBR, the subject utility will still be presented with a continuing sequence of new cost management challenges and its response to these challenges will continue to be influenced by its incentives. One salient issue is how the utility handles the steady succession of new asset cohorts approaching replacement age.[46] Another salient issue is how the utility responds to new industry developments such as new technologies. An example here is the opportunity to use AMI to implement time-sensitive pricing that could slow the need for additional distribution capacity.

Consider also that strong incentives don't guarantee good performance. Companies in unregulated markets, for instance, experience continually strong incentives to contain cost but nonetheless have varied efficiency levels. Many businesses in these markets fail every year. Analogously, all professional hockey players in the NHL have strong incentives to perform well but their performances nonetheless vary widely.

A stretch factor can also be warranted for reasons other than an expectation that the productivity growth of the subject utility will exceed the industry norm in the next plan. Here are some additional rationales.

- Utilities operating under MRPs are incented to defer certain costs until the next rate case. A stretch factor is one means of sharing the benefits of these deferrals to customers.
- A stretch factor can also be warranted to address overcompensation concerns (e.g., the sharing of O&M cost savings) which result from supplemental capex funding but are difficult to measure accurately.
- Stretch factors linked to benchmarking studies can strengthen cost containment incentives. We discuss this option further in the next section.

[46] It is notable in this regard that Alberta utilities and their expert witnesses have argued that stretch factors should apply only in a first-generation MRP while also arguing that supplemental capex funding should be available in every plan.

3.2. Role of Benchmarking

We noted in Section 2.3 above that utility operating efficiency is sometimes assessed in utility rate proceedings using statistical benchmarking. The methods used in these studies run the gamut from simple unit cost metrics to econometric modelling and data envelopment analysis. Benchmarking studies may focus on a utility's recent historical costs and/or on its forecasted/proposed future costs (e.g., its forward test year revenue requirement).

Since the likelihood of productivity growth exceeding the industry trend depends in part on current operating efficiency, statistical benchmarking studies can inform the selection of stretch factors. In succeeding MRPs, a linkage of the stretch factor to statistical benchmarking of the utility's forward test year cost proposal can also serve as an efficiency carryover mechanism that rewards the utility for achieving lasting performance gains and can penalize the utility for not doing so.

3.3. Notable Stretch Factor Precedents Outside Alberta

Ontario

The Ontario Energy Board is now in its fourth generation of PBR for jurisdictional power distributors. PBR is also used for gas and power transmission utilities. In each generation, PBR has taken the form of MRPs with rate or revenue cap indexes. In both the third and fourth generation plans, the X factor term in the formulas for these indexes has been the sum of a base TFP growth target and a stretch factor that is linked to statistical benchmarking.

In the current generation of PBR, most power distributors operate under a generic approach called the 4th Generation Incentive Ratemaking Mechanism ("4th GIRM"). This is an MRP with a price cap index. The stretch factors vary between utilities and over time with the outcome of annual benchmarking exercises that use an econometric total cost model. This model was developed by PEG using Ontario data.

Each distributor's stretch factor depends on its average econometric benchmarking score over the three most recent years. As detailed in the figure below, the best cost performers get a stretch factor of zero while the worst get a stretch factor of 0.60%.[47] Additionally, distributors are required to use the Board's econometric model to benchmark their forward test year cost proposals in rate cases.[48]

Ontario Energy Board Stretch Factor Assignments

Cost Performance in Econometric Model	Assigned Stretch Factor
Actual costs 25% or more below model's prediction	0.00%
Actual costs 10-25% below model's prediction	0.15%
Actual costs within +/-10% of model's prediction	0.30%
Actual costs 10-25% above model's prediction	0.45%
Actual Costs 25% or more above model's prediction	0.60%

The OEB explained why it continues to include stretch factors in MRPs in a decision on 4th GIRM, stating that:

> The Board believes that stretch factors continue to be required and is not persuaded by arguments that stretch factors are only warranted immediately after distributors switch from years of cost of service regulation to [MRPs]. Stretch factors promote, recognize and reward distributors for efficiency improvements relative to the expected sector productivity trend. Consequently, stretch factors continue to have an important role in [MRPs] plans after distributors move from cost of service regulation.[49]

Note the emphasis placed on performance incentives as a benefit of stretch factors.

Larger Ontario power distributors, along with the largest power transmitter in the province, operate under an alternative approach to PBR called Custom Incentive Ratemaking. This approach also features MRPs with rate or revenue cap indexes that have formulas with X factors. Custom IR stretch factors are typically linked to custom econometric benchmarking studies that use transnational

[47] Ontario Energy Board (2013), *EB-2010-0379 Report of the Board Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, p. 21.

[48] Ibid, pp. 19-20.

[49] Ontario Energy Board, *EB-2010-0379, Report of the Board Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, issued on November 21, 2013 and as corrected on December 4, 2013, p. 18-19.

(specifically U.S. and Ontario) data. The current stretch factor of Toronto Hydro is 0.6%, while that of Hydro Ottawa is 0.45% and that for power distributor services of Hydro One is 0.45%.[50]

British Columbia

FortisBC Energy (formerly Terasen Gas) and FortisBC (formerly West Kootenay Power) are gas and electric utilities, respectively, in British Columbia. Both had previously operated under multiple MRPs before the commission approved new MRPs in 2014. The British Columbia Utilities Commission ("BCUC") approved stretch factors of 0.20% for FortisBC Energy Inc. and 0.10% for FortisBC.[51] No benchmarking studies were performed.

In this decision, the BCUC also endorsed the possibility of including stretch factors in future generations of MRPs that are based on benchmarking evidence. The commission stated that there was

> a lack of evidence as to the efficiency of Fortis' operations relative to other utilities. This information would be helpful in making a determination on a stretch factor. A benchmarking study would provide the Commission with information on the utilities' efficiency relative to other utilities. While there is no such study available at this time, the Panel considers that it would be useful to have one completed prior to the application for the next phase of the PBR. **Accordingly, the Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018.**[52] [Emphasis in original]

Massachusetts

The Massachusetts Department of Public Utilities ("DPU") has considered statistical benchmarking studies to set the stretch factor in several MRP proceedings. These studies have used a mix of benchmarking methods that include unit cost metrics and econometric modelling. Several utilities have voluntarily provided econometric benchmarking studies.

In its approval of the current MRP for National Grid's Massachusetts power distributors, the DPU agreed to tie the stretch factor to performance in annual benchmarking studies. The magnitude of

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[50] Ontario Energy Board (2019), Decision and Order in EB-2018-0165, December 19, p. 40; Ontario Energy Board (2020), Decision and Order in EB-2019-0261, pp. 6-12; and Ontario Energy Board (2022) , Decision on Settlement Proposal and Order on Rates, Revenue Requirement and Charge Determinants, EB-2021-0110, Schedule A, p. 8.

[51] BCUC (2014), *Decision,* In the Matter of FortisBC Energy Inc. Multi-Year Performance Based Ratemaking Plan for 2014 Through 2018, p. 86 and *Decision,* In the Matter of FortisBC Inc. Multi-Year Performance Based Ratemaking Plan for 2014 Through 2018, p. 83.

[52] BCUC (2014), *Decision,* In the Matter of FortisBC Energy Inc. Multi-Year Performance Based Ratemaking Plan for 2014 Through 2018, p. 86 and British Columbia Utilities Commission (2014).

the stretch factor would change annually based on the company's performance in unit cost and productivity benchmarking studies compared to a national sample, as well as the growth of inflation. The schedule of benchmarking results and stretch factors is provided in the figure below.

Determination of Consumer Dividend ("CD") in the National Grid (MA) PBR Adjustment Formula[1]

The Company shall determine the value of the CD to be applied in the PBR Adjustment Formula as follows:

Performance Category	Company's Updated Unit Cost	Company's Updated TFP	Potential CD for Formula	CD if GDPPI ≤ 1%	CD if 1%< GDPPI >2%	CD if GDPPI ≥ 2%
All Unit Cost and TFP (Total Factor Productivity) percentages are in relation to the NA (National Average).						
Superior	≥ 18% below NA	≥ 21% above NA	0.25	0.00	0.125	0.25
Above-Average	>6% and <18% below NA	>7% and <21% above NA	0.33	0.00	0.165	0.33
Average	6% below to 6% above NA	<7% above to <7% below NA	0.40	0.00	0.20	0.40
Below-Average	>6% and <18% above NA	≥ 7% below NA	0.48	0.00	0.24	0.48
Poor	>18% above NA	>21% below NA	0.55	0.00	0.275	0.55

Beginning with the PBR Year ending September 2021, the CD shall be adjusted annually based on the Company's unit cost and Total Factor Productivity ("TFP") relative to the unit cost and TFP averages of the sample of 66 electric distribution companies used in D.P.U. 18-150 ("National Average" or "NA"), or as otherwise determined by the Department.

The annual adjustment to CD shall occur based upon the Company's updated unit cost and updated TFP measured against the thresholds identified above, using a three-year rolling average of data from the national sample of utilities, as available, known as the National Averages. If the thresholds in the same Performance Categories are not both met as shown above, the applicable PBR Year's Potential CD will be determined at the average of the two categories.

[1]National Grid USA Service Company, October 1, 2019. Massachusetts Electric Company & Nantucket Electric Company Performance-Based Ratemaking Provision. M.D.P.U. No. 1423, pages 4 and 5.

Québec

Hydro-Québec Transmission is operating under its first term of *reglementation incitatif.* Escalation of its O&M revenue is indexed. The Régie de l'énergie assigned it a standard stretch factor at the outset of the plan that was not based on benchmarking evidence. During the plan, the Régie convened a proceeding to consider statistical benchmarking studies that would inform its decision concerning the value of the stretch factor in the last plan year and in any subsequent plan.

Other Jurisdictions

Many MRPs, including most established through settlements, do not itemize the components of the X factor and thus do not indicate whether a stretch factor is included. This likely includes some second generation or later MRPs which had previously included an explicit stretch factor. The three approved price cap plans of Central Maine Power ("CMP") were all resolved with Commission-approved settlements. These settlements set a value for the overall X factor, referred to in Maine as a productivity offset, without identifying the specific value for a productivity stretch factor or any other components of an X factor. Nevertheless, stretch factors were frequently discussed in the Maine proceedings. In the proceeding leading to the most recently-approved price cap plan for CMP, Dr. Lowry, as a witness for the company, recommended a stretch factor of 0.4%.

Telecommunications

Telecommunications precedents are also of interest. While PEG has never done a full survey of telecom PBR precedents, some second-generation stretch factors were identified with very little work. Here are some examples.

- The U.S. Federal Communications Commission approved stretch factors in second-generation MRPs for AT&T and the interstate services of incumbent local exchange carriers.[53]
- The Illinois Commerce Commission approved a second-generation stretch factor in 2002 for Ameritech Illinois ("AI"), formerly Illinois Bell, a large local exchange carrier. The Commission stated in its decision that

> AI in its Briefs seems to suggest that under the Plan, ratepayers were only to receive a consumer dividend for the first term of the plan. The implication therefore is that once the original term of the plan expired, so too would the consumer dividend. We reject this implication. Ratepayers are to receive the first cut from any improvements which arise from technological and regulatory change under the original term of the Plan and just as importantly any modification or extension thereof.[54]

3.4. Incentive Power Research

In response to an information request from the Brattle Group in the PBR1 proceeding, PEG presented results of some research on the incentive power of alternative stylized regulatory systems.[55] This research was funded over several years by various clients that included the Ontario Energy Board

[53] Federal Communications Commission, FCC 93-326, Report Adopted June 24, 1993 in CC Docket 92-134. Federal Communications Commission, FCC 97-159, Fourth Report and Order Adopted May 7, 1997, in CC Dockets, 94-1 and 96-262. The latter decision was subsequently overturned by the US Court of Appeals for the District of Columbia Circuit in 1999.

[54] December 30, 2002 order in Illinois Commerce Commission case 00-0764, p. 100.

[55] AUC Proceeding 566, ATCO-CCA-59

and natural gas utilities. Results of this research have since been reported in a white paper on PBR which was published by Lawrence Berkeley National Laboratory.[56]

The research considered a hypothetical energy distributor that had opportunities to improve its performance. We then considered what strategy was optimal for the company under various stylized regulatory systems. The model was calibrated at a time when the typical productivity growth of energy distributors was more rapid than that achieved currently. However, we believe that results as to how performance gains differ under alternative regulatory systems are still meaningful.

Our research revealed that the incentive power of regulatory systems is increased by well-designed efficiency carryovers and less frequent rate cases and reduced by earnings sharing mechanisms. We can use this research to consider how the incentive power of the regulatory systems of utilities in our productivity study compares to that which is likely under PBR3.

Based on my experience, I believe that U.S. energy distributors typically hold rate cases about every three years. Earnings sharing mechanisms are uncommon inasmuch as MRPs are uncommon. Assuming a normal level of operating efficiency,[57] our incentive power model indicated that an MRP with a five-year rate case cycle would generate 51 basis points of additional average annual performance gains in the long run compared to a three-year rate case cycle. Thus, utilities under PBR3 that have average operating efficiency are expected to have average annual performance gains that exceed the industry norm by 51 basis points. Half of 51 basis points is about 26 basis points. This suggests that stretch factors for a utility with normal efficiency should lie in a range between 26 and 51 basis points.

For a utility with *high* operating efficiency,[58] PEG's incentive power model indicates that MRPs with a five-year rate case cycle and no ESM would yield ~~25~~ 39 extra basis points of average annual

[56] Mark Newton Lowry, J. Deason, and Matthew Makos, "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," Lawrence Berkeley National Laboratory, July 2017.

[57] We assumed that a utility with normal operating efficiency had 30% initial inefficiency compared to the production frontier. This assumption reflects our finding, over many benchmarking studies, that the best performers in the studies usually have a cost that is at least 30% below the average over a period of 3 years.

[58] We assumed on the same basis that a utility with high operating efficiency had 10% initial inefficiency compared to the production frontier.

performance gains. Half of ~~25~~ 39 basis points is about ~~13~~ 20 basis points. This suggests a [~~13~~20,~~25~~39] basis point range of reasonableness for the stretch factors of efficient utilities.

For a utility with *low* operating efficiency, our incentive power model indicates that MRPs with a five-year rate case cycle and no ESM should typically yield 60 basis points of additional average annual performance gains. Half of 60 is thirty basis points. This suggests a [30,60] basis point range of reasonableness for the stretch factors of inefficient utilities.

3.5. Relevant Empirical Power Research

In the Berkeley Lab project, PEG also did some empirical research to measure the impact of MRPs and extended rate stay outs on the productivity growth of U.S. electric utilities in the provision of distributor services. We found that the total factor productivity trend of utilities operating under MRPs and extended rate case stay outs exceeded the sample norm by 22 basis points. This difference was statistically significant.[59]

[59] Lowry, et. al., op cit. p. 79.

4. A Brief History of Alberta X Factors

4.1. First Generic PBR Proceeding

On September 12, 2012 the AUC approved its first generic PBR plan for Alberta energy distributors. During this plan, power distributors operated under price cap indexes with general formula

*growth Rates = Inflation * (1 + I – X) +/- Other Adjustments*

while gas distributors operated under revenue-per customer caps with general formula

*growth Revenue/Customer = Inflation * (1 + I – X) +/- Other Adjustments.*

In both formulas, the X factor was the sum of a common base TFP growth target and stretch factor. The Commission decided to use the "long-term productivity growth of the industry in question" as the base TFP growth target.[60]

The NERA study that the AUC commissioned pertained to power distribution productivity. Drs. Jeffrey Makholm and Agustin Ros were NERA's study team. PEG, working for the CCA, undertook research and testimony on productivity trends of U.S. gas distributors.

NERA calculated the power distribution TFP of 72 U.S. electric utilities over a 1972-2009 sample period. TFP growth averaged 0.96% over this lengthy period. Utility witnesses proposed to base X on results from NERA's study over truncated, more recent sample periods during which TFP growth had a markedly negative trend. The Commission agreed with "NERA's view that using the longest time period for which data are available is theoretically sound and represents the most objective basis for the TFP calculation."[61]

Some parties to the proceeding favored TFP growth targets that were more customized to Alberta business conditions. The Commission ruled that "the TFP estimate that informs the X factor is supposed to reflect industry growth trends, not the trends in Alberta alone or among a group of companies with similar operations and cost levels to those in Alberta."[62] However, we showed in Section 2.1 that drivers of productivity *growth* can be identified using mathematical theory and

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[60] AUC Decision 2012-237, September 12, 2012, p. 60.

[61] Ibid, p. 67.

[62] Ibid, p. 70.

empirical research and these drivers can vary between utilities. An example is customer growth, which provides opportunities to realize scale economies.

With respect to the best measure of output to use in the TFP research the AUC stated that "[it] agrees with NERA's and PEG's view that when selecting a particular output measure, it must be matched to the type (price cap or revenue-per-customer cap) of a PBR plan"[63] and that "[it] agrees with Dr. Lowry and his colleagues at PEG that for revenue-per-customer cap plans, the number of customers, rather than a volumetric output measure, is the correct output measure for a TFP study" whereas the "kWh sold output measure used by NERA in its TFP study remains an acceptable output measure to use for the purpose of the price cap PBR plans approved for ATCO Electric, Fortis and EPCOR."[64] However, Alberta gas and electric DFOs have high fixed charges that reduce the relevance of volume trends in X factor research.

The Commission chose NERA's *power* distribution TFP productivity trend for its full sample period to apply to *gas* distributors instead of alternative productivity results for gas distributors prepared by PEG which were based on a shorter sample period and used the number of customers served as the output metric. The Commission explained that

> NERA's study is preferable to use in this proceeding given the objectivity and transparency of the data and of the methodology used, the use of data over the longest time period available and the broad based inclusion of electric distribution companies from the United States.

Regarding the fact that most capital revenue would effectively not be indexed due to capital cost trackers, the Commission found that it

> agrees in principle with the CCA's and the UCA's view that because NERA's study measures changes in output compared to changes in all of the companies' inputs (that is, labour, materials and capital), NERA's TFP estimate may not be precisely applicable to PBR plans that exclude all or a part of capital from the application of the I-X mechanism.[65]

However, it made no such adjustment, being unsure about a suitable method for doing so.

As for the stretch factor, the AUC stated that

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[63] Ibid, p. 82.

[64] Ibid.

[65] Ibid, p. 96.

> The purpose of a stretch factor is to share between the companies and customers the *immediate expected increase* in productivity growth as companies transition from cost of service regulation to a PBR regime. [italics added][66]

The CCA, Fortis, and Brattle all took the view that the need for a stretch factor is greater the greater is the operating inefficiency of the Company.[67] However, the AUC eschewed the use of benchmarking to set the stretch factor, stating on the same page that

> the Commission does not wish to engage in this type of analysis for the purposes of PBR in Alberta because of the practical and theoretical problems associated with comparing efficiency levels among companies. Therefore, the Commission did not include the consideration of the companies' comparative levels of efficiency in its determination on the need for a stretch factor.

The Commission ultimately chose a 0.20% stretch factor for all distributors subject to PBR1. The X factor (TFP + Stretch factor) for these distributors was thus 1.16%.

4.2. Second Generic PBR Proceeding

In its PBR2 proceeding the Commission once again approved price cap indexes for power distributors and revenue/customer indexes for gas distributors. The formulas for these indexes once again included an X factor.

NERA did not present productivity evidence in this proceeding. On behalf of utility clients, the Brattle Group ("Brattle") and Laurits R Christensen Associates ("LRCA") recommended materially negative TFP growth targets based on updates of NERA's study and truncated, more recent sample periods. PEG presented an alternative power distribution productivity study that also used a comparatively short and recent sample period but yielded a 0.43% TFP trend over the full eighteen-year sample period.

Controversy arose in the proceeding over various issues in the methodology for calculating TFP trends. PEG, for example, questioned the suitability of NERA's simple one hoss shay capital cost specification with its low, fixed average service life, to measure recent TFP trends, its exclusion of administrative and general ("A&G") and customer account expenses from its calculations, its volumetric output index, and its focus on results for a national peer group. All of these features of NERA's

[66] Ibid, p. 100.

[67] Brattle nonetheless claimed that stretch factors were not warranted due to the strong performance incentives generated by the prior ratemaking regime, which featured frequent rate cases.

methodology were defended by Brattle and LRCA. The Commission expressed agnosticism concerning most of these issues, stating that

> there is no overwhelming new evidence in this proceeding that any of these particular assumptions are correct or incorrect… For this aspect of the analysis, the Commission is, therefore, unwilling to specify a preference for the set of assumptions used by any particular one of the three TFP growth studies.[68]

In the same spirit, the AUC said that

> the Commission views the variety of results that have been provided as confirming that the TFP growth value is likely not a correct single number, but that a reasonable value likely falls within a range of values, demarcated by the breadth of assumptions and data sets that may be reasonably employed in producing the studies.[69]

The AUC did not discuss in its decision empirical evidence on limitations of NERA's methods which PEG submitted in rebuttal testimony, shortly before oral testimony began. In a subsequent decision, the AUC denied funding for this work, explaining that "because working papers were not provided,… the Commission was not able to assess the probative value of the information provided."[70]

The Commission did not state a preference between a customer-based and volume-based output indexes. However, it expressed a preference for sensitivity analyses on this matter in future filings.[71]

The AUC once again balked at the customization of TFP trend studies to reflect Alberta business conditions, stating that

> Customization of TFP growth studies introduces a level of subjectivity that may obscure the objectivity and transparency of the TFP growth value that would result without the customization, unless the results are provided both with and without any added customizations.[72]

The Commission further stated that

> a key reason for implementing PBR for the distribution utilities in Alberta was a desire to ensure that the decision making and outcomes achieved by regulated distribution utilities emulated, to

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[68] AUC Decision 20414-D01-2016, December 16, 2016, p. 30.

[69] Ibid, p. 40.

[70] AUC Decision 22082-D01-2017, February 6, 2017, p. 9.

[71] Ibid, p. 33.

[72] Ibid, p. 26.

> the extent possible, the decision making and outcomes that would have arisen had decision makers in those firms been subject to the incentives found in competitive markets… in general, it is likely that in competitive markets, there is a variety of factors that influence the ability of firms operating in that market to achieve TFP gains. Since the design of the PBR plan for Alberta is meant to emulate these aspects of competitive markets, this suggests that it is preferable to use broad samples that will embody variation in more of the characteristics that influence productivity, as would be found in a competitive market. Accordingly, although the Commission considers that subsamples selected on a single criterion can provide useful information, analysis using the full sample, or possibly subsamples selected on multiple criteria, will better inform the Commission's judgement as to the possible range of TFP growth values that are reflective of competitive markets.[73]

However, some markets are inherently local in character, and energy distribution is closer to the sand and gravel end of the spectrum than to the video streaming end.

As for the stretch factor, the Commission reiterated its view that the purpose of the stretch factor is to share *initial* productivity gains from operation under PBR, stating that

> the stretch factor can be viewed as sharing with customers the expected additional cost reductions that result from the move from a low-incentive regime such as COS regulation to a higher-incentive regime such as PBR. For this reason, stretch factors are common in first-generation PBR plans.[74]

A stretch factor was deemed to be warranted in PBR2 mainly because the Commission replaced expansive use of capital cost trackers with a new K bar approach to providing capital cost funding which it hoped would be more incentivizing. The AUC contested the view that a stretch factor influenced performance incentives.[75]

The AUC ultimately chose a 0.30% X factor for all PBR2 distributors. A stretch factor is included in the 0.30% but was not itemized. In arriving at this figure, the Commission gave equal weight to results from PEG's study and from the Brattle study for both their truncated and full sample periods. This decision is remarkable insofar as most of the productivity trend calculations that the AUC deemed relevant were for a recent sample period whereas the AUC had previously placed major emphasis on NERA's use of a lengthy sample period as being a more objective methodology.

[73] Ibid, pp. 28-29.

[74] Ibid, p. 38.

[75] Ibid, pp. 38-39.

4.3. Where Are They Now?

Later research and testimony by some witnesses in Alberta's prior generic PBR proceedings merit brief note.

- As discussed further in Section 5, Jeff Makholm updated his U.S. power distribution TFP study in 2018 Ontario evidence that he provided as a witness for two large gas utilities that were merging into an entity that was then called "Amalco," and is now known as Enbridge Gas.[76]
- Dr. Meitzen's advocacy of markedly negative TFP growth targets caught the attention of Massachusetts energy distributors that were then contemplating a resumption of PBR after a hiatus of many years. In his first Massachusetts testimony, where he worked for a power distributor, Dr. Meitzen changed his output index from volumes to the number of customers.[77]
- In three Massachusetts proceedings in which he worked for utilities since the PBR2 proceeding, Dr. Meitzen added customer care and A&G expenses to his distributor TFP calculations.[78]
- In recent TFP testimony for a Massachusetts gas distributor, Dr. Meitzen recommended basing X on the TFP trend of a *northeastern* rather than a *national* U.S. peer group.[79]
- In his most recent power distribution TFP research and testimony in Massachusetts, Dr. Meitzen used a hyperbolic decay ("HD") capital cost specification instead of one-hoss shay. Dr. Meitzen reported a slightly positive 0.06% TFP trend over the most recent fifteen years (as he counts them) for the national sample.[80]

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[76] Ontario Energy Board Case EB-2017-0307, Exhibit B, Tab 2.

[77] Massachusetts Department of Public Utilities, D.P.U. 17-05, Exhibit ES-PBRM-1, pp. 68-69.

[78] Massachusetts Department of Public Utilities, D.P.U. 18-150, Exhibit NG-MEM-1, p. 30-32; Massachusetts Department of Public Utilities, D.P.U. 22-22, Exhibit ES-PBR/TFP-1, pp. 16; and Massachusetts Department of Public Utilities, D.P.U. 20-120, Exhibit NG-MEM/NAC-1, Appendix A, pp. 6-8.

[79] Massachusetts Department of Public Utilities, D.P.U. 20-120, Exhibit NG-MEM/NAC-1, pp. 32-36.

[80] Massachusetts Department of Public Utilities, D.P.U. 22-22, Exhibit ES-PBR/TFP-1, pp. 21.

- Reviewing the results of these LRCA studies in Table 2 for the common 2007-2014 period is informative. In each of his Massachusetts TFP studies, Dr. Meitzen made changes that accelerated the TFP trend. His results from the prior Alberta proceeding, using a OHS capital cost specification, volumetric output index, and excluding A&G and customer care expenses resulted in an average TFP trend of -1.76% for the common period. His first Massachusetts study for Eversource Energy switched the output measure to customers, accelerating the TFP trend for this period to -0.67% annually. In his next Massachusetts study, for National Grid, he kept customers as the output and incorporated A&G and customer care expenses, which resulted in an average TFP trend of 0.55% for these years. His most recent study, for Eversource Energy, featuring an HD capital cost specification, A&G and customer care expenses, and customers as the output measure increased the TFP trend in the 2007-2014 period by 10 basis points, to 0.65% per year.

- Dr. Agustin Ros, now with the Brattle Group, provided transmission productivity research and testimony on behalf of Hydro-Québec in a PBR proceeding.[81] In that proceeding he advocated use of a long sample period.[82]

> I recommend the use of a long-term trend because I'm interested in the long-term X-Factor. It's the long-term that provides the incentive properties of zero economic profits. So I like to use a long-term estimate of what total factor productivity is.

- PEG has presented X factor and benchmarking evidence in several Ontario proceedings, two Massachusetts proceedings, and a Québec proceeding. In a recent Ontario proceeding to develop new MRPs for the transmission and distribution services of Hydro One Networks, Dr. Lowry filed a Joint Report with the Hydro One expert witness which featured consensus empirical results.

[81] Régie de l'énergie, Demande R-4167-2021, HQT-5, document 2.

[82] Régie de l'énergie, Demande R-4167-2021, Notes sténographiques de l'audience du 13 décembre 2021 par visioconférence - Volume 3, pp. 51-53.

Table 2

TFP Trends in Recent LRCA Studies

Consultant	LRCA	LRCA	LRCA	LRCA
Client	EPCOR[1]	Eversource[2]	National Grid[3]	Eversource[4]
Jurisdiction	Alberta	Mass	Mass	Mass
Industry	Power Dx	Power Dx	Power Dx	Power Dx
Capital Cost Specification	OHS	OHS	OHS	HD
Output Specification	Volumes	Customers	Customers	Customers
Customer Care & A&G Included?	No	No	Yes	Yes
Even- or Size-Weighting	Size	Size	Size	Size
Year Submitted	2016	2017	2018	2022
2000	2.04%			
2001	-3.24%			
2002	1.84%	-0.09%		
2003	-2.14%	-2.08%	-2.32%	
2004	3.02%	1.86%	3.34%	
2005	2.24%	0.14%	-0.17%	
2006	-2.17%	-0.99%	-6.42%	
2007	0.46%	-0.37%	5.69%	3.63%
2008	-4.36%	-2.28%	0.68%	1.33%
2009	-3.74%	1.95%	-1.06%	-0.29%
2010	1.68%	-2.16%	-2.40%	-1.54%
2011	-3.86%	-1.93%	-1.10%	-1.41%
2012	-1.98%	0.61%	-0.91%	-0.20%
2013	-0.60%	-0.15%	3.01%	3.04%
2014	-1.66%	-1.04%	0.46%	0.61%
2015		0.15%	0.64%	1.31%
2016			-1.26%	-0.75%
2017				-2.06%
2018				0.09%
2019				-0.08%
2020				-2.89%
Averages				
2001-2014 (14 years)	**-1.04%**	NA	NA	NA
2002-2015 (14 years)	NA	**-0.46%**	NA	NA
2003-2016 (14 years)	NA	NA	**-0.13%**	NA
2007-2020 (14 years)	NA	NA	NA	**0.06%**
2007-2014 (8 common years)	**-1.76%**	**-0.67%**	**0.55%**	**0.65%**

[1]EPCOR Distribution & Transmission Inc. Next Generation Performance-based Regulation Plan Submission, March 23, 2016

[2]Direct Testimony of Mark E. Meitzen on Behalf of NSTAR Electric Company and Western Massachusetts Electric Company Each d/b/a/ EVERSOURCE ENERGY, January 17, 2017

[3]Pre-filed Direct Testimony of Mark E. Meitzen, DPU 18-150, November 15, 2018

[4]Performance-Based Ratemaking Mechanism on Behalf of NSTAR Electric Company d/b/a/ Eversource Energy, January 14, 2022

PBR Review

In March 2021 the AUC established proceeding 26356 to evaluate Alberta's experience with PBR. After reviewing comments, the Commission in Decision 26356-D01-2021 opted for a third PBR term that will commence in 2024 following a cost of service rebasing year. In this decision, the AUC acknowledged that, while PBR in Alberta had satisfied many of the objectives that the Commission had earlier established for it, "there remain areas for improvement."[83] For example, "Future PBR plans should be more reflective of ongoing economic conditions."[84] The Commission also stated that sharing of benefits of a PBR plan between customers and utilities "is an area of universal concern that needs to be carefully assessed and factored into the design of future PBR plans."[85]

The Efficiency Issue

In the recent rebasing proceedings for ATCO Electric, FortisAlberta, ATCO Gas, and Apex Utilities (formerly Altagas), the AUC inquired as to how each company measures change in its efficiency over time. The distributors explained that they do not monitor the efficiencies gained from specific projects and initiatives undertaken. In appraising the response of ATCO Gas and Apex Utilities, the AUC concluded that

> what is clear from the record of this proceeding is that neither ATCO Gas nor Apex has a documented process to which it could point in evidence, for tracking whether the projected efficiencies or cost savings associated with a particular initiative were indeed realized. The Commission is not inclined, at this time, to require the utilities to begin tracking all individual initiatives and programs that may result in efficiencies and the associated cost savings. The Commission does, however, expect that quite apart from the regulatory process and the very fundamentals of a PBR regime, which are based on the ability of utilities to achieve efficiency gains over time, the utilities can and should be tracking and measuring whether the programs and large-scale initiatives that they implement are achieving the intended goals, including efficiency gains and related cost savings.
>
> To avoid similar challenges in identifying the achieved efficiencies and calculating the realized savings at the next rebasing, the Commission directs ATCO Gas and Apex to present proposals in Proceeding 27388 where the parameters for PBR3 plans will be set, on how efficiencies can be effectively quantified and tracked over time. ATCO Gas provided examples of some possible forward-looking productivity and/or efficiency measures, including: (i) O&M per customer; (ii)

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[83] AUC Decision 26356-D01-2021, p. 1.

[84] Ibid, p. 21.

[85] Ibid, p. 1.

O&M per kilometre (km) of line; and (iii) O&M per GJ delivered. ATCO Gas emphasized the importance of service quality measures.[86]

In other proceedings, the AUC similarly ordered ATCO Electric and FortisAlberta to present proposals to quantify and track efficiency gains in the PBR proceeding.[87]

In May 2022, the Commission initiated Proceeding 27388 to establish the parameters of PBR3. In a June 2022 letter, the AUC invited comments on the appropriate list of PBR parameters to revisit in this proceeding. A final issues list was released in September 2022 and included the following salient issues, with the number that the Commission assigned to them.

2) Revenue caps vs. price caps

3) I factor

4) X Factor (base productivity trend and stretch factor)

5) Quantification and tracking of efficiencies

This review of the record prompts us to make several comments about the empirical research that is warranted in this proceeding.

- Given the lively controversy about base productivity trends and stretch factors in past Alberta PBR proceedings, and the tendency of utility witnesses to take markedly pro-utility views on both issues, it is desirable for an Alberta consumer group to sponsor an independent study of U.S. energy distributor productivity trends.
- Given the Commission's past preference for power distribution productivity research, the focus of U.S. productivity trend research in this proceeding should be power distributor productivity.
- This is a good time to start calculating the productivity trends of Alberta's PBR distributors and to start benchmarking the levels of their costs. Here are some reasons why.
    - Having measured the productivity trends of Alberta and U.S. power distributors, the incremental cost of a transnational cost level benchmarking study is reduced.

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[86] Alberta Utilities Commission Decision 26616-D01-2022, p. 21.

[87] EPCOR and ENMAX are not required to present these proposals.

- Benchmarking and productivity measurement using Alberta DFO data are both potentially useful for measuring efficiency gains that Alberta utilities have achieved under PBR and for analyzing the sources of their chronically high earnings. Benchmarking and Alberta productivity measurement are useful additions to the AUC's "dashboard" for monitoring the success of PBR and can inform plan design decisions. PBR3 is a good venue for "kicking the tires" of alternative efficiency research methods.
- The benchmarking studies can inform the selection of stretch factors. This can strengthen the utilities' cost containment incentives as well as helping to share plan benefits.
- Benchmarking is a useful complement for and not an alternative to traditional prudence reviews.
- Econometric benchmarking has matured to the point that econometric cost models have numerous business condition variables and are thereby less likely to markedly favor the interests of consumers or utilities.
- Alberta productivity trend studies can inform the choice of base productivity growth trends and shed light on the design of supplemental capex funding mechanisms.
- The studies can aid utilities in their cost management.
- The processed Alberta data will be available for benchmarking and productivity trend measurement in other jurisdictions (e.g. Ontario) where statistical cost research is used in ratemaking.

- The choice of a methodology for measuring the utility efficiency gains of Alberta distributors should not be left solely to utilities either. When asked their views on methods for measuring their efficiency, the utilities have thus far discussed only simple unit cost metrics that would have limited usefulness.

5. Constructively Critiquing NERA's Power Distribution Productivity Research

5.1. U.S. Power Distribution

To the best of our knowledge, NERA last updated their U.S. power distribution productivity study in 2017 evidence for two merging Ontario gas utilities. The merged entity, called "Amalco" at the time of the proceeding, is now called Enbridge Gas Inc. NERA calculated the TFP trend of 65 of U.S. utilities in the provision of power distribution services over the lengthy 1973-2016 sample period.[88] Like NERA's earlier Alberta study, the updated study found a materially *positive* power distribution productivity trend before 2000 and a materially *negative* trend after 2000. NERA witness Jeffrey Makholm reported a **0.54**% TFP trend over the full sample period he reported in his Ontario evidence.[89] While in Alberta and other proceedings he has argued in favor of calibrating X factors using the productivity trend for his *full* sample period, in Ontario he recommended basing X on a **0.0%** base TFP growth trend. He deemed this result appropriate for the amalgamated gas utility, stating in his direct testimony that, "The productivity of electric and gas distribution companies is similar."[90]

As a witness for OEB staff in this proceeding, PEG stated numerous concerns about NERA's research methods. To facilitate the AUC's review, we first discuss our major concerns before detailing some other concerns.

Major Concerns

Output Specification

One major concern was that NERA continued to measure output growth as a revenue-weighted average of the growth in sales volumes to different service classes. Recall from Section ~~3.1~~2.2 that this type of output index is not appropriate in a productivity study for an MRP with a revenue per customer index. Furthermore, Alberta's PBR3 distributors do not obtain much of their small-volume customer base rate revenue from volumetric charges.

[88] EB 2017-0307, Exhibit B, Tab 2, pp. 110 and 113.

[89] EB 2017-0307, Exhibit B, Tab 2, p. 113.

[90] Ibid., footnote 43, p. 24.

The output specification would matter less if trends in the volumetric index and the number of customers served by U.S. power distributors were similar. However, they were not. The difference between volume and customer growth is the growth of volume per customer (aka average use). This varied greatly for U.S. electric utilities over NERA's lengthy sample period. The average use of residential and commercial customers is particularly important in a power distribution productivity study.

NERA did not provide data on the number of customers served by the utilities in their sample. A possible reason is that these data are difficult (although not impossible) to obtain for their lengthy sample period. Thus, it is difficult to demonstrate the consequences of using their volumetric index without doing an alternative study or gathering extensive customer data for use with their other index formulae.

In the Amalco proceeding, PEG gathered the necessary average use data for the residential and commercial customers of the utilities in NERA's sample. Results are provided in Table 3 below. It can be seen that residential and commercial average use by customers of the utilities in NERA's sample averaged 1.6% annual *growth* from 1973 to 2000 but averaged a 0.3% annual *decline* from 2001 to 2016. Moreover, the decline in average use has accelerated since 2008. This is clearly a major reason for the slowing growth in NERA's TFP indexes after 2000 that utility witnesses have emphasized, but has limited relevance to the calibration of an X factor for a revenue per customer index or for utilities with high fixed charges.

Capital Cost Specification

We also have concerns about the simple one hoss shay approach that NERA used to measure capital cost. We discussed some *general* disadvantages of the OHS approach in Section 2.~~3~~ 5 above. Our emphasis here is that NERA's simple approach to executing OHS is inappropriate when the focus of research is on a truncation of its full sample period.

Since NERA did not itemize quantities of different kinds of distributor assets, their OHS approach is particularly sensitive to the ASL that they use to estimate the quantity of retirements. Recall from

Table 3

Comparison of Electric Utility Customer and Volume Trends[1,2]

	Average Volume Growth			Average Use Growth	
Year	Total Volume [A]	Residential and Commercial Volume [B]	Average Total Customer Growth [C]	Total Volumes [A-C]	Residential and Commercial Volumes [B-C]
1973	7.7%	7.7%	3.0%	4.7%	4.7%
1974	-0.1%	0.5%	2.5%	-2.6%	-2.0%
1975	1.1%	5.6%	1.7%	-0.6%	3.9%
1976	5.6%	3.5%	1.9%	3.7%	1.6%
1977	4.4%	5.0%	2.1%	2.4%	2.9%
1978	4.0%	3.8%	2.4%	1.6%	1.5%
1979	3.2%	2.5%	2.3%	0.9%	0.2%
1980	1.2%	3.7%	1.8%	-0.6%	1.9%
1981	1.1%	0.2%	1.4%	-0.3%	-1.2%
1982	-1.1%	2.4%	1.2%	-2.3%	1.2%
1983	3.0%	3.0%	1.4%	1.6%	1.6%
1984	4.9%	3.9%	1.5%	3.4%	2.4%
1985	1.7%	2.2%	1.8%	-0.1%	0.4%
1986	2.2%	3.8%	1.8%	0.4%	2.0%
1987	4.2%	4.3%	1.9%	2.3%	2.4%
1988	4.8%	5.6%	1.8%	3.0%	3.8%
1989	2.3%	1.9%	1.6%	0.7%	0.2%
1990	1.7%	2.3%	-0.2%	1.8%	2.5%
1991	2.2%	3.6%	1.3%	1.0%	2.3%
1992	0.0%	-1.2%	1.2%	-1.2%	-2.3%
1993	3.7%	5.2%	1.3%	2.4%	3.9%
1994	2.6%	2.7%	1.4%	1.2%	1.3%
1995	2.5%	4.2%	1.5%	1.0%	2.6%
1996	2.4%	2.7%	-0.1%	2.6%	2.9%
1997	1.1%	0.5%	1.3%	-0.2%	-0.8%
1998	2.7%	3.5%	1.3%	1.4%	2.2%
1999	1.8%	2.8%	3.7%	-1.9%	-0.9%
2000	3.4%	3.9%	1.3%	2.0%	2.6%
2001	-0.7%	1.1%	3.6%	-4.2%	-2.4%
2002	1.9%	4.2%	1.2%	0.7%	2.9%
2003	0.4%	0.5%	0.7%	-0.2%	-0.1%
2004	1.6%	1.0%	1.1%	0.5%	-0.2%
2005	2.4%	3.4%	1.4%	1.1%	2.1%
2006	-1.1%	-1.5%	0.3%	-1.4%	-1.8%
2007	3.1%	3.9%	0.9%	2.2%	2.9%
2008	-1.6%	-1.0%	0.7%	-2.2%	-1.7%
2009	-4.8%	-3.4%	0.2%	-5.0%	-3.6%
2010	3.8%	3.6%	0.5%	3.2%	3.1%
2011	-0.7%	-1.0%	0.4%	-1.1%	-1.3%
2012	-2.0%	-1.9%	0.5%	-2.4%	-2.4%
2013	0.6%	0.3%	0.6%	0.1%	-0.3%
2014	-0.3%	0.5%	0.6%	-0.9%	0.0%
2015	-0.7%	-0.6%	0.8%	-1.5%	-1.4%
2016	-0.5%	-0.1%	0.7%	-1.3%	-0.9%
Average Annual Growth Rates					
1973 - 2016	**1.7%**	**2.2%**	**1.4%**	**0.4%**	**0.9%**
1973 - 2000	**2.7%**	**3.2%**	**1.6%**	**1.0%**	**1.6%**
2001 - 2016	**0.1%**	**0.6%**	**0.9%**	**-0.8%**	**-0.3%**
2008 - 2016	**-0.7%**	**-0.4%**	**0.6%**	**-1.2%**	**-1.0%**

Notes

[1]All growth rates are calculated logarithmically. For example, growth rate of V = $\ln(V_t/V_{t-1})$.

[2]Average growth rates in a given year are the mean of the respective annual growth rates for all companies in NERA's sample for which plausible customer data are available.

Section 2.~~3~~ 5 above that ASL is especially important in OHS because it plays a key role in the quantity of retirements each year. The lower is the ASL, the smaller are retirements and the slower is TFP growth.

NERA assumed a 33-year ASL in all years of its lengthy sample period.[91] In response to an Ontario undertaking, NERA showed that this is the average ratio of power distribution gross plant value to power distribution depreciation expenses for a large sample of U.S. electric utilities from 1988 to 2009.[92] In order to test the reasonableness of this approach, for each company in NERA's sample PEG divided the end of year gross value of distribution plant by distribution depreciation expenses. We removed observations that were zero or negative, and then calculated the mean and standard deviation of the ASL estimate for all companies in a given year. We recalculated the mean average service life in each year by filtering out all observations that were more than two standard deviations from the initial mean. By repeating this process for each year, we generated a time series of industry ASL estimates. From 1988 to 2009, the period that NERA used to determine its ASL estimate of 33 years, we found that the mean estimate of ASL thus calculated was 32.7 years. The mean average ASL grew over this period from 31.1 in 1988 to 35.4 in 2009. Growth continued between 2009 and 2016, from 35.4 to 38.3.

We demonstrate mathematically in Appendix A.1 that NERA's calculation is appropriate for the analysis of *depreciation expenses*, not for *retirements.* Other research suggests that the appropriate ASL is higher. Table 4 summarizes data we gathered from utility filings on the ASLs of U.S. power distributors in recent years. It can be seen that they typically exceed 40 years. As explained further in Appendix A.1, we calculated an alternative ASL that is commensurate with retirements using a better formula and detailed retirement data from FERC Form 1. Our alternative estimate for recent years was 42 years.

[91] Exhibit B, Tab 2, p. 84 (Exhibit JDM-2).

[92] Exhibit JT 2.2, Attachment 1.

Table 4

Estimated Service Lives of Electric Distribution Assets of Select U.S. and Canadian Utilities

Studies (date):	360	361	362	364	365	366	367	368	369	370	371	373
	FERC Account											
	Land and Land Rights	Structures and Improvements	Station Equipment	Poles, Towers and Fixtures	Overhead Conductors and Devices	Underground Conduit	Underground Conductors and Devices	Line Transformers	Services	Meters	Installations on Customers Premises	Street Lighting and Signal Systems
Non-FERC Accounting												
Hydro Quebec, (2017)				47 (Lignes Aeriennes)		35 (Lignes souterraines)						
OEB (2010)		50	45	52.5	47.1	60	35	45	50.3	30		
EDTI (2010)		50	35	45	45	41	41	35		18		20
FortisBC (2014)	75		50	50	49			45	75	20	20	27
FERC Accounting												
Public Service of Colorado (2010)	90	60	55	50	50	60	45	45	48	22	26	33
San Diego Gas and Electric (2014)		63	51	47	55	57	45	34	54	48	34	36
San Diego Gas and Electric (2012)		54	49	44	48	53	40	33	49	48	19	32
Black Hills Power (2012)	40	40	45	50	50	37	40	36	62	21	30	25
Northwest Territories Power Corp (2015)		40	25	50	55	30	30	50	55	18	18	48
PECO (2016)		50	50	53	52	65	53	46	52	15	35	24
Florida Power and Light (2016)		65	45	45	48	60	39	34	49	29	30	35
PECO (2013)		50	50	53	52	65	53	46	52	25	25	24
Consolidated Edison (2014)		52	50	60	60	80	50	34	65		60	60
Duke Energy Carolinas (2008)		45	38	43	40	45	45	36	38	20	35	29
PPL (2012)	65	65	50	55	45	55	53	39	42	19	27	30
Idaho Power (2006)		65	50	44	47	60	50	37	35	18	13	25
Oklahoma Gas and Electric (2009)	60	60	35	50	50	55	55	36	55	25	30	40
Southern California Edison (2015)		50	65	55	55	59	43	33	45	20		48
Western Massachusetts Electric (2016)		65	47	56	55	65	60	34	56	18	25	25
NSTAR (2016)		70	60	58	48	75	45	36	58	23		20
Entergy Mississippi (2008)	65	60	61	30	35	52	50	25	36	32	35	17
Ameren Missouri (2013)		60	62	47	50	70	56	41	49	26	25	36
Rockland Electric Company (2015)		55	45	65	48	70	65	50	70	23	45	45
Duquesne Light (2013)		55	44	50	48	70	50	44	65	21		27
Pacific Gas and Electric (2014)	60	65	46	44	46	62	47	32	49	20	40	29
Rochester Gas and Electric (2007)	75	60	58	50	50	70	50	48	50	41		29
US Summary Statistics[3]:												
Average	**65**	**57**	**49**	**50**	**49**	**60**	**48**	**39**	**51**	**25**	**31**	**33**
Max	**90**	**70**	**65**	**65**	**60**	**80**	**65**	**50**	**70**	**48**	**60**	**60**
Median	**65**	**60**	**50**	**50**	**50**	**60**	**50**	**36**	**51**	**22**	**30**	**30**
Min	**40**	**40**	**25**	**30**	**35**	**30**	**30**	**25**	**35**	**15**	**13**	**17**
Mean / Median	**1.00**	**0.95**	**0.98**	**1.00**	**0.99**	**1.00**	**0.97**	**1.07**	**1.01**	**1.15**	**1.02**	**1.10**
Mean without Max and Min	**65.0**	**57.0**	**49.5**	**50.2**	**49.6**	**60.3**	**48.4**	**38.7**	**51.3**	**24.6**	**29.9**	**32.0**
Adjusted / Normal Mean	**100%**	**100%**	**101%**	**100%**	**100%**	**101%**	**100%**	**100%**	**100%**	**97%**	**98%**	**98%**
Weight Calculation:												
Aggregate Gross Value of Distribution Plant, Major US electric utilities, 1996[1,2]	**1,540,088**	**1,888,296**	**19,827,510**	**23,309,900**	**24,740,492**	**10,167,804**	**24,422,026**	**27,727,740**	**14,765,567**	**8,726,051**	**1,246,649**	**4,892,033**
Share of Total Distribution Plant, 1996 (%)	**0.94%**	**1.16%**	**12.15%**	**14.28%**	**15.15%**	**6.23%**	**14.96%**	**16.98%**	**9.04%**	**5.35%**	**0.76%**	**3.00%**
Weighted Average Life of Distribution Plant	**46.6**											

Footnotes:

[1] Thousands of dollars

[2] Source: Financial Statistics of Major U.S. Investor-Owned Electric Utilities 1996, EIA. Page 43.

[3] Service life studies that are not consistent with FERC Accounts are excluded from these calculations.

Notes:

Missing value indicates no service life estimate provided in corresponding study.

NERA's capital cost treatment and volumetric index together explain why TFP growth using their index slowed dramatically after 2000 and has been materially negative in recent years. The decline in average use is irrelevant and the quantities of retirements in the later years of the sample period have been underestimated. NERA obtains a reasonable TFP trend (e.g., +0.54%) over their lengthy *full* sample period because brisk growth in average use in the early years of the period offsets the productivity declines in later years. In recent years, NERA's TFP indexes have been declining due to a combination of declining average use and an ASL assumption that is inappropriate for these specific years. The slowdown in TFP growth using NERA's method invites controversy over the appropriate sample period when their methodology is used.

Cost Exclusions

NERA continued to needlessly exclude customer account and A&G costs from its productivity calculations. Such costs will be incurred by the Alberta DFOs and are a likely source of productivity gains. While Dr. Makholm sometimes argues against customizing productivity studies used to calibrate X factors, NERA *did* include these costs in their earlier productivity research and testimony for two power distributors (Central Maine Power and Utilicorp Canada) but excluded them from their study for the AUC.

Partial Factor Productivity

NERA is not in the habit of reporting trends in the productivity of O&M inputs and has denied their relevance in the design of rate and revenue cap indexes. However, the concept of partial factor productivity is well-established.

Other Concerns

A number of smaller problems with NERA's U.S. power distribution research in the Ontario gas utility proceeding also merit mention.

- Recall from Section ~~3.3~~2.5 that the computation of a capital quantity index starts in a certain year called the "benchmark" year with a calculation that is sometimes called the "benchmark year adjustment." We believe that NERA's calculations of capital quantity indexes in their initial benchmark year were incorrect. OHS is sometimes characterized as a method for calculating the capital quantity associated with *gross* plant value. Yet NERA deflated the *net* plant value of each utility in the benchmark year by triangularized weighted average of past values of a construction cost index. As a consequence, we believe that the initial quantities of capital for each utility in their sample were understated. This will tend to accelerate initial capital quantity growth and slow initial TFP growth.

  Their method effectively removed accumulated depreciation associated with older capital twice. It was first removed when calculating net plant value and then removed again when the original value of plant is retired.

  One reason that this matters is that, when a higher ASL is used to calculate capital quantities, this can result in negative capital quantities for some utilities in some years.

Utility witnesses in Alberta used these negative capital quantities as an argument against a higher average service life.[93]

- NERA's volume data were drawn entirely from FERC Form 1, which requests volumes of utility *sales* and not *deliveries*. With respect to residential volumes, for example, the instructions in the Uniform System of Accounts for Account 440, which is labeled "Residential Sales," state that

  A. This account shall include the net billing for electricity supplied for residential or domestic purposes.

  B. Records shall be maintained so that the quantity of electricity sold and the revenue received under each rate schedule shall be readily available.[94]

  It is easy to understand why these instructions might prompt a utility experiencing retail competition to report power *sales* volumes even when its power *delivery* volumes are larger. There were, as a consequence, marked declines in the reported volumes of some utilities that lost retail merchant business to competitors.

- There is too much weight on the trend in industrial volumes in NERA's volumetric index. In Ontario, NERA acknowledged in response to an information request that many large industrial customers of U.S. electric utilities receive their power directly from the transmission system.[95]

- NERA failed to correct for some mergers.

Alternative Results Using NERA's Ontario Data

To illustrate the problems with NERA's power distributor productivity research, PEG undertook several alternative runs in the Amalco proceeding. Results of this exercise are presented in Table 5. We focus here on the TFP results for 2001-2016, the most recent fifteen years of NERA's sample period. The table also presents results for the full sample period.

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[93] Brattle Undertaking #4 as filed in Alberta Utilities Commission Proceeding 20414 as Exhibit 20414-X0564 and Transcript Volume 8, pp. 2808-2809 from Alberta Utilities Commission Proceeding 20414.

[94] Code of Federal Regulations (2017), Title 18, Volume 1, Part 101 – Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, p. 488-491.

[95] EGDI_Union_IRR_Staff_20180323, Exhibit C, Staff 40(d), p 3.

Table 5

Summary of Corrections and Modifications to NERA's Productivity Calculations

	1973-2016			1973-2000			2001-2016		
	TFP Trend	Incremental Change	Cumulative Change	TFP Trend	Incremental Change	Cumulative Change	TFP Trend	Incremental Change	Cumulative Change
As Reported	0.54%			1.53%			-1.21%		
Modifications									
33 year triangularized weighted average	0.55%	0.02%	0.02%	1.55%	0.02%	0.02%	-1.19%	0.02%	0.02%
Gross Plant 33 Year ASL	0.78%	0.11%	0.24%	1.75%	0.10%	0.21%	-0.91%	0.13%	0.30%
Labor Quantity Calculation	0.81%	0.03%	0.27%	1.75%	0.00%	0.21%	-0.83%	0.08%	0.38%
Remove Merged Companies	0.79%	-0.03%	0.25%	1.73%	-0.02%	0.19%	-0.86%	-0.03%	0.35%
Average Service Life = 37 Years	1.23%	0.45%	0.69%	2.04%	0.29%	0.50%	-0.18%	0.73%	1.03%
Customers as Output	**0.85%**	**0.06%**	**0.31%**	**1.06%**	**-0.67%**	**-0.48%**	**0.49%**	**1.34%**	**1.69%**

- We first revised the benchmark year capital quantity calculation (in two steps) to deflate *gross* plant value by an arithmetic 33-year average of past construction cost index values. This raised the estimated TFP trend for the sample by about 30 basis points, from -1.21% to -0.91%.

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

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

- We next raised the average service life from 33 to 37 years. This raised the estimated TFP trend by a remarkable 68 basis points, to -0.18%.

- Finally, we replaced NERA's volumetric output index with the number of customers served. This raised the estimated TFP trend for the most recent fifteen years by another 67 basis points, to **+0.49%.** With all of these upgrades and corrections, the estimated TFP trend using OHS for the *full* (1973-2016) sample period was **+0.85%.**

Note that the cumulative impact of these changes is much larger for a truncated recent sample period than it is for the full sample period that Drs. Makholm and Ros recommended as the basis for X factor calibration in Alberta's PBR1 proceeding.

6. Empirical Research for the CCA

6.1. The Power Distributor Business

Reader understanding of the empirical research that is discussed in this section may be aided by a brief discussion of the general nature of a power distributor's business. Distributors deliver power from the transmission system to the premises of end users. The voltage of the power must be reduced from the rate at which it is transmitted to the rate at which end users consume it. Voltage is reduced by transformers at substations and there is a further reduction at line transformers located near customer premises. Distributors sometimes own and operate some substations and subtransmission lines as well as low voltage power lines and services, the poles and conduits that carry them, line transformers, and meters. Most distributors also incur costs to manage customer accounts. Additionally, certain administrative and general costs are incurred jointly in the provision of distribution and other services that the utility provides.

6.2. U.S. and Canadian Distribution Data

U.S. Data

Most American businesses and households receive their power distribution service from an investor-owned utility.[96] Most of these companies also transmit power, and many generate power as well. The division between transmission and distribution systems and the corresponding costs varies somewhat across the industry. U.S. power distributors also typically provide extensive customer account and information services.

Advantages

U.S. data have material advantages in the power distribution cost and productivity research that are needed in the PBR3 proceeding.

- The U.S. government has gathered detailed, standardized data for decades on the operations of more than sixty major investor-owned utilities that distribute power. The primary source of these data is Federal Energy Regulatory Commission ("FERC") Form 1. Most costs attributable to distribution and customer services are itemized on this form.

[96] Municipal utilities and rural electric cooperatives also provide power distribution services in the States. Notable examples include the LA Department of Water and Power and the Salt River Project in Arizona.

FERC Form 1 data are also available on peak loads and some important characteristics of distribution networks (e.g., the capacity of distribution substations).

- Form EIA-861 includes additional information on the operations of these utilities, including the number of customers that each serves.
- Customer account and customer service and information expenses are itemized for easy removal if desired. This facilitates comparisons to Alberta distributors, which offer fewer customer services.
- PEG has gathered data, from FERC Form 1 and antecedent forms, on the net value of distribution plant (and other kinds of plant) in 1964 and the corresponding gross plant additions since that year. This increases the accuracy of using monetary methods to measure capital costs and quantities.
- Regional Handy Whitman indexes are available on trends in the costs of distribution plant construction.
- Custom indexes can also be purchased (albeit at substantial cost) on trends in prices that power distributors face for materials and services.

These advantages make U.S. data the best in the world for calculating the costs and price and quantity indexes needed to measure distributor O&M, capital, and total factor productivity trends and to develop econometric benchmarking models for O&M, capital, and total distribution cost.

Disadvantages

There are also some notable disadvantages to using U.S. data in the distribution cost and productivity research for PBR3.

- Costs are denominated in U.S. rather than Canadian dollars.
- Data on distribution line length are not readily available for a large number of utilities over many years.
- Peak demand data are idiosyncratic, as discussed further below.
- U.S. distributors provide more customer services than Alberta distributors.

- Reported general costs are difficult to accurately allocate between the services that U.S. electric utilities provide. The values of distribution-related computer hardware, telecommunications equipment, and structures typically are included without itemization in general plant, and the value of computer software is included without itemization in intangible plant.
- DSM expenses are typically reported as customer service and information ("CS&I") expenses but are not clearly itemized for easy removal.

Alberta Data

The four electric DFOs that will be subject to PBR3 distribute power to most Alberta customers. These distributors also own, operate, and read meters, and manage metering data. However, due to the approach to the restructuring of retail power markets undertaken in Alberta, some billing and collection and customer information services are provided by affiliated and independent retailers. The Alberta distributors also typically do not provide extensive conservation services or operate facilities with voltage exceeding 25 kV.

EUB Directive 014 required Alberta power distributors to file extensive operating data and data have been provided for each year beginning in 2005. A uniform system of accounts for power distributors was issued in 2006 in Alberta Energy and Utility Board Bulletin 2006-25. Rule 005 of the AUC has required annual reports since 2008.[97] These data are publicly and electronically available.

While the companies are granted some latitude in how cost schedules are organized, most of the data needed for our cost research are generally available from Rule 005 filings and rebasing applications. Most distributors have itemized their total pension and benefit expenses and O&M salaries and wages.

Notwithstanding these advantages, Alberta data on power distributor operations have some limitations in productivity and cost benchmarking research which should be recognized.

- Data needed to calculate consistent capital cost and quantity indexes using monetary methods are available only since 2004. As discussed in Section 2.~~4~~ 5 above, this limits the

[97] Alberta Utilities Commission Rule 005 (formerly EUB Directive 014), *Rules on Annual Reporting Requirements of Operations and Financial Reports*, was approved January 2, 2008.

accuracy of statistical research on the capital cost and total cost performance of Alberta distributors, especially in the early years for which data are available. The accuracy of data on gross plant additions and O&M expenses are not affected by this problem.

- ENMAX made a major change in its approach to cost accounting that caused an O&M cost surge in 2013.
- There are some inconsistencies, between these four distributors and over time, in the itemization of O&M expenses.
- Standardized data on some important aspects of DFO operations (e.g., peak demand and service territory area and forestation) are not readily available.
- The DFOs rectified some of these data problems in response to the CCA's preliminary IRs.
- DFOs arrange for the provision of transmission system access service from the Alberta Electric System Operator ("AESO") and are required to make contributions to some power transmission projects (e.g., at point of delivery locations) and usually capitalize these outlays. These contributions to our knowledge have no counterpart in the U.S. data.
- We understand that contributions of retail customers in aid of construction ("CIAC") are unusually large in Alberta.

Ontario Data

About seventy utilities distribute power in Ontario. These utilities also provide a wide range of customer services that include conservation and demand management. The largest distributor, Hydro One Networks, also does most power transmission in Ontario.

The primary source of data on the cost and operating scale of Ontario power distributors is the Regulatory Recordkeeping Requirements ("RRR") reports. The OEB has required each jurisdictional power distributor to file this report since 2002. A uniform system of accounts called the *Accounting Procedures Handbook* has been established for the RRR reports. Some of the data distributors report have not been released to the public by the OEB.

Advantages of using Ontario data in the productivity and cost benchmarking research for PBR3 include the following.

- There is no need for currency conversions in an Alberta benchmarking study, and adjustments are fairly straightforward for regional differences between Ontario and Alberta input prices.
- Standardized, high quality data are publicly and electronically available on operations of about seventy Ontario power distributors for more than a decade. Thus, a large sample is available for peer group selection and econometric estimation of cost model parameters. There are some good peers for Alberta distributors (e.g., Hydro One Networks for ATCO Electric and Fortis and Toronto Hydro-Electric and Hydro Ottawa for ENMAX and EPCOR).
- Data that can be used to calculate the capital costs and quantities of most distributors are available since 1989. For these companies, calculation of capital costs and quantities can be made quite a few years into the past.
- Data are available for all distributors on peak loads and the lengths of overhead distribution lines (in structure miles) and of all distribution lines (in circuit miles).
- Data on pension and benefit, billing and collection, and energy conservation expenses are itemized for easy removal if desired.

Disadvantages of Ontario data include the following.

- Many Ontario power distributors recently transitioned to new Modified International Financial Reporting Standards ("MIFRS") that, among other things, reduces capitalization of O&M expenses for many companies. This may have materially slowed the O&M and total factor productivity trends of many distributors in the last few years.
- The data needed to calculate capital costs and quantities for some distributors is available only starting in 2002. These distributors include Hydro One Networks.
- Hydro One counts a sizable system carrying power at subtransmission voltage as a distribution operation.
- Data on gross plant additions, which we normally use to calculate capital costs and quantities, are only available starting in 2013. It is necessary to impute gross plant additions in earlier years using data on changes in total gross plant value. Another problem in measuring Ontario capital costs is that itemized data on distribution and general plant are

not readily available. These circumstances tend to reduce the accuracy of statistical research on the capital cost and total cost performance of Ontario utilities.

- A breakdown of O&M expenses into salary and wage and M&S expenses is not available. This reduces the accuracy of O&M input quantity calculations.
- A full itemization of O&M expenses by function is not readily available prior to 2013.
- Some of the business condition variables we use in our study have been calculated for only a few of the larger Ontario distributors.
- The *consistency* of O&M expense itemizations between Ontario distributors and over time has not been confirmed.
- The Ontario Energy Board has not authorized a study of the productivity trends of the provincial power distribution industry for many years.

Resolution

Given the many advantages of U.S. distributor operating data, material problems with Ontario data, and the limited budget for this project, we decided to prioritize the use of U.S. and Alberta data in our industry productivity trend and cost benchmarking research. This maintains some consistency as consultants in PBR proceedings in other Canadian provinces have typically also followed this strategy.

6.3. Data Sources Used in This Study

United States

The primary source of data on the operations of U.S. power distributors which we used in our research for the CCA is FERC Form 1. FERC Form 1 data were for many years published by the U.S. Energy Information Administration ("EIA").[98] More recently, the data have been available electronically from the FERC and in more processed forms from commercial vendors. To reduce concerns expressed by the AUC about the transparency and convenience of our research in prior Alberta proceedings, the FERC Form 1 data used in PEG's study were obtained directly from government agencies and processed by PEG. Customer data were drawn from FERC Form 1 in the early years of the sample period and from

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[98] This publication series had several titles over the years. A recent title is *Financial Statistics of Major U.S. Investor-Owned Electric Utilities.*

Form EIA-861 (the *Annual Electric Power Industry Report)* in later years.[99] We also relied on Form EIA-861 for data on AMI penetration.

Data on U.S. salary and wage prices were obtained from the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor. The GDPPI that we used to deflate M&S expenses of U.S. distributors was calculated by the Bureau of Economic Analysis of the U.S. Department of Commerce. Data on the *levels* of heavy construction costs in various U.S. and Alberta locations were obtained from RSMeans. Data on U.S. electric utility construction cost *trends* were drawn from the *Handy Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates. Three of the business condition variables we used in our econometric cost research were obtained from evidence that Power Systems Engineering prepared for utilities in Ontario proceedings.

Data on the costs of Alberta utilities were drawn chiefly from their Rule 005 filings and rebasing applications. Most data on Canadian prices used in the study were obtained from Statistics Canada. These included average weekly earnings, the gross domestic product implicit price index for final domestic demand, and an asset price index.

6.4. Sample

Data were eligible for inclusion in the sample from all major U.S. investor-owned electric utilities that, together with any important predecessor companies, filed the FERC Form 1 in 1964 (the benchmark year for the calculation of capital cost) and have reported the necessary data continuously. To be included in this study, the data also were required to be of good quality and plausible.

Data for 90 U.S. power distributors were used in our productivity trend research for the CCA. Data for 88 U.S. distributors were used in our econometric research. Three large California utilities were excluded from our productivity sample (and two from our econometric sample) because severe wildfires caused their O&M expenses to surge at the end of the sample period. These utilities were also excluded from productivity trend research in the aforementioned Joint Report of PEG and the Hydro One witness. The number of companies in our sample is considerably higher than the number NERA used in their recent Ontario evidence.

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[99] Data from the two sources for these variables are generally similar.

Table 6 lists the sampled utilities. It can be seen that most broad regions of the United States are well represented.[100] Companies in our western productivity peer group are identified.

We believe these data form a good base for rigorous research on distribution industry productivity trends and the cost performance of Alberta DFOs. The sample is large and varied enough to permit development of credible econometric cost models with several statistically significant business condition variables. Reasonable productivity peer groups can also be developed. Most regions of the United States are well-represented.

The sample period for our econometric cost research was the sixteen years from 2006 to 2021. The full sample period for our U.S. productivity research was the twenty-six (growth rate) years from 1996 to 2021.

6.5. Variables Used in the Study

Costs

United States

The cost of U.S. power distributors considered in our productivity and econometric studies was the sum of applicable capital costs and O&M expenses. We employed a monetary approach to capital cost, price, and quantity measurement which featured a geometric decay specification. Capital cost encompassed depreciation expenses and a return on net plant value less capital gains.[101] Plant was valued in current dollars. In addition to costs of *distribution* plant ownership, we included a sensible share of the costs of *general* plant ownership. Taxes and franchise fees were excluded from our calculations.

[100] Unfortunately, the requisite customer data are not available for most Texas distributors.

[101] Further details of our capital cost calculations are provided in Appendix section A.2.

Table 6

Electric Utilities Sampled in PEG's Empirical Research

Alberta

ATCO Electric	EPCOR
ENMAX	FortisAlberta

United States

Avista	Green Mountain Power	PECO Energy
Alabama Power	Gulf Power	Pennsylvania Power
ALLETE	*Idaho Power*	*Portland General Electric*
Appalachian Power	Indiana Michigan Power	Potomac Electric Power
Arizona Public Service	Indianapolis Power & Light	PPL Electric Utilities Corporation
Atlantic City Electric	Jersey Central Power & Light	*Public Service of Colorado*
Baltimore Gas and Electric	Kansas City Power & Light	Public Service of New Hampshire
Central Hudson Gas & Electric	Kansas Gas and Electric	Public Service Electric and Gas
Cleco Power LLC	Kentucky Power	*Puget Sound Energy, Inc.*
Cleveland Electric Illuminating	Kentucky Utilities	Rochester Gas and Electric
Commonwealth Edison	Kingsport Power	South Carolina Electric & Gas
Consolidated Edison	Louisville Gas and Electric	Southern Indiana Gas and Electric
Dayton Power and Light	Madison Gas and Electric	Southwestern Electric Power
Delmarva Power & Light	*MDU Resources*	Southwestern Public Service
Detroit Edison	Metropolitan Edison	Superior Water, Light and Power
Duke Energy Carolinas	MidAmerican Energy	Tampa Electric
Duke Energy Florida	Mississippi Power	Toledo Edison
Duke Energy Indiana	Monongahela Power	*Tucson Electric Power*
Duke Energy Kentucky	Narragansett Electric	Union Electric
Duke Energy Ohio	*Nevada Power*	United Illuminating
Duke Energy Progress	New York State Electric & Gas	Upper Peninsula Power
Duquesne Light	Niagara Mohawk Power	Virginia Electric and Power
El Paso Electric	Northern Indiana Public Service	West Penn Power
Empire District Electric	Northern States Power	Westar Energy
Entergy Arkansas	Ohio Power	Wheeling Power
Entergy Mississippi	Oklahoma Gas and Electric	Wisconsin Electric Power
Florida Power & Light	Orange and Rockland Utilities	Wisconsin Power and Light
Georgia Power	*PacifiCorp*	Wisconsin Public Service

Additional Companies in Productivity Work and Not Benchmarking Work

Ameren Illinois	Mt. Carmel Public Utility
NSTAR Electric	Fitchburg Gas and Electric Light
Otter Tail	Connecticut Light and Power

Additional Companies in the Econometric Work

Consumers Energy	Public Service of Oklahoma
Entergy New Orleans	San Diego Gas & Electric

Comments

The total number of US distributors is 88 in the econometric research and 90 in the productivity research.
Italics indicates that the distributor is a western peer

O&M expenses that we included comprised applicable distribution and customer account expenses and a sensible share of administrative and general expenses.[102] We excluded reported costs that the U.S. utilities reported for power production and procurement, power transmission, sales, CS&I, and any gas utility services that they provided.

The following categories of administrative and general expenses were included:

- administrative and general salaries and office supplies and expenses less administrative expenses transferred;
- outside services employed;
- property insurance;
- injuries and damages;
- regulatory commission expenses;
- general advertising expenses;
- miscellaneous general expenses;
- rents; and
- general plant maintenance.

Pension and other benefit expenses were included in our productivity research. They were however excluded from our benchmarking research. One reason is that pension expenses can be sensitive to volatile external business conditions such as stock prices. Another is that the health insurance obligations of U.S. and Canadian utilities can differ considerably. Pension and benefit (e.g., health care) expenses are reported on a consolidated basis on FERC Form 1, so it is not possible to exclude pension or health care expenses and include expenses for other benefits. In Canada, an additional problem with including pension and benefit expenses in cost research is the lack of federal

[102] We added to each utility's distribution cost a share of its general costs equal to the share of included distribution O&M in its net O&M cost. Since general costs are tied to the management of labor, in calculating net O&M for this purpose we excluded some O&M from these calculations which are large relative to their labor cost component. Examples of these excluded expenses are those for energy, and uncollectible bills.

labor price indexes that address them as well as salaries and wages. CS&I expenses were excluded because in the U.S. they contain large conservation expenses that Alberta distributors don't incur.

Alberta

The O&M expenses we included in the study for Alberta distributors were drawn from AUC Directive 014 and Rule 005 filings and data provided by the distributors in their recent rebasing proceedings. These included the normal expenses incurred by the distributors with the exception of expenses for taxes, franchise fees, and pensions and other benefits. The Alberta distributor capital costs we considered were those for distribution plant and all reported general plant.[103] Customer contributions, CWIP, and contributions to transmission were excluded.[104] Pension and other benefit expenses were included in the calculation of Alberta productivity trends.

Input Prices

Prices that distributors paid for inputs are needed in productivity and cost benchmarking research. These change from year to year and differ between utilities in each year. Price differences between utilities matter in cost level benchmarking but not in the calculation of productivity trends. We accordingly used separate but related input price indexes in our benchmarking and productivity trend research. The productivity trend research used input price trend indexes that are similar to the trend components of our input price indexes for benchmarking.

O&M Prices

Labor For the year 2019 we calculated indexes of labor price levels for Alberta DFOs and the sampled U.S. utilities. Occupational Employment Statistics ("OES") survey data from the U.S. Bureau of Labor Statistics were used to calculate wage rate indexes for U.S. utilities as weighted averages of comparisons of the hourly wage rates, for various job categories established in the occupational classification code, using cost share weights that correspond to the electric utility industry. These data were available for numerous metropolitan statistical areas, and we computed an average of the results for the areas in each service territory using population weights.

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[103] To the greatest extent possible, PEG excluded the expenses of ATCO Electric's isolated generation.

[104] Some unusual plant additions categories were excluded from ENMAX's plant additions data.

To calculate comparable wage rate index values for Alberta DFOs in 2019, we first compared the average weekly earnings for the utilities sectors of the United States (as computed by BLS) and Alberta (as computed by Statistics Canada). For the Alberta distributors, these values were adjusted to reflect variations in local labor prices using median income data from Statistics Canada.

For other years of the sample period, values of each company's wage rate index were calculated by adjusting these levels for changes in labor price trend indexes. For the U.S. utilities we used regionalized indexes of employment cost trends for the utilities sector of the economy. These indexes were constructed from BLS Employment Cost Indexes. For Alberta, we calculated the wage rate trend using the average hourly earnings ("AHE") for Alberta industry reported by Statistics Canada.

Materials and Services The prices U.S. utilities pay for materials and services were assumed to inflate over time at the rate of the U.S. gross domestic product price index. This is the U.S. government's featured index of inflation in prices of the economy's final goods and services. Final goods and services include consumer products, business equipment, and exports.

For the M&S price trends of Alberta utilities we used Statistics Canada's gross domestic product implicit price index for final domestic demand ("GDPIPIFDD") in Alberta. This is preferable to the more comprehensive GDPIPI because the latter is unduly sensitive to the volatile prices of Canada's sizable commodity (e.g., oil, gas, and metal) exports. Material and service prices in the U.S. and Canada were patched using U.S./Canadian purchasing power parities ("PPPs") for gross domestic product that were obtained from the OECD.

The levels of utility M&S input prices were assumed to differ in 2019 by 25% of the difference in the corresponding labor prices. We used our labor price index to effect this levelization.

Capital Asset Prices

The monetary approach to the calculation of capital cost that we used required us to construct capital (service) price indexes from asset price indexes and rates of return on capital. A multistep process was used to construct the capital asset prices used in the econometric research. We first calculated an index of construction cost levels which varied between the service territories of sampled utilities in 2019 in proportion to the relative cost of local construction as measured by total (material and installation) heavy construction cost indexes published by RSMeans.[105] RSMeans index values are available for multiple cities in the service territories of most sampled utilities, including some in Alberta. For these utilities, we typically computed a weighted average of these values using as weights the approximate populations of the pertinent cities.[106]

To obtain levelized asset price index values for other years, we trended the values for 2019 using asset price trend indexes. As asset price trend indexes for U.S. utilities we used the applicable regional Handy Whitman Indexes of Public Utility Construction Costs for Total Distribution Plant. As general plant asset price indexes for these utilities we used the applicable regional Handy Whitman Indexes of Public Utility Construction Costs for reinforced concrete building construction.

For Alberta utilities we developed an asset price trend index from the average annual growth rates of two indexes. One was the product of the Handy Whitman Indexes of Public Utility Construction Costs for Total Distribution Plant in the Plateau region and the PPP for gross domestic product. The other was Statistics Canada's implicit capital stock deflator for the utility sector of Alberta. Statistics Canada includes in the utility sector power generation and transmission, gas distribution, and water and sewer utilities as well as power distribution. We assigned equal weights to the trends in these two indexes. This treatment was used by PEG and the witness for Hydro One in the recent Joint Report on empirical research that we mentioned above.

For the rates of return of U.S. utilities we calculated 50/50 averages of rates of return for debt and equity.[107] For debt we used the embedded average interest rate on long-term debt of a large group of electric utilities as calculated from FERC Form 1 data. For equity we used the average allowed ROE approved in electric utility rate cases as reported by the Edison Electric Institute.[108] For Alberta DFOs, PEG calculated the weighted average cost of capital based on AUC approved capital structures and returns on equity along with the costs of debt and preferred equity that the distributors report on

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[105] *Heavy Construction Costs with RSMeans Data*, Gordian Publishers, 34th annual edition, 2020.

[106] When multiple utilities served a city, we counted only a portion of the population.

[107] This calculation was made solely for the purpose of measuring productivity trends and benchmarking cost performance and does not prescribe appropriate rate of return *levels* for utilities.

[108] The Edison Electric Institute is the principal trade association of U.S. electric utilities. The ROE data we used in the study were drawn from the backup data to the *EEI Rate Case Summary* quarterly reports.

their Rule 005 filings. The construction of capital service prices from these components is discussed further in Appendix A.

Summary Input Price Indexes

The summary O&M price indexes used in our research featured price subindexes for labor and materials and services.[109] Growth in each summary index was a weighted average of the growth of the two subindexes. In these calculations we used company-specific, time-varying cost-share weights that we calculated from FERC Form 1 and Alberta DFO data. The summary multifactor input price indexes that we used in the econometric cost research were constructed for each distributor by combining the summary capital and O&M price indexes using company-specific, time-varying cost share weights.

Scale Variables

Three scale variables were used in our econometric power distributor cost research: the number of customers served, ratcheted maximum peak demand, and the area served. We ratcheted the peak load data by using in each year the highest value yet attained since the start of the sample period. This is a proxy for the expected maximum peak demand that we believe drives distribution cost.

Alberta peak demand data were drawn from information requests.[110] For U.S. utilities we used monthly peak load as reported on page 401b of FERC Form 1. This is not expressly a *distribution* system peak and seems instead to have been intended originally as a measure of peak power *supply* to retail and requirements sales for resale customers (e.g., munis and cooperatives). It expressly excluded demand at the peak which is associated with non-requirements sales for resale. We adjust these data to make them more applicable to power distributors.

Service territory area was used as a proxy for the geographical extensiveness of the system. An alternative measure of system extensiveness, the length of distribution lines, was not available for most sampled distributors. Our area estimates were made by Power Systems Engineering ("PSE"), a Madison-based engineering consultancy, in work for Ontario utilities that has been used in PBR evidence. Details

[109] The formulas for our input price indexes are discussed further in Appendix A.2.

[110] Several distributors provided their peak load data measured in megavolt amperes.

of their calculations are provided in the Appendix. We expect this variable to have a positive sign in all three models.

We accorded the three scale variables in our econometric models a translog treatment by adding quadratic and interaction (aka "second-order") terms for these variables to the econometric cost model. This is a common practice in econometric cost research. To reduce controversies over the forms of cost functions, no second-order terms were included for the other variables in the model. The functional forms of econometric cost models are discussed further in Appendix A.~~2~~3.

Other Business Condition Variables

Several additional business condition variables were used in one or more of the econometric cost models.

One business condition variable used in the modelling was the extent of distribution system overheading. For U.S. utilities this was measured as the share of overhead plant in the gross value of distribution conductor, device, and structure (pole, tower, and conduit) plant. Analogous calculations could be made for ENMAX and EPCOR but not for ATCO and Fortis. We assigned the latter two utilities the values for this variable that are similar to one we used for Hydro One Networks in a recent Ontario proceeding.

Another additional business condition variable used in the modelling was the extent of service territory forestation. When lines are overhead rather than underground, the cost of operating and maintaining them is increased by the extent of forestation in the areas where these lines run. We expect the parameter for this variable to have a positive sign in the O&M and total cost models.

The share of electric customers in the sum of gas and electric customers is used to measure economies of scope from the joint provision of gas and electric service. Gas customer data are drawn from FERC Form 1. All Alberta DFOs are assumed to have zero values. We expect this variable to have a positive sign in all three cost models.

The model also includes a construction standards index for power distribution which PSE developed for an Ontario utility.   This variable measures how construction standards vary with weather in a utility's service territory. We retained PSE to calculate construction standard index values for the four Alberta DFOs. The variable that we use in the models is Construction Standards Index x

Overheading since weather chiefly affects the cost of overhead facilities. We expect the value of this variable's parameter to have a positive sign.

Our model also contains a trend variable. This permits predicted cost to shift over time for reasons other than changes in the business conditions that are specified in the cost model. Trend variables thereby capture the net effect on cost of changes in diverse conditions, such as technology and X inefficiency, which are otherwise excluded from the model. Parameters for such variables often have a negative sign in econometric research on utility cost. However, the expected value of the trend variable parameter in a cost model is a priori indeterminate.

We generally tried to use as many business condition variables with statistically significant and sensibly signed parameter estimates as we could in each cost model. The models are similar to those detailed in our recent Joint Report with a Hydro One witness. If a variable appears in one model and not another, it is because it did not have a correctly signed and statistically significant parameter estimate in that model. It makes sense that some variables matter more for O&M expenses that they do for capital cost and vice versa.

6.6. U.S. Productivity Trends

Methodology

We calculated indexes of the O&M, capital, and multifactor productivity of each sampled U.S. utility in the provision of power distributor services. The annual productivity growth rate of each distributor was calculated as the difference between the growth of its output and input quantity indexes. We feature even-weighted averages of the results for individual utilities because Alberta power distributors are below average in size and even-weighted averages are less sensitive to special challenges facing large distributors.

In the featured runs, the number of customers served was the sole output metric. As discussed in Section 2.2, this is the treatment most applicable to revenue per customer indexes and to price cap indexes of utilities that have high fixed charges. Our estimates of distribution output do not reflect any possible changes in distribution reliability that may have occurred during the sample period. Reliability has been treated as an output variable in distribution productivity research commissioned by the Australian Energy Regulator.[111]

We calculated input quantity indexes for O&M and capital. In each case, the growth in the input quantities was calculated as the difference between the growth of cost and an appropriate input price index.

Industry Trends

Tables 7a and 7b report results of our productivity calculations for the full sample period. Using even-weighted averages we found that, over the full 26-year sample period (1996-2021), the growth in the total factor distributor productivity of sampled U.S. utilities averaged 0.31% annual growth. Distribution O&M productivity averaged 0.82% annual growth while capital productivity averaged 0.13% annual growth. Over the most recent fifteen years for which data are available, TFP growth averaged 0.08% annually. O&M productivity averaged 0.66% annual growth while capital productivity averaged a 0.07% annual decline.

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[111] Denis Lawrence, Tim Coelli and John Kain, *Economic Benchmarking Results for the Australian Energy Regulator's 2020 TNSP Annual Benchmarking Report*, prepared for the Australian Energy Regulator, October 15, 2020, pp. 6-7.

Table 7a

U.S. Distribution Productivity Results

Year	Simple Averages of Productivity Growth Rates			Cost-Weighted Averages of Productivity Growth Rates		
	Total Factor	O&M	Capital	Total Factor	O&M	Capital
1995						
1996	-0.9%	-1.6%	-0.1%	-0.60%	-1.38%	0.02%
1997	2.7%	5.7%	0.4%	1.86%	4.01%	0.39%
1998	-0.5%	-2.0%	0.8%	-1.11%	-3.30%	0.60%
1999	-0.3%	-1.7%	0.6%	-0.68%	-2.27%	0.33%
2000	0.9%	2.0%	0.4%	0.82%	1.92%	0.51%
2001	1.2%	1.8%	1.0%	1.29%	1.55%	1.72%
2002	0.7%	1.9%	0.0%	0.38%	1.98%	-0.57%
2003	-1.2%	-3.3%	0.4%	-1.10%	-3.09%	0.19%
2004	2.6%	5.7%	0.4%	3.11%	6.93%	0.23%
2005	-0.1%	-0.3%	0.3%	-0.10%	-0.59%	0.35%
2006	1.8%	3.1%	0.3%	1.41%	2.42%	0.40%
2007	-2.5%	-4.1%	0.3%	-2.75%	-4.52%	0.13%
2008	-1.9%	-2.5%	-0.1%	-1.12%	-1.61%	0.31%
2009	1.2%	2.0%	-0.6%	1.48%	2.20%	-0.24%
2010	0.0%	0.2%	0.1%	-0.10%	-0.44%	0.26%
2011	0.1%	-0.2%	0.5%	0.05%	-0.50%	0.47%
2012	1.2%	2.2%	0.5%	1.40%	2.79%	0.55%
2013	1.3%	4.2%	-0.2%	1.34%	3.47%	0.13%
2014	-0.4%	-2.2%	0.4%	0.09%	-0.89%	0.62%
2015	1.2%	2.6%	0.4%	1.56%	3.49%	0.35%
2016	0.1%	-0.7%	0.3%	-0.11%	-0.85%	0.34%
2017	0.1%	0.9%	-0.1%	-1.24%	-2.37%	-0.09%
2018	-0.3%	-0.8%	-0.1%	1.10%	2.85%	-0.12%
2019	0.0%	1.4%	-0.7%	0.37%	1.70%	-0.41%
2020	-0.3%	1.4%	-1.0%	-0.61%	-0.11%	-0.58%
2021	1.3%	5.4%	-0.8%	0.89%	3.86%	-0.50%
Average Annual Growth Rates						
Full sample Period	**0.31%**	**0.82%**	**0.13%**	**0.29%**	**0.66%**	**0.21%**
Last 15 Years (2007-2021)	**0.08%**	**0.66%**	**-0.07%**	**0.16%**	**0.60%**	**0.08%**

Table 7b

Details of U.S. Power Distribution Industry Productivity Growth

Year	Customers	Input Quantity		
		Total Factor	O&M	Capital
1996	1.2%	2.1%	2.8%	1.3%
1997	1.4%	-1.2%	-4.3%	1.0%
1998	1.6%	2.0%	3.6%	0.8%
1999	0.9%	1.2%	2.5%	0.3%
2000	1.2%	0.2%	-0.8%	0.7%
2001	1.9%	0.7%	0.1%	0.9%
2002	0.8%	0.2%	-1.1%	0.9%
2003	1.2%	2.4%	4.5%	0.7%
2004	1.2%	-1.4%	-4.5%	0.8%
2005	1.3%	1.4%	1.6%	1.1%
2006	0.9%	-0.9%	-2.2%	0.6%
2007	1.0%	3.5%	5.1%	0.8%
2008	0.5%	2.3%	2.9%	0.6%
2009	0.2%	-1.1%	-1.9%	0.8%
2010	0.4%	0.4%	0.3%	0.3%
2011	0.2%	0.1%	0.4%	-0.2%
2012	0.4%	-0.8%	-1.8%	-0.1%
2013	0.4%	-0.9%	-3.8%	0.6%
2014	0.6%	1.0%	2.8%	0.3%
2015	0.7%	-0.5%	-1.9%	0.3%
2016	0.8%	0.7%	1.4%	0.4%
2017	0.6%	0.5%	-0.3%	0.7%
2018	0.8%	1.1%	1.6%	0.9%
2019	0.7%	0.7%	-0.7%	1.4%
2020	0.9%	1.2%	-0.5%	1.9%
2021	0.9%	-0.4%	-4.5%	1.7%
Average Annual Growth Rates[1]				
Full sample Period	**0.88%**	**0.57%**	**0.06%**	**0.75%**
Last 15 Years (2007-2021)	**0.61%**	**0.53%**	**-0.05%**	**0.69%**

[1] Growth rates of individual utilities are even-weighted.

Productivity results for the Western Peer Group can be found in Tables 8a and 8b. For the full sample period, it can be seen that the simple average of the annual TFP growth of sampled distributors was 0.75%. Over the most recent fifteen years the trend was a similar 0.71%. Capital productivity growth averaged 0.39% over the full sample period and 0.44% over the last fifteen years. O&M productivity growth averaged 1.28% over the full sample period and 1.08% over the most recent fifteen years. A comparison of Tables 7b and 8b shows that customer growth was substantially more rapid in the Western Peer Group during both sample periods and more similar to the customer growth experienced in Alberta.

Thus, the TFP growth of the Western Peer Group was much more rapid than that of the national peer group and hasn't experienced a material decline. This is of particular note inasmuch as the productivity growth drivers in the Western Peer Group may be more similar to Alberta's than those of the national peer group on balance.

6.7. X Factor Precedents

Table 9 provides a survey of acknowledged productivity trends, stretch factors, and "combo" X factors from other North American PBR proceedings. Amongst all current and expired plans, the average acknowledged utility industry productivity trend is 0.44% and the average value of itemized stretch factors is 0.35%. Amongst all current plans, it can be seen that the average acknowledged utility industry TFP trend is -0.19%. The average value of itemized stretch factors is 0.27%. X factors tend to be more negative in the U.S. because the inflation measure in rate or revenue cap indexes there is typically the gross domestic product price index and this often occasions the addition of a negative correction to the X factor for the inaccuracy of the GDPPI as an input price trend measure. In all current Canadian plans, the average base productivity trend is 0% and the average stretch factor is 0.30%.

Table 8a

Western Peer Group Distribution Productivity Results

Year	Simple Averages of Productivity Growth Rates			Cost-Weighted Averages of Productivity Growth Rates		
	Total Factor	O&M	Capital	Total Factor	O&M	Capital
1995						
1996	-3.6%	-6.8%	-0.6%	-2.2%	-4.1%	-0.6%
1997	2.8%	5.8%	0.1%	-0.2%	-2.6%	-0.2%
1998	1.3%	5.0%	-0.5%	1.3%	6.5%	-0.9%
1999	1.1%	2.2%	0.6%	-0.9%	-1.9%	-0.2%
2000	1.5%	2.6%	1.0%	3.9%	10.2%	1.5%
2001	1.2%	1.8%	0.5%	1.2%	-0.3%	1.1%
2002	0.8%	3.0%	-0.5%	0.9%	2.2%	0.2%
2003	-0.4%	-2.8%	1.1%	-0.3%	-3.5%	1.4%
2004	0.3%	0.2%	0.5%	-0.6%	-3.2%	1.2%
2005	1.7%	2.5%	1.1%	2.5%	3.6%	1.6%
2006	2.1%	3.7%	0.3%	1.0%	1.8%	0.2%
2007	-0.2%	-1.1%	1.1%	0.7%	0.1%	1.6%
2008	0.8%	1.2%	-0.9%	1.2%	1.6%	0.1%
2009	2.3%	3.9%	-1.1%	2.8%	4.6%	-0.2%
2010	1.3%	3.5%	-0.4%	2.2%	4.6%	0.3%
2011	0.3%	0.7%	0.6%	1.2%	2.5%	1.0%
2012	0.9%	1.6%	0.8%	1.6%	2.7%	1.2%
2013	0.0%	-2.5%	1.0%	0.8%	-1.3%	1.6%
2014	1.7%	2.6%	1.3%	2.6%	4.4%	2.0%
2015	2.4%	5.8%	0.8%	3.0%	5.7%	1.9%
2016	0.6%	0.2%	0.7%	1.3%	0.3%	1.7%
2017	1.4%	2.2%	1.0%	1.6%	1.5%	1.7%
2018	1.1%	0.9%	1.1%	1.8%	1.9%	1.6%
2019	0.9%	2.3%	0.4%	1.1%	2.4%	0.7%
2020	-0.2%	-1.1%	0.0%	-0.5%	-2.9%	0.4%
2021	-2.6%	-4.0%	0.2%	-3.0%	-4.9%	0.5%
Average Annual Growth Rates						
Full sample Period	**0.75%**	**1.28%**	**0.39%**	**0.96%**	**1.22%**	**0.83%**
Last 15 Years (2007-2021)	**0.71%**	**1.08%**	**0.44%**	**1.23%**	**1.53%**	**1.08%**

Table 8b

Details of Western Power Distributor Productivity Growth

Year	Customers	Input Quantity		
		Total Factor	O&M	Capital
1996	2.8%	6.3%	9.6%	3.4%
1997	2.7%	-0.1%	-3.1%	2.6%
1998	2.5%	1.2%	-2.5%	3.0%
1999	2.5%	1.4%	0.3%	1.9%
2000	2.4%	0.9%	-0.2%	1.4%
2001	2.1%	0.9%	0.4%	1.6%
2002	2.0%	1.2%	-1.0%	2.5%
2003	2.4%	2.8%	5.2%	1.3%
2004	2.1%	1.8%	1.8%	1.6%
2005	3.3%	1.6%	0.8%	2.1%
2006	1.5%	-0.6%	-2.3%	1.2%
2007	2.1%	2.3%	3.2%	1.1%
2008	1.3%	0.5%	0.1%	2.1%
2009	0.8%	-1.5%	-3.1%	1.8%
2010	0.7%	-0.6%	-2.8%	1.1%
2011	0.6%	0.4%	0.0%	0.0%
2012	1.2%	0.2%	-0.4%	0.3%
2013	1.1%	1.1%	3.6%	0.1%
2014	1.3%	-0.4%	-1.3%	0.0%
2015	1.5%	-0.9%	-4.3%	0.6%
2016	1.2%	0.6%	1.0%	0.5%
2017	1.3%	-0.1%	-0.9%	0.3%
2018	1.5%	0.4%	0.5%	0.3%
2019	1.3%	0.4%	-1.0%	0.9%
2020	1.5%	1.7%	2.7%	1.5%
2021	1.6%	4.2%	5.6%	1.4%
Average Annual Growth Rates[1]				
Full sample Period	**1.73%**	**0.99%**	**0.45%**	**1.34%**
Last 15 Years (2007-2021)	**1.26%**	**0.55%**	**0.18%**	**0.82%**

[1] Growth rates of individual utilities are even-weighted.

Table 9

Summary of Base Productivity Trend, Consumer Dividend, and X Factor Decisions in North American Multiyear Rate Plans

Applicable Services	Utilities	Jurisdiction	Term	Cap Form	Inflation Measure	Base Productivity Trend	Stretch Factor[2]	X-Factor Including Stretch Factor[3,4]	X-Factor Excluding Stretch Factor[5]
Bundled Power Service	PacifiCorp (I)	California	1994-1997, extended to 1999	Price Cap	Industry-specific	1.40%	NA	1.40%	1.40%
Bundled Power Service	Central Maine Power (I)	Maine	1995-1999	Price Cap	GDPPI	NA	NA	0.9% (Average)	NA
Oil Pipelines	All U.S.	United States	1995-2001	Price Cap	PPI-Finished Goods	NA	NA	1.00%	1.00%
Gas Distribution	Southern California Gas	California	1997-2002	Revenue Cap	Industry-specific	0.50%	0.80% (Average)	2.3% (Average)	1.50%
Power Distribution	Southern California Edison	California	1997-2002	Price Cap	CPI	NA	NA	1.48% (Average)	NA
Gas Distribution	Boston Gas (I)	Massachusetts	1997-2003	Price Cap	GDPPI	0.40%	0.50%	0.50%	0.00%
Power Distribution	Bangor Hydro Electric (I)	Maine	1998-2000	Price Cap	GDPPI	NA	NA	1.20%	NA
Power Distribution	PacifiCorp (II)	Oregon	1998-2001	Revenue Cap	GDPPI	NA	NA	0.30%	NA
Gas Distribution	San Diego Gas and Electric	California	1999-2002	Price Cap	Industry-specific	0.68%	0.55% (Average)	1.23% (Average)	0.68%
Power Distribution	San Diego Gas and Electric	California	1999-2002	Price Cap	Industry-specific	0.92%	0.55% (Average)	1.47% (Average)	0.92%
Power Distribution	All Ontario Distributors	Ontario	2000-2003	Price Cap	Industry-specific	0.86%	0.25%	1.50%	1.25%
Gas Distribution	Bangor Gas	Maine	2000-2009, extended to 2012	Price Cap	GDPPI	NA	NA	0.36% (Average)	NA
Gas Distribution	Union Gas	Ontario	2001-2003	Price Cap	GDPPI	NA	NA	2.50%	NA
Oil Pipelines	All U.S.	United States	2001-2006	Price Cap	PPI-Finished Goods	NA	NA	0.00%	0.00%
Power Distribution	Central Maine Power (II)	Maine	2001-2007	Price Cap	GDPPI	NA	NA	2.57% (Average)	NA
Power Distribution	Southern California Edison	California	2002-2003	Revenue Cap	CPI	NA	NA	1.60%	NA
Power Distribution	EPCOR (I)	Alberta	2002-2005, Terminated at end of 2003	Price Cap	Industry-Specific	NA	NA	15% * Inflation	NA
Gas Distribution	Berkshire Gas	Massachusetts	2002-2011	Price Cap	GDPPI	0.40%	1.00%	1.00%	0.00%
Gas Distribution	Blackstone Gas	Massachusetts	2004-2009	Price Cap	GDPPI	NA	NA	0.50%	NA
Gas Distribution	Boston Gas (II)	Massachusetts	2004-2013, terminated in 2010	Price Cap	GDPPI	0.58%	0.30%	0.41%	0.11%
Power Distribution	All Ontario Distributors	Ontario	2006-2009	Price Cap	GDP IPI Canada	NA	NA	1.00%	NA
Oil Pipelines	All U.S.	United States	2006-2011	Price Cap	PPI-Finished Goods	NA	NA	-1.30%	-1.30%
Power Distribution	NSTAR	Massachusetts	2006-2012	Price Cap	GDPPI	NA	NA	0.63% (Average)	NA
Gas Distribution	Bay State Gas	Massachusetts	2006-2015, terminated in 2009	Price Cap	GDPPI	0.58%	0.40%	0.51%	0.11%
Power Distribution	ENMAX	Alberta	2007-2013	Price Cap	Industry-specific	0.80%	0.40%	1.20%	0.80%
Gas Distribution	Enbridge Gas	Ontario	2008-2012	Revenue Cap	GDPPI	NA	NA	47% x Inflation (Average)	NA
Gas Distribution	Union Gas	Ontario	2008-2012	Revenue Cap	GDPPI	NA	NA	1.82%	NA
Power Distribution	Central Vermont Public Service	Vermont	2009-2011, extended to 2013	Revenue Cap	CPI	1.03%	NA	1.00%	1.00%
Power Distribution	Central Maine Power (III)	Maine	2009-2013	Price Cap	GDPPI	NA	NA	1.00%	NA
Power Distribution	All Ontario Distributors	Ontario	2010-2013	Price Cap	GDPPI	0.72%	0.40% (Average Across Firms)	1.12% (Average Across Firms)	0.72%
Power Distribution	Green Mountain Power	Vermont	2010-2013	Revenue Cap	CPI	NA	NA	1.00%	NA
Oil Pipelines	All U.S.	United States	2011-2016	Price Cap	PPI-Finished Goods	NA	NA	-2.65%	-2.65%
Power & Gas Distribution	All Distributors	Alberta	2013-2017	Price Cap for Power, Revenue per Customer Cap for Gas	Industry-specific	0.96%	0.20%	1.16%	0.96%
Gas Distribution	Union Gas	Ontario	2014-2018	Revenue Cap	GDPPI	NA	NA	60% x Inflation	NA

Table 9 (continued)

Summary of Base Productivity Trend, Consumer Dividend, and X Factor Decisions in North American Multiyear Rate Plans

Applicable Services	Utilities	Jurisdiction	Term	Cap Form	Inflation Measure	Base Productivity Trend	Stretch Factor[2]	X-Factor Including Stretch Factor[3,4]	X-Factor Excluding Stretch Factor[5]
Power Distribution	All Distributors except those who opt out	Ontario	2014-open	Price Cap	Industry-specific	0.00%	Range of 0% to 0.6%	Range of 0% to 0.6%	0.00%
Bundled Power Service	FortisBC	British Columbia	2014-2019	Revenue Cap	Industry-specific	0.93%	0.10%	1.03%	0.93%
Gas Distribution	FortisBC Energy	British Columbia	2014-2019	Revenue Cap	Industry-specific	0.90%	0.20%	1.10%	0.90%
Oil Pipelines	All U.S.	United States	2016-2021	Price Cap	PPI-Finished Goods	NA	NA	-1.23%	-1.23%
Hydro Power Generation	Ontario Power Generation	Ontario	2017-2021	Price Cap	Industry-specific	0.00%	0.30%	0.30%	0.00%
Power & Gas Distribution	All Distributors	Alberta	2018-2022	Price Cap for Power, Revenue per Customer Cap for Gas	Industry-specific	NA	NA	0.30%	NA
Power Distribution	Hydro-Québec	Québec	2018-2022	Revenue Cap	Industry-specific	NA	0.00%	0.30%	0.30%
Power Distribution	Eversource Energy[6]	Massachusetts	2018-2022	Revenue Cap	GDPPI	-0.46%	0.25% if GDPPI growth exceeds 2%	-1.31%	-1.56%
Gas Distribution	Amalco	Ontario	2019-2023	Price Cap	GDPPI	0.00%	0.30%	0.30%	0.00%
Power Transmission	Hydro One Sault Ste. Marie	Ontario	2019-2026	Revenue Cap	Industry-specific	0.00%	0.30%	0.30%	0.00%
Power Distribution	National Grid[7]	Massachusetts	2019-2024	Revenue Cap	GDPPI	-0.13%	Stretch factor contingent on GDPPI inflation and Company performance in benchmarking studies: PEG expects the consumer dividend to average 0.3%.	-1.42%	-1.72%
Gas Distribution	Nstar Gas	Massachusetts	2020-2030	Revenue Cap	GDPPI	-0.27%	0.15%	-1.03%	-1.18%
Bundled Power Service	Hawaiian Electric	Hawaii	2021-2026	Revenue Cap	GDPPI	NA	Two stretch factors: 0.22% and a fixed dollar amount	0.22%	0.00%
Oil Pipelines	All U.S.	United States	2021-2026	Price Cap	PPI-Finished Goods	NA	NA	0.21%	0.21%
Gas Distribution	Boston Gas	Massachusetts	2021-2026	Revenue Cap	GDPPI	-0.71%	0.30%	-1.00%	-1.30%
Power Distribution	Eversource Energy[6]	Massachusetts	2023-2028	Revenue Cap	GDPPI	NA	0.25% if GDPPI growth exceeds 2%	0.25%	0.00%

		Base Productivity Trend	Stretch Factor	X-Factor Including Stretch Factor	X-Factor Excluding Stretch Factor
Averages*	**All Current and Expired Plans**	**0.44%**	**0.35%**	**0.57%**	**0.06%**
	All Current Plans	**-0.19%**	**0.27%**	**-0.25%**	**-0.44%**
	All Current Canadian Plans	**0.00%**	**0.30%**	**0.30%**	**0.00%**
	All Current U.S. Plans	**-0.37%**	**0.24%**	**-0.52%**	**-0.67%**

*Averages exclude X factors that are percentages of inflation.

1 Shaded plans have expired.

2 Some approved X factors are not explicitly constructed from such components as a base productivity trend and a consumer dividend. Many of these are the outcome of settlements.

3 X factors may not be the sum of the acknowledged productivity trend and the consumer dividend, where these are itemized, for reasons that include the following: (1) a macroeconomic inflation measure is employed in the attrition relief mechanism or (2) the X factor may incorporate additional adjustments to account for special business conditions.

4 North American X factors typically include any consumer dividend that has been explicitly or implicitly approved.

5 This is a restatement of X factor values that removes explicit consumer dividends that have been approved by regulators. This statement of X is consistent with several recent US multiyear rate plan approvals (e.g., X and the consumer dividend are separate terms). X factors that may have included an implicit consumer dividend are reported as NA.

6 The approved X factor for Eversource Energy had a separate consumer dividend term. To ensure consistency across examples, we have recalculated the X factor to include the consumer dividend term, assuming that the 0.25% consumer dividend will be applied in all years.

7 The approved X factor for National Grid had a separate consumer dividend term. To ensure consistency across examples, we have recalculated the X factor to include the consumer dividend term, assuming that a 0.3% consumer dividend will be applied in all years.

6.8. Alberta Productivity Trends

The sample period for our research on the productivity trends of Alberta power distributors was the seventeen years from 2007 to 2023. This period encompasses the six-years from 2007 to 2012 during which only ENMAX operated under an MRP. The ENMAX plan had limited provisions for supplemental capital revenue, while the other distributors filed frequent rate cases.[112] The accuracy of the capital and total factor productivity trends is reduced in these years by the recent start of the capital quantity calculations. Our sample period also encompasses ten years, from 2013 to 2022, when all four DFOs operated under PBR.

Tables 10a, 10b, and Figure 1 provide results of our electric DFO productivity growth calculations.[113] In 2013, ENMAX changed its approach to accounting, causing its measured O&M productivity to plunge. We exclude the ENMAX O&M and TFP growth rates for this year from our average annual productivity growth calculations. The values affected by adjusting the averaging formulas have special shading in the tables.

Consider first the results for the six years before PBR, when three of the four distributors had frequent revenue rebasings. During these years, the 1.7% average annual decline in the TFP of the four DFOs was well below the TFP trend that U.S. power distributors achieved during the last fifteen years. The 0.1% TFP growth trend of ENMAX was considerably more rapid than the -2.3% TFP growth trend of the other three distributors. The 0.8% trend in the O&M productivity of ENMAX compared to the -0.7% trend in the O&M productivity of the other three. More remarkably, the -0.8% trend in the capital productivity of ENMAX compared to the -4.3% trend in the capital productivity of the other three.

During PBR1, it can be seen that the average O&M productivity growth of the four DFOs accelerated markedly on average, rising from -0.3% annually to 4.7% annually, while capital productivity growth worsened slightly. The acceleration in total factor productivity growth was nonetheless material, rising from -1.7% annually to -0.6% annually.

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[112] The accuracy of productivity calculations is reduced in these early years by the recent start date for the capital calculations.

[113] The productivity peer groups were not designed to provide productivity *trend* benchmarks.

Table 10a

Productivity Trends of Alberta Power Distributors

(Logarithmic Growth Rates)

Year	O&M						Capital						Total Factor					
	ATCO Electric	ENMAX	EPCOR	Fortis Alberta	Alberta Average	Average less ENMAX	ATCO Electric	ENMAX	EPCOR	Fortis Alberta	Alberta Average	Average less ENMAX	ATCO Electric	ENMAX	EPCOR	Fortis Alberta	Alberta Average	Average less ENMAX
2007	-3.2%	-0.3%	23.8%	3.3%	5.9%	8.0%	-4.3%	-1.4%	0.3%	-6.3%	-2.9%	-3.4%	-3.6%	-0.8%	15.4%	-0.8%	2.5%	3.6%
2008	-5.9%	-2.6%	3.6%	3.3%	-0.4%	0.3%	-3.6%	0.2%	-1.7%	-4.6%	-2.4%	-3.3%	-5.0%	-1.4%	1.9%	0.2%	-1.1%	-1.0%
2009	-1.6%	12.5%	-11.5%	6.0%	1.4%	-2.4%	-1.2%	-1.8%	-1.1%	-8.5%	-3.1%	-3.6%	-1.5%	6.0%	-7.8%	-0.4%	-0.9%	-3.2%
2010	-8.4%	-7.2%	-6.4%	-4.5%	-6.6%	-6.4%	-3.7%	-2.0%	-2.6%	-4.4%	-3.2%	-3.5%	-6.2%	-4.3%	-4.8%	-4.4%	-4.9%	-5.1%
2011	-9.5%	4.3%	1.8%	3.5%	0.0%	-1.4%	-6.2%	0.9%	-5.2%	-4.7%	-3.8%	-5.4%	-7.8%	2.2%	-1.5%	-1.6%	-2.2%	-3.6%
2012	-1.8%	-2.0%	-1.8%	-2.7%	-2.1%	-2.1%	-8.3%	-0.7%	-5.0%	-6.3%	-5.1%	-6.5%	-5.3%	-1.2%	-3.4%	-5.0%	-3.7%	-4.6%
2013	-3.7%	-35.8%	7.7%	4.8%	2.9%	NA	-9.0%	-0.3%	-1.3%	-4.3%	-3.7%	NA	-6.6%	-15.2%	3.2%	-1.2%	-1.5%	NA
2014	0.0%	-1.3%	6.1%	-0.8%	1.0%	NA	-5.8%	-3.8%	-2.6%	-1.9%	-3.5%	NA	-3.2%	-2.7%	1.5%	-1.5%	-1.5%	NA
2015	2.7%	6.9%	0.3%	2.5%	3.1%	NA	-3.1%	-3.7%	-7.1%	-3.0%	-4.2%	NA	-0.5%	1.1%	-3.7%	-1.2%	-1.1%	NA
2016	32.7%	13.0%	1.9%	0.7%	12.1%	NA	-2.9%	-0.5%	-9.1%	-3.1%	-3.9%	NA	10.8%	5.1%	-4.4%	-1.9%	2.4%	NA
2017	4.4%	-1.7%	15.3%	-0.9%	4.2%	NA	-1.7%	-3.5%	-8.6%	-3.3%	-4.3%	NA	0.2%	-2.8%	0.3%	-2.7%	-1.2%	NA
2018	-9.9%	-1.3%	18.0%	-3.4%	0.9%	NA	-0.4%	-3.8%	-0.8%	-2.5%	-1.9%	NA	-3.4%	-2.9%	5.0%	-2.7%	-1.0%	NA
2019	14.0%	9.9%	-1.3%	17.2%	9.9%	NA	-0.2%	-0.8%	-0.4%	-1.1%	-0.6%	NA	4.3%	3.1%	-0.7%	3.9%	2.6%	NA
2020	-20.5%	8.6%	2.8%	0.0%	-2.2%	NA	-0.5%	-0.8%	-2.9%	-1.0%	-1.3%	NA	-7.4%	2.6%	-1.0%	-0.7%	-1.6%	NA
2021	4.4%	-0.1%	-2.5%	-2.6%	-0.2%	NA	0.4%	-0.9%	-1.5%	-0.3%	-0.6%	NA	2.0%	-0.6%	-1.8%	-1.0%	-0.4%	NA
2022	*2.2%*	*-2.5%*	*-9.3%*	*1.4%*	*-2.1%*	NA	*-1.8%*	*-1.6%*	*-2.5%*	*-1.5%*	*-1.9%*	NA	*-0.2%*	*-2.0%*	*-5.1%*	*-0.6%*	-2.0%	NA
2023	*1.6%*	*0.0%*	*10.5%*	*0.8%*	*3.2%*	NA	*-2.5%*	*-2.4%*	*-0.8%*	*-0.8%*	*-1.6%*	NA	*-0.8%*	*-1.4%*	*3.5%*	*-0.3%*	0.2%	NA

Average Annual Growth Rates

	O&M						Capital						Total Factor					
2007-2022 (16 years)	**-0.3%**	**2.4%**	**3.0%**	**1.7%**	**1.7%**	**NA**	**-3.3%**	**-1.5%**	**-3.2%**	**-3.5%**	**-2.9%**	**NA**	**-2.1%**	**0.1%**	**-0.4%**	**-1.3%**	**-1.0%**	**NA**
2007-2012 (Pre-PBR)	**-5.1%**	**0.8%**	**1.6%**	**1.5%**	**-0.3%**	**-0.7%**	**-4.6%**	**-0.8%**	**-2.5%**	**-5.8%**	**-3.4%**	**-4.3%**	**-4.9%**	**0.1%**	**0.0%**	**-2.0%**	**-1.7%**	**-2.3%**
2013-2022 (PBR1 and PBR2)	**2.6%**	**3.5%**	**3.9%**	**1.9%**	**3.0%**	**NA**	**-2.5%**	**-2.0%**	**-3.7%**	**-2.2%**	**-2.6%**	**NA**	**-0.4%**	**0.1%**	**-0.7%**	**-1.0%**	**-0.5%**	**NA**
2013-2017 (PBR1)	**7.2%**	**4.2%**	**6.3%**	**1.3%**	**4.7%**	**NA**	**-4.5%**	**-2.4%**	**-5.7%**	**-3.1%**	**-3.9%**	**NA**	**0.1%**	**0.2%**	**-0.6%**	**-1.7%**	**-0.6%**	**NA**
2018-2022 (PBR2)	**-1.9%**	**2.9%**	**1.5%**	**2.5%**	**1.3%**	**NA**	**-0.5%**	**-1.6%**	**-1.6%**	**-1.3%**	**-1.2%**	**NA**	**-0.9%**	**0.0%**	**-0.7%**	**-0.2%**	**-0.5%**	**NA**

Notes: Shading indicates years during which the utility operated under a multiyear rate plan

Special shading indicates a number that was supported by a special calculation to remove the 2013 value for ENMAX.

Italicized data reflect utility forecasts.

Table 10b

Multifactor Productivity Trends of Alberta Power Distributors

(Logarithmic Growth Rates)

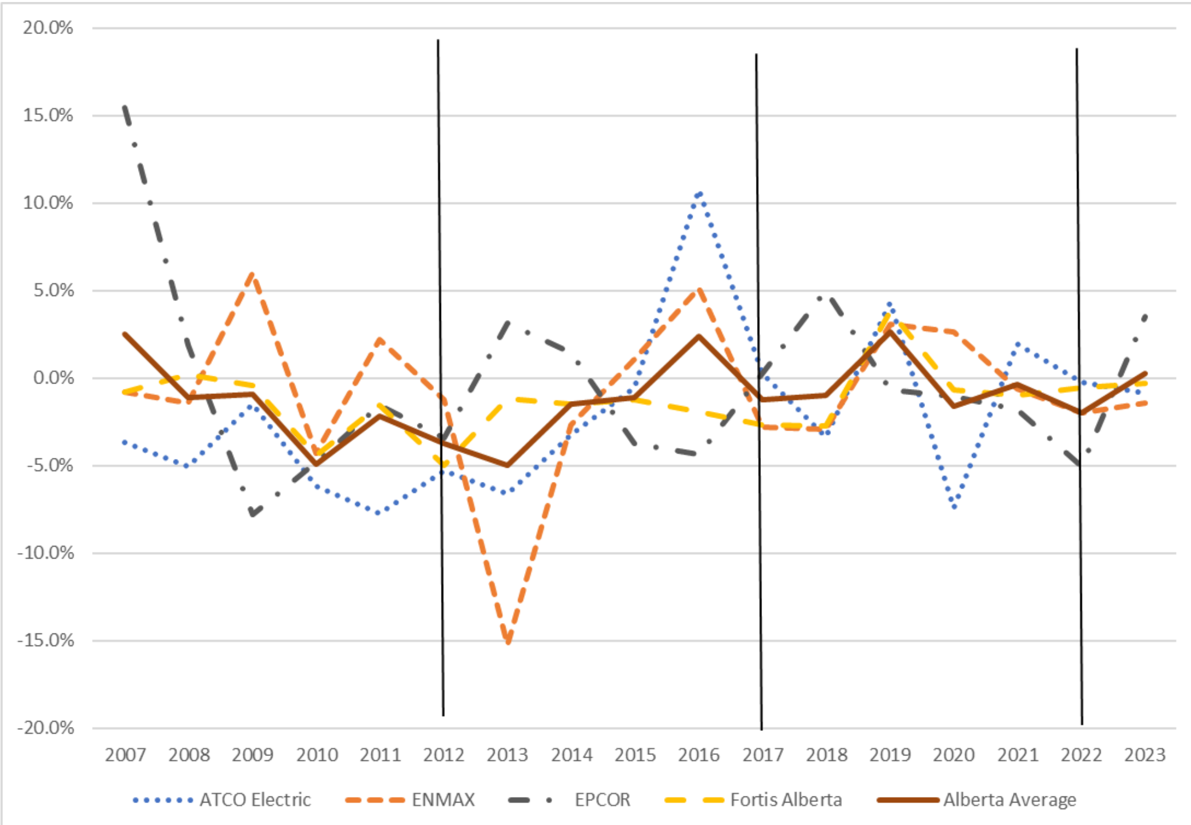
Year	Output (Customers)					Multifactor Inputs					Total Factor				
	ATCO Electric	ENMAX	EPCOR	Fortis Alberta	Alberta Average	ATCO Electric	ENMAX	EPCOR	Fortis Alberta	Alberta Average	ATCO Electric	ENMAX	EPCOR	Fortis Alberta	Alberta Average
2007	3.2%	2.1%	2.6%	3.7%	2.9%	6.8%	3.0%	-12.8%	4.5%	0.4%	-3.6%	-0.8%	15.4%	-0.8%	2.5%
2008	2.7%	2.3%	2.0%	3.4%	2.6%	7.8%	3.7%	0.1%	3.2%	3.7%	-5.0%	-1.4%	1.9%	0.2%	-1.1%
2009	2.0%	1.5%	1.3%	4.2%	2.3%	3.5%	-4.5%	9.2%	4.7%	3.2%	-1.5%	6.0%	-7.8%	-0.4%	-0.9%
2010	1.7%	1.8%	1.6%	2.1%	1.8%	7.9%	6.0%	6.4%	6.5%	6.7%	-6.2%	-4.3%	-4.8%	-4.4%	-4.9%
2011	1.1%	1.4%	1.6%	1.8%	1.5%	8.9%	-0.8%	3.1%	3.4%	3.7%	-7.8%	2.2%	-1.5%	-1.6%	-2.2%
2012	1.4%	1.7%	2.0%	1.7%	1.7%	6.6%	2.9%	5.4%	6.7%	5.4%	-5.3%	-1.2%	-3.4%	-5.0%	-3.7%
2013	1.8%	2.1%	2.5%	1.9%	2.1%	8.4%	17.4%	-0.7%	3.0%	3.6%	-6.6%	-15.2%	3.2%	-1.2%	-1.5%
2014	1.5%	2.1%	2.5%	2.0%	2.0%	4.7%	4.8%	1.1%	3.5%	3.5%	-3.2%	-2.7%	1.5%	-1.5%	-1.5%
2015	1.6%	2.3%	2.9%	2.0%	2.2%	2.2%	1.2%	6.6%	3.2%	3.3%	-0.5%	1.1%	-3.7%	-1.2%	-1.1%
2016	0.0%	2.4%	2.6%	1.8%	1.7%	-10.8%	-2.7%	7.0%	3.7%	-0.7%	10.8%	5.1%	-4.4%	-1.9%	2.4%
2017	-0.1%	1.7%	1.9%	1.5%	1.3%	-0.3%	4.5%	1.7%	4.1%	2.5%	0.2%	-2.8%	0.3%	-2.7%	-1.2%
2018	0.6%	1.7%	1.8%	1.3%	1.4%	4.0%	4.6%	-3.2%	4.0%	2.3%	-3.4%	-2.9%	5.0%	-2.7%	-1.0%
2019	0.5%	2.0%	1.7%	1.1%	1.3%	-3.8%	-1.1%	2.4%	-2.7%	-1.3%	4.3%	3.1%	-0.7%	3.9%	2.6%
2020	0.2%	1.9%	1.7%	0.8%	1.1%	7.6%	-0.7%	2.7%	1.5%	2.8%	-7.4%	2.6%	-1.0%	-0.7%	-1.6%
2021	0.2%	1.9%	1.6%	0.9%	1.1%	-1.8%	2.5%	3.4%	1.8%	1.5%	2.0%	-0.6%	-1.8%	-1.0%	-0.4%
2022	*0.3%*	*1.4%*	*1.2%*	*1.2%*	*1.0%*	*0.5%*	*3.4%*	*6.2%*	*1.8%*	*3.0%*	*-0.2%*	*-2.0%*	*-5.1%*	*-0.6%*	*-2.0%*
2023	*0.3%*	*2.3%*	*1.9%*	*1.2%*	*1.4%*	*1.1%*	*3.7%*	*-1.6%*	*1.5%*	*1.2%*	*-0.8%*	*-1.4%*	*3.5%*	*-0.3%*	*0.2%*
Average Annual Growth Rates															
2007-2021 (16 years)	**1.2%**	**1.9%**	**2.0%**	**2.0%**	**1.8%**	**3.4%**	**1.7%**	**2.2%**	**3.4%**	**2.7%**	**-2.1%**	**0.1%**	**-0.4%**	**-1.3%**	**-0.9%**
2007-2012	**2.0%**	**1.8%**	**1.9%**	**2.8%**	**2.1%**	**6.9%**	**1.7%**	**1.9%**	**4.8%**	**3.8%**	**-4.9%**	**0.1%**	**0.0%**	**-2.0%**	**-1.7%**
2013-2021	**0.7%**	**2.0%**	**2.1%**	**1.5%**	**1.6%**	**1.1%**	**1.6%**	**2.3%**	**2.5%**	**1.9%**	**-0.4%**	**0.4%**	**-0.2%**	**-1.0%**	**-0.4%**
2013-2017	**1.0%**	**2.1%**	**2.5%**	**1.8%**	**1.9%**	**0.8%**	**2.0%**	**3.1%**	**3.5%**	**2.4%**	**0.1%**	**0.2%**	**-0.6%**	**-1.7%**	**-0.6%**
2018-2021	**0.4%**	**1.9%**	**1.7%**	**1.0%**	**1.2%**	**1.5%**	**1.3%**	**1.3%**	**1.1%**	**1.3%**	**-1.1%**	**0.6%**	**0.4%**	**-0.1%**	**-0.1%**
2018-2022	**0.4%**	**1.8%**	**1.6%**	**1.1%**	**1.2%**	**1.3%**	**1.7%**	**2.3%**	**1.3%**	**1.6%**	**-0.9%**	**0.0%**	**-0.7%**	**-0.2%**	**-0.5%**

Notes: Shading indicates years during which the utility operated under a multiyear rate plan
Italicized data reflect utility forecasts.
Special shading indicates a number that was supported by a special calculation to remove the 2013 value for ENMAX.

Pacific Economics Group Research, LLC

Figure 1

TFP Growth of Alberta Distributors



During PBR2, the average O&M productivity growth of the four distributors slowed but was still brisk, averaging 1.3% annually. Capital productivity growth, while still negative, improved from -3.9% in PBR1 to -1.2% in PBR2. This was likely due partly to the new K-bar approach that the AUC used to supplement capital revenue. Despite slower customer growth, the average annual TFP growth of the four DFOs held steady at around -0.5% and was similar to the U.S. norm. The materiality of the impact of PBR is striking.

6.9. Econometric Cost Research

Using the latest available data on U.S. utility operations, PEG also developed new econometric models of the relationship of power distributor O&M expenses, capital cost, and total cost to an array of external business conditions. In each model, the dependent variable was *real* cost --- the ratio of nominal cost to the corresponding input price index. This specification enforces a key result of cost theory.[114]

Results of this research are reported in Tables 11-13. Each table reports econometric estimates of model parameters and their associated asymptotic t-statistics and p-values. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero can be rejected at a high level of confidence. These significance tests were used in model development. In all three models, all of the parameter estimates for the first-order terms of the business condition variables were statistically significant and plausible as to sign and magnitude.

Total Cost

Econometric results for PEG's power distribution total cost model are presented in Table 11. Here are some salient results.

- The parameter estimates for the number of customers, ratcheted peak demand, and area served are all highly significant and positive. Of these three, the number of customers has by far the highest estimated cost elasticity. The parameter estimates for most of the quadratic and interaction terms associated with three scale variables were also highly significant. The relationship of total cost to the scale variables was therefore significantly nonlinear.
- Total cost was also higher the fewer gas customers were served and the greater was the forestation of the service territory and the value of construction standards index x overheading.
- The estimate of the trend variable parameter suggests that there was a slight 0.1% annual decline in total cost annually for reasons other than changes in the values of the model's included business condition variables.
- The adjusted R^2 for the model was 0.970. This suggests that the model had a high level of explanatory power.

[114] Theory predicts that 1% growth in a multifactor input price index should produce 1% growth in cost.

Table 11

PEG's Featured Econometric Model of Total Power Distributor Cost

VARIABLE KEY

N =	Number of Customers
D =	Distribution Peak - Ratcheted
A =	Area of Service Territory
PELEC =	Percent of Total Customers Electric
FOR =	Forestation of Service Territory
CS*POH =	Dx Construction Standards Index times Overheading
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.638	33.453	0.000
D	0.309	21.569	0.000
A	0.051	25.661	0.000
N*N	0.683	19.225	0.000
D*D	0.731	26.350	0.000
A*A	0.053	24.744	0.000
N*D	-0.701	-22.568	0.000
N*A	-0.051	-2.476	0.024
D*A	0.001	0.053	0.959
PELEC	0.106	8.966	0.000
FOR	0.161	17.812	0.000
CS*POH	0.328	4.973	0.000
Trend	-0.001	-1.846	0.082
Constant	19.850	1303.440	0.000

Adjusted R^2	0.970
Sample Period	2006-2021
Number of Observations	1,473

Capital Cost

Details of PEG's power distributor capital cost research are presented in Table 12. Here are some key findings.

- The parameter estimates for the number of customers, ratcheted peak demand, and area served are all highly significant and positive. The elasticities of customers and ratcheted peak demand are more similar. Most of the parameter estimates for the quadratic and interaction terms for these scale variables were also highly significant. This suggests that the relationship of capital cost to the scale variables was significantly nonlinear.
- Distribution capital cost was also higher the fewer gas customers were served and the greater was service territory forestation and construction standards x overheading.
- The estimate of the trend variable parameter indicates that there was a slight 0.3% annual decline in capital cost for reasons other than changes in the values of the model's business condition variables.
- The 0.964 value of the adjusted R^2 statistic was very similar to that for the total cost model and indicates a high degree of explanatory power.

Table 12

PEG's Featured Econometric Model of Power Distributor Capital Cost

VARIABLE KEY

N =	Number of Customers
D =	Distribution Peak - Ratcheted
A =	Area of Service Territory
PELEC =	Percent of Total Customers Electric
FOR =	Forestation of Service Territory
CS*POH =	Dx Construction Standards Index times Overheading
Trend =	trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.555	22.345	0.000
D	0.417	23.465	0.000
A	0.072	20.019	0.000
N*N	0.692	23.400	0.000
D*D	0.742	28.932	0.000
A*A	0.052	9.313	0.000
N*D	-0.727	-28.024	0.000
N*A	-0.043	-1.284	0.216
A*D	0.007	0.229	0.822
PELEC	0.123	25.214	0.000
FOR	0.094	17.006	0.000
CS*POH	0.245	2.886	0.010
Trend	-0.003	-1.606	0.127
Constant	17.560	958.762	0.000

Adjusted R^2	0.964
Sample Period	2006-2021
Number of Observations	1,473

O&M Expenses

Results of PEG's econometric distribution O&M cost research are presented in Table 13. Please note the following.

- The parameter estimates for the number of customers served and ratcheted peak demand were statistically significant and positive. The number of customers had a considerably greater impact on O&M cost than it had on capital cost or total cost. This makes sense since O&M expenses include many customer-driven expenses. The data did not support inclusion of the area variable in this model.
- O&M expenses were also found to be higher the fewer gas customers were served and the greater was forestation and the value of construction standards index x overheading.
- The trend variable parameter estimate indicates a material 1.2% annual decline in O&M expenses for reasons other than changes in the values of the business condition variables included in the model.
- Table 13 also reports a 0.914 adjusted R^2 statistic for the O&M cost model. This is below those for the total cost and capital cost models. More of the sampled utilities received outlier scores. Evidently, O&M costs proved more difficult to accurately model than distributor capital cost or total cost.

Table 13

PEG's Featured Econometric Model of Power Distributor O&M Expenses

VARIABLE KEY

N =	Number of Customers
D =	Distribution Peak - Ratcheted
PELEC =	Percent of Total Customers Electric
FOR =	Forestation of Service Territory
CS*POH =	Dx Construction Standards Index times Overheading
Trend =	Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.819	45.169	0.000
D	0.118	7.459	0.000
N*N	0.636	7.485	0.000
D*D	0.778	8.868	0.000
N*D	-0.717	-8.110	0.000
PELEC	0.043	2.205	0.042
FOR	0.237	8.173	0.000
CS*POH	0.483	5.851	0.000
Trend	-0.012	-8.274	0.000
Constant	18.880	599.983	0.000

Adjusted R^2	0.914
Sample Period	2006-2021
Number of Observations	1,473

6.10. Cost Benchmarking Research

Introduction

We benchmarked the non-energy O&M expenses, capital cost, and total cost of the four Alberta electric DFOs using these econometric models. In the sections that follow we first provide a high-level discussion of our benchmarking methods and then compare the business conditions of each DFO to sample norms and provide salient benchmarking results.

Econometric Benchmarking

Econometric benchmarking results are provided for each year from 2013 to ~~2021~~ 2023 for ENMAX and from 2006 to 2023 for the other three electric DFOs. These benchmarks were based on the econometric model parameter estimates in Tables 11-13 and values for the business condition variables which are appropriate for each benchmarked distributor. The resultant benchmarks control for numerous business conditions that drive ~~gas~~ power distributor cost. They also generate estimates of *change* in cost efficiency that are generally more accurate than those provided by productivity indexes.

We report results for each historical year as well as average results for the two forecasted years of 2022-2023. Recollecting the recent year for starting capital cost and quantity calculations in Alberta, the capital cost and total cost benchmarking results are likely to be more accurate in these final years. However, we report results for all years to show that results are largely consistent with those from our productivity indexes.

ENMAX

Company Background

ENMAX Power Corporation ("EPC" or ENMAX) is an electric transmission and distribution utility based in Calgary. It distributes power to most of Calgary's metropolitan area, which in 2021 had a population of about 1.5 million. This is similar to the population of the Ottawa-Gatineau metro area in Canada or that of the Milwaukee area in the States. As the center of Canada's oil and gas industry, Calgary has an unusually large central business district for a city of its size. ENMAX served around 530,000 customers in 2021. With a predominantly urban service territory, a high percentage of the company's distribution facilities are undergrounded.

ENMAX also owns and operates power transmission facilities in the Calgary area but does not distribute natural gas. This limits opportunities to realize scale economies. An affiliate, ENMAX Energy, provides generation and miscellaneous other energy services in Alberta. Another affiliate, Versant Power (formerly Bangor Hydro Electric), is a small electric utility in Maine. ENMAX Corporation, the parent company, is owned by the City of Calgary.

ENMAX has been rolling out AMI for its customers but these facilities are not yet fully operational.

ENMAX Data

Here are some notable idiosyncrasies of ENMAX data.

- Customer account and customer service and information expenses have been itemized only since 2015. In response to a data request, ENMAX provided 5 additional years of data.
- ENMAX reported several categories of plant additions that were not reported by other DFOs including: AFUDC/IDC Adjustments, Capital Accrual, and Construction Funds Collected From Customers in some or all of its Rule 005 filings.
- ENMAX reported its plant additions net of customer contributions in all of its Rule 005 filings.
- O&M labor costs were not available for the forecasted years of 2022 and 2023. PEG had to make an imputation for these.

How the Business Conditions of ENMAX Compare to Sample Norms

Table 14 compares the costs and business conditions of ENMAX to those of the U.S. electric utilities in our productivity research sample. Average values for ENMAX are compared to sample mean averages for the utilities in our econometric sample. The following results of these comparisons are salient.

- The real (input price adjusted) total cost and capital cost of ENMAX were both about 0.4 times the U.S. sample mean. Real O&M expenses were 0.32 times the mean.
- The number of customers served was about 0.6 times the mean while ratcheted peak demand was 0.39 times the mean and the area served was only 0.06 times the mean.
- Customer density and the extent of system undergrounding were both far above the mean.
- AMI penetration was 0.72 times the mean.

Table 14

How the Recent Costs and External Business Conditions of ENMAX Compare to Sample Norms (revised)

Costs and Business Conditions		Units	ENMAX 2021	ENMAX 2022	ENMAX 2023	ENMAX Average 2021-2023 [A]	U.S. Sample Mean (2021) [B]	ENMAX Ave / 2021 Sample Mean [C=A/B]
Costs								
Total Cost	[D]	Canadian Dollars for ENMAX	202,605,680	211,709,470	208,868,136	207,727,762	542,901,444	0.38
O&M Expenses	[E]	Canadian Dollars for ENMAX	70,880,000	74,226,231	79,047,126	74,717,785	197,493,884	0.38
Capital Cost	[F]	Canadian Dollars for ENMAX	131,725,680	137,483,239	129,821,011	133,009,977	345,407,560	0.39
Input Prices								
Total Factor	[K]	Index Number	1.02	1.04	0.98	1.01	1.02	0.99
O&M Expenses	[L]	Index Number	1.19	1.22	1.25	1.22	1.08	1.13
Capital	[M]	Index Number	6.52	6.60	5.95	6.36	6.96	0.91
Real Costs								
Total Cost	[D/K]	Index Number	198,407,144	203,906,881	213,028,223	205,114,083	531,996,501	0.39
O&M Expenses	[E/L]	Index Number	59,438,675	60,724,024	63,070,050	61,077,583	182,563,252	0.33
Capital Cost	[F/M]	Index Number	20,195,356	20,821,805	21,826,717	20,947,959	49,602,619	0.42
Scale Variables								
Customers	[G]	Number	532,799	540,438	552,850	542,029	909,974	0.60
Ratcheted Peak Demand	[H]	MW	1,869	1,869	1,869	1,869	4,824	0.39
Area	[I]	Square km	1,089	1,089	1,089	1,089	18,311	0.06
Customer Density	[G/I]	Ratio	489	496	508	498	122	4.09
Share Service Territory Congested Urban		Ratio	0.61%	0.61%	0.61%	0.61%	0.26%	2.35
Percentage of Line Plant that is Overhead		Percent	21%	21%	21%	21%	63%	33%
Percentage of Service Territory Forested		Percent	8%	8%	8%	8%	58%	0.14
Construction Standards Index		Index Number	0.53	0.53	0.53	0.53	0.31	1.70
Construction Standards x Overhead		Index Number	0.110	0.110	0.110	0.11	0.195	0.57
Share of Gas & Electric Customers Gas		Percent	0%	0%	0%	0%	18%	0.00
Recent Customer Growth		Ratio	1.33	1.33	1.33	1.33	1.10	1.21
Share of Meters AMI		Ratio	39%	45%	45%	43%	59%	0.72

Costs and Business Conditions		Units	ENMAX 2021	ENMAX 2022	ENMAX 2023	Average 2021-2023 [A]	U.S. Sample Mean (2021) [B]	ENMAX Ave / 2021 Sample Mean [C=A/B]
Costs								
Total Cost	[D]	Canadian Dollars for ENMAX	202,605,680	211,709,470	208,868,136	207,727,762	550,774,530	0.38
O&M Expenses	[E]	Canadian Dollars for ENMAX	70,880,000	74,226,231	79,047,126	74,717,785	205,366,971	0.36
Capital Cost	[F]	Canadian Dollars for ENMAX	131,725,680	137,483,239	129,821,011	133,009,977	345,407,560	0.39
Input Prices								
Total Factor	[K]	Index Number	1.02	1.04	0.98	1.01	1.02	0.99
O&M Expenses	[L]	Index Number	1.19	1.22	1.25	1.22	1.08	1.13
Capital	[M]	Index Number	6.52	6.60	5.95	6.36	6.96	0.91
Real Costs								
Total Cost	[D/K]	Index Number	198,545,125	204,048,686	213,176,371	205,256,727	539,380,385	0.38
O&M Expenses	[E/L]	Index Number	59,566,878	60,854,999	63,206,085	61,209,321	189,841,129	0.32
Capital Cost	[F/M]	Index Number	20,195,356	20,821,805	21,826,717	20,947,959	49,602,619	0.42
Scale Variables								
Customers	[G]	Number	532,799	540,438	552,850	542,029	909,974	0.60
Ratcheted Peak Demand	[H]	MW	1,869	1,869	1,869	1,869	4,824	0.39
Area	[I]	Square km	1,089	1,089	1,089	1,089	18,311	0.06
Customer Density	[G/I]	Ratio	489	496	508	498	122	4.09
Share Service Territory Congested Urban		Ratio	0.61%	0.61%	0.61%	0.61%	0.26%	2.35
Percentage of Line Plant that is Overhead		Percent	21%	21%	21%	21%	63%	33%
Percentage of Service Territory Forested		Percent	8%	8%	8%	8%	58%	0.14
Construction Standards Index		Index Number	0.53	0.53	0.53	0.53	0.31	1.70
Construction Standards x Overhead		Index Number	0.110	0.110	0.110	0.11	0.195	0.57
Share of Gas & Electric Customers Electric		Percent	0%	0%	0%	0%	18%	0.00
Recent Customer Growth		Ratio	1.33	1.33	1.33	1.33	1.10	1.21
Share of Meters AMI		Ratio	39%	45%	45%	43%	59%	0.72

- The ENMAX value for the construction standards index was well above the mean.
- Construction standards index x overhead was below the mean due to limited overheading.
- The recent growth of ENMAX customers was well above the mean.
- Forestation was well below the mean.
- ENMAX does not serve gas customers.

Econometric Benchmarking Results

Table 15 and Figure 2 report results of our econometric benchmarking work for ENMAX. Here are some highlights.

Total Cost The total cost benchmarking scores of ENMAX were generally good and fairly stable during the PBR years. On average, the projected/proposed total cost of ENMAX during the 2022-2023 period was below the model's benchmarks by about 18%. This is commensurate with a top quartile ranking amongst our sampled U.S. distributors.

Capital Cost The capital cost benchmarking scores of ENMAX tended to deteriorate during the PBR years but deterioration slowed during PBR2. On average, the projected/proposed capital cost of ENMAX in 2022 and 2023 will be about 4% below our econometric benchmarks. This is commensurate with a middle quartile ranking amongst our sampled U.S. distributors.

O&M Expenses The O&M cost benchmarking scores of ENMAX improved markedly during the PBR years. On average, the projected/proposed O&M cost of ENMAX during 2022 and 2023 will be about 21% below our econometric benchmarks. This is commensurate with a second quartile ranking amongst our sampled U.S. distributors.

Table 15

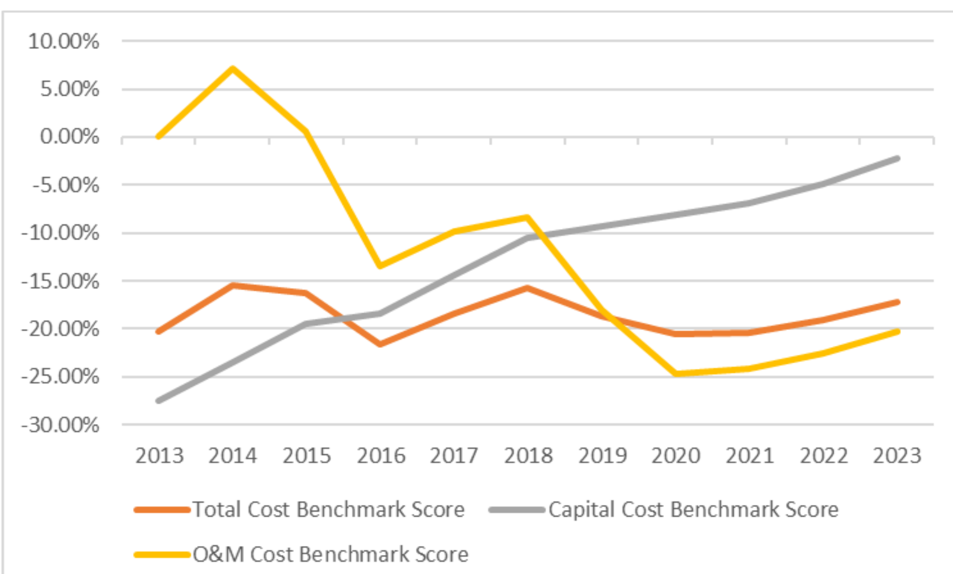
Year-by-Year Econometric Cost Benchmarking Scores: ENMAX

[Actual – Predicted Cost]

Period	Total Cost Benchmark Score	Capital Cost Benchmark Score	O&M Cost Benchmark Score
2013	-20.23%	-27.44%	0.07%
2014	-15.39%	-23.42%	7.11%
2015	-16.24%	-19.41%	0.63%
2016	-21.55%	-18.45%	-13.39%
2017	-18.38%	-14.40%	-9.84%
2018	-15.68%	-10.46%	-8.34%
2019	-18.62%	-9.32%	-18.03%
2020	-20.58%	-8.11%	-24.65%
2021	-20.36%	-6.91%	-24.14%
2022	-19.11%	-4.95%	-22.51%
2023	-17.18%	-2.23%	-20.25%
Annual Averages			
2019-2021	**-19.86%**	**-8.11%**	**-22.27%**
2022-2023	**-18.14%**	**-3.59%**	**-21.38%**

Figure 2

Econometric Cost Benchmarking Scores: ENMAX



EPCOR

Company Background

EPCOR Distribution and Transmission Inc. ("EDTI") is an electric utility based in Edmonton that is owned by the city of Edmonton. It owns and operates the power distribution system within the boundaries of the city. In 2021 the Edmonton metropolitan area had a population of about 1.42 million. This is similar to the population of the Calgary, Milwaukee, Ottawa-Gatineau and Raleigh metro areas in other parts of North America. About 420,000 customers were served in 2021. With a predominantly urban service territory, a high percentage of EPCOR's distribution facilities are undergrounded. EPCOR has completed a buildout of AMI to its electric customers.

EPCOR also provides power transmission, water, and wastewater treatment services in Edmonton. This creates opportunities to realize scope economies which we have not captured in our models. Water utility services are also provided in other Alberta communities and in British Columbia, Saskatchewan, Arizona, New Mexico, and Texas.

EPCOR Data

Here are some notable idiosyncrasies of EPCOR data.

- O&M labor costs were not itemized for 2022 and 2023 and had to be imputed.
- EPCOR did not itemize CSI in any of its Rule 005 filings.
- EPCOR reported its costs differently in 2005 and 2006, such that a specific customer accounts expense level was not itemized.
- EPCOR's Rule 005 filings reported plant additions net of CIAC in all years.
- EPCOR's rebasing proceeding was resolved in a "black box" settlement, which made changes to the 2023 revenue requirement without providing readily available revised forecasts for 2022 and 2023.

How the Business Conditions of EPCOR Compare to Sample Norms

Table 16 compares the costs and business conditions of EPCOR to those of the U.S. electric utilities in our productivity sample. Average values for EPCOR are compared to sample mean averages for the utilities in our econometric sample. The following results of these comparisons are salient.

Table 16

How the Recent Costs and External Business Conditions of EPCOR Compare to Sample Norms (revised)

Costs and Business Conditions		Units	EPCOR 2021	2022	2023	Average 2021-2023 [A]	U.S. Sample Mean (2021) [B]	EPCOR Ave / 2021 Sample Mean [C=A/B]
Costs								
Total Cost	[D]	Canadian Dollars for EPCOR	184,254,310	198,924,089	184,185,552	189,121,317	542,901,444	0.35
O&M Expenses	[E]	Canadian Dollars for EPCOR	62,731,000	72,160,072	67,114,965	67,335,346	197,493,884	0.34
Capital Cost	[F]	Canadian Dollars for EPCOR	121,523,310	126,764,017	117,070,587	121,785,971	345,407,560	0.35
Input Prices								
Total Factor	[K]	Index Number	1.09	1.10	1.04	1.08	1.02	1.06
O&M Expenses	[L]	Index Number	1.22	1.25	1.28	1.25	1.08	1.15
Capital	[M]	Index Number	7.16	7.20	6.47	6.95	6.96	1.00
Real Costs								
Total Cost	[D/K]	Index Number	169,008,969	180,252,179	177,033,710	175,431,619	531,996,501	0.33
O&M Expenses	[E/L]	Index Number	51,495,600	57,788,656	52,420,234	53,901,497	182,563,252	0.30
Capital Cost	[F/M]	Index Number	16,966,075	17,602,347	18,091,124	17,553,182	49,602,619	0.35
Scale Variables								
Customers	[G]	Number	424,801	429,822	438,026	430,883	909,974	0.47
Ratcheted Peak Demand	[H]	MW	1,444	1,444	1,444	1,444	4,824	0.30
Area	[I]		783	783	783	783	18,311	0.04
Customer Density	[G/I]	Ratio	543	549	559	550	122	4.52
Share Service Territory Congested Urban		Ratio	0.58%	0.58%	0.58%	0.58%	0.26%	2.21
Percentage of Line Plant that is Overhead		Percent	24%	24%	24%	24%	63%	0.38
Percentage of Service Territory Forested		Percent	15%	15%	15%	15%	58%	0.26
Construction Standards Index		N/A	0.38	0.38	0.38	0.38	0.31	1.23
Construction Standards x Overhead		Index Number	0.091	0.091	0.091	0.09	0.195	0.47
Share of Gas & Electric Customers Gas		Percent	0%	0%	0%	0%	18%	0.00
Recent Customer Growth		Ratio	1.36	1.36	1.36	1.36	1.10	1.23
Share of Meters AMI		Ratio	100%	101%	101%	101%	59%	1.70

Costs and Business Conditions		Units	EPCOR 2021	EPCOR 2022	EPCOR 2023	EPCOR Average 2021-2023 [A]	U.S. Sample Mean (2021) [B]	EPCOR Ave / 2021 Sample Mean [C=A/B]
Costs								
Total Cost	[D]	Canadian Dollars for EPCOR	184,254,310	198,924,089	184,185,552	189,121,317	550,774,530	0.34
O&M Expenses	[E]	Canadian Dollars for EPCOR	62,731,000	72,160,072	67,114,965	67,335,346	205,366,971	0.33
Capital Cost	[F]	Canadian Dollars for EPCOR	121,523,310	126,764,017	117,070,587	121,785,971	345,407,560	0.35
Input Prices								
Total Factor	[K]	Index Number	1.09	1.10	1.04	1.08	1.02	1.05
O&M Expenses	[L]	Index Number	1.22	1.25	1.28	1.25	1.08	1.15
Capital	[M]	Index Number	7.16	7.20	6.47	6.95	6.96	1.00
Real Costs								
Total Cost	[D/K]	Index Number	169,194,504	180,450,056	177,228,054	175,624,205	539,380,385	0.33
O&M Expenses	[E/L]	Index Number	51,590,206	57,894,824	52,516,539	54,000,523	189,841,129	0.28
Capital Cost	[F/M]	Index Number	16,966,075	17,602,347	18,091,124	17,553,182	49,602,619	0.35
Scale Variables								
Customers	[G]	Number	424,801	429,822	438,026	430,883	909,974	0.47
Ratcheted Peak Demand	[H]	MW	1,444	1,444	1,444	1,444	4,824	0.30
Area	[I]		783	783	783	783	18,311	0.04
Customer Density	[G/I]	Ratio	543	549	559	550	122	4.52
Share Service Territory Congested Urban		Ratio	0.58%	0.58%	0.58%	0.58%	0.26%	2.21
Percentage of Line Plant that is Overhead		Percent	24%	24%	24%	24%	63%	0.38
Percentage of Service Territory Forested		Percent	15%	15%	15%	15%	58%	0.26
Construction Standards Index		N/A	0.38	0.38	0.38	0.38	0.31	1.23
Construction Standards x Overhead		Index Number	0.091	0.091	0.091	0.09	0.195	0.47
Share of Gas & Electric Customers Electric		Percent	0%	0%	0%	0%	18%	0.00
Recent Customer Growth		Ratio	1.36	1.36	1.36	1.36	1.10	1.23
Share of Meters AMI		Ratio	100%	101%	101%	101%	59%	1.70

- The real total and capital cost of EPCOR were both about 0.34 times the sample. Real O&M expenses were 0.28 times the mean.
- The number of customers served was about 0.47 times the mean while ratcheted peak demand was 0.30 times the mean and the area served was only 0.04 times the mean.
- Customer density and the extent of system undergrounding were far above the mean.
- The EPCOR value of the construction standards index was well above the mean.
- The value of the construction standards index x overheading was below the mean due to extensive undergrounding.
- The share of service territory forested was well below the mean.

- Customer growth was well above the mean.
- AMI penetration was well above the mean.
- EPCOR does not serve gas customers.

Econometric Benchmarking Results

Table 17 and Figure 3 report results of our econometric benchmarking work for EPCOR. Here are some highlights.

Total Cost The total cost benchmarking scores of EPCOR were generally good and fairly stable during the years considered. On average, the projected/proposed total cost of EPCOR during 2022 and 2023 will be 22% below our econometric benchmarks. This score is commensurate with a top quartile ranking in our U.S. sample.

Capital Cost The capital cost benchmarking scores of EPCOR tended to decline, especially before PBR2. On average, the projected/proposed capital cost of EPCOR during 2022 and 2023 will be 10% below our econometric benchmarks. This is commensurate with a top quartile ranking in our U.S. sample.

O&M Expenses The O&M benchmarking scores of ENMAX improved markedly during the PBR years. On average, the projected/proposed O&M cost of EPCOR in 2022 and 2023 will be 29% below the benchmarks from our econometric models. This score is commensurate with a top quartile ranking in our U.S. sample.

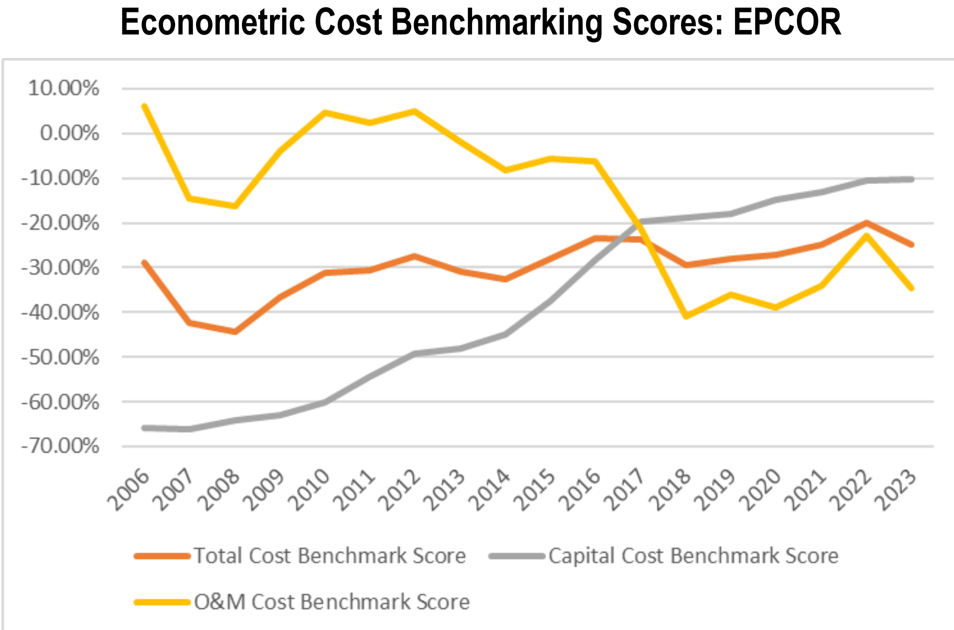
Table 17

Year-by-Year Econometric Cost Benchmarking Scores: EPCOR

[Actual – Predicted Cost]

Period	Total Cost Benchmark Score	Capital Cost Benchmark Score	O&M Cost Benchmark Score
2006	-28.82%	-65.93%	6.09%
2007	-42.51%	-66.06%	-14.47%
2008	-44.29%	-64.30%	-16.33%
2009	-36.68%	-62.91%	-3.89%
2010	-31.25%	-60.04%	4.78%
2011	-30.52%	-54.51%	2.30%
2012	-27.37%	-49.34%	5.08%
2013	-30.89%	-47.97%	-1.94%
2014	-32.73%	-45.02%	-8.24%
2015	-28.04%	-37.62%	-5.52%
2016	-23.48%	-28.31%	-6.28%
2017	-23.79%	-19.73%	-21.43%
2018	-29.35%	-18.75%	-41.04%
2019	-28.05%	-18.09%	-36.11%
2020	-27.30%	-14.97%	-38.97%
2021	-24.99%	-13.07%	-33.92%
2022	-20.09%	-10.54%	-22.94%
2023	-24.79%	-10.22%	-34.63%
Annual Averages			
2019-2021	**-26.78%**	**-15.38%**	**-36.33%**
2022-2023	**-22.44%**	**-10.38%**	**-28.78%**

Figure 3



ATCO Electric

<u>Company Background</u>

ATCO Electric is an investor-owned electric utility based in Edmonton, Alberta. The company's distribution division ("AED") distributes power to small cities, towns, and rural areas in northern Alberta and parts of east-central and southeast Alberta. Fort MacMurray and Grande Prairie are notable communities served. In 2021, the Company served around 230,000 customers. Customer density is unusually low.

The estimated 153,340 sq. km of AED's service territory is vast. Much of the northern region AED serves is forested, while much of the east-central and southeast region outside of towns is crop or range land. The company estimates that 55% of the area it serves is forested.

Winter weather can be unusually severe. Some areas are difficult to access and/or environmentally sensitive. All of these conditions raise cost.

Cost pressures facing AED during the sample period included the rapid growth of the tar sands extraction and processing industry centered in Fort MacMurray and the severe wildfires that afflicted this and other areas of the service territory in 2016.[115] Generation service is provided in some remote communities.

Some of AED's service territory overlaps with those of Rural Electrification Associations ("REAs"). In these shared service areas, members not served by REAs are served by AED. Assets of the company and the REAs are intermingled. AED enters into operating agreements with the REAs and operates some REA assets. In addition to the 69,000 km of distribution lines that it owns, ATCO operates roughly 4,000 km of distribution lines on behalf of REAs. Some company assets carry power to REA customers.

ATCO Electric's Transmission Division provides power transmission services in the service territory. Subsidiary companies provide vertically integrated electric service in Yukon and the Northwest Territories. An affiliated company, ATCO Gas, distributes gas in many parts of Alberta, while ATCO Pipelines provides gas transmission service in the province. Other affiliates of ATCO Electric provide energy services in Australia and Mexico.

The company is currently rolling out AMI.

ATCO Electric Data

ATCO Electric's data have some notable idiosyncrasies.

- O&M labor costs were not itemized for 2022 and 2023 and had to be imputed.
- For the 2005-2012 period, CIAC in plant additions was not separately reported and had to be imputed based on the difference in end of year CIAC balances.
- ATCO Electric provided data on customer contributions for transmission.
- The plant balance for isolated generation was not reported for the benchmark year. This had to be imputed based on the 2012 end of year balance less additions from the intervening years.
- ATCO Electric serves REA customers, but these costs are not clearly itemized in the available data.

[115] Higher costs resulting from these wildfires may, however, have been deferred and amortized.

- ATCO Electric's labor cost data includes salaries and wages and employee benefits data for distribution operations, corporate operations, and other.
- Data on the share of line assets that are overhead or underground were not available.

How ATCO Electric's Business Conditions Compare to Sample Norms

Table 18 compares the costs and business conditions of ATCO Electric to those of the U.S. electric utilities in our productivity sample. Average values for ATCO Electric are compared to sample mean averages for the utilities in our econometric sample. The following results of these comparisons are salient.

- The real total cost of ATCO Electric was 0.60 times the U.S. sample mean while capital cost was 0.65 times the mean and O&M expenses were 0.52 times the mean,
- The number of customers served was meanwhile only 0.25 times the mean while ratcheted peak demand was 0.36 times the mean and the area served was a remarkable 8.37 times the mean.
- Customer density and system undergrounding were far below the mean.
- The ATCO Electric value for the construction standards index was well above the mean.
- The value of construction standards index x overhead was far above the mean.
- Forestation is close to the mean.
- The customer growth of ATCO was modestly above the mean.
- AMI penetration was well below the mean.
- ATCO Electric does not serve gas customers.

Table 18

How the Recent Costs and External Business Conditions of ATCO Electric Compare to Sample Norms (revised)

Costs and Business Conditions		Units	ATCO Electric 2021	2022	2023	Average 2021-2023 [A]	U.S. Sample Mean (2021) [B]	ATCO Electric Ave / 2021 Sample Mean [C=A/B]
Costs								
Total Cost	[D]	Canadian Dollars for ATCO Electric	362,153,594	369,786,867	355,027,106	362,322,522	542,901,444	0.67
O&M Expenses	[E]	Canadian Dollars for ATCO Electric	139,170,500	138,806,849	140,436,646	139,471,332	197,493,884	0.71
Capital Cost	[F]	Canadian Dollars for ATCO Electric	222,983,094	230,980,017	214,590,460	222,851,191	345,407,560	0.65
Input Prices								
Total Factor	[K]	Index Number	1.13	1.15	1.09	1.13	1.02	1.10
O&M Expenses	[L]	Index Number	1.36	1.40	1.43	1.40	1.08	1.29
Capital	[M]	Index Number	7.05	7.15	6.46	6.89	6.96	0.99
Real Costs								
Total Cost	[D/K]	Index Number	319,821,103	320,756,204	324,663,863	321,747,056	531,996,501	0.60
O&M Expenses	[E/L]	Index Number	102,050,558	99,297,159	97,980,652	99,776,123	182,563,252	0.55
Capital Cost	[F/M]	Index Number	31,614,083	32,299,813	33,219,678	32,377,858	49,602,619	0.65
Scale Variables								
Customers	[G]	Number	230,031	230,714	231,424	230,723	909,974	0.25
Ratcheted Peak Demand	[H]	MW	1,739	1,739	1,739	1,739	4,824	0.36
Area	[I]		153,340	153,340	153,340	153,340	18,311	8.37
Customer Density	[G/I]	Ratio	1.50	1.50	1.51	1.50	122	0.01
Share Service Territory Congested Urban		Ratio	0.00%	0.00%	0.00%	0.00%	0.26%	0.00
Percentage of Line Plant that is Overhead		Percent	87%	87%	87%	87%	63%	1.39
Percentage of Service Territory Forested		Percent	55%	55%	55%	55%	58%	0.95
Construction Standards Index		N/A	0.39	0.39	0.39	0.39	0.31	1.25
Construction Standards x Overhead		Index Number	0.338	0.338	0.338	0.34	0.195	1.73
Share of Gas & Electric Customers Gas		Percent	0%	0%	0%	0%	18%	0.00
Recent Customer Growth		Ratio	1.20	1.20	1.20	1.20	1.10	1.10
Share of Meters AMI		Ratio	14%	17%	17%	16%	59%	0.27

Costs and Business Conditions		Units	ATCO Electric 2021	2022	2023	Average 2021-2023 [A]	U.S. Sample Mean (2021) [B]	ATCO Electric Ave / 2021 Sample Mean [C=A/B]
Costs								
Total Cost	[D]	Canadian Dollars for ATCO Electric	362,153,594	369,786,867	355,027,106	362,322,522	550,774,530	0.66
O&M Expenses	[E]	Canadian Dollars for ATCO Electric	139,170,500	138,806,849	140,436,646	139,471,332	205,366,971	0.68
Capital Cost	[F]	Canadian Dollars for ATCO Electric	222,983,094	230,980,017	214,590,460	222,851,191	345,407,560	0.65
Input Prices								
Total Factor	[K]	Index Number	1.13	1.15	1.09	1.13	1.02	1.10
O&M Expenses	[L]	Index Number	1.37	1.40	1.44	1.40	1.08	1.29
Capital	[M]	Index Number	7.05	7.15	6.46	6.89	6.96	0.99
Real Costs								
Total Cost	[D/K]	Index Number	319,480,969	320,415,075	324,318,578	321,404,874	539,380,385	0.60
O&M Expenses	[E/L]	Index Number	101,907,217	99,157,685	97,843,027	99,635,977	189,841,129	0.52
Capital Cost	[F/M]	Index Number	31,614,083	32,299,813	33,219,678	32,377,858	49,602,619	0.65
Scale Variables								
Customers	[G]	Number	230,031	230,714	231,424	230,723	909,974	0.25
Ratcheted Peak Demand	[H]	MW	1,739	1,739	1,739	1,739	4,824	0.36
Area	[I]		153,340	153,340	153,340	153,340	18,311	8.37
Customer Density	[G/I]	Ratio	1.50	1.50	1.51	1.50	122	0.01
Share Service Territory Congested Urban		Ratio	0.00%	0.00%	0.00%	0.00%	0.26%	0.00
Percentage of Line Plant that is Overhead		Percent	87%	87%	87%	87%	63%	1.39
Percentage of Service Territory Forested		Percent	55%	55%	55%	55%	58%	0.95
Construction Standards Index		N/A	0.39	0.39	0.39	0.39	0.31	1.25
Construction Standards x Overhead		Index Number	0.338	0.338	0.338	0.34	0.195	1.73
Share of Gas & Electric Customers Electric		Percent	0%	0%	0%	0%	18%	0.00
Recent Customer Growth		Ratio	1.20	1.20	1.20	1.20	1.10	1.10
Share of Meters AMI		Ratio	14%	17%	17%	16%	59%	0.27

Econometric Benchmarking Results

Table 19 and Figure 4 report results of our econometric benchmarking work for ATCO Electric. Here are some highlights.

Total Cost The total cost benchmarking scores of ATCO Electric deteriorated notably before PBR and have stabilized since then. On average, the projected/proposed total cost of ATCO during 2022 and 2023 will be 55% above our benchmarks.

Capital Cost The capital cost benchmarking scores of ATCO Electric deteriorated markedly over the years considered but stabilized during PBR2. On average, the projected/proposed capital cost of ATCO Electric in 2022 and 2023 will be about 67% above our econometric benchmarks. This is the worst score in Alberta and is commensurate with a bottom quartile ranking amongst the sampled U.S. distributors.

O&M Expenses The O&M benchmarking scores of ATCO Electric tended to deteriorate before PBR. On average, the projected/proposed O&M expenses of ATCO Electric during 2022 and 2023 will be around 71% above our econometric benchmarks.

All of these scores are the worst in Alberta and commensurate with a bottom quartile ranking in the U.S. sample. While it is certainly possible that some special operating conditions of the company have not been captured by our benchmarking model, there is no evidence of average much less superior cost performance.

Table 19

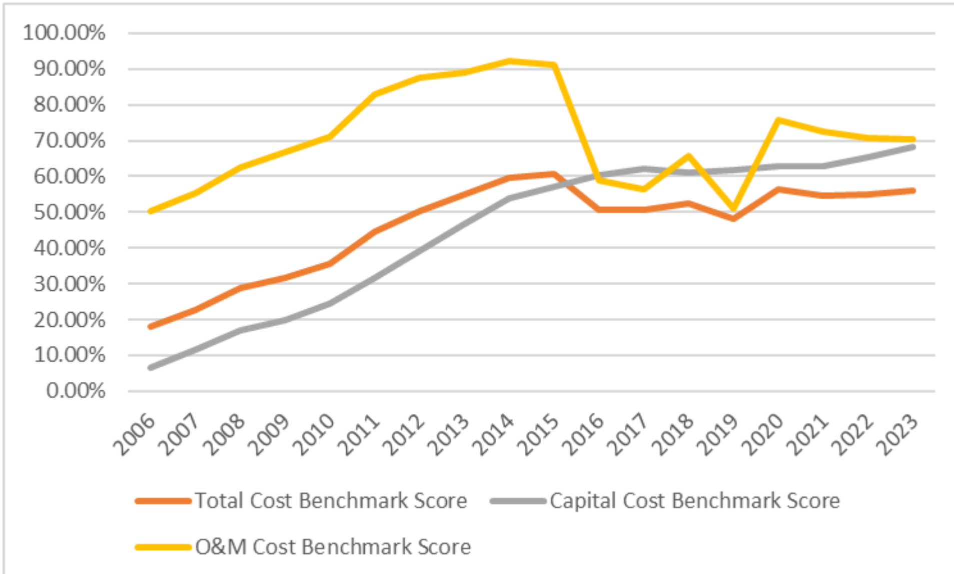
Year-by-Year Econometric Cost Benchmarking Scores: ATCO Electric

[Actual – Predicted Cost]

Period	Total Cost Benchmark Score	Capital Cost Benchmark Score	O&M Cost Benchmark Score
2006	18.07%	6.44%	50.33%
2007	22.75%	11.72%	55.30%
2008	28.84%	17.09%	62.64%
2009	31.71%	19.67%	66.72%
2010	35.79%	24.60%	71.02%
2011	44.56%	31.69%	82.99%
2012	50.45%	39.27%	87.77%
2013	54.91%	46.80%	89.07%
2014	59.77%	53.76%	92.32%
2015	60.82%	57.18%	91.15%
2016	50.58%	60.44%	58.77%
2017	50.59%	62.02%	56.58%
2018	52.38%	61.09%	65.60%
2019	48.13%	61.92%	51.03%
2020	56.31%	62.84%	75.79%
2021	54.57%	62.87%	72.52%
2022	54.85%	65.26%	70.77%
2023	56.04%	68.32%	70.42%
Annual Averages			
2019-2021	**53.00%**	**62.54%**	**66.45%**
2022-2023	**55.44%**	**66.79%**	**70.59%**

Figure 4

Econometric Cost Benchmarking Scores: ATCO Electric



Fortis Alberta

Company Background

FortisAlberta ("Fortis") is an investor-owned electric utility based in Calgary. It distributes power to some cities near Calgary and Edmonton and to numerous towns and rural areas in central and southern Alberta. In 2021, the company served about 600,000 electric customers. Customer density is low.

In addition to serving many agricultural businesses, Fortis serves many oil and gas installations. There are extensive forests in the northern and western reaches of its service territory and extensive crop and pastureland in other areas. Roughly 36% of the service territory is forested.

Some areas of the company's service territory overlap with those of REAs. In these shared service areas, customers not served by REAs are served by Fortis. Assets of the company and the REAs are intermingled. Fortis enters into operating agreements with the REAs and operates some REA assets. Some company assets carry power to REA customers. The Fortis cost to serve REAs was recently estimated to be $10 million.

Fortis provides no power generation, transmission, or gas utility services in Alberta.[116] This limits opportunities to realize scope economies. However, its corporate parent Fortis Inc. owns energy utilities in other Canadian jurisdictions (e.g., FortisBC Energy, formerly known as Terasen Gas) and in the United States, Central America, and the Caribbean.

Fortis Data

The FortisAlberta data have some notable idiosyncrasies.

- FortisAlberta did not itemize customer account and CSI expenses prior to 2012.
- Prior to 2012, Fortis did not itemize all of its taxes other than income taxes.
- O&M labor costs were not itemized for 2022 and 2023 and had to be imputed.
- Prior to 2009, Fortis did not itemize the amount of CIAC in plant additions. PEG imputed these values based on the change in end of year CIAC balances.
- Labor costs reported in Rule 005 filings included salaries and wages and employee benefits data for "distribution operations" and "other".
- FortisAlberta serves REA customers, but these costs are not clearly itemized in the available data.
- Data on the share of line assets that are overhead or underground were not available.

How the Business Conditions of Fortis Compare to Sample Norms

Table 20 compares the costs and business conditions of Fortis to those of the U.S. electric utilities in our econometric sample. Average values for Fortis are compared to sample mean averages for the utilities in our econometric sample. The following results of these comparisons are salient.

[116] Most transmission service in the service territory of Fortis is provided by AltaLink.

Table 20

How the Recent Costs and External Business Conditions of Fortis Compare to Sample Norms (revised)

Costs and Business Conditions		Units	FortisAlberta 2021	FortisAlberta 2022	FortisAlberta 2023	FortisAlberta Average 2021-2023 [A]	U.S. Sample Mean (2021) [B]	FortisAlberta Ave / 2021 Sample Mean [C=A/B]
Costs								
Total Cost	[D]	Canadian Dollars for FortisAlberta	443,056,670	460,369,092	440,620,616	448,015,459	542,901,444	0.83
O&M Expenses	[E]	Canadian Dollars for FortisAlberta	130,900,000	133,921,217	137,738,660	134,186,626	197,493,884	0.68
Capital Cost	[F]	Canadian Dollars for FortisAlberta	312,156,670	326,447,875	302,881,956	313,828,834	345,407,560	0.91
Input Prices								
Total Factor	[K]	Index Number	1.07	1.09	1.03	1.07	1.02	1.04
O&M Expenses	[L]	Index Number	1.20	1.23	1.26	1.23	1.08	1.14
Capital	[M]	Index Number	7.09	7.22	6.57	6.96	6.96	1.00
Real Costs								
Total Cost	[D/K]	Index Number	413,360,998	421,012,685	427,301,410	420,558,364	531,996,501	0.79
O&M Expenses	[E/L]	Index Number	108,809,402	108,601,016	108,936,724	108,782,381	182,563,252	0.60
Capital Cost	[F/M]	Index Number	44,004,046	45,196,783	46,105,723	45,102,184	49,602,619	0.91
Scale Variables								
Customers	[G]	Number	604,792	612,236	619,553	612,194	909,974	0.67
Ratcheted Peak Demand	[H]	MW	3,796	3,796	3,796	3,796	4,824	0.79
Area	[I]		224,542	224,542	224,542	224,542	18,311	12.26
Customer Density	[G/I]	Ratio	2.69	2.73	2.76	2.73	122	0.02
Share Service Territory Congested Urban		Ratio	0.00%	0.00%	0.00%	0.00%	0.26%	0.00
Percentage of Line Plant that is Overhead		Percent	87%	87%	87%	87%	63%	1.39
Percentage of Service Territory Forested		Percent	36%	36%	36%	36%	58%	0.61
Construction Standards Index		N/A	0.45	0.45	0.45	0.45	0.31	1.45
Construction Standards x Overhead		Index Number	0.395	0.395	0.395	0.39	0.195	2.02
Share of Gas & Electric Customers Gas		Percent	0%	0%	0%	0%	18%	0.00
Recent Customer Growth		Ratio	1.35	1.35	1.35	1.35	1.10	1.23
Share of Meters AMI		Ratio	94%	93%	93%	93%	59%	1.58

Costs and Business Conditions		Units	FortisAlberta 2021	FortisAlberta 2022	FortisAlberta 2023	FortisAlberta Average 2021-2023 [A]	U.S. Sample Mean (2021) [B]	FortisAlberta Ave / 2021 Sample Mean [C=A/B]
Costs								
Total Cost	[D]	Canadian Dollars for FortisAlberta	443,056,670	460,369,092	440,620,616	448,015,459	550,774,530	0.81
O&M Expenses	[E]	Canadian Dollars for FortisAlberta	130,900,000	133,921,217	137,738,660	134,186,626	205,366,971	0.65
Capital Cost	[F]	Canadian Dollars for FortisAlberta	312,156,670	326,447,875	302,881,956	313,828,834	345,407,560	0.91
Input Prices								
Total Factor	[K]	Index Number	1.07	1.09	1.03	1.06	1.02	1.04
O&M Expenses	[L]	Index Number	1.20	1.23	1.26	1.23	1.08	1.14
Capital	[M]	Index Number	7.09	7.22	6.57	6.96	6.96	1.00
Real Costs								
Total Cost	[D/K]	Index Number	413,785,100	421,444,637	427,739,814	420,989,850	539,380,385	0.78
O&M Expenses	[E/L]	Index Number	109,057,542	108,848,681	109,185,154	109,030,459	189,841,129	0.57
Capital Cost	[F/M]	Index Number	44,004,046	45,196,783	46,105,723	45,102,184	49,602,619	0.91
Scale Variables								
Customers	[G]	Number	604,792	612,236	619,553	612,194	909,974	0.67
Ratcheted Peak Demand	[H]	MW	3,796	3,796	3,796	3,796	4,824	0.79
Area	[I]		224,542	224,542	224,542	224,542	18,311	12.26
Customer Density	[G/I]	Ratio	2.69	2.73	2.76	2.73	122	0.02
Share Service Territory Congested Urban		Ratio	0.00%	0.00%	0.00%	0.00%	0.26%	0.00
Percentage of Line Plant that is Overhead		Percent	87%	87%	87%	87%	63%	1.39
Percentage of Service Territory Forested		Percent	36%	36%	36%	36%	58%	0.61
Construction Standards Index		N/A	0.45	0.45	0.45	0.45	0.31	1.45
Construction Standards x Overhead		Index Number	0.395	0.395	0.395	0.39	0.195	2.02
Share of Gas & Electric Customers Electric		Percent	0%	0%	0%	0%	18%	0.00
Recent Customer Growth		Ratio	1.35	1.35	1.35	1.35	1.10	1.23
Share of Meters AMI		Ratio	94%	93%	93%	93%	59%	1.58

- The real total cost of Fortis was 0.78 times the sample mean while real capital cost was 0.91 times the mean and real O&M expenses were 0.57 times the mean.
- The number of customers served was meanwhile about 0.67 times the mean while ratcheted peak demand was 0.79 times the mean and the area served was a substantial 12.26 times the mean.
- Customer density and the extent of system undergrounding were both far below the mean.
- The Fortis value for the construction standards index was well above the mean.
- The value of construction standards index x overheading was well above the mean.
- Forestation was well below the mean.
- AMI penetration was well above the mean.

- The customer growth of Fortis was well above the mean.
- Fortis does not serve gas customers.

Econometric Benchmarking Results

Table 21 and Figure 5 report results of our econometric benchmarking work for Fortis. Here are some highlights.

Total Cost The total cost benchmarking scores of Fortis were generally good but declined during the sample period before stabilizing during PBR2. On average, the projected/proposed total cost of Fortis in 2022 and 2023 will be about 24% below our econometric benchmarks. This is commensurate with a top quartile ranking amongst the sampled US distributors.

Capital Cost The capital cost benchmarking scores of Fortis were generally good but tended to deteriorate during the years considered, but deterioration slowed during PBR2. On average, projected/proposed capital cost of Fortis during the 2022 and 2023 will be about 14% below our econometric benchmarks. This is commensurate with a second quartile ranking amongst the sampled US distributors.

O&M Expenses The O&M benchmarking scores of Fortis tended to improve during the years considered. On average, projected/proposed O&M expenses of Fortis in 2022 and 2023 will be about 9% below our econometric benchmarks. This is commensurate with a second quartile score in our U.S. sample.

Table 21

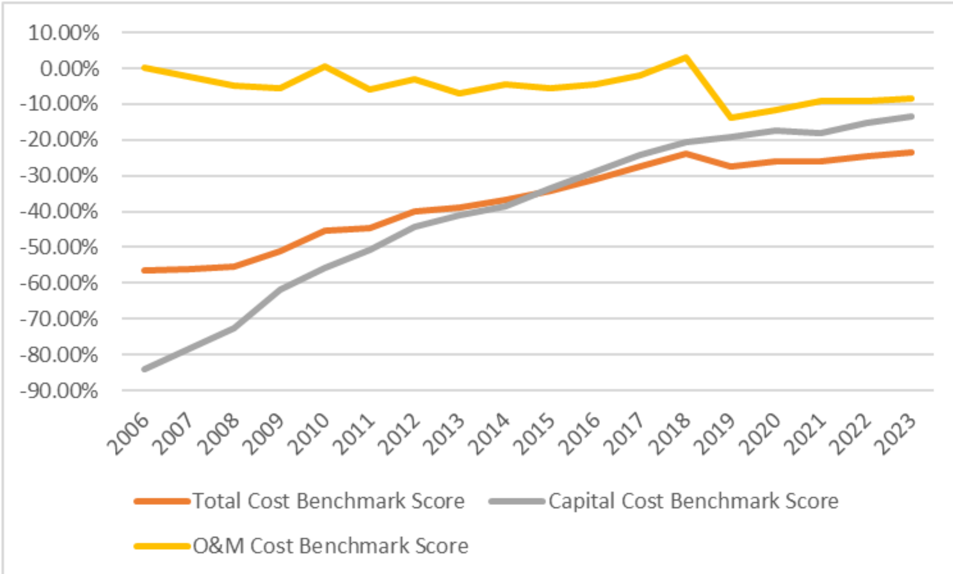
Year-by-Year Econometric Cost Benchmarking Scores: Fortis

[Actual – Predicted Cost]

Period	Total Cost Benchmark Score	Capital Cost Benchmark Score	O&M Cost Benchmark Score
2006	-56.64%	-84.14%	0.16%
2007	-55.96%	-78.31%	-2.51%
2008	-55.47%	-72.77%	-4.89%
2009	-50.97%	-61.73%	-5.73%
2010	-45.23%	-55.89%	0.65%
2011	-44.79%	-50.77%	-5.99%
2012	-39.83%	-44.31%	-2.98%
2013	-39.08%	-40.88%	-6.90%
2014	-36.92%	-38.46%	-4.35%
2015	-34.31%	-33.67%	-5.51%
2016	-31.08%	-29.02%	-4.44%
2017	-27.42%	-24.34%	-2.04%
2018	-23.76%	-20.70%	3.20%
2019	-27.26%	-19.04%	-13.80%
2020	-25.86%	-17.30%	-11.74%
2021	-25.95%	-17.99%	-9.07%
2022	-24.46%	-15.35%	-9.00%
2023	-23.33%	-13.38%	-8.41%
Annual Averages			
2019-2021	**-26.36%**	**-18.11%**	**-11.54%**
2022-2023	**-23.90%**	**-14.36%**	**-8.70%**

Figure 5

Econometric Cost Benchmarking Scores: Fortis



7. X Factor Implications

7.1. Base Productivity Growth Trend

The following considerations are salient in choosing a base TFP growth trend for Alberta power distributors.

- In research for the CCA in this proceeding, PEG has found that TFP trends of sampled U.S. power distributors over the fifteen years from 2007 to 2021 averaged **0.08%.** During this same period, the O&M productivity growth of these distributors averaged 0.66% annually while their capital productivity growth averaged a 0.07% annual decline. Over the same fifteen years, the TFP growth of PEG's Western productivity Peer Group averaged **0.71%** annually while its O&M productivity growth averaged 1.08% annually and its capital productivity growth averaged 0.44% annually.

- The AUC has previously expressed an interest in productivity results over a sample period the choice of which was not subject to concerns about subjectivity. The full sample period for our research for the CCA was chiefly limited by the non-availability of electronic data files prior to the mid-1990s. A longer sample period would have taken more work than time and budget allowed. Hence, no subjectivity was involved.

  Over the full 26-year 1996-2021 period over which we gathered and processed data for this study, the TFP growth of sampled U.S. power distributors averaged **0.31%** annually. O&M productivity growth averaged 0.82% annually while capital productivity growth averaged 0.13% annually. PEG's Western Peer Group averaged **0.75%** annually during this period while its O&M productivity averaged 1.28% annually and its capital productivity averaged 0.39% annually.

- NERA most recently presented a U.S. power distribution TFP study in a 2018 Ontario proceeding to support the X factor proposal of his client, a large gas utility. For its full sample period, NERA reported a **0.54%** TFP trend. However, NERA witness Jeff Makholm recommended a **0.00%** base TFP growth trend for his gas utility client. When NERA's research in the Ontario proceeding was corrected and upgraded, PEG reported that the TFP growth of sampled U.S. power distributors averaged **0.49%** annually from 2001-2016.

- The average acknowledged productivity growth target in current Canadian plans is 0.0%.
- The Commission prefers to use the TFP growth trends of power distributors to calibrate the X factors of gas as well as electric power distributors.

Based on the assembled evidence, we recommend a **0.08%** base TFP trend for all gas and electric power distributors. Should the Commission choose a regulatory approach that occasions O&M-specific and capital-specific ARMs, the corresponding base O&M productivity trend is **0.66%** while the capital productivity trend is -0.07%.

Better benefit sharing is an important goal for PBR3. Should the Commission seek an alternative productivity growth target that more effectively shares benefits, we recommend that it consider the **0.31%** national TFP national trend over our full sample period or the **0.71%** fifteen-year TFP trend of our Western Peer Group. However, the benefits of a higher TFP growth target will be reduced by the continuation of K-bar.

7.2. Stretch Factor

We believe that we have made a strong case for the AUC to reconsider its approach to setting stretch factors. There are solid arguments for continuing stretch factors. Linking them to results of statistical benchmarking studies strengthens performance incentives. Stretch factors linked to benchmarking are common in Ontario and Massachusetts. The low implicit stretch factor in PBR2 has been one cause of chronic DFO overearning. A 0% stretch factor should be rewarded, if at all, for convincing evidence of superior total cost performance.

We have provided evidence on DFO cost performance that is useful for setting stretch factors. Results for 2023 are especially pertinent since this is the first year of PBR3 and each company's forecasted/proposed cost for this year has been normalized.

- The forecasted total cost of ENMAX in 2023 was 17% below our econometric benchmark.
- The forecasted total cost of EPCOR in 2023 was 25% below our econometric benchmark.
- The forecasted total cost of ATCO Electric in 2023 was 56% above our econometric benchmark.
- The forecasted total cost of Fortis Alberta in 2023 was 23% below our econometric benchmark.

We provide in Table 22 the stretch factors that are indicated for these scores using various approaches to linking stretch factors to benchmarking which we have discussed. If K-bars continue, their formulas should be adjusted so that the stretch factors do not increase K-bar.

Table 22

Indicated Stretch Factors for Alberta's Electric DFOs

Utility	Total Cost Benchmarking Score, 2023	Ontario Energy Board	Massachusetts DPU	PEG Incentive Power Research	
				Customers get half of expected performance gains	Customers get all of expected performance gains
ATCO Electric	56%	0.60	0.55	0.30	0.60
ENMAX	-17%	0.15	0.33	0.20	0.39
EPCOR	-25%	0.15	0.25	0.20	0.39
FortisAlberta	-23%	0.15	0.25	0.20	0.39

Appendix A: Additional Information on Research Methods

A.1 Average Service Life

Estimation of the quantity of retirements was noted in Section ~~3.2~~2.5 to be a special challenge when the one hoss shay approach is used in a TFP study to estimate the quantity of capital. We seek the *quantity* of capital retirements ("XK_t^R") that corresponds to the *value* of plant retirements ("VK^R") that utilities report. Suppose that the value of retirements is the sum of the values of the gross plant additions of each asset type *j* that were made in year t-N_j ("$VKA_{j,t-N_j}$"), where N_j is the actual service life of the asset. The value of the asset price index in the year that each such addition was made can be denoted as $WKA_{j,t-N_j}$. Then

$$XK_t^R = \sum_j \frac{VKA_{j,t-N_j}}{WKA_{j,t-N_j}} = VK^R \cdot \sum_j \frac{VKA_{j,t-N_j}}{VK_t^R} \cdot \frac{1}{WKA_{j,t-N_j}}. \qquad [A1]$$

Please note the following:

- The quantity of retirements depends on the service life of each asset and the share of each in the value of retirements.
- Since utilities report plant value in historical dollars, assets with shorter service lives tend to get more (implicit) weight in the calculation because they tend to have been installed more recently. On the other hand, these are typically assets, such as meters, that tend to involve a small share of total plant value.
- It is reasonable to approximate equation [A1] with the following

$$XK_t^R = \frac{VK_t^R}{WKA_{t-ASL^R}} \qquad [A2a]$$

where

$$ASL^R = \sum_j \frac{VKA_{j,t-N_j}}{VK_t^R} \cdot N_j. \qquad [A2b]$$

- ASL^R may change over time if service lives and the mix of assets change.

NERA estimated the ASL by taking the ratio of the gross value of all distribution assets ("VK^{gross}") to total distribution depreciation expenses ("*CKD*"). Suppose now that, in each year *t*, the depreciation expense for each asset *j* is the ratio of the gross value of the corresponding plant addition in year *t-s* to the expected service life of the asset ("N_j"). Then

$$\frac{VK_t^{gross}}{CKD_t} = \frac{VK_t^{gross}}{\sum_j \sum_s \frac{VKA_{j,t-s}}{N_j}}$$

$$= \frac{\cancel{VK_t^{gross}}}{\cancel{VK_t^{gross}} \sum_{j,s} \frac{VKA_{j,t-s}}{VK_t^{gross}} \cdot \frac{1}{N_j}}$$

$$= \frac{1}{\sum_{j,s} \frac{VKA_{j,t-s}}{VK_t^{gross}} \cdot \frac{1}{N_j}}$$

$$\approx \cancel{=} ASL_t^D. \quad [A3]$$

Please note the following.

- ASL^D is a reasonable approximation to an average service life. However, it is the average *expected* service life that corresponds to *depreciation* expenses, not the average *actual* service life corresponding to reported *retirements*.
- The formula places a particularly heavy weight on lives of all assets that have been added in recent years (not just short-lived assets such as meters) since these are less depreciated and, with book valuation of capital, are valued in more inflated dollars.
- ASL^D may change over time.
- There are no depreciation expenses corresponding to assets that are fully depreciated but remained a part of gross plant value for several years because they were still serviceable. Thus, ASL_t^D is not a true average.

In the Amalco project PEG calculated an alternative estimate of the ASL corresponding to power distribution plant retirements. We began by reviewing a collection of utility service life studies and compiling the service lives for 12 power distribution asset classes that are reported on the FERC Form 1. For each asset class, we took the arithmetic average of the 23 studies to determine an average service life. Next, we pulled down detailed retirement value data from FERC Form 1. This allowed us to determine what fraction of total retirements corresponded to each asset category. We used this to calculate a mean average service life of the asset categories weighted by the fractions. We did this for each year and company in the sample, except for NSTAR LLC for which we had no data. Then, we dropped all observations that had a mean average service life that was zero or negative. Additionally, there were instances where the sum of the retirement asset categories does not match the total distribution retirements reported by the company. When the difference between the sum and the reported total was more than 1 percent of the summation, we dropped the observation. Some companies reported negative retirements in individual asset categories. This results in negative service lives for those assets, so we dropped these observations as well. After this winnowing process of retirements, we had 1295 observations between 1995 and 2016. The average service life over the full period is 41.9. Furthermore, we observed that the ASL thus calculated barely changed between 1995 and 2016, falling from 41.9 to 41.8.

A.2 Technical Details of PEG's Empirical Research

This section contains more technical details of our empirical research. We first discuss our input quantity and productivity indexes. We then address our methods for calculating input price inflation and capital cost.

Input Quantity Indexes

We have constructed summary O&M, capital, and (for the U.S. only) multifactor input quantity trend indexes~~. In each case~~ in which~~,~~ the growth in the input quantity index is the difference between the growth in cost and the growth in the corresponding input price index.

$$\ln\left(\frac{Input\ Quantities\cancel{Prices}_t}{Input\ \cancel{Price}Quantities_{t-1}}\right) = \ln\left(\frac{Cost_t}{Cost_{t-1}}\right) - \ln\left(\frac{Input\ Prices_t}{Input\ Prices_{t-1}}\right) \qquad [A4]$$

Productivity Growth Rates and Trends

The annual growth rate in each company's productivity index is given by the formula

$$\ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right) = \ln\left(\frac{Outputs_t}{Outputs_{t-1}}\right) - \ln\left(\frac{Inputs_t}{Inputs_{t-1}}\right). \qquad [A5]$$

We then compute the productivity trend of the national or regional peer group by taking an average of the individual company trends. The trend in productivity is its average annual growth rate over multiple years.

Capital Cost and Quantity Specification

A monetary approach was used to measure the capital cost of each utility. Recall from Section 3.4 that under this approach capital cost is the product of a capital quantity index and a capital price index.

$$CK = WKS \cdot XK.$$

Geometric decay was assumed in the construction of both of these indexes.

Data previously processed by PEG permitted us to use 1964 as the initial year for our U.S. capital cost and quantity calculations. The value of each capital quantity index for each U.S. utility in 1964 depends on the net ("book") value of the (distribution or general) plant that it and any predecessor utilities reported. We estimated the quantities of capital in that year by dividing these values, respectively, by triangularized weighted averages of 36 consecutive values of a regional Handy Whitman Index of power distribution construction cost and 16 values of a regional Handy Whitman Index of reinforced concrete building construction cost for periods ending in the benchmark year. A triangularized weighted average places a greater weight on more recent values of the construction cost index. This makes sense intuitively since more recent plant additions are less depreciated and to that extent tend to have a bigger impact on net plant value.

The following geometric decay perpetual inventory equation was used to compute values of each capital quantity index in subsequent years. For any asset category *j*,

$$XK_{j,t} = (1\text{-}d) \cdot XK_{j,t\text{-}1} + \frac{VKA_{j,t}}{WKA_{j,t}}. \qquad \text{[A6]}$$

Here, the parameter *d* is the (constant) economic depreciation rate and $VKA_{j,t}$ is the value of gross additions to utility plant. To determine a value for *d* for U.S. utilities we assumed a 36-year average service life for distribution plant, a 16-year average service life for general plant, a 1.65 declining balance rate for equipment, and a 0.91 declining balance rate for structures *d*.

The ~~formula for the~~ corresponding capital service price indexes used in the research ~~was~~were smoothed versions of the formula

$$WKS_{j,t} = d \cdot WKA_{j,t} + r_t \cdot WKA_{j,t\text{-}1} + (WKA_{j,t} - WKA_{j,t\text{-}1}). \qquad \text{[A7]}$$

The first term corresponds to the cost of depreciation. The second term corresponds to the return on capital. The term in parentheses corresponds to capital gains.

A.3 Econometric Research Methods

This section of the Appendix provides additional and more technical details of our econometric research. We begin by discussing the choice of a form for the econometric benchmarking models. There follows a discussion of econometric methods.

Form of the Econometric Cost Model

Specific forms must be chosen for cost functions used in econometric research. Forms commonly employed by scholars include the linear, double log, and translog. Here is a simple example of a *linear* cost model:

$$C_{h,t} = a_0+a_1 \cdot N_{h,t}+a_2 \cdot D_{h,t}. \quad [A8]$$

Here, for each company h in year t, $C_{h,t}$ is cost, N is the number of customers, and D is ratcheted peak demand. Here is an analogous cost model of *double log* form:

$$\ln C_{h,t} = a_0+a_1 \cdot \ln N_{h,t} +a_2 \cdot \ln D_{h,t}. \quad [A9]$$

The double log model is so-called because variables and the right and left sides of the equation are logged.[117] This specification makes the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, parameter a_1 indicates the percentage change in cost resulting from 1% growth in the number of customers. Elasticity estimates are informative and make it easier to assess the reasonableness of the parameter estimates. It is also noteworthy that, in a double log model, elasticities are *constant* in the sense that they are the same for every value that the cost and business condition variables might assume. This feature is restrictive and may be inconsistent with the true form of the cost relationship we are trying to model.

Here is an analogous model of *translog* form:

$$\ln C_{h,t} = a_o + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln D_{h,t} + a_3 \cdot \ln N_{h,t} \cdot \ln N_{h,t} + a_4 \cdot \ln D_{h,t} \cdot \ln D_{h,t} + a_5 \cdot \ln N_{h,t} \cdot \ln D_{h,t}. \quad [A10]$$

This form differs from the double log form in the addition of quadratic and interaction terms. These are sometimes collectively called second-order terms. Quadratic terms like $\ln D_{h,t} \cdot \ln D_{h,t}$ permit the elasticity of cost with respect to a business condition variable to vary with the value of the variable. The elasticity of cost with respect to a scale variable may, for example, be lower for a small utility than for a

[117] In other words, the variable is used in the equation in natural logarithmic form, as ln(X) instead of X.

large utility. Interaction terms like ln $L_{h,t}$ ·ln $D_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable. For example, the elasticity of cost with respect to forestation may depend on the extent of system undergrounding.

The translog form is a “flexible” functional form. Flexible forms can accommodate a greater variety of the possible functional relationships between cost and the business condition variables. A disadvantage of the translog form is that it involves more variables than simpler forms like the double log. We explained in Section 2.3 that as the number of variables in an econometric model increases, statistical theory suggests that the precision of the model’s parameter estimates and cost predictions falls. It is therefore common in econometric cost research to limit the number of variables accorded translog treatment. Most commonly, only output (and any input) price variables on the right-hand side of the model are translogged.

In our econometric work for the CCA in this proceeding, we have chosen a functional form that has second-order terms only for the scale variables. This permits the model to recognize some nonlinearities. The second-order terms in our model generally had strong statistical support.

Econometric Model Estimation

A variety of parameter estimation procedures are used by econometricians. The appropriateness of each procedure depends on the distribution of the error terms in the cost model. The estimation procedure that is best known, ordinary least squares (“OLS”), is readily available in commercial econometric software. It has good statistical properties under simple assumptions about the structure of the error terms. These assumptions are often violated by real world economic data. Alternatives to OLS are designed to produce better results when error term assumptions are violated.

To diffuse controversy, we have adopted in recent Ontario proceedings and in this study the estimation procedure that has been favored by utility witnesses in Ontario. Specifically, we have used an OLS estimator with robust standard errors which is available in the Stata statistical software package. This approach was used by PEG and the Hydro One Networks witness in the recent Joint Report in a Hydro One PBR proceeding.

A.4 Details of the Power Systems Engineering Forestation, Construction Standards, and Area Variables

Forestation Variable

A forestation variable developed by Power Systems Engineering ("PSE") was used in several cost benchmarking studies that utility witnesses prepared for Ontario PBR proceedings. Here is PSE's discussion of its forestation variable from a recent Ontario report. [118]

> The **percentage of forestation** variable is based on GIS (geographic information system) land cover maps. PSE used the GlobCover 2009 product processed and produced by the European Space Agency ("ESA") and the Université Catholique de Louvain. These maps are matched with the areas served by each utility to create the forestation variable. We would expect that the higher the level of forestation, the higher O&M costs required for right-of-way clearing and service restoration activities. GIS variable data is available for all sampled U.S. utilities and for Hydro One.

For the Alberta utilities, we use estimates of service territory forestation that the distributors provided in response to our preliminary IRs.

Construction Standards Index

PSE also developed a construction standards variable for distribution for an Ontario utility. Given the weather challenges faced by Fortis and ATCO Electric particularly, we have engaged PSE to calculate values for the four Alberta electric DFOs.

The **construction standards index (or loading)** variable measures the minimum requirements for strength of distribution structures, which vary by geographic region. Distribution lines constructed in different regions must withstand different combinations of ice and wind due to local weather. A line designed for harsher loading conditions is more expensive to construct because it may require higher class poles, greater set depth, specialized insulators, and/or stronger hardware.

The loading variable is a way to quantify the expense associated with distribution line construction based on local weather conditions and the resultant regulatory requirements. This is accomplished by evaluating the percentage of strength capacity utilized under required load cases for a

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[118] Fenrick, Steve, Power System Engineering, "Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry," OEB Proceeding EB-2017-0049, Exhibit A-3-2, Attachment 1, November 4, 2016, p. 10.

base distribution structure in different regions. We would expect that a higher minimum construction requirement for a utility would result in higher total costs.

Per the Canadian Standards Association (CSA) and the National Electrical Safety Code (NESC), overhead distribution lines constructed throughout Canada and the United States must withstand a minimum combination of accumulated ice and wind based on local extreme historical weather conditions. As a result, the required minimum design/build structural strength for an overhead distribution line is dependent on the physical location of the line.

This minimum structural strength requirement has a direct influence on the overall capital cost a utility must devote to its overhead distribution plant. For example, a distribution structure designed for harsher loading conditions is more expensive to construct because it may require larger diameter poles, greater setting or foundation depth, specialized insulators, and/or stronger hardware.

Furthermore, since these minimum strength requirements are developed from documented historical weather conditions, they provide an indirect indication of the severity of extreme ice and wind storms that overhead distribution lines are exposed to, which can influence operational and maintenance costs.

To account for the influence of CSA and NESC minimum overhead distribution line structure strength requirements and associated extreme weather conditions as they relate to total cost benchmarking, Power System Engineering's distribution line design engineers developed a related variable for statistical analysis. This was accomplished by evaluating the percentage of utilized strength capacity, under required CSA and NESC load cases, for a base distribution structure in different zones.

"Percentage of utilized strength capacity" is the percentage of the load resulting from specific design criteria (e.g., this line was designed to meet winds of X mph and ice of Y thickness) as a function of the overall maximum strength of the structure. The variable is a way to quantify the expense associated with distribution line construction based on local weather conditions. There were three main steps in developing the variable, as described below.

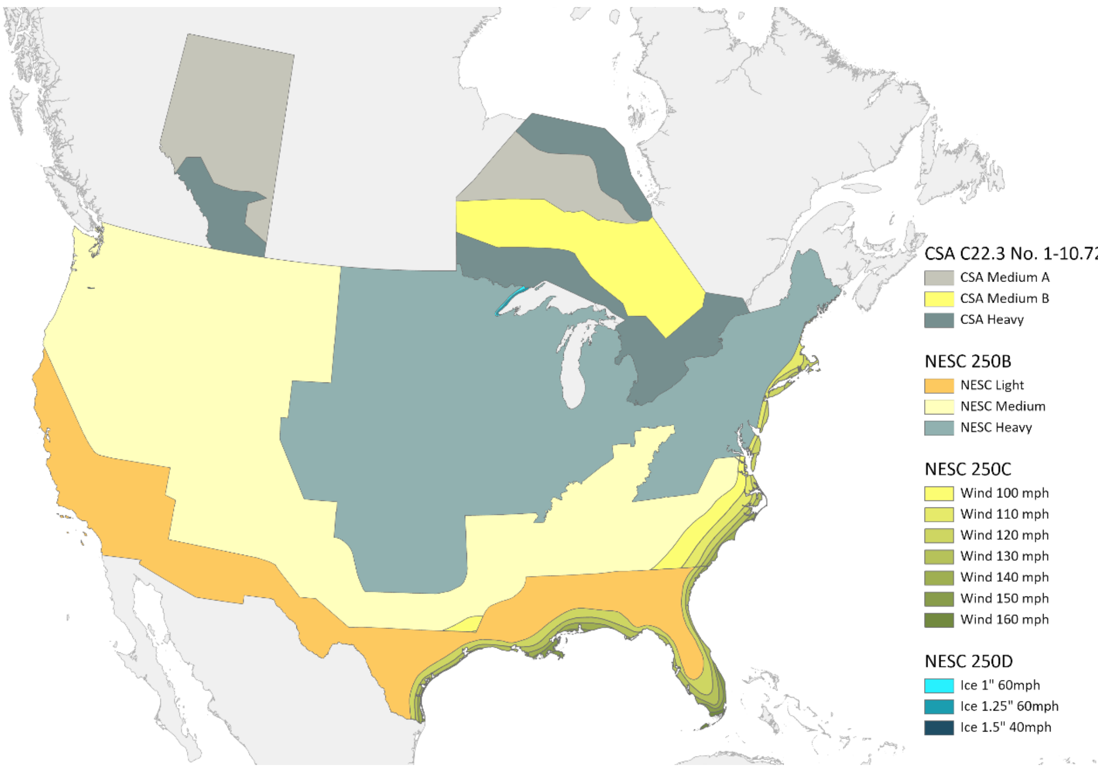
Development of Variable

1. Zones specified by the CSA and NESC were mapped and overlaid with utility service territories.

Industry standards in Canada and the United States dictate minimum requirements for strength of distribution structures, which vary by geographic zone. During design, ice and wind loads are applied to a structure model to analyze strength in terms of percentage of strength capacity used. The zone boundaries and the required ice and wind load cases are outlined in the Canadian Standards Association (CSA) Overhead Systems Standard C22.3 No. 1-10 for Canada, and the National Electrical Safety Code (NESC) for the United States. The loading zones are illustrated in Figure A.1 below.

Utility service territories were overlaid with the above loading zone map. GIS analysis revealed the percentage of a given utility's service territory that fell into each loading zone.

Figure A.1



2. Loading capacity was evaluated for a base structure in each zone.

A base distribution structure was identified to represent a typical application throughout the industry. Specifications are outlined in Table A.1. Although this structure cannot represent an exact base structure for every utility, it is reasonable for side-by-side comparison of relative structure loading values for utilities in each zone.

Table A.1

Base Distribution Structure Specifications

	Metric		English	
Pole Material	Wood - Douglas Fir			
Pole Length	13.72	m	45	ft
Pole Class	3			
Span Length	45.72	m	150	ft
Framing	RUS - C1.11			
Voltage	15 kV			
Construction Grade	CSA Grade 2 / NESC Grade C			
Distribution Conductor	336 (18/1) ACSR			
Neutral Conductor	336 (18/1) ACSR			
Design Tension @ NESC Heavy	11.74	kN	2640	lb

Thus, Table A.2 represents the loads as a percentage of the maximum allowable for the base distribution structure. For example, the design criteria for CSA 7.2 zone "Medium A" is 38.2% of the maximum load strength of the base structure described in Table 13. The design criteria required for a structure in CSA 7.2 zone "Severe" is 72.7% of the maximum load strength of the base structure described in Table A.1.

Industry best practice is to consider local historical weather data for distribution line designs, but the deterministic load cases defined by the CSA and NESC provide minimum requirements for each zone. Therefore, the load cases identified in CSA C22.3 No. 1-20 7.2 and NESC Rule 250B were used for analysis. It is noted that NESC Rules 250C and 250D are not applicable to structures and supported facilities shorter than 18 meters (60 feet) above ground or water level, and the base structure described in Table A.1 does not meet this criteria. Loading zones with the same names in Canada and the United States are not equivalent, e.g. the CSA "Heavy" zone specifies different accumulated ice and wind loads than the NESC "Heavy" zone. Multipliers, including strength factors for structure components and load factors for ice and wind loads, are also specified in each code and were included in this analysis. PLS-CADD Lite, an engineering modeling software application for distribution and transmission structures, was used to complete nonlinear analysis of the base structure for each zonal load case.

Table A.2

Loading Capacity Usage Percentages by Loading Zone

	Zone	Loading [%]
CSA 7.2	Medium A	38.2
	Medium B	40.0
	Heavy	52.9
	Severe	72.7
	Zone	Loading [%]
NESC 250B	Light	34.8
	Medium	23.9
	Heavy	33.1

3. Loading values were calculated for each utility based on the area and loading percentages.

The area percentages derived from the zone map and utility service territory map were multiplied by loading value percentages from PLS-CADD analysis for each loading zone present in a given utility service territory. These values were summed to produce an overall loading value for each utility. This overall loading value represents (roughly) the minimum design/build structural strength required for the utility's service territory.

Data Sources

1. United States load cases: National Electrical Safety Code (NESC) Rules 250B, 250C, and 250D
2. Canadian load cases: Canadian Standards Association (CSA) Overhead Systems C22.3 No. 1-10 7.2
3. Nonlinear loading models: PLS-CADD Lite Version 17.50
4. GIS mapping software: ArcGIS Pro v2.1, ArcGIS Server 10.5, SQL Server 2014
5. Utility service territories: S&P Global – Platts and Power System Engineering acquired service territories <https://www.platts.com/maps-geospatial>

PLS-CADD Lite Model Inputs

Zonal weather criteria are defined in NESC 250B and CSA 22.3 No. 1-10 7.2 and summarized in Table A.3 below. The NESC set includes two additional sets of load cases which do not have counterparts in the CSA. These are Rule 250C: extreme wind loading and Rule 250D: extreme ice with concurrent wind loading. Separate zones were identified for these rules as well.

Table A.3

Weather Criteria

		Wire Ice Density		Air Density Factor		Wind Pressure		Wire Ice Thickness		Ambient Temp		NESC Constant	
		[kg/m^3]	[lbs/ft^3]	[Pa/(m/s)^2]	[psf/mph^2]	[Pa]	[psf]	[mm]	[in]	[°C]	[°F]	[N/m]	[lb/ft]
NESC	Heavy					190.5	4	12.7	0.5	-17.8	0	4.38	0.3
	Medium					190.5	4	6.4	0.25	-9.4	15	2.92	0.2
	Light	913	57.0	0.613	0.00256	428.6	9	0.0	0	-1.1	30	0.73	0.05
	Warm Islands (<9000 ft)					428.6	9	0.0	0	10.0	50	0.73	0.05
	Warm Islands (>9000 ft)					190.5	4	6.4	0.25	-9.4	15	2.92	0.2
CSA	Severe					400	8.40	19.0	0.75	-20	-4		
	Heavy	900	56.2	0.613	0.00256	400	8.40	12.5	0.49	-20	-4	N/A	
	Medium A					400	8.40	6.5	0.26	-20	-4		
	Medium B					300	6.30	12.5	0.49	-20	-4		

Load factors and strength factors are summarized in Tables A.4 and A.5, respectively.

Table A.4

Load Factors

	NESC Grade C	CSA Grade 2
Vertical	1.90	2.70
Tansverse - wind	1.75	1.50
Transverse - wire tensions	1.30	1.50
Longitudinal - at deadends (with terminations or tension changes)	1.30	1.50
Longitudinal - general (without terminations or tension changes)	1.00	1.00

Table A.5

Strength Factors

Type of Load	NESC 250B Grade C	CSA Grade 2
Wood Structures	0.85	not specified - accounted for in load factors
Wood Crossarms & Braces	0.85	
Support Hardware	1.0	
Guy Wire	0.9	
Guy Anchor and Foundation	1.0	

Area Variable

The square kilometers variable that PSE used in Ontario evidence was calculated using GIS coordinates of each utility's service area provided to PSE by Platts. The variable equals the total square kilometers of the area of the distributors service territory. PSE introduced this variable in testimony for Hydro One Networks in EB-2017-0049. For more information on the Platts service see https://www.spglobal.com/platts/en/products-services/oil/map-data-pro. For Alberta utilities, we use area served estimates that the utilities provided in response to PEG's preliminary information requests.

A.5 Insights from Incentive Power Research

PEG Research has for many years undertaken research on the incentive power of alternative regulatory systems. The work has been sponsored by numerous utilities and regulatory agencies, including two Canadian gas distributors, the Ontario Energy Board, and the state of Victoria, Australia's Essential Services Commission. Incentive power research can be used to explore MRP design options such as efficiency carryover mechanisms. Our research in this area was for several years spearheaded by Travis Johnson, a graduate of the Massachusetts Institute of Technology and Stanford Business School who is now a professor at the University of Texas.

This Appendix section first presents a non-technical discussion of the methods used in our incentive power research. We then discuss research results.

Overview of Research Program

At the heart of our research is a mathematical optimization model of the cost management of a company subject to rate regulation. We consider a company facing business conditions that resemble those of a medium-sized energy distributor. In the first year of its hypothetical decision problem, the total annual cost of the company is around $500 million for a company of average efficiency. Capital accounts for a little more than half of the total cost of base rate inputs. The annual depreciation rate is 5%, the weighted average cost of capital is 7%, and the income tax rate is 30%.[119]

Some assumptions are made to simplify the analysis. There is no inflation or output growth that would cause cost to grow over time. Under these assumptions, the utility's revenue will be the same year after year in the absence of a rate case. There is thus no need for complicated adjustments in rate cases to the costs incurred in historical reference years or for attrition relief mechanisms between rate cases.

The company is assumed to have opportunities to reduce its cost of service through cost reduction effort. Two kinds of cost reduction projects are available. Projects of the first type lead to temporary (specifically, one year) cost reductions. Projects of the second type involve a net cost increase in the project's first year in exchange for sustained reductions in future costs. Projects in this category vary in their payback periods. The payback periods we consider are one year, three years, and

[119] The comparatively low WACC reflects our assumption that there is no input price inflation.

five years, respectively. For projects of each kind, there are diminishing returns to additional cost reduction effort in a given year. In total, we currently consider eight kinds of projects, four for O&M expenses and four for capex. The company is permitted to pass up each kind of project in a given year but cannot choose negative levels of effort that amount, essentially, to deliberate waste. This is tantamount to assuming that deliberate waste would be recognized by the regulator and its cost disallowed.

Companies can increase earnings by undertaking cost containment projects, but employees experience distress and other unaccountable costs when pursuing such projects. These costs are assumed for simplicity to occur up front. We have assigned these a value, in the reckonings of employees, that is about one quarter the size of the accountable upfront costs.

The company is assumed to choose the cost containment strategy that maximizes the net present value of its earnings in a given year, less the distress costs of performance improvement, given the regulatory system, the income tax rate, and the available cost reduction opportunities. We are interested in examining how the company's cost management strategy differs under alternative regulatory systems.

Regulatory Systems Considered

Regarding the regulatory systems considered, we have developed five "reference" systems that constitute useful comparators for MRPs. One is "cost plus" regulation, in which a company's revenue is exactly equal to its cost. Another is a full externalization of rates, such as might obtain if the company were to embark on a permanent revenue cap regime with no prospect for future cost-based revenue requirement true-ups.

The other three reference regimes try to approximate traditional regulation. In each, there is a predictable rate case cycle. We consider rate case cycles of ~~one,~~ two~~,~~ and three years.

Various MRPs can be considered using our research method. All are revenue cap plans. The plans differ with respect to three kinds of plan provisions. One is the term of the plan. We consider terms of five, six, and ten years. There is no stretch factor shaving the revenue requirement mechanistically from year to year.

Plans considered vary, secondly, with respect to the earnings sharing specification. We consider earnings sharing mechanisms that have various company/customer allocations of earnings variances.

Company shares considered are 0%, 25%, 50%, and 75%. We will refer to a rate plan that lacks an earnings sharing mechanism as a "basic" rate plan. None of the mechanisms considered have dead bands, as these complicate the calculations. This limits the relevance of the results since many ESMs approved by regulators do have dead bands.

Our characterization of the rate case is important in modeling both traditional regulation and the MRP regimes. We assume in most runs that rates in the initial year of the new regulatory cycle are, with one qualification, set to reflect the cost of service in the last year of the previous regulatory cycle. The qualification is that any up-front accountable costs of initiatives for sustainable cost reductions that are undertaken in the historical reference year are amortized over the term of the plan. This reduces the incentive for the utility to time cost reduction projects to occur in the reference year.

We have also considered the impact of some stylized efficiency carryover mechanisms. In one mechanism the revenue requirement at the start of a new plan is based α% on the *cost* in the last year of the previous plan and (1-α)% on the *revenue requirement* in that year. This effectively permits the company to share any deviation between its cost and the revenue requirement. We consider alternative values of α, ranging from 90% to 50%. [Thus, the externalized share ranges from 10% to 50%].

We also considered an ECM in which the revenue requirement in the first year of a new rate plan is adjusted for a percentage of the variance resulting from a benchmarking appraisal that is completely unrelated to past revenue requirements. We suppose that

$$Requirement_t = Cost_{t-1} + Carryover_{t-1}$$

where the carryover is α% of the difference between a benchmark for cost in period t-1 and the actual cost that was incurred.

$$Carryover_t = \alpha \times (Benchmark_{t-1} - Cost_{t-1})$$

Then

$$Requirement_t = Cost_{t-1} + \alpha \times (Benchmark_{t-1} - Cost_{t-1})$$

$$= \alpha \times Benchmark_{t-1} + (1-\alpha) \times Cost_{t-1}$$

The revenue requirement for the first year of the new MRP plan thus depends only (1-α)% on the cost of service in year t-1.

We have also considered a novel approach to incenting long term efficiency gains which we will call the "revenue option" approach. It gives the company the option to trade a revenue requirement, for the first year of the next rate plan, which is established by conventional means for a revenue requirement that is established on the basis of a predetermined formula. The formula that we consider is a stretch factor reduction in the revenue requirement that is established in the preceding rate plan.

Another decision that must be made in comparing alternative regulatory systems is what occurs at the conclusion of a plan. Our view is that the best way to compare the merits of alternative systems is to have them repeat themselves numerous times. For example, we examine the incentive impact of five-year plan terms by examining the cost containment strategy of a company faced with the prospect of a lengthy series of five-year plans.

Identifying the Optimal Strategy

Numerical analysis was used to predict the utility's optimal strategy. Under this approach we considered, for each regulatory system and each kind of cost containment initiative, thousands of different possible responses by the company. We chose as the predicted strategy the one yielding the highest value for the utility's objective function.

One advantage of numerical analysis in this application is that it permits us to consider regulatory systems of considerable realism. Another is that it facilitates review of our research by stakeholders. The numerical analysis is intuitively appealing, and verification can focus less on how results are derived and more on how sensible and thorough is our characterization of cost containment opportunities and alternative regulatory systems. In a world of input price and output growth, a more complex formula would be required.

Research Results

A summary of results from the incentive power model is found in Tables A.6-A.8

. For each of several regulatory systems, the table shows the net present value of cost reductions from the operation of the system over many years. In the columns on the right-hand side of the table we report the average percentage reduction in the company's total cost that results from the regulatory system. We report outcomes for the first and second rate plans and the long run, and discuss here only the long run results. Results are presented for 10%, 30% and 50% levels of initial operating efficiency. We focus here on the 30% results since our statistical benchmarking research over the years suggests that this is a normal level of operating efficiency.[120] The 30% results can be found in Table A.6, while the 10% and 50% results are found in Tables A.7 and A.8.

Results for Reference Regulatory Systems

Inspecting the results for the reference regulatory systems, it can be seen that no cost reduction initiatives are undertaken under true cost plus regulation. This reflects the fact that there is no monetary reward for undertaking the cost reduction initiatives, all of which involve some cost and effort. At the other extreme, a complete externalization of future rates produces performance improvements relative to cost plus regulation that, over many years, accumulate to an NPV of more than $2 billion.

As for the traditional regulatory systems, it can be seen that a two-year rate case cycle incents companies to achieve long run savings with an NPV of about $657 million ---a major improvement over cost plus regulation but less than half of those that are potentially available. Average annual performance gains rise from 0% to 0.66%. The fact that some cost savings occur under traditional regulation isn't surprising inasmuch as the assumed two-year regulatory cycle permits some gains to be reaped from temporary cost reduction opportunities and from projects with one year payback periods.

Impact of Plan Term

Consider now the effect of extending the plan term beyond the two-year rate case cycle. For a company of average efficiency it can be seen that extending the term from two years to five more than doubles the net present value of cost savings. The average annual performance gain in the long run increases by 75 basis points. The cost saving after ten years would be around 7.5%.

[120] Our statistical benchmarking studies typically find that the worst and best performers identified in the studies have costs that differ from the benchmarks by at least 30%.

Table A.6

Results from the Incentive Power Model

30% initial inefficiency

30% initial inefficiency	**Net Present Value ($m) of Cost Redutions**	**Relative Incentive Power**	**Average Annual Performance Gain***	
			First two rate cycles	Long run
Reference Regulatory Options				
Cost plus	0	**0%**	0.00%	0.00%
2 Year Cost of Service	657	**29%**	1.19%	0.66%
3 Year Cost of Service	899	**39%**	1.22%	0.90%
Full Rate Externalization	2299	**100%**	3.93%	2.71%
Impact of Plan Term				
Term = 3 years	899	**39%**	1.22%	0.90%
Term = 5 years	1318	**57%**	1.93%	1.41%
Term = 6 years	1428	**62%**	1.96%	1.58%
Term = 10 years	1664	**72%**	2.35%	2.23%
Impact of Earnings Sharing Mechanism				
5-year plans				
No Sharing	1318	**57%**	1.93%	1.41%
Company Share = 75%	1075	**47%**	1.29%	1.17%
Company Share = 50%	966	**42%**	1.14%	1.01%
Company Share = 25%	879	**38%**	1.03%	0.88%
Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)				
3-Year Plans, Extern				
Externalized Percentage = 0%	899	**39%**	1.93%	0.90%
Externalized Percentage = 10%	990	**43%**	1.29%	1.07%
Externalized Percentage = 25%	1336	**58%**	1.80%	1.66%
Externalized Percentage = 50%	1799	**78%**	3.41%	2.15%
5-Year Plans, Extern				
Externalized Percentage = 0%	1318	**57%**	1.93%	1.41%
Externalized Percentage = 10%	1469	**64%**	2.07%	1.55%
Externalized Percentage = 25%	1598	**70%**	2.30%	1.76%
Externalized Percentage = 50%	1989	**86%**	3.00%	2.27%
Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)				
3-Year Plans				
Externalized Percentage = 0%	899	**39%**	1.93%	0.90%
Externalized Percentage = 10%	1535	**67%**	2.26%	1.93%
Externalized Percentage = 25%	1824	**79%**	3.68%	2.29%
Externalized Percentage = 50%	2016	**88%**	3.84%	2.54%
5-Year Plans				
Externalized Percentage = 0%	1318	**57%**	1.93%	1.41%
Externalized Percentage = 10%	1621	**70%**	2.34%	1.80%
Externalized Percentage = 25%	1908	**83%**	3.08%	2.31%
Externalized Percentage = 50%	2109	**92%**	3.57%	2.56%
Rate Option Plans				
3-Year Plans				
No rate option	899	**39%**	1.93%	0.90%
Yearly rate reduction = 1%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 1.5%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2.5%	899	**39%**	1.93%	0.90%
5-Year Plans				
No rate option	1318	**57%**	1.93%	1.41%
Yearly rate reduction = 1%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 1.5%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2%	1318	**57%**	1.93%	1.41%
Yearly rate reduction = 2.5%	1318	**57%**	1.93%	1.41%

*** = measured by the average year-over-year percent decrease in costs**

Table A.7

Results from the Incentive Power Model

10% initial inefficiency

10% initial inefficiency	Net Present Value ($m) of Cost Redutions	Relative Incentive Power	Average Annual Performance Gain* First two rate cycles	Average Annual Performance Gain* Long run
Reference Regulatory Options				
Cost plus	0	**0%**	0.00%	0.00%
2 Year Cost of Service	436	**29%**	1.08%	0.57%
3 Year Cost of Service	623	**42%**	1.02%	0.76%
Full Rate Externalization	1496	**100%**	2.64%	2.32%
Impact of Plan Term				
Term = 3 years	623	**42%**	1.02%	0.76%
Term = 5 years	811	**54%**	1.10%	1.15%
Term = 6 years	976	**65%**	1.19%	1.30%
Term = 10 years	1088	**73%**	1.48%	1.73%
Impact of Earnings Sharing Mechanism				
5-year plans				
No Sharing	811	**54%**	1.10%	1.15%
Company Share = 75%	723	**48%**	0.97%	0.97%
Company Share = 50%	653	**44%**	0.87%	0.84%
Company Share = 25%	602	**40%**	0.83%	0.73%
Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)				
3-Year Plans, Extern				
Externalized Percentage = 0%	623	**42%**	1.02%	0.76%
Externalized Percentage = 10%	672	**45%**	1.09%	0.87%
Externalized Percentage = 25%	887	**59%**	1.32%	1.36%
Externalized Percentage = 50%	1123	**75%**	1.87%	1.80%
5-Year Plans, Extern				
Externalized Percentage = 0%	811	**54%**	1.10%	1.15%
Externalized Percentage = 10%	932	**62%**	1.20%	1.27%
Externalized Percentage = 25%	1025	**69%**	1.36%	1.47%
Externalized Percentage = 50%	1239	**83%**	1.91%	1.90%
Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)				
3-Year Plans				
Externalized Percentage = 0%	623	**42%**	1.02%	0.76%
Externalized Percentage = 10%	1037	**69%**	1.65%	1.64%
Externalized Percentage = 25%	1182	**79%**	2.08%	1.94%
Externalized Percentage = 50%	1253	**84%**	2.48%	2.16%
5-Year Plans				
Externalized Percentage = 0%	811	**54%**	1.10%	1.15%
Externalized Percentage = 10%	1033	**69%**	1.42%	1.42%
Externalized Percentage = 25%	1229	**82%**	1.97%	1.83%
Externalized Percentage = 50%	1280	**86%**	2.41%	2.26%
Rate Option Plans				
3-Year Plans				
No rate option	623	**42%**	1.02%	0.76%
Yearly rate reduction = 1%	1496	**100%**	3.93%	2.71%
Yearly rate reduction = 1.5%	1496	**100%**	3.93%	2.71%
Yearly rate reduction = 2%	623	**42%**	1.02%	0.76%
Yearly rate reduction = 2.5%	623	**42%**	1.02%	0.76%
5-Year Plans				
No rate option	811	**54%**	1.10%	1.15%
Yearly rate reduction = 1%	1496	**100%**	2.64%	2.32%
Yearly rate reduction = 1.5%	811	**54%**	1.10%	1.15%
Yearly rate reduction = 2%	811	**54%**	1.10%	1.15%
Yearly rate reduction = 2.5%	811	**54%**	1.10%	1.15%

*** = measured by the average year-over-year percent decrease in costs**

Table A.8

Results from the Incentive Power Model

50% initial inefficiency

50% initial inefficiency	**Net Present Value ($m) of Cost Redutions**	**Relative Incentive Power**	**Average Annual Performance Gain***	
			First two rate cycles	Long run
Reference Regulatory Options				
Cost plus	0	**0%**	0.00%	0.00%
2 Year Cost of Service	905	**30%**	1.33%	0.75%
3 Year Cost of Service	1430	**47%**	2.36%	1.05%
Full Rate Externalization	3022	**100%**	4.75%	3.05%
Impact of Plan Term				
Term = 3 years	1430	**47%**	2.36%	1.05%
Term = 5 years	1778	**59%**	2.29%	1.65%
Term = 6 years	2143	**71%**	2.37%	1.82%
Term = 10 years	2520	**83%**	3.29%	2.42%
Impact of Earnings Sharing Mechanism				
5-year plans				
No Sharing	1778	**59%**	2.29%	1.65%
Company Share = 75%	1603	**53%**	2.06%	1.36%
Company Share = 50%	1520	**50%**	1.96%	1.22%
Company Share = 25%	1354	**45%**	1.75%	1.02%
Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)				
3-Year Plans, Extern				
Externalized Percentage = 0%	1430	**47%**	2.36%	1.05%
Externalized Percentage = 10%	1551	**51%**	2.48%	1.21%
Externalized Percentage = 25%	2017	**67%**	3.17%	1.90%
Externalized Percentage = 50%	2481	**82%**	4.08%	2.42%
5-Year Plans, Extern				
Externalized Percentage = 0%	1778	**59%**	2.29%	1.65%
Externalized Percentage = 10%	1979	**65%**	2.52%	1.81%
Externalized Percentage = 25%	2279	**75%**	2.75%	2.02%
Externalized Percentage = 50%	2666	**88%**	3.68%	2.60%
Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)				
3-Year Plans				
Externalized Percentage = 0%	1430	**47%**	2.36%	1.05%
Externalized Percentage = 10%	2202	**73%**	3.58%	2.20%
Externalized Percentage = 25%	2531	**84%**	4.30%	2.61%
Externalized Percentage = 50%	2793	**92%**	4.61%	2.84%
5-Year Plans				
Externalized Percentage = 0%	1778	**59%**	2.29%	1.65%
Externalized Percentage = 10%	2309	**76%**	2.81%	2.04%
Externalized Percentage = 25%	2558	**85%**	3.68%	2.54%
Externalized Percentage = 50%	2880	**95%**	4.35%	2.88%
Rate Option Plans				
3-Year Plans				
No rate option	1430	**47%**	2.36%	1.05%
Yearly rate reduction = 1%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 1.5%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2.5%	3022	**100%**	4.75%	3.05%
5-Year Plans				
No rate option	1778	**59%**	2.29%	1.65%
Yearly rate reduction = 1%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 1.5%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2.5%	1778	**59%**	2.29%	1.65%

*** = measured by the average year-over-year percent decrease in costs**

Impact of Earnings-Sharing

With respect to earnings sharing note first that, in plans of a given duration, the addition of earnings sharing mechanisms reduces cost savings modestly compared to a plan of the same duration with no sharing mechanism. The lower is the company's share of earnings variances, the lower are cost savings. However, plans of longer duration that have an earnings sharing mechanism can deliver more cost savings than plans of shorter duration that lack an earnings sharing mechanism. For example, a five-year plan with 75/25 sharing produces 51 basis points of additional performance gains compared to a two-year rate case cycle.

Impact of Revenue Requirement Benchmark

Let's consider now the impact of the efficiency carryover mechanism that uses the predetermined revenue requirement from the previous plan as the benchmark. It can be seen that, in the context of a three-year rate plan, assigning the benchmark a weight of only 10% causes average annual performance gains to increase from 0.90% to 1.07%. Gains are similar in a 5-year plan.

Impact of Efficiency Carryover Mechanism with Fully External Benchmark

Let's turn now to the alternative efficiency carryover mechanism approach in which cost in the historical reference year is compared to a fully external benchmark such as that produced by an econometric model developed using industry data. Remarkably, it can be seen that assigning the benchmark a weight of only 10% causes average annual performance gains to increase from 0.90% to 1.93% in a 3-year plan. This suggests that benchmarking has the potential to strengthen performance incentives rather substantially. With a five-year plan term, the effect of the same 10% externalization is still substantial but more modest than in a three-year term. This is mainly due to the fact that more of the potential cost savings are achieved by the five-year term.

Impact of Revenue Option Efficiency Carryover Mechanism

Let's turn now to the impact of the rate option approach to efficiency carryover mechanism design. It can be seen that for stretch factors of 1%, 1.5%, and 2.0%, the rate option approach produces the same substantial cost efficiency savings that would result from full rate externalization with both three- and five-year plan terms. Cost efficiency growth averages 2.71% annually in the long run. Evidently, the company judges that with a high level of cost containment effort it can get its costs permanently below the cost growth target and acts accordingly.

Conclusions

We believe that our incentive power research has yielded important results on the consequences of alternative regulatory systems. Most fundamentally, the results show that the design of a multiyear rate plan can have a major impact on utility performance. Generally speaking, incentives are strengthened by longer plan terms and by ECMs and other schemes to share long term performance gains.

Appendix B: PEG Credentials

PEG is an economic consulting firm with headquarters on Capitol Square in Madison, Wisconsin USA. We are the leading North American consultancy on PBR and statistical research on energy utility productivity trends and cost performance. Our personnel have over sixty years of experience in these fields, which share a common foundation in economic statistics. We have testified or submitted productivity studies in PBR proceedings in at least 18 jurisdictions, from Quebec to Australia.

PEG has also for many years routinely monitored the progress of PBR, preparing surveys and white papers on various plan design topics.

Work for a mix of utilities, regulators, government agencies, and consumer and environmental groups has given us an unusual reputation for objective empirical research and commitment to good regulation. We have had a material impact on the evolution of energy utility PBR in the United States and Canada.

Mark Newton Lowry, the author of this report and principal investigator for this project, is the President of PEG. He has over thirty years of experience as an applied economist, most of which have been spent addressing energy utility issues. Dr. Lowry has prepared productivity and benchmarking research and testimony in more than 30 separate proceedings.

Author of dozens of professional publications, he has also spoken at numerous conferences on utility regulation and statistical performance measurement. He recently coauthored two influential white papers on PBR for Lawrence Berkeley National Laboratory. An advisor on PBR to the British Columbia and Ontario regulatory commissions, he has in the last seven years alone testified or provided commentary in PBR proceedings in Alberta, British Columbia, Colorado, Hawaii, Massachusetts, Minnesota, North Carolina, Ontario, Pennsylvania, Québec, and Washington state. He holds a PhD in applied economics from the University of Wisconsin and resides in Shorewood Hills, Wisconsin near Madison.

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Incentive Rate-Setting for Hydro One Transmission and Distributor Services

12 January 2022

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1. Introduction and Summary

1.1. Introduction

In its August 2021 joint rate application, Hydro One Networks ("Hydro One" or "the Company") proposed a new Custom Incentive Rate-Setting ("CIR") framework for its power transmission and distributor ("T&D") services.[1] The framework involves multiyear rate plans that would apply over the five years from 2023 to 2027. Following a rebasing of transmission and distributor rates for 2023, for the period from 2024 to 2027, in each plan, growth in a revenue cap index ("RCI") would be tied to inflation but slowed by a Productivity Factor ("X") that is the sum of a base productivity growth target and a stretch factor. A Custom Capital Factor ("C") would ensure recovery of substantially all forecasted/proposed capital costs if they were actually incurred.[2]

The proposed X factors are supported by transmission productivity and transmission and distributor ("T&D") cost benchmarking research by Clearspring Energy Advisors, Inc. ("Clearspring"), a Madison, Wisconsin consulting firm.[3] The author of Clearspring's report, Steve Fenrick, prepared similar studies in prior Hydro One proceedings as an employee of Power Systems Engineering.

Hydro One's Custom IR evidence merits careful examination in this proceeding for several reasons.

- Hydro One is Ontario's largest power distributor and provides virtually all transmission services in the province.
- Custom IR has proven to be a controversial approach to ratemaking.
- The stretch factor has an impact on capital cost containment incentives.

[1] EB-2021-0110.

[2] While the revenue cap index formula ensures pass-through of forecasted in-service capital additions, a separate Capital In-service Variance Account would true-up after 2027 (i.e., after the term of the plan) for planned in-service additions not executed over the plan term.

[3] Fenrick, Steve, "Benchmarking and Productivity Research for Hydro One Networks' Joint Rate Application," Exhibit A-4-1/Attachment 1, filed 5 August, 2021.

- Hydro One proceedings have become an important occasion to consider the statistical cost research methods used in Ontario energy rate regulation.

Pacific Economics Group Research LLC ("PEG") is North America's leading energy utility productivity and statistical benchmarking consultancy. Incentive rate-setting ("IR") for power T&D services are company specialties. We have done several power transmission productivity and benchmarking studies and have played a prominent role in the development of IR for power transmission in Québec as well as Ontario. Ontario Energy Board ("OEB") Staff have retained PEG to consider and respond to Clearspring's evidence and the Company's IR proposals.

This is our report on this work. Following a brief summary of our findings, Section 2 provides a summary of Hydro One's proposal. Section 3 provides our critique of Clearspring's transmission research and testimony. Section 4 discusses results of transmission productivity and benchmarking research by PEG using alternative methods. Section 5 provides our critique of Clearspring's distributor cost benchmarking research and testimony. Section 6 discusses distributor productivity and benchmarking results by PEG. Appendix A of the report discusses at a high level the use of index research in the design of a revenue cap index. Appendix B discusses some methodological issues in the research in more detail. Appendix C discusses pertinent features of North America's power transmission industry. Appendix D discusses the evolution of Hydro One ratemaking and Custom IR. A brief discussion of PEG's credentials is provided in Appendix E.

1.2. Summary

Empirical Issues: Transmission

Clearspring developed an econometric model of total power transmission cost using operating data for United States ("U.S.") utilities over the 2000-2019 period. This model was used to benchmark the total cost that Hydro One incurred over the 2003-2019 historical period and the Company's forecasted/proposed cost over the 2020-2027 period. Clearspring also calculated the multifactor productivity ("MFP") trends of 50 U.S. electric utilities in the provision of transmission services from 2000 to 2019.

U.S. Transmission Productivity Trends

Clearspring reported that the sampled U.S. transmitters averaged a 1.66% annual MFP decline over their full 2001-2019 sample period. Productivity in the use of operation, maintenance, and administration ("OM&A") inputs averaged a 2.30% annual decline while capital productivity averaged a 1.50% decline. Clearspring nevertheless recommends a 0.00% base productivity trend for the transmission revenue cap index, and Hydro One embraced this proposal. The 1.66% difference between zero and the calculated transmitter MFP trend is portrayed as an implicit stretch factor.

Our review of Clearspring's productivity research raised the following major concerns.

- The 2001-2019 sample period that Clearspring featured in its productivity research was one during which U.S. power transmission productivity was adversely influenced by special circumstances that included the Energy Policy Act of 2005. The Federal Energy Regulatory Commission ("FERC") was given jurisdiction to oversee reliability standards organizations and to approve mandatory reliability standards. Incentives to contain cost were weakened by special investment incentives and by FERC-administered formula rate plans under which a growing number of transmitters operated. Some transmitters made investments to access remote renewable resources and improve the functioning of bulk power markets. It is not at all clear that the productivity growth challenges faced by U.S. transmitters during this period are comparable on balance to those that Hydro One Transmission currently faces and will face in the next few years.
- Clearspring's treatment of OM&A expenses doesn't handle structural change in the U.S. transmission industry well. Many sampled utilities joined independent transmission system operators ("ISOs") or regional transmission organizations ("RTOs"), and this seems to have triggered idiosyncratic reporting of OM&A expenses of some members. In our view, data for some of the affected companies should be excluded from the research.

PEG's contract with OEB Staff for work in this proceeding does not include new productivity research. We believe that the most pertinent research on the productivity trends of U.S. power transmitters was reported by PEG in a recent proceeding of the Régie de l'énergie in Québec.[4] This research used a longer sample period than Clearspring's and was free of other problems we discuss in this report. Over the full 1996-2019 period, we reported that sampled transmitters averaged -0.62% multifactor productivity growth and -0.68% growth in the productivity of OM&A inputs.

Hydro One's Transmission Cost Performance

Clearspring reported Hydro One's transmission cost performance to be exceptionally good throughout the lengthy sample period that they considered albeit declining over time. The Company's total transmission cost was a substantial 46.6% below the benchmarks from Clearspring's econometric cost model on average over the 2018-2020 period. The Company's forecasted/proposed total cost was 34.5% below the econometric benchmarks during the years of the proposed IRM (2023-2027). The Company's cost efficiency would decline by an average of 1.88% annually between 2023 and 2027.

Our chief concerns about Clearspring's transmission benchmarking work include the following:

- Several companies with implausible transmission OM&A data were included in the study.
- Inappropriate measures of peak load, substations, and the potential for scope economies were used.
- Clearspring did not provide itemized results for Hydro One's transmission OM&A or capital cost performance.

These and other concerns prompted us to develop an alternative econometric total cost benchmarking model while relying chiefly on the Clearspring data. We also developed econometric benchmarking models for capital cost and OM&A expenses ("opex"). These models are sensible (e.g., in terms of explanatory variables, coefficient signs and functional forms) and generate results that should be informative to the OEB, the Company, and other stakeholders.

The results of our alternative total transmission cost benchmarking were quite different from those of Clearspring. Hydro One's total transmission cost was found to be about 7% above our

[4] Lowry, Mark N., "Transmission Productivity and Benchmarking Study," filed in Règie de l'ènergie, R-4167-2021, as exhibit C-AQCIE-CIFQ-0009, 15 February 2021.

benchmarks on average during the three most recent years for which the requisite historical data were available (2017-2019). Hydro One's forecasted/proposed total costs were about 14% above our model's predictions on average during the five years of the proposed new IR plan (2023-2027). The decline in the Company's total cost efficiency would average 1.12% annually between 2023 and 2027.

Hydro One's transmission capital cost was found to be about 6% above our benchmarks on average during the three most recent historical years. The Company's forecasted/proposed capital cost is about 19% above our benchmarks on average during the five years of the proposed new IR plan.

Hydro One's transmission opex was found to be about 36% above our benchmarks on average during the three most recent historical years. The Company's forecasted/proposed opex is about 7% above our model's prediction on average during the five years of the proposed new IR plan. This is a noteworthy improvement.

Stretch Factor

We disagree with Clearspring's 0% stretch factor recommendation. One reason is that we do not get such favorable benchmarking results for Hydro One Transmission. Another is that we believe that a supplemental stretch factor is warranted to adjust for the unusually weak cost containment incentives that many U.S. transmitters experienced in some years of the sample period. We recommend a 0.75% stretch factor that is the sum of a 0.45% base stretch factor and a 0.30% supplemental stretch factor.

X Factor Recommendation

Our research supports a **-0.62%** base productivity trend, drawn from our Québec transmission MFP research for the full sample period, and a **0.75%** stretch factor. The resultant X factor would be 0.13%.

Empirical Issues: Distribution

Hydro One's Distribution Cost Performance

Clearspring developed an econometric model of total power distributor cost using operating data from 81 U.S. electric utilities over the 2000-2019 period. This model was used to benchmark the total cost of base rate inputs which Hydro One Distribution incurred over the historical 2003-2019 period, as well as the Company's forecasted/proposed cost over the 2020-2027 period.

Clearspring reported Hydro One's total distributor cost performance to have been good in the early years of its sample period but to have trended downward over time. The Company's forecasted/proposed total cost is 7% above Clearspring's benchmarks during the years of the proposed CIR plan (2023-2027). Using guidelines established by the OEB for Price Cap IR stretch factors, Clearspring recommends a stretch factor of 0.30%.[5]

Despite our agreement with Clearspring on many methodological issues, we disagree with some of the methods used in their distribution cost benchmarking study. Here are some of our larger concerns.

- Clearspring does not use a plausible value for the area of Hydro One, and this is an important variable in their cost model.
- The substation and scope economy data used in the study were flawed.
- We believe that it desirable to go beyond econometric total cost benchmarking in Custom IR proceedings by benchmarking OM&A and capital costs.

PEG developed a total distributor cost benchmarking model using alternative methods but relying chiefly on Clearspring's data. We found that Hydro One's total distributor cost was about 35% above our benchmark on average during the three most recent historical years. Its projected/proposed total cost is about 37% above our benchmarks on average during the five years of the proposed plan. The Company's total cost efficiency would average a 1.38% annual decline from 2023 to 2027.

PEG also developed models to evaluate Hydro One's projected/proposed distributor opex and capital cost. Hydro One's distributor opex was found to be about 5% above our benchmarks on average during the three most recent historical years. The Company's forecasted/proposed opex is about 7% below our model's prediction on average during the five years of the proposed new IR plan.

[5] Exhibit 1/Tab 1/Schedule 12/Attachment A, p. 8. See also 1.0-VECC-8, OEB-10 b) and OEB-13.

Hydro One's distributor capital cost was found to be about 65% above our benchmarks on average during the three most recent historical years. The Company's forecasted/proposed capital cost is about 72% above our model's prediction on average during the five years of the proposed new CIR plan. It follows that the Company's high capital cost is chiefly responsible for its poor total cost performance.

On the basis of our research, we believe that a 0.60% stretch factor is appropriate for Hydro One's distributor services. Assuming a 0% base MFP trend, we recommend an X factor of 0.60% for these services.

Scale Escalator

Cost theory and index logic support use of a scale escalator in a revenue cap index. It would be reasonable for Hydro One to add a customer growth term to their revenue cap index formula. This would reduce the need for a C factor.

Other Plan Design Issues

We are concerned about some other features of Hydro One's proposal. The proposed ratemaking treatment of capital cost is our chief concern.

- Incentives to contain capex would be weakened by the proposed C factor, Capital In-Service Variance Account ("CISVA"), other capital cost variance accounts, and the Z factor provisions of the revenue cap index. The Company is perversely incented to spend excessive amounts on capital in order to trim OM&A expenses. The weak incentives to contain capex violate the spirit of the Board's Custom IR guidelines and are all the more worrisome given the capital-intensive nature of power transmission technology.
- Notwithstanding the CISVA, Hydro One is still incentivized to exaggerate its need for supplemental capital revenue. The regulatory cost for the OEB and stakeholders is substantially raised and, ultimately, it is ratepayers who bear the burden of the capital cost increases.
- While customers must fully compensate Hydro One for the bulk of expected capital revenue *shortfalls* when capex is high for reasons beyond its control, the Company need not return

any *surplus* capital revenue in future plans if capital cost growth is unusually slow for reasons beyond its control. Over multiple plans, the revenue escalation between rate cases would not guarantee customers the full benefit of the industry's multifactor productivity trend, even when it is achievable.

- The kinds of capex accorded C-factor and variance account treatment are, for the most part, conventional T&D capex like that incurred by transmitters in studies used to calibrate base productivity trends. The Company can then be compensated twice for the same capex: once via the C factor and then again by low X factors in past, present, and future IRMs.
- The RCI would effectively apply chiefly to the (modest) revenue for OM&A expenses and provide only a floor for revenue growth, even though it is not designed to play either of these roles.

We discuss several possible upgrades to the ratemaking treatment of capital cost in Section 6 of the report. It seems desirable to consider how to make Custom IR more streamlined, incentivizing, and fair to customers while still ensuring that it is reasonably compensatory over time for efficient distributors. Utilities should be encouraged to not stay on Custom IR indefinitely.[6] As discussed further below, regulators in other jurisdictions (e.g., Alberta and Britain) who championed IR but found themselves saddled with a system that retained too many cost of service features have reconsidered and reformed IR at the end of each round of plans.

The other reforms discussed in the report range from evolutionary measures such as an incentivized capital variance account to larger departures from the Board's recent Custom IR approaches, such as those used in Alberta and California. Having considered the pros and cons of these

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[6] See EB-2018-0165, Decision and Order, December 19, 2019. While approving Toronto Hydro's Custom IR plan for 2020-2024, the OEB stated:

> The OEB notes that the Custom IR approach taken has required extensive evidence and time to consider the details provided. Toronto Hydro is encouraged to consider an alternative approach in the future that might be more efficient in establishing the revenue requirement for the base year and following years as well as meeting OEB RRF objectives, and improving the balance of risk between customers and the utility. Toronto Hydro should not assume that future panels will continue to accept Toronto Hydro's current proposed Custom IR framework. (p. 24)

options, we recommend an extra stretch factor term for setting the C-factor. The OEB first approved this kind of provision in its recent Hydro One Distribution decision.[7]

We endorse the Company's proposal to be able to keep a small percentage of accumulated capex underspends because this provision strengthens capex containment incentives. We recommend that the Hydro One's share of the value of underspends be 5%, and not 2% as the Company proposes. Hydro One should also be permitted to keep a share of its demonstrated productivity savings.

[7] EB-2017-0049. Decision and Order issued March 7, 2019.

2. Hydro One's Custom IR Proposal

Hydro One has in this proceeding proposed CIR frameworks for its power transmission and distributor services. Multiyear rate plans would set rates for the five-year period from 2023 to 2027. The revenue requirements for 2023 would be established by conventional rebasings that use forward test years. Allowed revenue for the remaining years of the plan would then be escalated using an RCI with a formula that features an Inflation Factor ("I"), Productivity Factor ("X"), Custom Capital Factor ("C"), and Z factor.

$$Growth\ RCI = I - X + C +/- Z.$$

The Company proposes industry-specific inflation measures like those used in its previous CIR plans. For each group of services, the growth rate of the inflation measure would be a weighted average of the growth in two Statistics Canada inflation indexes: Canada's gross domestic product implicit price index for final domestic demand ("$GDPIPIFDD^{Canada}$") and the Average Weekly Earnings for Workers in Ontario ("$AWE^{Ontario}$"). The respective weights on these two indexes would be based on the average shares of labor and other inputs as approved by the OEB in previous decisions. The weights for transmission were approved in the OEB's decisions approving IR plans for Hydro One Sault Ste. Marie and the current CIR plan for HON, based on the total applicable transmission costs of the utilities in the econometric samples in those proceedings.[8] The weights for distribution were approved by the OEB in its December 2013 Report, "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors."[9] The inflation measure would be updated annually.

Each proposed X factor would be fixed during the plan as the sum of a base productivity growth factor and a stretch factor. 0% base productivity growth factors are proposed, which is consistent with

[8] EB-2018-0218 and EB-2019-0082.

[9] EB-2010-0379.

the OEB's 4th generation IRM decision.[10] The proposed stretch factors are supported by Clearspring's total cost benchmarking report.

The proposed C Factor in each RCI is the percentage change in the total revenue requirement which is needed to eliminate any positive difference between the growth in the Company's approved capital revenue requirement and the growth in its capital revenue that is otherwise produced by the RCI. The capital revenue requirement thus defined would include depreciation, return on rate base, and taxes. Hydro One's forecasted/proposed transmission and distributor capital costs are supported by system plans. Supplemental stretch factors of 0.15% would slow the growth in the capital revenue requirement. Its C factor for distribution would average 2.85%, while its C factor for transmission would average 3.04%. HON proposes to update the C Factors each year for inflation.

Several of the Company's costs would be addressed by variance accounts. These would include the costs of pensions and other post-employment benefits and of the development of some new projects and externally-driven projects (e.g., those required by governmental authorities) for transmission. Variance accounts for distribution include the costs of pensions and other post-employment benefits, externally-driven distribution projects (e.g., 3rd-party initiated, distributed energy resource connections, or service upgrades), and AMI 2.0 deployment for distribution. Subsequent to the filing of its Custom IR proposal, Hydro One received approval of a separate variance account for the costs of transmission projects that it is ordered to undertake by the IESO, Order in Council, or direction of the Minister of Energy and that are expected to be owned and included in the rate base of any new partnership affiliated with Hydro One Transmission.[11]

An asymmetrical capital in service variance account ("CISVA") would track the cumulative impact on the revenue requirement of variances between the actual and approved value of in-service plant additions. 98% of any cumulative shortfalls would be disposed of to the benefit of customers at

[10] OEB, EB-2010-0379, *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, November 21, 2013 and as corrected on December 4, 2013.

[11] Examples of projects that would be addressed by this variance account are new transmission lines: the Waasigan Transmission Line, the Chatham to Lakeshore Transmission Line, and the Lambton to Chatham Transmission Line.

the end of the Custom IR term. Hydro One would keep the value of the first 2% of underspends. The Company could also keep shortfalls resulting from verifiable productivity gains.

The company could request Z factor treatment if qualifying events occurred, based on the OEB's existing Z factor policy. A qualifying event would need to result in a change in the revenue requirement of $3 million or more. Events that could trigger a Z factor claim include severe storms and investments that are government-mandated or outside of management's control for other reasons. Z-factor claims in Ontario may address OM&A and/or capital costs of qualifying events. While there is a materiality threshold, that threshold is not used as a dead zone.

Asymmetrical T&D earnings-sharing mechanisms ("ESMs") would share 50% of earnings which exceed the target rate of return on equity ("ROE") by more than 100 basis points in any year. Hydro One has also proposed to apply the OEB's existing off-ramp policy. An off-ramp would be triggered if the Company actual achieved ROE on a regulated basis varied from the OEB-approved ROE by more than 300 basis points (i.e., ± 300 b.p.) in a single year. If an off-ramp is triggered, a regulatory review may be initiated. This review would be prospective in nature and could result in modifications to the plan, the plan continuing without change, or the termination of the plan.

3. Critique of Clearspring's Power Transmission Research

Mr. Fenrick has changed his transmission productivity and benchmarking research methods in the following areas where we were critical of his work as filed and tested in past OEB proceedings.[12] This eliminates some areas of controversy. Here are some notable examples.

- The initial or benchmark year used for the calculation of capital costs and quantities is 1948 now instead of 1988.
- The featured sample period for the U.S. transmission productivity research has 19 (growth rate) years, not 13 years.
- Capital asset prices are levelized using data from multiple cities in the service territory of each utility.
- Construction cost trends in Ontario were computed as a weighted average of the trends in two asset price indexes.
- The OM&A input price indexes now have company-specific weights.
- Pensions and benefits were excluded from the data for Hydro One and all of the U.S. utilities.

3.1 U.S. Transmission Productivity

Clearspring Study

Clearspring calculated the transmission productivity trends of 50 U.S. electric utilities over the nineteen-year 2001-2019 period. A **-1.66**% average annual multifactor productivity growth trend was reported for the sampled transmitters over this period. Growth in OM&A productivity averaged -2.30% while capital productivity growth averaged -1.50%.

Output growth was calculated using a multidimensional index with two scale variables: line length and a 10-year rolling average of maximum peak demand. The weights for these variables were

[12] See for example EB-2017-0049 (Hydro One Dx), EB-2018-0082 (Hydro One Tx), EB-2018-0218 (Toronto Hydro) and EB-2019-0165 (Hydro Ottawa).

based on estimates of their cost elasticities. These estimates were obtained from an econometric model of total power transmission cost which Clearspring developed with data from 50 U.S. utilities for the nineteen-year 2001-2019 period. The weight for line length was 36.6% in the scale index whereas the weight for peak demand was 63.4%.

Capital cost was measured using a variant of the geometric decay method in which capital gains were not considered. The benchmark year in the capital cost computation was 2002 for Hydro One.

PEG Critique

Our examination of Clearspring's productivity research raised several concerns. To facilitate the Board's review of the numerous and often complicated issues that arise in productivity studies, we first highlight our chief concerns with Clearspring's methods. There follows brief discussion of some of our other concerns. Geometric decay and other monetary methods for calculating capital costs, prices, and quantities are discussed in Appendix Section A.2.

Chief Concerns

Sample Period Even though Clearspring lengthened the sample period for its productivity study from thirteen years to nineteen years, the resultant productivity trend may still not be appropriate for the determination of Hydro One's X factor. The transmission capex of sampled utilities was boosted during these years by the need to improve the functioning of bulk power markets and to access remote renewable resources whose development was stimulated by federal tax policy and state renewable portfolio standards. The FERC increased its oversight over transmission reliability, causing many transmitters to incur Critical Infrastructure Protection ("CIP") costs. In addition to the fact that the slowdown in productivity growth due to CIP standards may be temporary, Hydro One may seek to Z factor qualifying material new CIP costs driven by external agencies which the Company incurs during the proposed plan term.

Changes in U.S. regulation weakened transmission cost containment incentives. The FERC has offered ROE premia for some kinds of transmission capex, and a large and growing number of the sampled transmitters operated under formula rate plans administered by the FERC. These plans are essentially comprehensive cost trackers.

The reasons for negative MFP growth in the U.S. during its chosen sample period may thus be very different from the challenges that the Company faces. In this regard, it is notable that Clearspring makes no claim in its evidence that productivity results for its chosen sample period are particularly suitable for Hydro One during the term of the proposed plan. In response to OEB staff interrogatory 339-b in this proceeding, Clearspring stated that

> The challenges that have arisen in the transmission industry have reduced the MFP trend of the sector substantially. These challenges remain present or are growing larger throughout the CIR period. We cannot comment on the relative importance of the drivers and have not conducted a study to disentangle their impacts.

The nineteen-year sample period used by Clearspring is considerably shorter than those featured by both expert witnesses in a recent proceeding by the Régie de l'énergie to reconsider the revenue cap index in the multiyear rate plan of Hydro-Québec Transmission. The Brattle Group represented Hydro-Québec in that proceeding and based its 1.04% X factor recommendation on the transmission MFP trend that it calculated over the 25-year 1995 to 2019 sample period.[13] Dr. Agustin Ros led the Brattle research team and stated on the witness stand in the proceeding that

> I recommend the use of a long-term trend because I'm interested in the long-term X-Factor. It's the long-term that provides the incentive properties of zero economic profits. So I like to use a long-term estimate of what total factor productivity is.[14]

PEG represented a group of industrial intervenors in this Québec proceeding. The 0.62% base productivity trend that we recommended was the MFP trend of sampled U.S. transmitters calculated over the 24-year 1996 to 2019 sample period.

Structural Change Clearspring's treatment of opex does not handle structural change in the U.S. transmission industry well. As discussed further in Appendix C, many U.S. electric utilities joined independent system operators ("ISOs") or regional transmission organizations in the last twenty years. ISO members began purchasing a wide range of transmission services from these agencies and some

[13]Ros, Agustin, Graf, W., Shetty, S., Castaner, M., "Total Factor Productivity and the X-factor for Hydro-Québec TransÉnergie," filed in Règie de l'ènergie proceeding R-4167-2021, as Exhibit B-0012, HQT-5, Document 2, February 19, 2021.

[14] Régie de l'énergie R-4167-2021, Exhibit A-0044,Transcript for 13 decembre 2021, pp.51-52.

members reported these costs idiosyncratically. We believe that this materially affected the reported costs of some companies in ways that are not pertinent to the X factor of Hydro One Transmission.

Capital Cost Specification Capital cost data for Hydro One are available only since 2002.[15] While this situation can't be helped, it can materially reduce the accuracy of capital cost and quantity estimates, as we discuss further in Appendix Section A.2.

3.2 Transmission Cost Benchmarking

Clearspring Research

Clearspring used its econometric transmission cost model to benchmark the total transmission cost of Hydro One. The Company's total cost was substantially below the featured Clearspring benchmarks throughout the sample period but the benchmark scores tended to worsen (i.e., trended towards the benchmark) over time. The Company's cost was nearly 70% below the benchmark in 2008 but its forecasted/proposed total cost is about 35% below the benchmarks on average during the five years of the proposed plan (2023-2027). From 2023 to 2027, the Company's total transmission cost efficiency would average a 1.12% annual decline.

PEG Critique

Our review of Clearspring's transmission benchmarking research raised several concerns. We group these with respect to their importance.

<u>Biggest Concerns</u>

Here are our biggest concerns.

- The econometric sample included data from several companies that reported implausibly large values for dispatch-related and/or miscellaneous transmission expenses. All of these companies were ISO members.

[15] Hydro One apparently does not have plant value data that would permit an earlier benchmark year. We understand that this is due in part to historical circumstances beyond the Company's control.

- Data have been reported on FERC Form 1 for transmission peak demand since 2004. A longer time series is available on the form for monthly peak demand. This is a notion of peak demand that conforms to a utility's native load and requirement sales for resale.[16]

  Clearspring based its peak demand variable on the monthly peak demand data when transmission peak demand is more appropriate. We acknowledge that Clearspring needed to use monthly peak demand for its productivity trend research because the transmission peak load data did not start until 2004 and Clearspring sought an earlier start date. However, there was no need to use the same peak demand variable in the benchmarking research, or to have a sample period for the econometric benchmarking research which was the same as that for the productivity trend research.

- We believe that it is more appropriate to ratchet monthly peak demand than it is to take a rolling average. The term ratcheted peak demand means that the value of the variable equals the highest monthly peak demand that has yet been attained during the sample period. This variable is a reasonable proxy for the expected maximum possible peak demand for grid services.

- In PEG's view, Clearspring's transmission substation data are inaccurate. This is discussed at some length in Appendix Section B.2.

- Clearspring did not include the construction standards index as a cost driver. Mr. Fenrick used this variable in his prior transmission cost benchmark study for Hydro One.

- As a scope economy variable Clearspring used the ratio of transmission gross plant value to total gross plant value. A more appropriate variable is the ratio of transmission gross plant value to total gross plant value less the value of general plant. We are also concerned that scope economy variables based on plant value shares have a large parameter estimate that

[16] An idiosyncrasy of these alternative demand data is that they do not include non-requirements sales for resale. The requirement sales for resale that are included are contractually firm enough that the party receiving the power is able to count on it for system capacity resource planning. Non-requirements sales for resale do not meet this standard and include economy energy. The load associated with non-requirements sales for resale can be shed in times of capacity constraints.

may reflect a correlation between the value of transmission plant and transmission capital cost.

- Clearspring includes an ISO binary variable in its model that assumes a value of 1 if the utility was an ISO member and 0 if it wasn't. The parameter estimate for this variable is unfortunately bolstered by the inappropriate inclusion in the Clearspring sample of data for some ISO members that seem to have idiosyncratically reported their OM&A expenses. We are also concerned that the parameter estimate for this variable may be bolstered by a tendency of ISO members to face cost pressures, not elsewhere properly captured in Clearspring's model, which are unrelated to ISO membership. For example, ISO members are more likely to serve areas with high input prices and urban congestion.

Other Concerns

Here are some less important but nonetheless notable concerns that we have with Clearspring's transmission cost performance research for this proceeding.

- Only Handy Whitman indexes for *transmission* plant were used to calculate capital price and quantity trends even though a modest portion of the assets in the calculations are *general* plant.

4. Alternative Transmission Research by PEG

Our concerns about Clearspring's transmission research have prompted us to produce results using alternative and more defensible methods. In this research, we relied chiefly on Clearspring data but used these data in different ways.

4.1. Benchmarking

Dependent Variable

As in the Clearspring study, the dependent variable in each cost model we developed was *real* cost: the ratio of (nominal) cost to an input price index. This specification enforces a key result of cost theory.[17] Even though input prices are not listed as a business condition variable, our benchmarks therefore reflect the input prices in Hydro One's transmission service territory.

Output Variables

Two output (aka scale) variables were used in our econometric cost model: length of transmission line and ratcheted maximum peak demand. We used Clearspring's line length data, which were drawn from Transmission Line Statistics on page 422 of FERC Form 1. We constructed a ratcheted peak demand variable using the transmission peak demand data Mr. Fenrick relied on in his prior work for Hydro One Transmission.[18]

We followed Clearspring's practice of according the two scale variables in our model a "translog" treatment by adding quadratic and interaction (aka "second-order") terms for these variables to the econometric cost model. No second-order terms were included in this model for the other business condition variables. Functional form issues are discussed further in Appendix Section B.1.

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[17] Theory predicts that 1% growth in a multifactor input price index should produce 1% growth in cost.

[18] See EB-2018-0218, Exhibit D-1-1, Attachment 1, Fenrick, Steve and Sonju, Erik, Power System Engineering, Inc., "Transmission Study for Hydro One Networks: Recommended CIR Parameters and Productivity Comparisons," May 23, 2018, and EB-2019-0082, Fenrick, Steve and Sonju, Erik, Power System Engineering, Inc., "Transmission Study for Hydro One Networks: Recommended CIR Parameters and Productivity Comparisons," January 24, 2019.

Other Business Condition Variables

Seven other business condition variables were used in our transmission cost modelling. Four of these variables address characteristics of the transmission system. These are the average voltage of transmission lines, substation capacity per substation, the number of substations per transmission line kilometer, and the share of transmission assets that are overhead.[19] We expect the parameters of the first three variables to have positive signs, while that for the third should have a negative sign in a transmission total cost or capital cost model.

The extent of transmission plant overheading was measured as the share of overhead plant in the gross value of overhead and underground transmission conductor, device, and structure (pole, tower, and conduit) plant. System overheading typically involves lower capital costs. Since transmission is a capital-intensive business, high overheading should lower total cost.

To measure scope economies we calculated the share of transmission in the gross value of total plant less the value of general plant. The model also includes a forestation variable and the construction standards index for transmission tower construction which Mr. Fenrick developed and used in his prior study for Hydro One Transmission. We expect both of these variables to have positive parameter estimates.

Each model also has a trend variable. This permits cost benchmarks to shift over time for reasons other than changes in the specified business conditions. Trend variables thereby capture the net effect on cost of diverse conditions, such as technical change, which are otherwise excluded from the model. Parameters for such variables often have a negative sign in econometric research on utility cost. However, the expected value of the trend variable parameter in a cost model is *a priori* indeterminate.

[19] The extent of transmission plant overheading was measured as the share of overhead plant in the gross value of overhead and underground transmission conductor, device, and structure (pole, tower, and conduit) plant. System overheading typically involves lower capital costs. Since transmission is a capital-intensive business, high overheading should lower total cost.

4.2 Econometric Results

Details of our three featured econometric cost models are found in Tables 1-3. Each table reports estimates of business condition parameters and their associated asymptotic t-statistics and p-values. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. These significance tests were used in model development. In all three models, the parameters of the business condition variables are statistically significant at a high level of confidence and have sensible signs and parameter values.[20]

Total Cost

Results for our featured total cost model are reported in Table 1. Our research indicates that transmission costs tended to be higher to the extent that sampled utilities had higher peak demand and line length. The parameter estimates for the quadratic and interaction terms for the scale variables were insignificant.

Total transmission cost was also higher to the extent that utilities had

- higher average line voltage;
- more substation capacity per substation;
- more substations per transmission line km;
- more transmission facilities underground;
- higher required construction standards;
- more forestation; and
- transmission plant that constituted a larger share of the gross value of total plant less general plant.

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[20] This remark pertains to the "first order" terms in the model, and not to the parameters of the second-order (quadratic and interaction) terms.

Table 1

PEG's Featured Econometric Model of Transmission Total Cost

VARIABLE KEY

YL =	Kilometers of Transmission Line
D =	Ratcheted Max Transmission Peak
PCTPTX =	Percent Transmission Plant of Total Plant net General Plan
MVA =	MVA per Substation
SUBKM =	Substation per KM of Transmission Line
VOLT =	Average Voltage of Transmission Lines
PCTOH =	Percentage Overhead Distribution Plant
CS =	Construction Standards Index
FOR =	Forestation of Service Territory
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YL	0.355	26.390	0.000
D	0.581	35.020	0.000
YL*YL	0.024	1.930	0.073
D*D	0.113	5.610	0.000
D*YL	-0.059	-3.000	0.009
PCTPTX	0.387	8.300	0.000
MVA	0.099	4.420	0.000
SUBKM	0.101	3.690	0.002
VOLT	0.180	7.450	0.000
PCTOH	-1.153	-5.350	0.000
CS	0.145	4.810	0.000
FOR	0.092	7.670	0.000
Trend	0.014	7.370	0.000
Constant	12.063	348.140	0.000

Adjusted R^2	0.944
Sample Period	2004-2019
Number of Observations	803

The parameter estimates for the scale variables suggest that ratcheted peak demand had an estimated long-run cost elasticity of 0.581% whereas the estimated cost elasticity of transmission line length was 0.355%. The parameter estimate for the trend variable suggests that transmission cost tended to rise over the full sample period by about 1.34% annually for reasons that aren't explained by the business condition variables in the model. The adjusted R-squared for the model is 0.944.

Please also note the following.

- If the two substation variables in our model are replaced with the corresponding two Clearspring substation variables, the parameter estimates on the replacement variables have substantially lower statistical significance.

Capital Cost

Econometric results for PEG's capital cost model are presented in Table 2. Here are some key findings.

- The parameter estimates for the number of transmission line kilometers and ratcheted peak demand were highly significant and positive. Two of the three second-order scale variables had significant estimates.
- Capital cost was also higher the greater was average line voltage, MVA per substation, the number of substations per kilometer of transmission line, required construction standards, the extent of service territory forestation, and the share of transmission in total gross plant value less the value of general plant.
- Capital cost was lower the greater was the share of transmission lines that were overhead.

Table 2

PEG's Featured Econometric Model of Transmission Capital Cost

VARIABLE KEY

YL =	Kilometers of Transmission Line
D =	Ratcheted Max Transmission Peak
PCTPTX =	Percent Transmission Plant of Total Plant net General Plan
MVA =	MVA per Substation
SUBKM =	Substation per KM of Transmission Line
PCTPOH=	Percentage Overhead Lines
CS =	Construction Standards Index
VOLT =	Average Voltage of Transmission Lines
FOR =	Forestation of Service Territory
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YL	0.313	37.020	0.000
D	0.657	46.450	0.000
YL*YL	-0.069	-3.670	0.002
D*D	0.108	3.570	0.003
D*YL	-0.005	-0.160	0.873
PCTPTX	0.435	7.400	0.000
MVA	0.079	2.630	0.019
SUBKM	0.083	3.300	0.005
VOLT	0.204	15.160	0.000
PCTOH	-1.084	-5.100	0.000
CS	0.142	4.710	0.000
FOR	0.074	7.490	0.000
Trend	0.012	4.460	0.000
Constant	9.867	266.280	0.000

Adjusted R^2	0.942
Sample Period	2004-2019
Number of Observations	803

Pacific Economics Group Research, LLC

- The estimate of the trend variable parameter indicates a 1.2% annual increase in capital cost for reasons other than changes in the values of the model's business condition variables.

- The 0.942 value of the adjusted R^2 for the capital cost model was similar to that of the total cost model.

OM&A Expenses

Results for PEG's transmission opex model are presented in Table 3. Please note the following.

- The parameter estimates for the number of transmission line kilometers and ratcheted peak demand were highly significant and positive. The estimates for the three quadratic and interaction terms associated with the scale variables were also highly significant. This suggests that the relationship of cost to the two scale variables was significantly nonlinear.
- Opex was higher the greater was the share of transmission plant in the gross value of total plant less general plant.
- Opex was also higher the higher was MVA per substation, the number of substations per kilometer of transmission line, and the share of the service territory that was forested.
- Opex was lower the greater was the share of transmission lines that were overhead.
- The trend variable parameter estimate indicates a 2.1% annual increase in opex for reasons other than changes in the values of included business condition variables. This increase is slightly more rapid than that in the total cost model.
- Table 3 also reports a 0.784 adjusted R^2 statistic for the opex model. This is well below that for the total cost and capital cost models.

Table 3

PEG's Featured Econometric Model of Transmission OM&A Expenses

VARIABLE KEY

YL =	Kilometers of Transmission Line
D =	Ratcheted Max Transmission Peak
PCTPTX =	Percent Transmission Plant of Total Plant net General Plan
MVA =	MVA per Substation
SUBKM =	Substation per KM of Transmission Line
PCTPOH=	Percentage Overhead Lines
FOR =	Forestation of Service Territory
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YL	0.438	10.310	0.000
D	0.326	14.560	0.000
YL*YL	0.383	14.440	0.000
D*D	0.126	5.530	0.000
D*YL	-0.303	-17.230	0.000
PCTPTX	0.177	7.570	0.000
MVA	0.131	7.260	0.000
SUBKM	0.107	2.940	0.010
PCTOH	-1.193	-3.900	0.001
FOR	0.188	5.510	0.000
Trend	0.021	5.440	0.000
Constant	10.111	172.570	0.000

Adjusted R^2	0.784
Sample Period	2004-2019
Number of Observations	802

4.3 Business Conditions Facing Hydro One Transmission

Before discussing the benchmarking results for Hydro One Transmission using these models we consider the external business conditions that the Company faces. Hydro One provides virtually all power transmission services in the sprawling province of Ontario. The population of Ontario is by far the largest in Canada and exceeds that of Wisconsin, Minnesota, and the two Dakotas combined. Most power production and consumption in the province occurs in the southern lowlands that border the Great Lakes and the two largest rivers. However, Hydro One Transmission also serves a large region on the Canadian shield which is dotted by hydroelectric generating sites and resort, forestry, and mining communities. In this region forests are thick, igneous rock is near the surface, and winter weather is severe.

Table 4 compares the cost and external business conditions of Hydro One Transmission to the sample mean values in 2019. Consider first results for the important cost, price, and scale variables.

- Hydro One's total cost was 7.34 times the sample mean while its input prices were 1.15 times the mean. The Company's real total cost was 6.46 times the mean.
- Hydro One's ratcheted transmission peak was 3.36 times the mean while its line miles were 3.72 times the mean (and second highest in the sample).
- Combining all of these metrics, the Company's bilateral multifactor productivity level was 0.54 times the sample mean in 2019. Its O&M productivity level was 0.65 times the mean while its capital productivity level was 0.53 times the mean. These simple benchmarking metrics are not favorable to the Company.

Here are comparisons for some of the additional business conditions that Hydro One faced.

- The number of substations served was 4.65 times the mean.
- The MVA per substation was 1.18 times the mean.
- The average voltage of transmission lines was 1.27 times the mean.
- The share of transmission in the gross value of Hydro One's total plant less general plant was 2.88 times the mean and the highest in the sample.

Table 4

How the Model Variables for HON Tx Compare to the Sample Mean (2019)

	HON	Sample Mean	HON / Mean	HON Rank
Cost				
Total Cost	$ 2,036,426	$ 277,392	7.34	1
OM&A Cost	$ 304,934	$ 43,291	7.04	1
Capital Cost	$ 1,731,492	$ 234,101	7.40	1
Input Prices				
Input Price Index	1.458	1.265	1.15	4
OM&A	1.318	1.000	1.32	
Capital Price	10.82	9.64	1.12	7
Labor Price	89,695.97	65,602.52	1.37	1
M&S Price	139.40	112.35	1.24	1
Real Cost (Cost / Price Index)				
Total Cost	1,396,477	216,049	6.46	
OM&A Cost	231,407	43,291	5.35	
Capital Cost	160,090	24,285	6.59	
Scale				
Substations	264	57	4.65	1
Mva	109,320	17,576	6.22	1
Mva / Station	414	350	1.18	15
km of Line	20,783	5,580	3.72	2
Monthly Peak Load	21,791	5,005	4.35	2
Ratcheted 10 Year Monthly Peak	23,541	5,034	4.68	1
Ratcheted Transmission Peak	23,541	7,006	3.36	4
Scale Index				
Lines	3.72	1.00	3.72	
Peak	3.36	1.00	3.36	
Weight on Lines	38%	38%		
Weight on Peak	62%	62%		
Scale Index	3.49	1.00	3.49	
Bilateral Productivity Level				
Multifactor	0.541	1.00	0.54	
OM&A	0.654	1.00	0.65	
Capital	0.530	1.00	0.53	
Other Business Conditions				
Share of Transmission Plant in Total Gross Plant Value less General Plant	61.3%	21.3%	2.88	1
MVA per Station	414.1	350.1	1.18	15
Substations per km of Transmission Line	0.0127	0.0129	0.99	17
Percent Overhead	98.6%	97.3%	1.01	41
Construction Standards Index	0.867	0.674	1.29	4
Average Voltage of Lines	222	174	1.27	12
Percent Forestation	74.4%	55.6%	1.34	17

- The extent of forestation in the service territory was 1.34 times the mean.
- The Company is a member of an ISO whereas a number of the sampled US utilities are not.
- The value of the construction standards index was 1.29 times the mean and one of the highest in the sample.
- The percent of plant underground was similar to the mean.

In summary, the productivity level calculations raise concern that Hydro One Transmission may be a poor cost performer. However, the business conditions that it faces do seem to be unusually challenging on balance. We turn to the econometric model to see how these considerations balance out.

4.4 Transmission Cost Benchmarking Results

We used our three econometric transmission cost models to benchmark the corresponding costs of Hydro One. In this exercise we used Clearspring's forecasts for growth in input prices. Due to the unavailability of older capital cost data for Hydro One, results of the total cost and capital cost benchmarking will tend to be more accurate in the later years considered.

Total Cost

Results of our transmission total cost benchmarking work are presented in Table 5 and Figure 1. It can be seen that Hydro One's total cost performance has been trending downward since 2008. Its cost was about 7% above our benchmarks on average from 2017 to 2019, the three most recent historical years for which data for all required variables were available. The downward trend seems to have been arrested during the current CIR. The Company's forecasted/proposed total costs are about 14% above the model's prediction on average during the five years of its proposed IR plan (2023-2027). Between 2023 and 2027, total cost efficiency is expected to average a 1.12% average annual decline.

Table 5

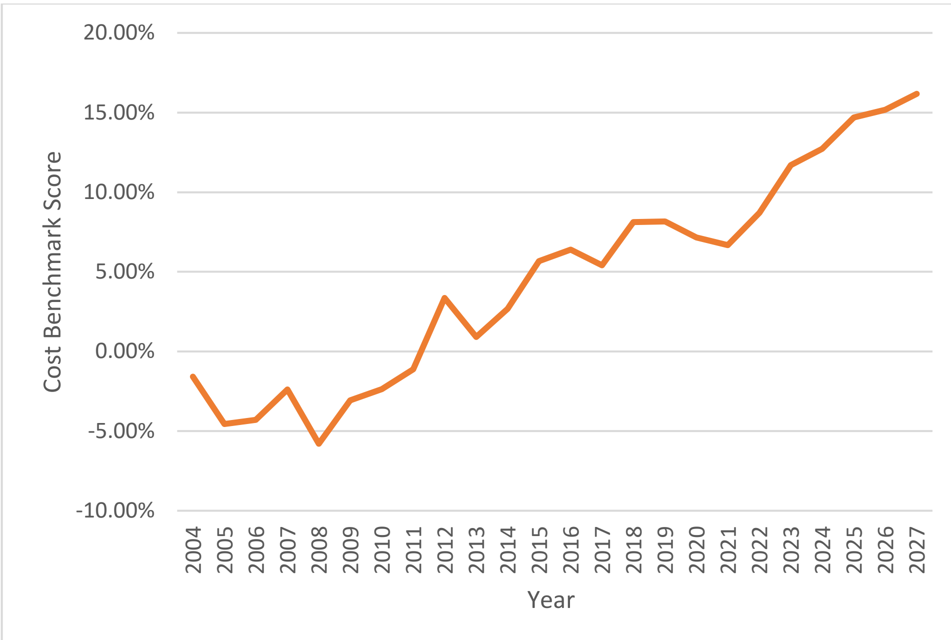
Transmission Total Cost Performance of Hydro One Using PEG's Alternative Econometric Model

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2004	-1.58%
2005	-4.56%
2006	-4.30%
2007	-2.39%
2008	-5.80%
2009	-3.07%
2010	-2.37%
2011	-1.11%
2012	3.35%
2013	0.92%
2014	2.68%
2015	5.67%
2016	6.38%
2017	5.41%
2018	8.12%
2019	8.16%
2020	7.16%
2021	6.67%
2022	8.71%
2023	11.70%
2024	12.71%
2025	14.69%
2026	15.17%
2027	16.18%
Average 2017-2019	**7.23%**
Average 2023-2027	**14.09%**

Figure 1

Hydro One's Total Transmission Cost Benchmarking Scores Using PEG's Alternative Econometric Model



Capital Cost

Results of our transmission capital cost benchmarking work are presented in Table 6 and Figure 2. It can be seen that the Hydro One's capital cost performance began a steady decline after 2008. Its cost was about 6% above the model's prediction on average from 2017 to 2019, the three most recent historical years for which data for all required variables were available. The Company's forecasted/proposed total costs are about 19% above the model's prediction on average during the five years of its proposed IR plan (2023-2027). From 2023 to 2027, capital cost efficiency is expected to average a 1.66% annual decline.

Table 6

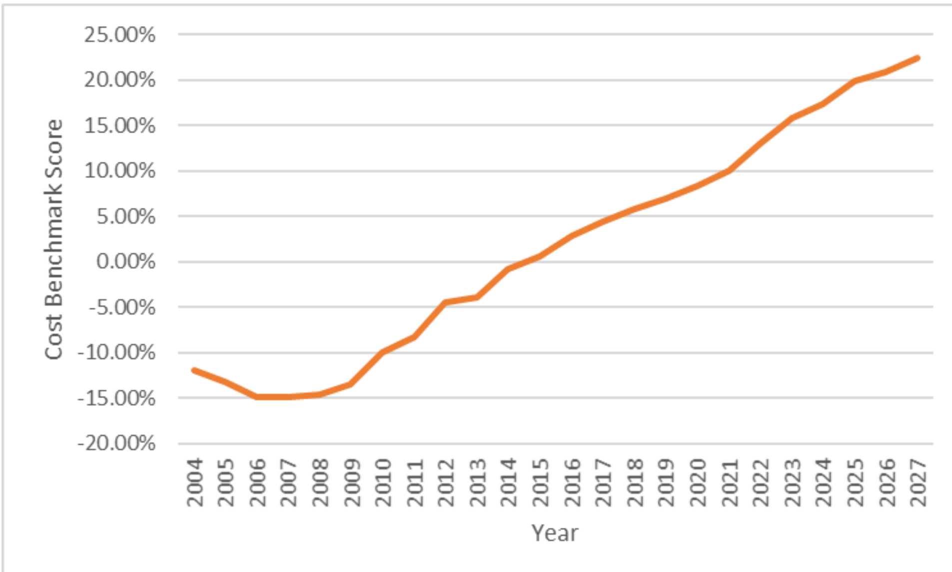
Transmission Capital Cost Performance of Hydro One Using PEG's Alternative Econometric Model

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2004	-11.90%
2005	-13.26%
2006	-14.88%
2007	-14.84%
2008	-14.63%
2009	-13.43%
2010	-10.02%
2011	-8.32%
2012	-4.53%
2013	-3.87%
2014	-0.85%
2015	0.60%
2016	2.82%
2017	4.39%
2018	5.86%
2019	6.88%
2020	8.29%
2021	9.99%
2022	12.98%
2023	15.75%
2024	17.31%
2025	19.95%
2026	20.91%
2027	22.41%
Average 2017-2019	**5.71%**
Average 2023-2027	**19.27%**

Figure 2

Hydro One's Transmission Capital Cost Benchmarking Scores Using PEG's Alternative Econometric Model



OM&A Expenses

Results of our transmission O&M cost benchmarking work are presented in Table 7 and Figure 3. It can be seen that Hydro One's opex performance has tended to improve since 2007. The Company's opex was about 36% above the model's prediction on average from 2017 to 2019, the three most recent historical years for which data for all required variables were available. Opex efficiency should improve markedly during the current CIR. This favorable trend is interrupted by a setback in 2023, the forward test year. The Company's forecasted/proposed total costs are about 7% above the model's prediction on average during the five years of its proposed IR plan (2023-2027). From 2023 to 2027, opex efficiency would improve at a 2.15% average annual pace.

Table 7

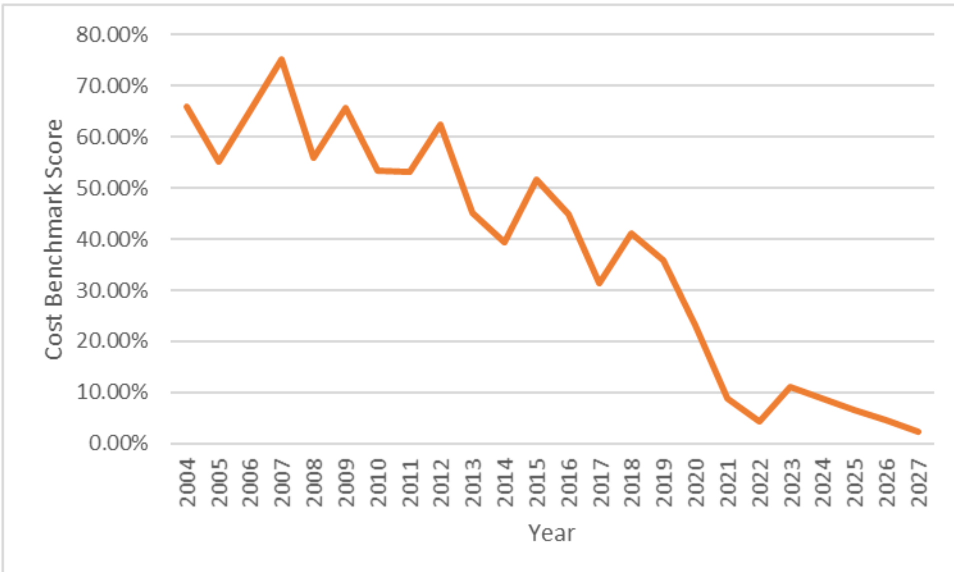
Transmission OM&A Cost Performance of Hydro One Using PEG's Alternative Econometric Model

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2004	66.01%
2005	55.18%
2006	64.84%
2007	75.08%
2008	55.89%
2009	65.57%
2010	53.44%
2011	53.27%
2012	62.54%
2013	45.12%
2014	39.51%
2015	51.55%
2016	44.90%
2017	31.44%
2018	41.11%
2019	35.80%
2020	23.07%
2021	8.93%
2022	4.43%
2023	10.98%
2024	8.87%
2025	6.67%
2026	4.54%
2027	2.36%
Average 2017-2019	**36.12%**
Average 2023-2027	**6.68%**

Figure 3

Hydro One's Transmission OM&A Cost Benchmarking Scores Using PEG's Alternative Econometric Model



4.5 Productivity Research

The calculation of transmission industry productivity trends was not part of PEG's scope of work in this proceeding. However, we recently undertook research and testimony on this matter in a Québec proceeding.[21] Our clients there were the Association Québécoise des Consommateurs Industriels d'Électricité and the Conseil de l'Industrie Forestière du Québec.

Our productivity research methodology was broadly similar to that of Clearspring in this proceeding. Notable differences included the following.

- Companies with implausible transmission-dispatch-related and miscellaneous transmission expenses were excluded.

[21] Lowry, 2021 op. cit.

- There were differences in the sampled companies.
- A longer sample period was considered.

Results of this research can be found in Table 8 below. For the full sample period, it can be seen that the multifactor productivity growth of sampled U.S. transmitters averaged -0.62% per annum while OM&A productivity growth averaged -0.68% per annum.

Table 8

PEG's Transmission Productivity Results from the Hydro-Québec Proceeding

Sample Period	Average Annual Productivity Growth Rate		
	OM&A	**Transmission Capital**	**Multifactor**
1996-2019 (24 years)	-0.68%	-0.46%	-0.62%
2005-2019 (15 years)	-1.74%	-2.16%	-2.26%

4.6 Transmission X Factor Recommendations

Base Productivity Trend

We believe that the **-0.62**% trend in the MFP of the U.S. power transmission industry which we calculated for our full 1996-2019 sample period in the Québec proceeding is a reasonable base productivity trend for Hydro One.

Stretch Factor

We disagree with Clearspring's 0.0% stretch factor recommendation, which is based on the contentions that an explicit stretch factor is not warranted given Hydro One's superior cost performance. We discuss the general considerations that go into the choice of a stretch factor in Appendix Section A1. Based on this general discussion, we provide here some considerations that we feel are pertinent for choosing a transmission stretch factor for Hydro One.

- The Company's cost performance does not score as well in our study as in Clearspring's study. We found that the Company's forecasted/proposed total cost during the five years of the proposed plan would be 14% above our model's prediction on average. In 4GIRM this kind of cost benchmarking score is commensurate with a 0.45% stretch factor.

- Stretch factors should reflect the difference between the incentive power of the proposed plan and the incentive power of the regulatory systems of companies in the productivity studies used to establish the base productivity trend. The incentive power of U.S. transmission regulation was unusually weak during the ample period of the productivity study due to the FERC's use of ROE premia and formula rate plans. This problem loomed larger during Clearspring's shorter and more recent sample period.
- The RCI formula does not include a scale escalator to help fund output growth. On the other hand, growth in the Company's output has been slow in recent years and this is expected to continue. The plan includes variance accounts for costs of major line extensions, and supplemental revenue for growth-related capex may also be obtained via the C factor.
- Stretch factors linked to cost performance have the additional benefit of serving as efficiency carryover mechanisms that reward utilities for long-term cost savings and penalize them for their absence.

Balancing these considerations, we believe that a 0.75% stretch factor is reasonable for Hydro One. This would include a 0.45% "normal" stretch factor based on the total cost benchmarking work and a 0.30% adder for the unusually weak performance incentives of sampled US utilities.

X Factor

A -0.62% base productivity trend and a 0.75% stretch factor would produce a 0.13% X factor. This is the X factor we recommend for Hydro One's transmission services.

5. Critique of Clearspring's Power Distribution Research

5.1 Summary of Clearspring's Work

Clearspring benchmarked the total cost of Hydro One's distributor base rate inputs over the 16-year historical period from 2005 to 2019. The Company's projected/proposed costs were benchmarked for the 2020-27 period that includes the five years of the new rate plan (2023-2027). Clearspring did not separately benchmark Hydro One's component opex and capital costs or its reliability.

An econometric model provided the cost benchmarks. Clearspring developed this model using data on power distributor operations of 81 investor-owned utilities in the United States. The sample period was the twenty years from 2000 to 2019.

The dependent variable in the model was real cost. Differences in the wage levels and construction costs that utilities in the sample faced were considered in the construction of the input price indexes. The model has three scale variables: the number of customers served, the area of the service territory area, and a moving average of maximum monthly peak demand.

The model also contained the following variables that measure other drivers of distributor cost.

- share of the service territory area that has urban congestion;
- share of customers with advanced metering infrastructure ("AMI");
- share of electric customers in the sum of gas and electric customers served;
- % of distribution plant overhead x share of service territory forested; and
- % of transmission lines with ratings above 50kV.

The model also contains a (linear) trend variable.

With respect to the form of Clearspring's distribution cost model, the model contains a full complement of quadratic and interaction terms (e.g., Customers x Customers, Customers x Area, and Customers x Peak Demand) for the three scale variables in addition to the corresponding first-order terms (Customers, Area, and Ratcheted Peak Demand). All parameter estimates for the variables in the model are highly significant and those for the first order terms have plausible signs. The estimate of the trend variable parameter suggests that cost was *falling* by about 0.4% annually over the sample period for reasons other than changes in the values of the included business condition variables.

Clearspring reported that Hydro One's total distribution costs were well below the benchmarks yielded by its model in the early years considered (e.g., 2005 to 2010). However, the Company's cost performance tended to erode. Cost performance is expected to improve modestly from 2019 to 2022. However, deterioration is forecasted to resume in the new plan. The Company's forecasted/proposed costs over the five years of the proposed new plan exceed the corresponding benchmarks by 7% on average. From 2023 to 2027, Clearspring reports that Hydro One's distribution total cost efficiency will average a 1.75% annual decline.

5.2 Critique

Mr. Fenrick has changed his power distribution benchmarking methodology in several areas where we were critical of his approach in past Ontario proceedings. As in his transmission research,

- The initial or benchmark year for the calculation of capital costs and quantities is 1948, not 1988.
- The construction cost was levelized in the correct year.
- Construction cost trends in Ontario were computed as a weighted average of the trends in two asset price indexes.
- The OM&A input price indexes now have company-specific weights.
- Pensions and benefits were excluded from the data for Hydro One and all of the U.S. utilities.

Additionally,

- Quadratic and interaction terms for other business conditions have been reduced.
- Attention to urban and rural cost challenges is more balanced.

We nonetheless disagree with some of the methods Clearspring used in this study. Our concerns range from major concerns to concerns that are small but nonetheless notable. We discuss our larger concerns first to facilitate the Panel's review.

Major Concerns

Density Issues

Clearspring has in past proceedings developed a service territory area variable that is potentially useful in benchmarking costs of power distributors. Unfortunately, it is problematic to use this variable when benchmarking Hydro One due to uncertainty about the appropriate value for the Company. In his previous work for Hydro One Distribution Mr. Fenrick used as his estimate the total area of Ontario, including water bodies. In the new study he used the value that PEG used for Hydro One in the last Custom IR proceeding for Hydro Ottawa. This is the area of Ontario's land surface less the estimated service territory areas of other utilities. However, even this estimate includes an enormous area in the north of the province that does not have distribution service.

Distribution Work

We agree that a variable measuring the extent of distribution subtransmission lines is worthwhile. However, we don't' think that the variable Clearspring used for this purpose (% of transmission lines with ratings above 50kV) is appropriate.

Other Major Concerns Here are some other major concerns that we have with Clearspring's benchmarking work in this proceeding.

- The denominator of the scope economy variable should not include general plant.
- Total cost benchmarking does not shed light on the sources of high and low costs that utilities incur. Knowledge of strengths and weaknesses in more granular management of major cost categories such as OM&A expenses is useful to utilities and regulators alike.

Smaller Concerns

Here are some smaller concerns we have with Clearspring's benchmarking study. We do not believe that these problems individually had a major impact on the benchmarking results. However, we believe that future benchmarking studies, for Hydro One and other utilities, which steer clear of these problems will have more credibility.

- Data are frequently mean-scaled in econometric cost studies. This ensures that elasticities are calculated at sample mean values of the business condition variables. Clearspring mean-scaled the data for some variables, but not for others.[22]

- Clearspring benchmarked the reliability of Hydro Ottawa in its recent evidence for that company. They gathered a respectable sample of publicly available U.S. data that span the years 2010-2017. Major event days were excluded, if not with fully consistent definitions. The models presented by Clearspring are a good starting point for further improvements. Cost benchmarking should ideally be combined with reliability benchmarking to gain a balanced view of performance, and reliability performance is germane when considering requests for supplemental capex funding. Reliability results for Hydro One would have been informative.

5.3 Business Conditions Facing Hydro One Distribution

The external cost drivers faced by Hydro One Distribution should be considered when benchmarking their cost. The Company is headquartered in Toronto, a high-cost urban area, but provides distributor service to numerous small towns and rural areas of the province. Its service territory includes numerous forest products and resort communities on the Canadian shield. As is the case for Hydro One Transmission, dense forests and severe winter weather are the norm in this region. However, due in part to the growth of metropolitan areas and to acquisitions by Hydro One, the Company does serve some larger towns and suburban areas. All customers now have AMI.

Table 9 compares Hydro One's cost and external business conditions to the sample mean values in 2019. The following results are notable.

- Hydro One's total cost was 2.07 times the sample mean.

- The input prices that the Company faced were 1.17 times the mean. Thus, the Company's real total cost was 2.19/1.16 = 1.78 times the mean. The Company's customer count was 1.30 times the mean while its ratcheted peak demand was 1.14 times the mean. The

[22] HON Technical Conference, Transcript December 16, 2021, p. 26-27.

reported area served was a fantastical 31 times the mean. However, the Company's transmission line length was a more plausible 3.89 times the mean. A scale index computed using transmission line miles had a value 1.35 times the mean.

- Combining all of this information, Hydro One's multifactor distributor productivity level in 2019 was 0.77 times the mean. Its O&M productivity was 0.83 times the mean while its capital productivity was 0.73 times the mean.

These benchmarking metrics are unfavorable to the Company. For Hydro One to be deemed a good distribution cost manager, it would therefore have to face other cost drivers that are markedly less favorable than the sample norms on balance. The table indicates that several business conditions were more challenging.

- Forestation in the Company's service territory was 1.30 times the mean.
- The share of customers with AMI was about twice the mean.
- The share of electric customers in the sum of gas and electric customers was 1.13 times the mean. The Company does not provide gas services.

On the other hand,

- the share of distribution assets overhead was 1.15 times the mean;
- the reported share of the Company's service territory area in the urban core was well below the mean.

Table 9
How the Model Variables for HON Dx Compare to the Sample Mean (2019)

	HON	Sample Mean	HON / Mean	HON Rank
Cost ($000)				
Total Cost	$ 1,626,272	$ 784,186	2.07	7
OM&A Cost	$ 490,079	$ 230,612	2.13	7
Capital Cost	$ 1,136,193	$ 553,574	2.05	7
Input Prices				
Input Price Index	1.588	1.360	1.17	3
OM&A	1.683	1.280	1.31	1
Capital Price	12.361	11.206	1.10	13
Labor Price	89,696	66,704	1.34	1
M&S Price	139.396	112.348	1.24	1
Real Cost (Cost / Price Index)				
Total Cost	1,023,811	576,658	1.78	
OM&A Cost	291,270	180,233	1.62	
Capital Cost	91,917	49,398	1.86	
Scale				
Customers	1,343,959	1,037,379	1.30	17
Peak Load	6,465	5,174	1.25	18
Ratcheted 10 Year Peak	6,045	5,239	1.15	20
PEG Ratcheted Peak	6,465	5,688	1.14	23
Area	20.25	0.66	30.71	1
Area Measured by Tx Miles	20,783	5,347	3.89	2
Scale Index				
Customers	1.30	1.00		
PEG Ratcheted Peak	1.14	1.00		
Area Measured by Tx Miles	3.89	1.00		
Weight on Customers	70.2%	70.2%		
Weight on Peak	22.6%	22.6%		
Weight on Area	7.3%	7.3%		
Scale Index	1.36	1.00		
Bilateral Productivity Level				
Multifactor	0.768	1.00	0.77	
OM&A	0.843	1.00	0.84	
Capital	0.732	1.00	0.73	
Business Conditions				
Percent AMI	100.0%	50.6%	1.98	1
Percent Forestation	74%	57%	1.30	25
Percent Overhead	91%	79%	1.15	11
Percent Electric	100.0%	88.7%	1.13	1
Gas Customers	0%	162,318	0.00	23
Percent Dx Plant in Total Plant	38.7%	42.2%	0.92	28
Percent Dx Plant in T&D Plant	38.7%	65.9%	0.59	1
Urban Core	0.00%	0.08%	0.00	36

5.4 Econometric Distribution Cost Research

Relying chiefly on Clearspring's data, we developed an alternative econometric model of the total cost of power distributor base rate inputs. We also developed econometric models of distributor opex and capital cost.

Differences from the Clearspring Methodology

The following methods that we used in model development differed from Clearspring's.

- Lacking a good estimate of the area of Hydro One's service territory, we replaced the area variable that Clearspring used with their transmission line length variable. This variable should be highly correlated with distribution service territory and sidesteps the problem of obtaining an accurate value for Clearspring's area variable for Hydro One.
- We mean-scaled all variables.
- We did not use Clearspring's distribution work or scope economy variables and instead used the share of distribution in the sum of T&D gross plant value.
- We benchmarked the OM&A and capital cost of Hydro One as well as its total cost.

Econometric Results

Details of this research are reported in Tables 10-12. In all three models, all of the parameter estimates for the first-order terms of the business condition variables were statistically significant and plausible as to sign and magnitude.

Econometric results for PEG's distributor total cost model are presented in Table 10. Here are some salient results.

- The parameter estimates for the number of customers, ratcheted peak demand, and area variables are all highly significant and positive. The parameter estimates for all of the quadratic and interaction terms associated with these three scale variables were also highly significant. The relationship of cost to the three scale variables was therefore significantly nonlinear.

Table 10

PEG's Featured Econometric Model of Distribution Total Cost

VARIABLE KEY

YL =	KM Transmission Line
N =	Number of Customers
D =	Ratcheted Max Distribution Peak
PELEC =	Percent Electric Customers
PCTOH =	Percent Overhead Distribution Plant
OHFOR =	Percent Overhead Distribution Plant times Forestation of Service Territory
PCTPDX =	Percent Distribution of Transmission & Distribution Plant
AMI =	Percent AMI
PTCU =	Percent Service Territory Congested Urban
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YL	0.072	4.500	0.000
N	0.694	26.320	0.000
D	0.223	15.120	0.000
YL*YL	0.041	3.110	0.006
N*N	0.716	15.090	0.000
D*D	0.884	23.580	0.000
Y*N	0.144	18.650	0.000
YL*D	-0.178	-44.730	0.000
N*D	-0.766	-19.510	0.000
PELEC	0.257	11.290	0.000
PCTOH	-0.104	-1.160	0.262
OHFOR	0.053	8.450	0.000
PCTPDX	0.181	9.700	0.000
AMI	0.011	5.990	0.000
PTCU	0.013	16.210	0.000
Trend	-0.001	-0.680	0.504
Constant	13.153	1224.700	0.000

Adjusted R^2	0.974
Sample Period	2002-2019
Number of Observations	1,171

Pacific Economics Group Research, LLC

- Total cost was also higher the higher was the share of the service territory that was congested and urban, the share of distribution assets overhead x the share of service territory area forested, AMI penetration, the share of electric plus any gas customers that were electric, and the share of distribution in T&D gross plant value.
- The estimate of the trend variable parameter suggests that there was essentially no shift in total cost annually for reasons other than changes in the values of the included business condition variables.

The adjusted R^2 for the model was 0.974. This suggests that the model had a high level of explanatory power.

Capital Cost

Details of PEG's distributor capital cost research are presented in Table 11. Here are some key findings.

- The parameter estimates for the number of customers, ratcheted peak demand, and the area variable were all highly significant and positive. All of the parameter estimates for the extra quadratic and interaction terms for the scale variables were also highly significant. This suggests that the relationship of capital cost to the three output variables was significantly nonlinear.
- Distribution capital cost was also higher the greater was the share of the area served that was congested and urban, AMI penetration, the share of distribution plant in the gross value of T&D plant, and the ratio of electric customers to the sum of gas and electric customers.
- Capital cost was lower the greater was the share of lines overhead.
- The estimate of the trend variable parameter indicates that there was no significant shift in capital cost for reasons other than changes in the values of the model's business condition variables. This is noteworthy given the frequent claims by distribution utility witnesses that a need for high capex is pervasive in the distribution industry.
- The 0.968 value of the adjusted R^2 model was very similar to that for the total cost model.

Table 11

PEG's Featured Econometric Model of Distribution Capital Cost

VARIABLE KEY

YL =	KM Transmission Line
N =	Number of Customers
D =	Ratcheted Max Distribution Peak
PELEC =	Percent Electric Customers
PCTPOH=	Percent Overhead Lines
PCTPDX =	Percent Distribution Plant of Transmission & Distribution Plan
AMI =	Percent AMI
PTCU =	Percent Service Territory Congested Urban
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YL	0.063	5.960	0.000
N	0.584	29.090	0.000
D	0.368	26.630	0.000
YL*YL	-0.031	-3.920	0.001
N*N	0.510	12.860	0.000
D*D	0.643	15.480	0.000
Y*N	0.095	11.480	0.000
Y*D	-0.054	-4.980	0.000
N*D	-0.573	-16.720	0.000
PELEC	0.205	16.860	0.000
PCTOH	-0.245	-6.390	0.000
PCTPDX	0.393	7.040	0.000
AMI	0.015	6.830	0.000
PTCU	0.015	20.200	0.000
Trend	0.000	-0.520	0.607
Constant	10.677	1355.750	0.000

Adjusted R^2	0.968
Sample Period	2002-2019
Number of Observations	1,171

OM&A Expenses

Results of PEG's econometric distribution opex research are presented in Table 12. Please note the following.

- The parameter estimates for transmission line length, number of customers, and ratcheted peak demand were all significant and positive.[23] Notice that the number of customers had a considerably greater impact on opex than in the total cost model, while peak demand had a much smaller impact. This makes sense since OM&A expenses include many customer-driven expenses like those for metering, billing, and collection.
- The parameter estimates for the additional quadratic and interaction terms associated with the included scale variables were all highly significant. This suggests that the relationship of cost to the three scale variables was significantly nonlinear.
- The share of distribution in T&D gross plant value had the wrong sign so we instead used the share of distribution in total gross plant value less general plant.
- Opex was higher the greater was the share of the service territory that was congested and urban.
- Opex was also higher the higher was system overheading, share overhead x share forestation, AMI penetration, and the share of electric in the sum of gas and electric customers.
- The trend variable parameter estimate indicates a 0.13% annual growth in opex for reasons other than changes in the values of included business condition variables.
- Table 12 also reports a 0.935 adjusted R^2 statistic for the opex model. This is modestly below that for the total cost and capital cost models. Evidently, distributor opex proved more difficult to accurately model that distributor capital cost or total cost.

[23] Ratcheted peak demand was significant using a one-tailed test.

Table 12
PEG's Featured Econometric Model of Distribution OM&A Expenses

VARIABLE KEY

YL =	KM Transmission Line
N =	Number of Customers
D =	Ratcheted Max Distribution Peak
PELEC =	Percent Electric Customers
PCTOH=	Percentage Overhead Distribution Plant
PFOR =	Forestation of Service Territory
AMI =	Percent AMI
PTCU =	Percent Service Territory Congested Urban
PCTPDX =	Percent Distribution Plant of Total Plant net General Plant
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YL	0.089	4.530	0.000
N	0.799	33.960	0.000
D	0.066	2.680	0.016
YL*YL	0.064	4.510	0.000
N*N	1.280	10.650	0.000
D*D	1.203	10.160	0.000
YL*N	0.136	14.880	0.000
YL*D	-0.218	-12.040	0.000
N*D	-1.172	-10.640	0.000
PELEC	0.153	4.330	0.000
PCTOH	0.701	10.650	0.000
PCTOH*PFOR	0.054	13.140	0.000
AMI	0.006	2.130	0.048
PTCU	0.015	7.150	0.000
PCTPDX	0.283	9.300	0.000
Trend	0.001	0.900	0.379
Constant	11.973	660.470	0.000

Adjusted R^2	0.935
Sample Period	2002-2019
Number of Observations	1,171

Pacific Economics Group Research, LLC

5.5 Econometric Benchmarking Results

We benchmarked the OM&A, capital, and total distributor cost of Hydro One in each year of the historical 2005-2019 period as well as in the 2020-2027 period for which the Company has provided proposals/projections. All benchmarks were based on our econometric model parameter estimates and values for the business condition variables which are appropriate for the Company in each historical and future year.

Tables 13-15 and Figures 4-6 report results of this benchmarking work. For each cost considered, the tables report results for each year and highlight the average results for the last three historical years and the five years of the proposed new Custom IR plan. Recollecting the recent benchmark years for estimating Hydro One's capital cost, the capital cost and total cost benchmarking results are likely to be more accurate in these three years.

Total Cost

Table 13 and Figure 4 show results of our distribution *total* cost benchmarking. It can be seen that Hydro One's total distribution cost trended downward from 2005 to 2014. Total cost efficiency will improve modestly during the Company's current IR plan and then resume its deterioration. On average, projected/proposed total cost during the new plan will exceed the benchmarks by about 37% during the 2023-2027 term of the CIR plan. From 2023 to 2027, cost efficiency will average a 1.38% annual decline.

Capital Cost

Table 14 and Figure 5 show results of our distribution *capital* cost benchmarking. It can be seen that Hydro One's capital cost efficiency has trended downward since 2002. Efficiency was fairly stable under the current CIR plan but is expected to resume its deterioration in the next plan. On average, projected/proposed capital cost during the new plan will be 71% above our benchmarks for the 2023-27 period. From 2023 to 2027, capital cost efficiency will average a 2.21% annual decline.

Table 13

Year-by-Year Total Distribution Cost Benchmarking Results

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2002	20.15%
2003	19.52%
2004	14.17%
2005	16.59%
2006	19.49%
2007	27.85%
2008	26.06%
2009	31.25%
2010	30.64%
2011	32.39%
2012	32.12%
2013	35.89%
2014	38.82%
2015	35.09%
2016	34.97%
2017	33.47%
2018	34.97%
2019	35.43%
2020	33.84%
2021	31.10%
2022	30.41%
2023	34.27%
2024	35.72%
2025	37.61%
2026	38.65%
2027	39.77%
Average 2017-2019	**34.62%**
Average 2023-2027	**37.20%**

Figure 4

Hydro One's Total Distribution Cost Benchmarking Scores

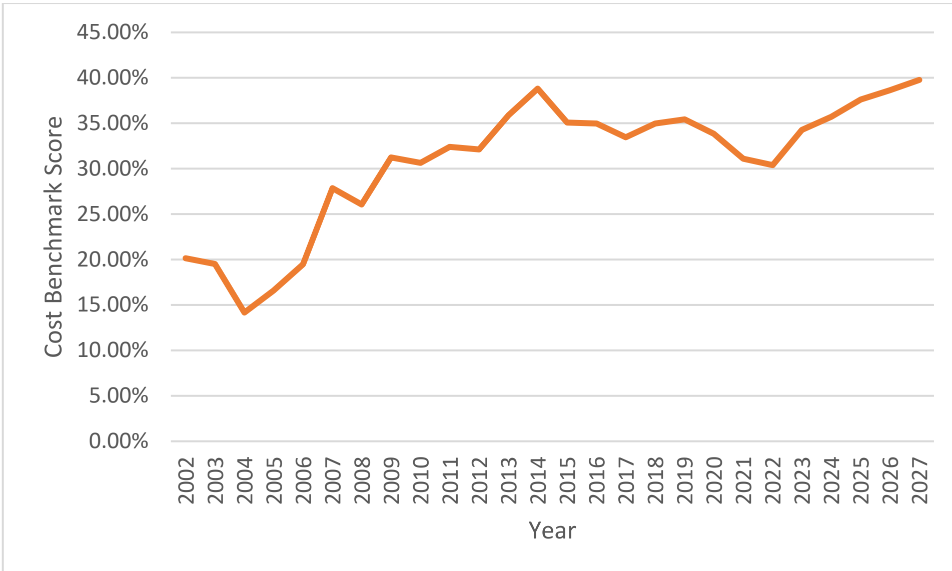


Table 14

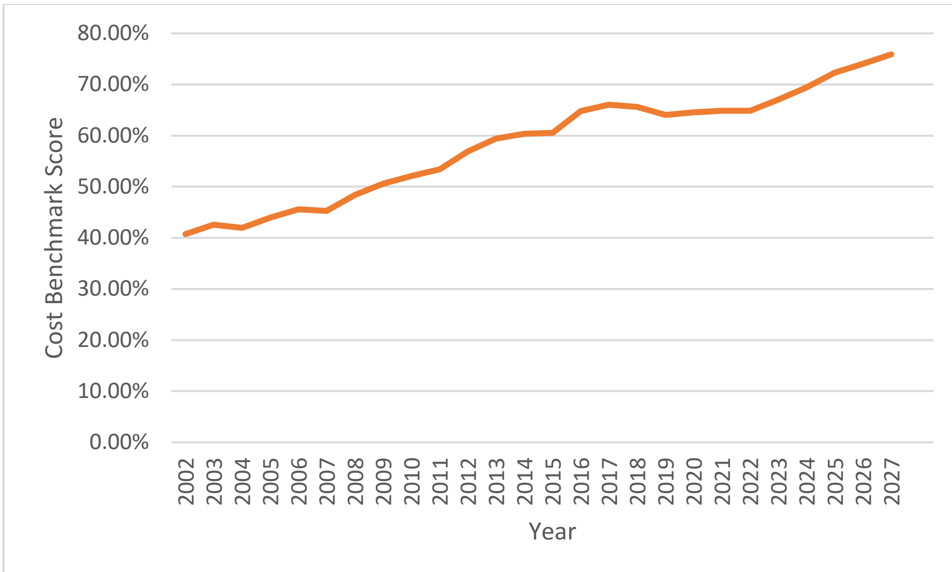
Year-by-Year Distribution Capital Cost Benchmarking Results

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2002	40.73%
2003	42.57%
2004	41.94%
2005	43.93%
2006	45.60%
2007	45.28%
2008	48.37%
2009	50.59%
2010	52.11%
2011	53.40%
2012	56.91%
2013	59.42%
2014	60.38%
2015	60.53%
2016	64.81%
2017	66.05%
2018	65.61%
2019	64.07%
2020	64.54%
2021	64.84%
2022	64.87%
2023	67.08%
2024	69.43%
2025	72.34%
2026	74.07%
2027	75.90%
Average 2017-2019	**65.24%**
Average 2023-2027	**71.76%**

Figure 5

Hydro One's Distribution Capital Cost Benchmarking Scores



OM&A Cost

Table 15 and Figure 6 show results of our distribution opex benchmarking. It can be seen that Hydro One's distribution opex efficiency trended downward from 2004 to 2014 but has tended to improve since that time. Improvement is expected to occur during the expiring CIR. Opex efficiency will be markedly worse in 2023 and then resume improvement. On average, projected/proposed opex during the new plan will be 7% below the benchmarks during the 2023-27 Custom IR term. From 2023 to 2027, distribution opex efficiency will average about a 1.2% annual improvement.

Table 15

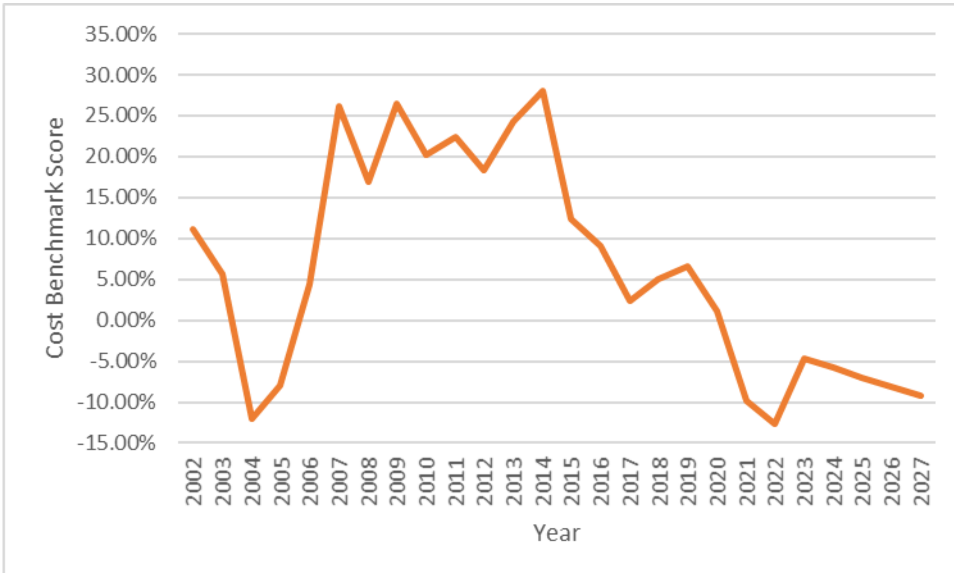
Year-by-Year Distribution OM&A Cost Benchmarking Results

[Actual - Predicted Cost]

Year	Cost Benchmark Score
2002	11.12%
2003	5.59%
2004	-12.04%
2005	-7.94%
2006	4.35%
2007	26.20%
2008	16.88%
2009	26.49%
2010	20.25%
2011	22.38%
2012	18.39%
2013	24.31%
2014	27.99%
2015	12.37%
2016	9.15%
2017	2.35%
2018	5.09%
2019	6.54%
2020	1.10%
2021	-9.78%
2022	-12.73%
2023	-4.60%
2024	-5.77%
2025	-6.97%
2026	-8.13%
2027	-9.29%
Average 2017-2019	**4.66%**
Average 2023-2027	**-6.95%**

Figure 6

Hydro One's Distribution OM&A Cost Benchmarking Scores



5.6 Distribution X Factor Recommendations

Stretch Factor

Since performance incentives in U.S. power distribution regulation are not unusually weak, the stretch factor should be based solely on the total cost efficiency of Hydro One's base rate inputs. Hydro One's 37% average total cost benchmarking score over the five years of the new IR plan would be commensurate with a 0.60% stretch factor under Price Cap IR conventions. On the basis of our research, we believe that a 0.60% stretch factor is indicated for Hydro One's distribution services.

X Factor

Assuming a 0% base MFP growth trend, the indicated X factor for Hydro One Distribution is 0.60%.

Scale Escalator

We show in Appendix A.1 that cost theory and index logic suggest that the RCI should provide an allowance for growth in the operating scale of the subject utility. This matters more to the extent that a utility that will be experiencing brisk growth in scale. We support the addition of a customer growth escalator to the RCI for Hydro One Distribution. In the absence of such an escalator expected customer growth is an implicit stretch factor.

6. Other Plan Design Issues

Hydro One's proposed Custom IR framework is similar to those that the Board previously approved in separate proceedings for the Company's T&D services.[24] Some of the proposed provisions are uncontroversial. As in past CIR proceedings that we have participated in, the proposed ratemaking treatment of capital is our chief concern. The various problems we discuss matter especially for transmission, which has an unusually capital-intensive technology.

The C factor would ensure that Hydro One would recover almost all of its projected/proposed capital cost if it incurred this cost. The great bulk of the annual capital cost reduction due to any cumulative capex underspend would be returned to ratepayers. Several additional variance accounts and the Z factor would also address capex. Hence, capital revenue would chiefly be established on a cost of service basis.

The clawback of almost all cost savings from capex underspends and the Y factor and Z factor treatments of some kinds of capex would greatly weaken Hydro One's incentive to contain capex. Incentives to contain capex and opex would be imbalanced, creating a perverse incentive to incur excessive capex in order to reduce opex. This is detrimental to the legitimate interests of the Company's employees. The weak incentives to contain capex are inconsistent with the Board's Custom IR guidelines which, as we note in Appendix Section D, proscribe a multiyear cost of service approach to ratemaking and require "explicit financial incentives for continuous improvements and cost control targets," that go beyond the stretch factors used in 4GIRM.

Despite the proposed clawback of most capex underspends, Hydro One would still have some incentive to exaggerate its capex needs. Exaggerations reduce the risk of capex overspends, strengthen the case for a C Factor, and reduce the pressure on the Company to contain capex. Exaggeration of capex needs may reduce the credibility of Hydro One's forecasts in future proceedings. However, the Company can always claim that it "discovered" ways to economize. British distributors operating under

[24] Ontario Energy Board, EB-2017-0049, Decision and Order, Hydro One Networks Inc., March 7, 2019 and EB-2019-0082, Decision and Order, Hydro One Networks Inc., April 23, 2020.

several generations of IR with revenue requirements based on cost forecasts have repeatedly spent less on capex than they forecasted.[25]

Hydro One would also be incentivized to "bunch" its deferrable capex in ways that increase supplemental revenue. If, for example, the Company could somehow manage to time its capex so that the I – X escalation was compensatory, it would obtain no supplemental revenue. This bunching will be more of a concern if and when Hydro One approaches the end of its need for high capex.

Another problem with the proposal is that, while customers must fully compensate Hydro One for the bulk of its expected capital revenue *shortfalls* when capex is high for reasons beyond its control, the Company would be under no obligation to return any *surplus* capital revenue if in the future it chose to operate under a conventional IRM and its capital cost growth were unusually *slow* for reasons beyond its control. Slow capital cost growth may very well occur in the future for reasons other than good cost management. For example, depreciation of recent and prospective surge capex which have provided the rationale for Custom IR will tend to slow future capital cost growth and accelerate productivity growth. Over multiple plans, the revenue escalation between rate cases may therefore not guarantee customers the full benefit of the industry's multifactor productivity trend, even if it is achievable. A possible defense to this line of argument is that the Company intends to operate under CIR continuously.

A related problem is that most of the capex addressed by the C factors and Z factors would be similar in kind to that incurred by the utilities in past and future productivity studies that are used to calibrate Hydro One's X factors.[26] The Company can then be compensated twice for the same capex: once via the C factor and then again by low X factors in past, present, and future IRMs.

This "double counting" issue has been debated in several IR proceedings and no consensus has been established regarding its remedy. Some regulators have eschewed X factor adjustments for double counting and based X factors on unadjusted *MFP* trends. However, the Hawaii Public Utilities

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[25] See, for example, Ofgem (1999), Reviews of Public Electricity Suppliers, Distribution Price Control Review: Draft Proposals and Ofgem (2009), Regulating Energy Networks for the Future: RPI-X @ 20: History of Energy Network Regulation

[26] Hydro One would not, however, be compensated during the plan for capex overruns.

Commission ruled, in a recent IR proceeding, that X factors in revenue cap indexes for the three Hawaiian Electric companies should be set at zero, despite evidence that they should be materially negative, due in part to the fact that their major plant additions will be eligible for cost tracking.[27]

Given Hydro One's weak incentive to contain capex, the inherent unfairness to customers of asymmetrically funding capital revenue shortfalls, and the Company's incentive to exaggerate capex requirements and bunch capex, stakeholders and the Board must be especially vigilant about the Company's capex proposal.[28] This raises regulatory cost. The need for the OEB to approve multiyear capital revenue requirements greatly complicates CIR proceedings and is one of the reasons why the Board now requires and must review complicated T&D system plans - a major expansion of its workload and that of stakeholders. Despite the extra regulatory cost, OEB Staff and stakeholders will inevitably struggle to effectively challenge the Company's capex proposal. In essence, the OEB's Custom IR rules have sanctioned British (forecast-based) approaches to determining multiyear capital revenue requirements, without necessarily making the same investment that British (and Australian) regulators have made in the capability for appraising and ruling on multiyear capex proposals.[29]

The substantial compensation for capex funding shortfalls which has been permitted by the OEB under Custom IR may be more remunerative than that available under the ACMs and ICMs featured in 4GIRM. As discussed in Appendix D, these modules feature materiality thresholds that include a modest markdown on capex that is eligible for supplemental revenue. If the markdowns under Custom IR and 4GIRM are imbalanced, utilities may choose Custom IR, with its weaker performance incentives and higher regulatory cost, even though compensatory operation under 4GIRM is feasible.

In pondering this quandary, the following remarks of the OEB in its decision approving a Custom IR plan for Toronto Hydro resonate.

> The record in this case is one of the largest that the OEB has ever seen. It is important to strike a balance between the amount of evidence necessary to evaluate the Application and the goal

[27] Hawaii Public Utilities Commission (2020), Decision and Order No. 37507, Docket No. 2018-0088.

[28] Proposed programs that raise capex and reduce OM&A expenses merit especially close examination.

[29] Consider, for example, that Ofgem's own view of a power transmitter's required cost growth is assigned a 75% weight in contested IR proceedings. This view is supported by independent engineering and benchmarking.

> of striving for regulatory efficiency. It is important to note that it is not the OEB's role, nor the intervenors, to manage the utility or substitute their judgment in place of the applicant's management. That is the job of the utility. The OEB has established a renewed regulatory framework for electricity (RRFE) which places a greater emphasis on outcomes and less of an emphasis on a review of individual line items in an application.[30]

In light of these remarks, it seems desirable to consider how to make Custom IR more mechanistic, incentivizing, and fair to customers while still ensuring that it is reasonably compensatory over time for efficient utilities.

Informed by our familiarity with Custom IR and by research and testimony in many proceedings outside Ontario, we believe that the following alternatives to the current CIR treatment of capital merit consideration. Consider first that in California many gas and electric utilities have operated over the years under multiyear rate plans with hybrid revenue caps that index OM&A revenue but have a different ratemaking treatment for capital. Consumer advocates are influential there and have sometimes refused to consider in advance the prudence of forecasted/proposed plant additions beyond the (forward) test year. Budgets for plant additions have in several plans been set at the average of recent historical values or the value that is featured in the forward test year.

The Alberta Utilities Commission ("AUC") had an unhappy experience with capital cost trackers to fund capex surges in their first-generation IR plans for provincial gas and electric power distributors. A number of possible reforms to the ratemaking treatment of capital were discussed in the AUC's generic proceeding on second-generation plans. The AUC eventually chose a means for providing supplemental capital revenue which was much less dependent on distributor capex forecasts. Regulatory cost was reduced thereby, and capex containment incentives were strengthened.

A "K-bar" value was established for each distributor for the first year of the plan based on the extent to its recent *historical* capex levels, adjusted for growth in inflation, X, and billing determinant growth, were not funded by base rates. K-bar values in subsequent years have been escalated by the growth that would otherwise be produced by the rate or revenue cap index. Capital cost trackers may

[30] OEB, *Decision and Order*, EB-2014-0116, December 29, 2015, p. 2.

be requested to provide supplemental funding for eligible capex of a type that is required by a third party and extraordinary and not previously included in the distributor's rate base.[31]

Each of these approaches to ratemaking could make sense for Hydro One were it not for one fact: it forecasts plant additions that are well in excess of its recent historical norms. Here are some other ratemaking treatments of capital that merit consideration.

a) One obvious candidate is the approach previously advocated by PEG and chosen by the OEB in some recent Custom IR proceedings. A supplemental stretch factor would apply to the calculation of the C factor. Hydro One has proposed a modest 0.15% supplemental stretch factor in this proceeding.

b) Capital costs that occasion supplemental revenue could be subject to continued tracking in later plans. Customers would then receive the benefit of depreciation of the surge capex between plans. Once again, knowledge that there is a price to be paid in the long run for asking for extra revenue now would strengthen Hydro One's capex containment incentives. The IR plans for the Fortis companies in British Columbia track the costs of *all* older capital.[32] A problem with this approach is that they make operation under 4GIRM or its successor more difficult. Hydro One can then claim that only continued operation under CIR can be compensatory.

c) The proposed capex budget could be reduced by a material amount, as in some past Custom IR decisions.

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[31] In the first generation of PBR plans in Alberta, capital cost trackers were the sole means by which a distributor could obtain supplemental funding for eligible capex.

[32] This is true of the current generation of plans for the FortisBC companies as well as the previous generation. British Columbia Utilities Commission (2020), Decision and Orders G-165-20 and G-166-20.

British Columbia Utilities Commission (2014), "In the Matter of FortisBC Inc. Multi-Year Performance Based Ratemaking Plan For 2014 Through 2018 Decision", Commission Order G-139-14, September 15, 2014.

d) Hydro One could be permitted to keep a portion of the benefit of capex underspends.

e) Some of these approaches could be sensibly combined.

After considering the pros and cons of these options, we recommend that the OEB at a minimum add a supplemental stretch factor to Hydro One's C factor calculation. This factor should be no less than the comparable markdown on plant additions that is produced by the ICM. Several arguments can be advanced for making the supplemental capital cost stretch factor even higher.

- The Board rationalized the 10% markdown factor for ACMs and ICMs chiefly on the grounds that it may reduce regulatory cost. We have ventured a much wider range of arguments in favor of a markdown.
- The 10% markdown factor in the ICM formula actually marks down otherwise-eligible capex by considerably less than 10%.

We also believe that Hydro One should be permitted to keep a share of the annual cost savings from any capex underspends that it achieves. This would strengthen the Company's incentive to contain capex (but also its incentive to exaggerate its capex needs). We believe that the Company should be permitted to keep 5% of the value of capex underspends, and not the "first" 2% as the Company proposes. The Company should also be permitted to keep a share of the benefits of demonstrated productivity initiatives.

Appendix A: Index Research for X Factor Calibration

In this Appendix we discuss pertinent principles and methods for the design of revenue cap indexes. We begin by discussing basic indexing concepts. There follow discussions of the use of indexing research in revenue cap index design and other important methodological issues.

A.1 Principles and Methods for Revenue Cap Index Design

Basic Indexing Concepts

Input Price and Quantity Indexes

The cost of each input that a company uses is the product of a price and a quantity. The aggregate cost of many inputs is, analogously, the product of a cost-weighted input price index ("*Input Prices*") and input quantity index ("*Inputs*").

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

These indexes can provide summary comparisons of the prices and quantities of the various inputs that a company uses. Depending on their design, these indexes can compare the *levels* of prices (and quantities) of different utilities in a given year, the *trends* in the prices (and quantities) of utilities over time, or *both.* Capital, labor, and miscellaneous materials and services are the major classes of inputs that are typically addressed by the base rates of gas and electric utilities. These are capital-intensive businesses, so heavy weights are placed on the capital subindexes.

The growth rate of a company's cost can be shown to be the sum of the growth in (properly designed) input price and quantity indexes.[33]

$$growth\ Cost = growth\ Input\ Prices + growth\ Inputs. \qquad [2]$$

Rearranging terms, it follows that input quantity trends can be measured by taking the difference between cost and input price trends.

$$growth\ Inputs = growth\ Cost - growth\ Input\ Prices. \qquad [3]$$

[33] This result, which is due to the French economist François Divisia, holds for particular kinds of growth rates.

This greatly simplifies input quantity measurement.

Productivity Indexes

A productivity index is the ratio of an output quantity (or scale) index ("*Outputs*") to an input quantity index.

$$Productivity = \frac{Outputs}{Inputs}. \quad [4]$$

Indexes of this kind are used to measure the efficiency with which firms convert production inputs into the goods and services that they provide. Depending on their design, productivity indexes can compare productivity levels of different companies in a given year, measure productivity *trends*, or do both. The growth of a productivity trend index can be shown to be the difference between the growth of the output and input quantity indexes.[34]

$$growth\ Productivity = growth\ Outputs - growth\ Inputs. \quad [5]$$

Productivity grows when the output index rises more rapidly (or falls less rapidly) than the input index. Productivity can be volatile for various reasons that include fluctuations in output and/or the uneven timing of certain expenditures. The volatility of productivity growth tends to be greater for individual companies than the average for a group of companies.

The scope of a productivity index depends on the array of inputs that are addressed by the input quantity index. A *multifactor* productivity index measures productivity in the use of multiple inputs. These are sometimes call *total* factor productivity indexes even though they rarely address all inputs. Some indexes measure productivity in the use of a single input class (e.g., labor or capital.) These indexes are sometimes called *partial* factor productivity indexes.

Output Indexes

Depending on their design, an output index can compare the output levels of utilities in a given year, measure output trends, or do both. If output is multidimensional in character, its level or trend can be measured by a multidimensional output index. Each output dimension that is itemized is

[34] This result holds true for particular kinds of growth rates.

measured by a sub-index, and the summary index is a weighted average of the growth in the sub-indices.

In designing an output index, choices concerning sub-indices and weights should depend on the way the index is to be used. One possible objective of output research is to study the impact of output on *cost.*[35] In that event, the index should be constructed from one or more output variables that measure the "workload" that drives cost. If there is more than one output variable, the weights for these variables should reflect their relative cost impacts.

The sensitivity of cost to a small change in the value of an output or any other business condition variable is commonly measured by its cost "elasticity."[36] Cost elasticities can be estimated econometrically using data on the costs of utilities and on outputs and other business conditions that drive these costs. Such estimates provide the basis for elasticity-weighted output indexes.[37] A productivity trend index calculated using a cost-based output index ("$Outputs^C$") will be denoted as $Productivity^C$.

$$growth\ Productivity^C = growth\ Outputs^C - growth\ Inputs. \qquad [6a]$$

The corresponding productivity level index is

$$Productivity^C = Outputs^C / Inputs. \qquad [6b]$$

<u>Sources of Productivity Growth</u>

Economists have studied the drivers of productivity growth using mathematical theory and empirical methods.[38] This research has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit firms to produce given output

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[35] Another possible objective is to measure the impact of output on *revenue*. In that event, the sub-indices should measure *billing determinants* and the weight for each itemized determinant should reflect its share of *revenue*.

[36] The cost elasticity of output *i* is the effect on cost of 1% growth in that output.

[37] An early discussion of elasticity-weighted output indexes is found in Denny, Michael, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

[38] The seminal paper on this topic is Denny, Fuss and Waverman, *Ibid.*

quantities with fewer inputs.

A second important source of productivity growth is output growth. In the short run, output growth can spur a company's productivity growth to the extent that it has excess capacity. In the longer run, economies of scale can be realized even if capacity additions are required provided that output growth exceeds its impact on cost. The realization of scale economies will typically be lower the slower is output growth. Incremental scale economies may also depend on the current scale of an enterprise. For example, larger utilities may be less able than smaller utilities to achieve incremental scale economies from the same rate of output growth.

Productivity growth is also driven by changes in X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum possible efficiency. Productivity growth will increase to the extent that X inefficiency diminishes. A company's potential for future productivity growth from this source is greater the lower is its current efficiency.

Technological change, scale economies, and X inefficiency are generally considered to be dimensions of operating efficiency. This has encouraged the use of productivity indexes to measure operating efficiency. However, theoretical and empirical research reveals that productivity index growth is also affected by changes in miscellaneous external business conditions, other than input price inflation and output growth, which also drive cost. One example for a power transmitter is the extent to which facilities must be underground. If growth in the urban areas served by a utility requires it to increase transmission system undergrounding, its productivity growth will be slowed.

System age is another business condition that affects productivity. Productivity growth tends to be greater to the extent that the current capital stock is large relative to the need to refurbish or replace aging plant. If a utility requires unusually high replacement capital expenditures its cost growth surges and productivity growth can be unusually slow and even decline. Highly depreciated facilities are replaced by facilities that are designed to last for decades and may need to comply with new performance standards. On the other hand, cost growth slackens and productivity growth can accelerate after a period of unusually high capex.

This analysis has some noteworthy implications. One is that productivity indexes are imperfect measures of operating efficiency. Productivity can fall (or rise) for reasons other than deteriorating (improving) efficiency. Our analysis also suggests that productivity growth can differ between utilities, and over time for the same utility, for reasons that are beyond their control. For example, a utility with unusually slow output growth and an unusually high number of assets needing replacement can have unusually slow productivity growth.

Use of Indexing in Revenue Cap Index Design

Revenue Cap Indexes

Cost theory and index logic support the design of revenue cap indexes. Consider first the following basic result of cost theory:

$$growth\ Cost = growth\ Input\ Prices - growth\ Productivity^{C} + growth\ Outputs^{C}.$$ [39] [7]

The growth in the cost of a company is the difference between the growth in its input price and productivity indexes plus the growth in a consistent cost-based output index. This result provides the basis for a revenue cap index of general form:

$$growth\ Allowed\ Revenue^{Utility} = growth\ Input\ Prices - (X + S) + growth\ Scale^{Utility}$$ [7a]

where:

$$X = \overline{Productivity^{C}}.$$ [7b]

S = stretch factor

Here X, the productivity or X factor, reflects a base productivity growth target ("$\overline{Productivity^{C}}$") which is typically the average trend in the productivity indexes of a regional or national sample of utilities. A consistent cost-based output index is used in the supportive productivity research. A stretch factor (aka consumer dividend) is often added to the formula which slows revenue cap index growth in a manner that shares with customers the financial benefits of performance improvements which are expected under the multiyear rate plan.

[39] See Denny, Fuss, and Waverman, o*p. cit.*

An alternative basis for a revenue cap index can be found in index logic. Recall from [2] that growth in the cost of an enterprise is the sum of the growth in an appropriately-designed input price index and input quantity index.[40] It then follows that

$$\begin{aligned} \textit{growth Cost} &= \textit{growth Input Prices} + \textit{growth Outputs}^C \\ &\quad - (\textit{growth Outputs}^C - \textit{growth Input Quantities}) \\ &= \textit{growth Input Prices} - \textit{growth Productivity}^C + \textit{growth Outputs}^C \qquad [8] \end{aligned}$$

Simple vs. Size-Weighted Averages

In calculating industry productivity trends, a choice must be made between simple and size-weighted averages of results for individual utilities. The arguments for size-weighted averages include the following.

- This is a better measure of the *industry* productivity trend.
- To the extent that productivity growth depends on a utility's size, size-weighted results are more pertinent in X factor studies for larger utilities.

Arguments for even-weighted averages include the following.

- Absent evidence that size affects productivity trends, the results for individual utilities are equally important. Econometric cost research places the same weight on all observations.
- Size-weighted averages are sometimes unduly sensitive to results for a few utilities.
- Even if size does affect productivity trends, even-weighted averages are more pertinent in X factor studies for smaller utilities.

PEG typically uses size-weighted (even-weighted) averages in X factor studies applicable to larger (smaller) utilities.

[40] This result is also due to François Divisia.

Dealing with Cost Exclusions

It is important to note that relation [8] applies to *subsets* of cost as well as to total cost. Thus, a revenue cap index designed to escalate only OM&A revenue can reasonably take the form

$$growth\ Revenue^{OM\&A} = Inflation - (X + S) + \text{growth } Scale^{OM\&A}$$

where

$$X = \overline{Productivity}^{OM\&A}.$$

Here X is the trend in the productivity of a group of utilities in the management of OM&A inputs. The scale escalator involves one or more output variables that drive OM&A cost.

If the multiyear rate plan ("MRP") provides for certain costs to be addressed by variance accounts, relation [8] similarly provides the rationale for excluding these costs from the X factor research. This principle is widely (if not unanimously) accepted, and certain costs that are frequently accorded variance account treatment in MRPs (e.g., costs of energy, demand-side management, and pension programs) are frequently excluded from the supportive X factor studies.

This reasoning is important when considering how to combine a revenue cap index with *MRP* provisions that furnish extra funding for capex. Many multiyear rate plans with indexed rate or revenue caps have had provisions for supplemental capital revenue. The rationale is that the index formula cannot by itself provide reasonable compensation for capex surges. Reasons that such surges might be needed include "lumpy" plant additions, a desire to install costly "smart grid" equipment, or a surge in plant that has reached replacement age. Provisions for funding capex surges often involve variance accounts that effectively exempt capital revenue or a portion thereof from indexing. In Ontario, for example, a "C factor" is sometimes added to a revenue (or price) cap index formula that helps capital revenue grow at a rate that is close to that of forecasted capital cost.

Scale Escalators

Formula [7a] raises the issue of the appropriate scale escalator for a revenue cap index. For gas and electric power distributors, the number of customers served is a sensible component of a revenue cap index scale escalator, for several reasons. The customers served variable often has the highest estimated cost elasticity amongst the scale variables studied in econometric research on distributor cost. The number of customers clearly drives costs of connections, meters, and customer services and has a high positive correlation with peak load and delivery capacity. Consider also that a scale escalator that includes volumes or peak demand as output variables diminishes a utility's incentive to promote demand side management. This is an argument for excluding these system-use variables from a revenue cap index scale escalator.[41] In power transmission no single scale variable is dominant. A multidimensional scale index with weights based on econometric research on transmission cost is therefore more appropriate.

Revenue cap indexes do not always include explicit scale escalators. A revenue cap index of general form

$$growth\ Revenue^{Allowed} = growth\ GDPIPI - X \quad [9a]$$

where

$$X = \overline{MFP}^{C}_{Industry} + Stretch.$$

is equivalent to the following:

$$growth\ Revenue^{Allowed} = growth\ GDPIPI - X + Stretch^{Augmented} \quad [9b]$$

where

$$X = \overline{MFP}^{C}_{Industry}$$

$$Stretch = Expected\ growth\ Scale_{Utility} + Stretch^{Normal}. \quad [9c]$$

It can be seen that if the *MRP* does not otherwise compensate the utility for growth in its operating scale, the expected scale index growth of the utility is an implicit stretch factor. The value of this implicit stretch factor will be larger the more rapid is the utility's expected scale index growth.

[41] In choosing a scale escalator for a North American power distributor, it is also pertinent that data on miles of distribution line, another important distribution cost driver, are not readily available for most U.S. power distributors. This bolsters the arguments for using the number of customers as the sole scale variable in an RCI for a U.S. power distributor.

Inflation Issues

If a macroeconomic inflation index, such as the GDPIPI, is used as the inflation measure in a revenue cap index, Relation [7] can be restated as:

$$\begin{aligned} growth\ Cost &= growth\ Input\ Prices - growth\ Productivity^{C} + growth\ Outputs^{C} \\ &\quad + growth\ GDPIPI - growth\ GDPIPI \\ &= growth\ GDPIPI - [growth\ Productivity^{C} + (growth\ GDPIPI - growth\ Input\ Prices)]. \\ &\quad + growth\ Outputs^{C}. \end{aligned} \qquad [10]$$

Relation [10] shows that cost growth depends on GDPIPI inflation, growth in operating scale and productivity, and on the difference between GDPIPI and utility input price inflation (which is sometimes called the "inflation differential".)

The GDPIPI is the Canadian government's featured index of inflation in the prices of the economy's final goods and services.[42] It can then be shown that the trend in the GDPIPI equals the difference between the trends in the economy's input price and (multifactor) productivity indexes.

$$growth\ GDPIPI = growth\ Input\ Prices^{Economy} - growth\ MFP^{Economy}. \qquad [11]$$

The formula for the X factor can then be restated as:

$$X = [(\overline{Productivity}^{C} - \overline{MFP}^{Economy}) + (\overline{Input\ Prices}^{Economy} - \overline{Input\ Prices}^{Industry})]. \qquad [12]$$

Here, the first term in parentheses is called the "productivity differential." It is the difference between the productivity trends of the industry and the economy. The second term in parentheses is called the "input price differential." It is the difference between the input price trends of the economy and the industry.

Relation [12] has been the basis for the design of several approved X factors in *MRP* plans in the United States.[43] Since the *MFP* growth of the U.S. economy has tended to be brisk it has contributed to the approval of substantially negative X factors in several American *MRPs* for energy distributors. MFP

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[42] Final goods and services include consumer products, government services, and exports.

[43] This approach has, for example, been approved in Massachusetts on several occasions. See, for example, D.P.U. 96-50, D.T.E. 03-40, D.T.E. 05-27, D.P.U. 17-05, and D.P.U. 18-150.

growth has historically been slower in Canada's economy, and macroeconomic price indexes are less frequently the sole inflation measures in revenue cap indexes.

Stretch Factors

The stretch factor term of an RCI should reflect an expectation of how the productivity growth of the subject utility will differ from the base productivity growth target. This depends in part on the utility's operating efficiency at the start of the multiyear rate plan. It also depends on how the performance incentives generated by the plan compare to those in the regulatory systems of utilities in productivity studies that are used to set the base productivity trend.

Initial operating efficiency is often assessed in IR proceedings by statistical benchmarking studies. The methods used in these studies run the gamut from unit cost and productivity level metrics like those we presented in Tables 4 and 9 to sophisticated econometric modelling and data envelopment analysis. In succeeding multiyear rate plans, the linkage of the stretch factor to statistical benchmarking of the utility's forward test year cost proposal can serve as an efficiency carryover mechanism that rewards the utility for achieving lasting performance gains and can penalize it for a failure to do so.[44]

In prior testimony, PEG presented results of some incentive power research that it had previously prepared.[45] Results of this research were published by Lawrence Berkeley National Laboratory.[46] We showed that the incentive power of regulatory systems can be increased by efficiency carryover mechanisms and less frequent rate cases and reduced by earnings sharing mechanisms. This model can be used to consider how the frequency of rate cases, the prevalence of earnings sharing, and other aspects of ratemaking for sampled utilities compares to provisions in the multiyear rate plan of the subject utility and what the implications are for the stretch factor.

[44] See, for example, Mark Newton Lowry, "Outstanding Issues in the Design of an MRI for Hydro-Québec Transmission," 9 November 2018, p. 27.

[45] Mark Newton Lowry and Matt Makos, "Incentive Regulation for the Transmission and Distributor Services of Hydro-Québec," Revised HQT Draft 24 February 2017, pp. 136-145.

[46] Mark Newton Lowry, J. Deason, and Matthew Makos, "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," Lawrence Berkeley National Laboratory, July 2017.

Most power distributors in Ontario operate under the 4th Generation Incentive Ratemaking Mechanism. The X factor term of the price cap index includes a base productivity growth target and a stretch factor. The stretch factor varies with the outcome of an econometric total cost benchmarking study that is updated annually. As detailed in the table below, the best performers get a stretch factor of zero whereas the worst get a stretch factor of 0.6%.[47] No explicit consideration has to date been paid by the OEB to how the incentive power of a multiyear rate plan differs from that of utilities in the productivity study.

Ontario Energy Board Stretch Factor Assignments

Cost Performance in Econometric Model	Assigned Stretch Factor
Actual costs 25% or more below model's prediction	0.00%
Actual costs 10-25% below model's prediction	0.15%
Actual costs within +/-10% of model's prediction	0.30%
Actual costs 10-25% above model's prediction	0.45%
Actual Costs 25% or more above model's prediction	0.60%

A.2 Capital Specification

Monetary Approaches to Capital Cost and Quantity Measurement

The capital cost ("CK") specification is critical in research on T&D cost because the technology of distribution and (especially) transmission is capital intensive. The annual cost of capital includes depreciation expenses, a return on investment, and some taxes. If the price (unit value) of the asset changes over time this cost may also be net of any capital gains or losses.

Monetary approaches to the measurement of capital prices and quantities are conventionally used in research on the costs and input price and productivity trends of utilities. These approaches permit the decomposition of capital cost into a consistent capital quantity index ("*XK*") and capital price index ("*WK*") such that

[47] Ontario Energy Board (2013), *EB-2010-0379 Report of the Board Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, p. 21.

$$CK = WK \cdot XK.^{48} \qquad [13]$$

The growth rate of capital cost then equals the sum of the growth rates of the capital price and quantity indexes.

In U.S. electric utility research, capital quantity indexes are typically constructed by deflating the value of gross plant additions using a Handy Whitman electric utility construction cost index and subjecting the resultant quantity estimates to a mechanistic decay specification. Capital prices are calculated from these same construction cost indexes and from data on the rate of return on capital.[49] Good construction cost trend indexes have not been available for Canadian utilities for many years.

Alternative Monetary Approaches

Several monetary methods for measuring capital cost have been established. A key issue in the choice between these methods is the pattern of decay in the quantity of capital from the plant additions that are made each year.[50] Another issue is whether plant is valued in historic or replacement dollars. Here are brief descriptions of the three monetary methods that have been most commonly used in the design of rate and revenue cap indexes.

1. Geometric Decay ("GD"). Under the GD method, the capital quantity is treated as the flow of services from plant additions in a given year. The flow is assumed to decline at a constant rate over time. Plant is typically valued in replacement dollars. Cost is usually computed net of capital gains.

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[48] In rigorous statistical cost research, it is often assumed that a capital good provides a stream of services over some period of time (the "service life" of the asset). The capital *quantity* index measures this flow, while the capital *price* index measures the trend in the simulated price of renting a unit of capital service. The design of the capital service price index is consistent with the assumption about the decay in the service flow. The product of the capital service price index and the capital quantity index is interpreted as the annual cost of using the flow of services.

[49] If taxes are included in the study, capital prices are also a function of tax rates.

[50] Decay can result from many factors including wear and tear, casualty loss, increased maintenance requirements, and technological obsolescence. The pattern of decay in assets over time is sometimes called the age-efficiency profile.

A GD capital quantity index is typically combined with a consistent GD capital price that simulates the price for capital services in a competitive rental market in which the capital stocks of suppliers experience GD. The trend in this capital service price is driven by trends in construction costs and the rate of return on capital.

2. One-Hoss-Shay ("OHS"). Under the OHS method, the flow of services from a capital asset is assumed to be constant until the end of its service life, when it abruptly falls to zero. This is the pattern that is typical of an incandescent light bulb. However, in energy utility research this constant flow assumption has typically been applied to the total plant additions for assets that have varied service lives. Plant is once again valued at replacement cost and cost is computed net of capital gains. As with GD, it is common to use a capital service price that is consistent with the OHS assumption.

3. Cost of Service ("COS"). The GD and OHS approaches for calculating capital cost use assumptions that are quite different from those used to calculate capital cost under traditional cost of service ratemaking.[51] Replacement valuation of plant, capital gains, and use of capital service prices can together give rise to volatile GD and OHS capital costs and prices. The derivation of a revenue cap index using index logic does not require a service price treatment of the capital price.

   An alternative COS approach to measuring capital cost has been developed by PEG that is so-called because it is based on the straight-line depreciation and historical plant valuations, techniques used in utility capital cost accounting. Capital cost can still be decomposed into a price and a quantity index, but the capital price cannot be represented as a capital service price. The price and quantity index formulae are complicated, making them more difficult to code and review. However, capital prices are less volatile.

Benchmark Year Adjustments

Utilities have diverse methods for calculating depreciation expenses that they report to regulators. When calculating capital quantities using a monetary method, it is therefore customary to

[51] The OHS assumptions are more markedly different.

rely on the reporting companies chiefly for the value of *gross* plant additions and then use a standardized decay specification for all companies. Since some of the plant a utility owns may be 40-60 years old, it is desirable to have gross plant addition data for many years in the past.

For the earlier years that are pertinent in these calculations the desired gross plant addition data are frequently unavailable. It is then customary to take the total value of plant, with its diverse vintages, at the end of this limited-data period and to estimate the quantity of capital that it reflects using construction cost indexes from earlier years and assumptions about the historical plant addition pattern. The year for which this estimate is undertaken is commonly called the "benchmark year" of the capital quantity index. Since the estimate of the capital quantity in the benchmark year is inexact, it is preferable to base capital and total cost research on a sample period that begins many years after the benchmark year. Research on capital and total cost will be less accurate to the extent that this is impossible.

Appendix B: Additional Information on Research Methods

B.1 Econometric Research Methods

This section of Appendix B provides additional and more technical details of our econometric research. We begin by discussing the choice of a form for the econometric benchmarking models. There follow discussions of econometric methods.

Form of the Econometric Cost Model

Specific forms must be chosen for cost functions used in econometric research. Forms commonly employed by scholars include the linear, double log, and translog. Here is a simple example of a *linear* cost model:

$$C_{h,t} = a_0 + a_1 \cdot L_{h,t} + a_2 \cdot D_{h,t}. \qquad \text{[B1]}$$

Here is an analogous cost model of *double log* form:

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln L_{h,t} + a_2 \cdot \ln D_{h,t}. \qquad \text{[B2]}$$

Here, for each company h, $C_{h,t}$ is cost, L is the length of transmission lines and D is ratcheted peak demand.

The double log model is so-called because the right- and left-hand side variables in the equation are all logged.[52] This specification makes the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, parameter a_1 in function [B1] indicates the percentage change in cost resulting from 1% growth in the length of transmission lines. Elasticity estimates are useful and make it easier to assess the reasonableness of model results. It is also noteworthy that, in a double log model, elasticities are *constant* in the sense that they are the same for every value that the cost and business condition variables might assume. This model specification is restrictive and may be inconsistent with the true form of the cost relationship we are trying to model.

Here is an analogous model of *translog* form:

[52] i.e., the variable is used in the equation in natural logarithmic form, as ln(X) instead of X.

$$\ln C_{h,t} = a_o + a_1 \cdot \ln L_{h,t} + a_2 \cdot \ln D_{h,t} + a_3 \cdot \ln L_{h,t} \cdot \ln L_{h,t} + a_4 \cdot \ln D_{h,t} \cdot \ln D_{h,t} + a_5 \cdot \ln L_{h,t} \cdot \ln D_{h,t} \quad [B3]$$

This form differs from the double log form in the addition of quadratic and interaction terms. These are sometimes called second-order terms. Quadratic terms like $\ln D_{h,t} \cdot \ln D_{h,t}$ permit the elasticity of cost with respect to output growth to depend the size of the company. The elasticity of cost with respect to output growth may, for example, be lower for a small utility than for a large utility. Interaction terms like $\ln L_{h,t} \cdot \ln D_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable. For example, the elasticity of cost with respect to growth in peak load may depend on the length of a transmitter's transmission lines.

The translog form is an example of a "flexible" functional form. Flexible forms can accommodate a greater variety of possible functional relationships between cost and the business condition variables. A disadvantage of the translog form is that it involves many more variables than simpler forms like the double log. As the number of variables accorded translog treatment increases, the precision of a model's parameter estimates and cost predictions falls. It is therefore common in econometric cost research to limit the number of variables accorded translog treatment.

In our econometric work for this proceeding, we have chosen a functional form that has second-order terms only for the scale variables. This preserves degrees of freedom but permits the model to recognize some nonlinearities. Most of the second-order terms in our cost models had statistically significant parameter estimates.

Econometric Model Estimation

A variety of parameter estimation procedures (aka "estimators") are used by econometricians. The appropriateness of each estimator depends on the assumed distribution of the model prediction errors. The estimator that is most widely known, ordinary least squares ("OLS"), is familiar to many, readily available in econometric software, and has good statistical properties under simplified assumptions about the distribution of errors. Another class of estimators, called generalized least squares ("GLS"), is appropriate under assumptions of more complicated and realistic error specifications. When, for example, there is autocorrelation in the error terms, parameter estimates are less precise and the GLS estimator produces more precise parameter estimates. However, OLS estimators are asymptotically unbiased to the extent that the variables in the model are not correlated with excluded relevant variables. In this study we used OLS escalators with robust Driscoll-Kraay standard errors. This removes a source of methodological controversy between PEG and Mr. Fenrick in past CIR proceedings.

Note, finally, that the model specification was determined using data for all sampled companies. However, estimation of parameters and appropriate standard errors for the cost model actually used for benchmarking required that the utility of interest be dropped from the sample. The parameter estimates used in developing the cost models and reported in Tables 1-3 and 10-12 above therefore vary slightly from those in the models used for benchmarking.

B.2 Substation Data

For the 51 non-Hydro One companies in both Clearspring's and PEG's samples, Clearspring measures an average yearly total of 1,628 more substations than PEG does. This comes out to an average of 32 extra substations per utility per year. Of course, these summary numbers only point to the overall differences. The two datasets align for a number of utilities, and very large differences – up to a 5x increase - occur for others. This error is significant, and since the extent of the mismeasurement depends on how the particular utility reports its data, the extent of the data distortion on the econometric model is not predictable. PEG's question on this issue in the Technical Conference was intended to reflect our concern about the *entire* substation dataset; the two examples were provided as clear demonstrations of the problem. Mismeasurement error causes bias in an econometric model and obfuscates the true cost relationship.

In Clearspring's Undertaking JT-4.05, they indicated that they count multiple rows of identically-named substations as individual observations. This method is demonstrably incorrect; upon careful examination of the data, it is very clear that some companies consistently list a single substation on multiple lines to accommodate detailed listing of transformer data. It is unfortunate, from a data collection perspective, that the Form 1 substation page design encourages listing the transformers individually, forcing utilities to devise their own methods for naming and listing substations housing multiple transformers. Any utility listing their subtotals and totals does so independently and free-form.

However, once the data practitioner is familiar with the structure of the Form 1 page and the data practices the utilities tend to use for this section of the Form 1 report, Clearspring's error can be verified in several ways:

- For the companies with significant overcounting, as a rule the substation line indicates that it reports data for a single transformer. It does not seem plausible that utilities would build a new substation at the same location for each transformer. For example, for the second utility discussed in JT-4.05, to rely on Clearspring's data one must believe there are no fewer than 30 separate transmission substations in a single location, plus a group of 5 entire substations at another location in Spencer, North Carolina, population 3,267. PEG believes it is likely that Clearspring's numbers are much closer to a "number of transformers" variable. While such a variable might be appropriate to consider, it has not been vetted for overall accuracy nor is the name and description accurate.
- The Form 1 Substations page has a column to identify spare transformers; these are also listed on individual lines with the same substation name. It is implausible that utilities construct spare substations to house spare transformers.
- A number of utilities – typically, the ones for which Clearspring's and PEG's data are in agreement – list each substation address one time and then leave the name/address portion blank for the next several lines in which they list each individual transformer. Others in agreement tend to have only one transmission transformer at a given substation, or in a very few cases the utility chooses to fill out their Form 1 in a way that allows them to include multiple transformers on one line.
- Several utilities, including but not limited to the two discussed by Clearspring, often summarize the number of substations, number of transformers, and MVa by category. When comparing the numbers of substations with unique locations, it is clear that the utilities are not generally miscounting their own number of substations.

These issues are apparent in the attached pdf files containing excerpts of the Form 1 substations page for a few utilities in different years. Note that the data for a single line is spread over two pages; the line numbers and pages must be matched up to see the full data.

Alabama Power 2016 Substation Form

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALABAMA POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Flatbridge DS-Near Anniston	DS - Unattended	12.47		
2	Flatbridge DS-Near Anniston	DS - Unattended	115.00	12.47	
3	Flomaton DS-Near Mobile	DS - Unattended	46.00	12.47	
4	Flomaton DS-Near Mobile	DS - Unattended	12.47		
5	Flomaton DS-Near Mobile	DS - Unattended	12.47		
6	Flomaton DS-Near Mobile	DS - Unattended	12.47		
7	Flomaton DS-Near Mobile	DS - Unattended	46.00	12.47	
8	Flomaton DS-Near Mobile	DS - Unattended	46.00	12.47	
9	Flomaton DS-Near Mobile	DS - Unattended	46.00	12.47	
10	Flomaton TS-Near Mobile	TS - Unattended	115.00		
11	Flomaton TS-Near Mobile	TS - Unattended	115.00		
12	Flomaton TS-Near Mobile	TS - Unattended	46.00		
13	Flomaton TS-Near Mobile	TS - Unattended	46.00		
14	Flomaton TS-Near Mobile	TS - Unattended	115.00	46.00	
15	Flomaton TS-Near Mobile	TS - Unattended	115.00	46.00	
16	Flomaton TS-Near Mobile	TS - Unattended	115.00	46.00	
17	Flomaton TS-Near Mobile	TS - Unattended	115.00	46.00	
18	Forbes Road DS-Near Montgomery	DS - Unattended	115.00	12.47	
19	Forestdale DS-Near Birmingham	DS - Unattended	12.47		
20	Forestdale DS-Near Birmingham	DS - Unattended	115.00	12.47	
21	Forestdale DS-Near Birmingham	DS - Unattended	115.00	12.47	
22	Fort Deposit TS-Near Montgomery	TS - Unattended	115.00		
23	Fort Deposit TS-Near Montgomery	TS - Unattended	115.00	46.00	
24	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
25	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
26	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
27	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
28	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
29	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
30	Fort McClellan DS-Near Anniston	DS - Unattended	7.20		
31	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
32	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
33	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
34	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
35	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
36	Fort McClellan DS-Near Anniston	DS - Unattended	12.47		
37	Fort McClellan DS-Near Anniston	DS - Unattended	115.00	12.47	
38	Fort Mitchell TS-Near Eufaula	TS - Unattended	115.00	46.00	
39	Fort Rucker DS-Near Eufaula	DS - Unattended	12.47		
40	Fort Rucker DS-Near Eufaula	DS - Unattended	12.47		

Pacific Economics Group Research, LLC

Alabama Power 2016 Substation Form (continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
ALABAMA POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	12/31/2016	End of 2016/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
1			Regulator	1		1
25	1		Transformer	1		2
1	1	1	Transformer	1		3
			Regulator	1		4
			Regulator	1		5
			Regulator	1		6
1	1		Transformer	1		7
1	1		Transformer	1		8
1	1		Transformer	1		9
30			Capacitor Bank	1		10
30			Capacitor Bank	1		11
10			Capacitor Bank	1		12
1			Regulator	1		13
20	1		Transformer	1		14
20	1		Transformer	1		15
20	1		Transformer	1		16
20	1	1	Transformer	1		17
37	1		Transformer	1		18
2			Capacitor Bank	1		19
22	1		Transformer	1		20
22	1		Transformer	1		21
30			Capacitor Bank	1		22
20	1		Transformer	1		23
			Capacitor Bank	1		24
1			Regulator	1		25
1			Regulator	1		26
1			Regulator	1		27
1			Regulator	1		28
1			Regulator	1		29
1			Regulator	1		30
1			Regulator	1		31
1			Regulator	1		32
1			Regulator	1		33
1			Regulator	1		34
1			Regulator	1		35
1			Regulator	1		36
22	1		Transformer	1		37
20	1		Transformer	1		38
2			Capacitor Bank	1		39
1			Regulator	1		40

Duke Energy 2019 Substation Form

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WOODLAWN TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
2	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00	0.40	
3	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00		
4	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00		
5	WOODRUFF RET WOODRUFF SC	DIST	44.00	13.00	
6	WOODRUFF RET WOODRUFF SC	DIST	44.00	13.00	
7	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
8	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
9	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
10	WOODRUFF TIE WOODRUFF SC	TRANS	24.00	0.20	
11	WRENN RET PIEDMONT SC	DIST	100.00	13.00	
12	WRENN RET PIEDMONT SC	DIST	100.00	13.00	
13	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
14	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
15	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
16	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
17	WYLIE SW STA FORT MILL SC	TRANS	100.00	44.00	
18	WYLIE SW STA FORT MILL SC	TRANS	100.00	44.00	
19	WYNDWARD POINT RET NEWRY SC	DIST	100.00	24.00	
20	WYNDWARD POINT RET NEWRY SC	DIST	100.00	24.00	
21	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
22	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
23	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
24	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
25	YORK E C DEL 6 TIRZAH SC	DIST	44.00	13.00	
26	YORK E C DEL 6 TIRZAH SC	DIST	44.00	13.00	
27	YORK E C DEL 9 HANCOCK SC	DIST	44.00	13.00	
28	YORK RET YORK SC	DIST	100.00	13.00	
29	YORK RET YORK SC	DIST	100.00	13.00	
30	YORK RET YORK SC	DIST	13.00	2.40	0.60
31	YORK RET YORK SC	DIST	13.00	2.40	0.60
32	YORK RET YORK SC	DIST	13.00	2.40	0.60
33	YORK RET YORK SC	DIST	100.00	24.00	13.00
34	ZF TRANSMISSIONS GVILLE LLC GRAY COURT SC	TRANS	100.00	13.00	
35	ZION CHURCH RD RET HICKORY NC	DIST	100.00	13.00	6.90
36	TOTAL		225554.96	54961.68	8330.10
37					
38	TRANSMISSION -				
39	GEORGIA	TRANS			
40	NORTH CAROLINA	TRANS			

Duke Energy 2019 Substation Form (continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
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2	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00	0.40	
3	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00		
4	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00		
5	WOODRUFF RET WOODRUFF SC	DIST	44.00	13.00	
6	WOODRUFF RET WOODRUFF SC	DIST	44.00	13.00	
7	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
8	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
9	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
10	WOODRUFF TIE WOODRUFF SC	TRANS	24.00	0.20	
11	WRENN RET PIEDMONT SC	DIST	100.00	13.00	
12	WRENN RET PIEDMONT SC	DIST	100.00	13.00	
13	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
14	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
15	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
16	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
17	WYLIE SW STA FORT MILL SC	TRANS	100.00	44.00	
18	WYLIE SW STA FORT MILL SC	TRANS	100.00	44.00	
19	WYNDWARD POINT RET NEWRY SC	DIST	100.00	24.00	
20	WYNDWARD POINT RET NEWRY SC	DIST	100.00	24.00	
21	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
22	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
23	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
24	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
25	YORK E C DEL 6 TIRZAH SC	DIST	44.00	13.00	
26	YORK E C DEL 6 TIRZAH SC	DIST	44.00	13.00	
27	YORK E C DEL 9 HANCOCK SC	DIST	44.00	13.00	
28	YORK RET YORK SC	DIST	100.00	13.00	
29	YORK RET YORK SC	DIST	100.00	13.00	
30	YORK RET YORK SC	DIST	13.00	2.40	0.60
31	YORK RET YORK SC	DIST	13.00	2.40	0.60
32	YORK RET YORK SC	DIST	13.00	2.40	0.60
33	YORK RET YORK SC	DIST	100.00	24.00	13.00
34	ZF TRANSMISSIONS GVILLE LLC GRAY COURT SC	TRANS	100.00	13.00	
35	ZION CHURCH RD RET HICKORY NC	DIST	100.00	13.00	6.90
36	TOTAL		225554.96	54961.68	8330.10
37					
38	TRANSMISSION -				
39	GEORGIA	TRANS			
40	NORTH CAROLINA	TRANS			

Duke Energy 2019 Substation Form (continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/10/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
300	1					1
1	1		AUX			2
29	1		GND	1	28,672	3
29	1		GND	1	28,672	4
8	1					5
8	1					6
12	1					7
30	1					8
30	1					9
	1					10
20	1		1			11
20	1					12
15	1		STU			13
15	1		STU			14
15	1		STU			15
15	1		STU			16
12	1					17
12	1					18
22	1					19
22	1					20
6		1				21
6	1					22
6	1					23
6	1					24
5	1					25
10	1					26
10	1					27
12	1					28
12	1					29
1	1					30
1	1					31
1	1					32
12	1					33
22	1		1			34
12	1					35
86032	2470	204		70	711,745	36
						37
						38
65	1					39
46013	586	30				40

Pacific Economics Group Research, LLC

Duke Energy 2019 Substation Form (continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
23055	421	32				1
69133	1008	62				2
						3
						4
12784	1030	95				5
4115	432	47				6
16899	1462	142				7
						8
						9
						10
						11
						12
						13
						14
						15
						16
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						21
						22
						23
						24
						25
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						39
						40

FERC FORM NO. 1 (ED. 12-96) Page 427.67

Empire District Electric 2018 Substation Form

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	[illegible]	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	457 Ozark South MO	Trans Unattended			12.47
2	460 Pierce City North MO	Dist Unattended	69.00	12.47	
3	467 Decatur-North AR	Dist Unattended	69.00	12.47	
4	469 Joplin-Silver Creek	Dist Unattended	161.00	12.47	
5	471 Joplin-Kodiak	Dist Unattended	69.00	12.47	
6	477 Joplin-Wildwood Ranch	Dist Unattended	161.00	12.47	
7	602 Bolivar Plant MO	Dist Unattended	69.00	12.47	
8	614 Greenfield	Dist Unattended	69.00	4.16	
9	614 Greenfield	Dist Unattended	69.00	12.47	
10	700 Gravette AR	Dist Unattended	69.00	12.47	
11					
12	109 Subtotal		15342.27	3064.97	263.62
13	29 Substations with Capacity < 10,000		1369.59	301.55	12.00
14	138 Total Substations		16711.86	3366.52	275.62
15					
16					
17					
18	6 Substation	Plant Attended	2280.27	241.65	13.80
19	1 Substations	Trans Attended	161.00	69.00	24.00
20	101 Substations	Dist Unattended	8384.59	1223.27	
21	30 Substations	Trans Unattended	5886.00	1832.60	237.82
22	138 Total		16711.86	3366.52	275.62
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
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37					
38					
39					
40					

FERC FORM NO. 1 (ED. 12-96) Page 426.4

Empire District Electric 2018 Substation Form (continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
The Empire District Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/13/2019	End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
10	1					2
22	1					3
22	1					4
22	1					5
22	1					6
22	1					7
5	1					8
6	1					9
22	1					10
						11
5861	167	28				12
136	56	6				13
5997	223	34				14
						15
						16
						17
1727	23	1				18
100	1					19
1825	153	16				20
2345	46	17				21
5997	223	34				22
						23
						24
						25
						26
						27
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Appendix C: Background on North America's Power Transmission Industry

C.1 Federal Regulation of U.S. Power Transmission

To appraise the relevance of statistical cost research using U.S. transmission data for the situation of Hydro One, it is important to understand some key factors of the U.S. transmitter operating environment. Regulation of U.S. power transmission rates is undertaken today chiefly by the FERC. Transmitter productivity has been greatly affected by FERC regulation and by state and federal policies.

Unbundling Transmission Service

Prior to the mid-1990s, U.S. power transmission regulation reflected the vertically-integrated structure of most investor-owned electric utilities in that era. These utilities typically provided most transmission, distribution, and retail sales in the areas they served and obtained most of their electricity from their own power plants. There were fewer bulk power sales and independent power producers, using transmission services than there are today.

Since the 1970s, federal policy has increasingly encouraged third party generators and well-functioning bulk power markets. This increased the need for non-discriminatory tariffs for unbundled transmission services. In 1996, FERC Order 888 required transmitters to provide services under open access transmission tariffs ("OATTs"). Many details of the resultant functional unbundling of transmission services were addressed in FERC Order 889.

Bulk power markets were also expanded by the initiatives of many American states to restructure retail power markets. In these states, many utility generating assets were sold to independent power producers or spun off. Utilities in a few states (e.g., Iowa, Michigan, Ohio, and Wisconsin) sold or spun off transmission assets.

ISOs and RTOs

As another means to promote development of bulk power markets and non-discriminatory transmission service, in 1996 the FERC encouraged electric utilities to transfer operation of their transmission facilities to an independent system operator ("ISO"). Transfer of control was voluntary and utilities retained ownership of most of their facilities. Several ISOs were formed between 1996 and 2000.

ISOs have scheduled transmission service, managed transmission facility maintenance, provided system information to potential customers, ensured short-term grid reliability, and addressed network constraints. ISO services are provided under OATTs that recover ISO costs.

In 1999, the FERC pushed for further structural change in markets for transmission services by encouraging formation of regional transmission organizations ("RTOs"). These organizations typically have a larger footprint, serving multiple states while ISOs typically serve a single state. The FERC has approved applications for RTOs that serve much of the Northeast, East Central, and Great Plains regions of the U.S. The Midwest ISO (now called the Midcontinent ISO) and PJM Interconnection received an RTO status in 2001, while the Southwest Power Pool and ISO New England became RTOs in 2004. ISOs that are not RTOs still operate in New York, Texas, and California.[53] Many utilities in southeastern, intermountain, and northwestern states are not ISO or RTO members.[54] The FERC still regulates the rates charged by members of ISOs and RTOs.

Energy Policy Act of 2005

Beginning in the late 1970s, U.S. transmission capex trended downward in real terms. This was partly due to diminished need. Generation plant additions declined, especially in the 1990s. Another reason for the capex lull was difficulties in siting transmission lines. The grid did not always handle the demands placed on it by growing bulk power market transactions, and congestion occurred in some areas. This sparked concerns by the FERC and other policymakers that insufficient capex by transmitters could jeopardize the success of bulk power markets.

This is the context in which the Energy Policy Act of 2005 ("EPAct") was passed. It affected transmission capex and many other aspects of transmitter operations. The Act gave the FERC authority to establish mandatory transmission reliability standards and penalties. Development of these standards, now called Critical Infrastructure Protection ("CIP") standards, was largely delegated to the

[53] Transmitters in the Electricity Reliability Council of Texas are generally not subject to FERC regulation.

[54] In recent years, several South Central U.S. transmitters joined the MISO.

North American Electric Reliability Corporation ("NERC"), which oversees six regional reliability entities. Numerous NERC Reliability Standards were approved by the FERC in 2007. These standards are intended to prevent reliability problems resulting from numerous sources including operation and maintenance of the system, resource adequacy, cybersecurity, and cooperation between operators. Concerns about the siting of transmission lines were mitigated by a provision of the Act allowing the federal government to designate "national interest electric transmission corridors" to serve areas of significant transmission congestion.

The EPAct also authorized the FERC to incentivize transmission capex and participation in an RTO or ISO. Specifically, the act required the FERC to adopt rules that would

> (1) promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities;
>
> (2) provide a return on equity that attracts new investment in transmission facilities (including related transmission technologies);
>
> (3) encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities; and
>
> (4) allow recovery of—
>
> > (A) all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to section 215; and
> >
> > (B) all prudently incurred costs related to transmission infrastructure development pursuant to section 216.[55]

In FERC Orders 679 and 679-A, released in 2006, the FERC adopted a wide range of incentives to encourage transmission investment. Permissible incentives included the ability for a transmitter to

[55] Energy Policy Act of 2005, Title XII, Sec. 1241 (b).

include 100% of construction work in progress in rate base, ROE premiums for some plant additions, accelerated depreciation, full cost recovery for abandoned facilities and pre-operation costs, and cost tracking for individual projects. In addition, ROE premiums were permitted for transmitters who joined or remained in an RTO or ISO.

In this framework, a transmission operator would need to file an application and show that the requested incentives were appropriate. These applications could also be tied to a request by a transmitter to switch from a fixed rate adjusted only in rate proceedings to a formula rate that is updated annually. Between 2006 and 2012 alone, the FERC reviewed more than 80 applications for incentives related to proposed transmission projects.

Formula Rates

Rates for transmission services can be set by the FERC in periodic rate cases. However, transmitters can also obtain mechanisms that reset rates annually to reflect the changing cost of their service following expedited reviews. These cost of service "formula rates" may rely on a transmitter's historical cost and revenue data or on forward-looking cost and revenue data with a subsequent true up of forecasts to actual values. Formula rates involve what are essentially comprehensive cost variance accounts.

Formula rates have been used at the FERC and its predecessor, the Federal Power Commission, to regulate interstate services of gas and electric utilities since at least 1950.[56] Economies in regulatory cost have been an important reason for their use. Regulatory cost is a major consideration for a commission with jurisdiction over the transmission services of more than 100 electric utilities as well as numerous interstate oil pipelines and natural gas pipelines.

Use of formula rates by the FERC was encouraged in the 1970s and early 1980s by rapid input price inflation. Despite slower inflation in more recent years, the FERC's use of formula rates has grown in the power transmission industry. Growing use of OATTs greatly increased the need to set rates for transmission services by some means. Formula rates were also encouraged by national energy policies

[56] A useful discussion of early precedents for formula rates at the FERC can be found in a March 1976 administrative law judge decision in Docket No. RP75-97 for Hampshire Gas.

such as the EPAct which promoted transmission investment and increased attention to reliability. Early adopters of formula rates in power transmission included midwestern and New England utilities and the Southern Company. Many of the formula rate mechanisms approved by the FERC have been the product of settlements.

In 2004 about 15 of the 52 sampled U.S. transmitters in our econometric sample operated under formula rates. By 2019 fewer than 15 sampled transmitters *did not* operate under formula rates. PEG is not aware of any transmitters that abandoned formula rate plans during these years. Thus, about two-fifths of the U.S. transmitters in our sample received approval of formula rate plans during this period.

C.2 The Canadian Power Transmission Industry

The services provided by Canadian power transmitters are broadly similar to those of their U.S. counterparts. Power market restructuring has been less pervasive than in the States, and ISOs have been established only in Alberta and Ontario. However, to trade power with the U.S. freely, many Canadian utilities abide by an array of U.S. transmission regulations. One (Manitoba Hydro) is a member of a US RTO, and most are members of regional reliability councils and interconnections such as the Northeast Power Coordinating Council or the Western Interconnection. Transmission rates are regulated at the provincial rather than the federal level.

Transmission services of most Canadian utilities are subject to cost of service ratemaking. A notable exception is the CIR plan of Hydro One Transmission, which we discuss in Section D.3 below.

In Québec, a *mechanisme de reglementation incitatif* was required by statute for T&D services of Hydro-Québec.[57] This resulted in the 2019 approval of a multiyear rate plan for Hydro-Québec Transmission ("HQT") which has a 4 year term.[58] This plan provides for escalation of OM&A revenue by the formula I-X+G, where I is a weighted average of labor and non-labor price inflation, the 0.57% X factor was based on judgment, and G is a growth term. The Régie de l'énergie committed to

[57] This provision, Section 48.1 of the Act Respecting the Régie de l'énergie, was subsequently repealed, and Hydro-Québec Distribution now operates under a legislatively-determined multiyear rate plan. The approved plan for Hydro-Québec Transmission has not been affected to date.

[58] Régie de l'énergie D-2019-060.

undertaking multifactor productivity and statistical benchmarking studies during the latter years of the plan.

Capital revenue is addressed through annual filings of HQT's forecast of capital cost. An earnings sharing mechanism addresses overearnings. HQT's share of surplus earnings is tied to its service quality performance (e.g., worse performance would result in greater levels of overearnings being refunded to customers). An off-ramp is available should HQT's earnings vary by more than 125 basis points from the allowed ROE after application of the ESM.

Appendix D: Notable OEB Regulatory Precedents

D.1 Power Distributor Ratemaking

The Early Years

Hydro One's initial distribution revenue requirement was established in 1999. The OEB approved the first generation incentive regulation mechanism ("1GIRM") for an initial 2000-2002 term for provincial power distributors, including Hydro One. This IRM featured a price cap index and an ESM. The Board subsequently delayed implementation of 1GIRM to 2001 and removed the ESM. The OEB later extended 1GIRM to March 2005 to allow the utilities additional time to "explore the incentives for improvements and savings provided by the current PBR regime." However, Bill 210, enacted in December 2002, froze existing distributor rates until May 2006 unless approval was otherwise granted by the Minister of Energy. Rates were adjusted in May 2006 pending the outcome of rebasings that were filed in 2005. Between 1999 and 2006, it follows that Ontario power distributors operated without a rate case or ESM. During this period, utilities had strong incentives to contain costs and some utilities may have responded by deferring capex.

The second-generation IRM used the 2006 rates as a starting point. The Board introduced staggered terms allowing approximately 1/3 of distributors to rebase rates each year between 2008 and 2010.[59] Utilities would thus have up to 3 years on the new price cap index.

The term of the third generation IRM (a/k/a 3GIRM) term was initially fixed at three years plus a rebasing year.[60] Hydro One had its distribution rates rebased for 2008 and in a multiple forward test year rate case for 2010-2011. For 2012 and 2013 Hydro One's rates were set according to the provisions of IRM3.

The Renewed Regulatory Framework ("RRF") (initially known as the Renewed Regulatory Framework for Electricity or "RRFE") resulted from initiatives the OEB began in 2010 to review their

---

[59] Due to the staggered nature of rate reviews, a handful of utilities were on IRM 2 as late as 2011.

[60] Some companies operated under 3GIRM as early as 2009, depending upon when their rate rebasing occurred.

policies in the areas of ratemaking, distribution system planning, and performance measurement. The Board stated that the goal of the RRF is

> to support cost-effective modernization of the network while at the same time controlling rate and/or bill impacts on consumers.[61]

The Board provided three ratemaking options under the RRF: the fourth-generation standard incentive ratemaking mechanism (now called "Price Cap IR"), the Annual IR index, and Custom IR. Each distributor can request its preferred ratemaking approach. Rates for 2014 were escalated based on the provisions of Price Cap IR.

Hydro One requested a Custom IR plan in 2013 with a 5 year term, based entirely on forecasts of its costs and revenues. The Board rejected this proposal, explaining that

> The OEB expects Custom IR rate setting to include expectations for benchmark productivity and efficiency gains that are external to the company. The OEB does not equate Hydro One's embedded annual savings with productivity and efficiency incentives. Incentive-based or performance-based rates are set to provide companies with strong incentives to continuously seek efficiencies in their businesses.
>
> The OEB does not believe that Hydro One's plan contains adequate efficiency incentives to drive year-over-year continuous improvement in the company. Furthermore, the plan lacks measurement of increased efficiency year-over-year, that is in a form indicating trending and that is transparent.[62]

<u>Provisions for High Capex</u>

No special ratemaking provisions for capital were discussed in the OEB's 1GIRM decision. In 2GIRM, companies proposed a mechanism for supplemental capital revenue called a K-Factor. This was rejected due to a lack of perceived need but distributors were permitted to file a rate case early. The OEB expressed concerns about special ratemaking provisions for capital in its decision.

> 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,

[61] Ontario Energy Board, *Renewed Regulatory Framework for Electricity Frequently Asked Questions*, filed in Ontario Energy Board Case EB-2010-0379, November 8, 2011, p. 1.

[62] Ontario Energy Board, *Decision,* EB-2013-0416/EB-2014-0247*,* March 12, 2015, p. 14.

> and monitoring requirements for 2nd Generation IRM because it would require special consideration to be implemented effectively.[63]

3GIRM contained special provisions for capital called the Incremental Capital Module ("ICM"). The Board described the ICM in its decision as "reserved for unusual circumstances that are not captured as a Z-factor and where the distributor has no other options for meeting its capital requirements within the context of its financial capabilities underpinned by existing rates."[64] The OEB set a high bar for approval as amounts were required to exceed a formulaic materiality threshold, meet three need criteria, and be prudent. The materiality threshold was determined formulaically and was intended to be a level of plant additions materially higher than that funded by the price cap index, depreciation, and growth in billing determinants.

The need criteria were that the investments be related to a driver, non-discretionary, and incremental to existing rates. A prudence review of the capex and a decision on the ratemaking treatment of overspending of budgets would occur at the time that the capex is brought into base rates while underspending would result in refunds to ratepayers. Recovery of amounts approved under the ICM was realized via rate riders.

The ACM was developed during the term of 4th generation IR to address concerns that distributors were strategically bunching capex around the year of the rebasing and not in accordance with a prudent asset management program. The Board in its decision discussed the advantages of the ACM.

> Advancing the reviews of eligible discrete capital projects, included as part of a distributor's Distribution System Plan and scheduled to go into service during the IR term, is expected to facilitate **enhanced pacing and smoothing of rate impacts**, as the distributor, the Board and other stakeholders will be examining the capital projects over the five-year horizon of the DSP.

---

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

[64] Ontario Energy Board, *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, p. 31. Filed September 17, 2008 in EB-2007-0673. As Dr. Makholm testified to, this has been amended to remove the requirement of unusual circumstances. His assertion in response to question 21 of his testimony is not verifiable on the public record.

> The ACM approach should also facilitate regulatory efficiency by placing the requirement to establish the need and prudence for any additional incremental capital spending within a cost of service proceeding. This is well suited to such forms of review and when the five-year DSP is tested. Consequently, largely mathematical calculations of ACM/ICM-related matters, such as the determination of the rate riders, will remain part of the streamlined IR applications in subsequent years.
>
> When coupled with the requirement for five-year DSPs and other policies that impose discipline upon distributors in their planning, the ACM should **reduce incentives for clustering capital projects around the rebasing year.** Further, this also provides options for distributors to recover costs for discrete capital projects when they are needed throughout the Price Cap IR cycle….
>
> The ACM approach will also assist in large part to preserve the **regulatory efficiency** of IR applications, as many qualifying capital projects should be identifiable through the DSP. More importantly, it provides **greater assurance of recovery for prudent and appropriately prioritized capital projects** regardless of when the investments might be made. The Board would also expect **improved performance with respect to capital forecasting** both in terms of timing of and the level of projects, taking into account bill impacts on customers as well on the financial, human and other resources of the utility to carry out its capital projects as planned.[65] [Emphasis added]

As part of its decision to implement an ACM option, the Board reduced the markdown for ICMs, limited the scope of ICMs, and added a means test to prevent capital module requests from distributors that are overearning by more than 300 basis points.

Custom IR Guidelines

In their decision in the Renewed Regulatory Framework proceeding, the OEB sanctioned the CIR approach to ratemaking that is popular amongst larger utilities.[66] Under the Custom IR approach, a distributor-specific rate trend is determined by the Board that is

[65] Ontario Energy Board, *Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module,* EB-2014-0219, September 18, 2014, pp. 11-12.

[66] Ontario Energy Board, *Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,* October 18, 2012.

> informed by: (1) the distributor's forecasts (revenue and costs, inflation, productivity); (2) the Board's inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor's forecasts.[67]

The OEB acknowledged that "The adjudication of an application under the Custom IR method will require the expenditure of significant resources by both the Board and the applicant."[68]

The *Handbook for Utility Rate Applications* ("Rate Handbook") provides the following guidelines for energy utilities requesting CIR.[69]

> **The annual rate adjustment must be based on a custom index supported by empirical evidence (using third party and/or internal resources) that can be tested. Custom IR is not a multi-year cost of service; explicit financial incentives for continuous improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast).**
>
> The index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes. **If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service.** An application containing a proposed custom index which lacks the required supporting empirical information may be considered to be incomplete and not processed until that information is provided.
>
> **It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications**. **Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.**[70] [Emphasis added]

[67] OEB, *Renewed Regulatory Framework*, *op. cit*., p. 13.

[68] *Ibid*., p. 19.

[69] OEB, *Handbook for Utility Rate Applications*, October 2016, pp. 18-19 and 24-28.

[70] *Ibid*., pp. 25-26.

First Toronto Hydro Custom IR Proceeding

In its order approving Toronto Hydro's first CIR plan,[71] the OEB approved many of the basic features of subsequent CIR plans, including an earning sharing mechanism ("ESM"), the addition of a C factor to the revenue or (in this case) rate escalation formula ESM, and the refund of capital cost underspends at the end of the plan term. The approved plan had a nearly 5-year term and escalated rates using the formula I – X + C, where I was the inflation factor, X was the sum of a 0% productivity trend and a 0.6% stretch factor, and C was a custom capital factor. The C factor would be reduced by a stretch factor. A symmetrical ESM addressed non-capital related earnings variances outside of a 100-basis point dead band, while a variance account refunded all capex underspends to customers. The OEB cut Toronto Hydro's proposed capex budget by 10% annually for the Custom IR term, without specifying which proposed components were disallowed.

The first Toronto Hydro CIR decision also provided general commentary on what the Board expected Custom IR plans to entail:

> Custom IR is described in the [Renewed Regulatory Framework for Electricity (RRFE)] as a suitable choice for distributors with large or highly variable capital requirements. . . **The custom option in the policy allows for proposals that are tailored to a distributor's needs as well as for innovative proposals intended to align customer and distributor interests**.[72] [Emphasis added]

Presumably then, the OEB is open to further innovations in CIR intended to align customer and utility interests. The OEB further stated that:

> [a] Custom IR, unlike other rate setting options in the RRFE, does not include a predetermined formulaic approach to annual rate adjustments, it does not automatically trigger a financial incentive for distributors to strive for continuous improvement. **The OEB expects that Custom IR applications will include features that create these incentives in the context of the distributor's particular business environment.[73]**

[71] EB-2014-0116

[72] *Ibid*., p. 4.

[73] *Ibid*., p. 5.

Hydro One Distribution's Current Custom IR Plan

The OEB approved a CIR plan for Hydro One Distribution in EB-2017-0049. This decision also suggests a wariness on the part of the Board with respect to multiyear capex forecasts and the related C factor. The Board disallowed $300 million (about 8.4%) of Hydro One Distribution's capex forecast.

In addition, the OEB ordered Hydro One Distribution to provide reports on various issues to show that the forecasts and expected efficiency gains it approved in this proceeding had been realized. For example, Hydro One Distribution was asked to report at the next rebasing on the actual performance of the capital program relative to the approved plan and improvements in performance in benchmarked areas (e.g., pole replacement) which resulted from discussing best practices with better performing peers. Hydro One Distribution was also ordered to report on the achievement of forecasted productivity savings.

The OEB also adopted an additional 0.15% stretch factor to apply solely to Hydro One Distribution's C-factor beyond the 0.45% stretch factor that applied to the entire revenue requirement on the basis of econometric benchmarking studies. This decision was made in part due to the OEB's concern that forecasted capex was causing rate base to grow more rapidly than inflation and in part to "incent further productivity improvements throughout the term, and to provide customers the benefit from these additional improvements upfront."[74] The OEB was also influenced by Hydro One Distribution's prior capital overspending and comments by OEB Staff's expert witness that the C Factor led to perverse incentives for companies to spend excessive amounts on capital to contain OM&A expenses.[75]

D.2 Power Transmission Ratemaking

The Early Years (1999-2018)

Hydro One's initial transmission revenue requirement was established in 1999 and updated to reflect a change in the Company's allowed rate of return on equity ("ROE") in 2000. After that, the

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[74] *Ibid*., p. 32.

[75] *Ibid*., p. 32-33

Company's revenue requirement was unchanged until 2007. Hydro One subsequently filed transmission rate cases in 2008, 2010, 2012, 2014, and 2016. Each rate case considered two forward test years. Concerns about capex underspending led to the adoption of an In-Service Capital Additions Variance Account which requires the Company to return the revenue impact of underspends to customers.

In EB-2018-0218, the OEB issued a decision that detailed an IRM for transmission services of Hydro One Sault Ste. Marie. This decision includes the following noteworthy provisions.

- An RCI allows revenue requirement escalation based on the formula Inflation less an X factor +/- Z factors. No scale escalator was approved for the RCI formula, and the Board commented that parties had presented insufficient evidence to justify the inclusion of such a term.
- Hydro One's proposed inflation measure was accepted. Weights for the two inflation subindexes are 14% for labor and 86% for non-labor.
- The base productivity trend was set at zero, reflecting in part the OEB's prior decisions and their ongoing desire to keep base productivity trends non-negative. No party had supported a negative base productivity trend, even though both productivity studies presented in evidence reported negative MFP trends for U.S. transmitters.
- The stretch factor was set at 0.3%. The Board chose this value in part because they believed that "a stretch factor of 0.3% provides incentives to find further efficiency improvement beyond those proposed by the acquisition."[76]
- Hydro One SSM can request supplemental funding for capex through Incremental Capital Module filings.

The Board later approved the request of Hydro One SSM to escalate its revenue requirement by an RCI for a single year. This RCI had an I-X formula, where the I factor was set at 1.4% and the X factor was set at 0%.

[76] EB-2018-0218, p. 21.

D.3 Hydro One Transmission's Current Custom IR Plan

The current Custom IR plan for Hydro One Transmission is broadly similar to previously-approved CIR plans, though there are some subtle differences. These differences include the use of a revenue cap index rather than a price cap index, different weights for the inflation measure, and a shorter 3-year term.

In its decision, the Board hinted at a wariness of multiyear capital cost forecasts. It expressed concern that the productivity improvements built into Hydro One's forecasts were insufficient given the substantial increase in forecasted capex. In its review of transmission line replacement capex, the Board concluded that

> the increased pace of replacing transmission lines (more than three-fold between 2016-2018 and 2020-2022) has not been justified in view of the fact that the forced outage frequency and duration for overhead conductors has been trending down on average, and the ESL of most conductors has increased from 70 to 90 years according to the EPRI study.[77]

Hydro One's capex budget was cut by more than 10% in the decision. In addition, the OEB expected Hydro One to provide a summary of its internal monthly productivity reports in its next rebasing application.

As part of its decision approving CIR for Hydro One Transmission, the Board added an incremental capital stretch factor of 0.15%. The Board explained its decision as follows:

> This stretch factor is consistent with what the OEB approved for Hydro One's distribution business and is intended to incent the utility to seek additional productivity gains on its forecasted capital plan and budget.
>
> Hydro One's proposal for an incentive rate-setting mechanism application includes a forecast of capital expenditures for each year of the three-year term. Hydro One's transmission business is capital intensive, so this is a large part of revenue requirement that will escalate well beyond the I – X component of the RCI adjustment. The OEB concludes that it is appropriate to include the incremental stretch factor given that the revenue cap framework includes an update to rate base each year based on this forecast of capital expenditures.[78]

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[77] Ontario Energy Board, "Decision and Order", EB-2019-0082, April 23, 2020, p. 85.

[78] *Ibid*, p. 39.

In its decision the Board noted that Hydro One's transmission and distribution operations had widely varying cost performances.

> The TFP analysis provided in this proceeding by PSE indicated that Hydro One's total costs for its transmission operations are well below the benchmark expectations. In Hydro One's last distribution proceeding, PSE's analysis showed that Hydro One's average total cost levels for its distribution operations were well above benchmark expectations. The OEB does not have the evidence to make any conclusions about why the same company can have such different results for its operations. There are significant common costs that are allocated between the operations…. The OEB also expects Hydro One to review the different benchmark cost performance between its transmission and distribution operations and provide explanations for this difference in the next rebasing application.[79]

[79] *Ibid*, pp. 32-33.

Appendix E: PEG Credentials

Pacific Economics Group Research LLC is an economic consulting firm based in Madison, Wisconsin USA. We are a leading North American consultancy on incentive ratemaking and statistical research on the performance of electric and natural gas utilities. Our personnel have over seventy years of experience in these fields, which share a common foundation in economic statistics. Work for a mix of utilities, regulators, government agencies, and consumer and environmental organizations has given us a reputation for objectivity and dedication to good research methods. Our practice is international in scope and has included several projects in each of the larger populous of Canada.

Mark Newton Lowry, the senior author and principal investigator for this project, is the President of PEG. He has over thirty years of experience as an industry economist, most of which have been spent addressing utility issues. He has prepared IR, productivity, and benchmarking research and testimony in more than 50 proceedings. Author of dozens of professional publications, Dr. Lowry has chaired numerous conferences on performance measurement and utility regulation. He recently coauthored two influential white papers on IR for Lawrence Berkeley National Laboratory. In the last few years, he has played a prominent role in IR proceedings in Alberta, British Columbia, Colorado, Hawaii, Massachusetts, Minnesota, North Carolina, and Québec as well as Ontario. He holds a PhD in applied economics from the University of Wisconsin.

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Clearspring/PEG Joint Report on Hydro One Benchmarking and Productivity Research

11 June 2022

Hydro One Networks ("Hydro One") has filed a joint rate application that proposes new custom incentive ratemaking ("CIR") plans for its power transmission and distribution ("T&D") services. In this proceeding, Hydro One consultant Clearspring Energy Advisors LLC ("Clearspring") and Ontario Energy Board ("OEB") staff consultant Pacific Economics Group Research LLC ("PEG") have submitted statistical benchmarking and productivity research and testimony that are relevant in determining the T&D revenue escalation formulas. Clearspring's report was filed in August 2021 while PEG's report was filed in January 2022. Clearspring filed reply comments in March 2022 which critiqued PEG's work and responded to PEG's criticisms of their own work.

In April 2022, the OEB issued its fifth procedural order in the proceeding. Pursuant to Rule 13A.04 of the OEB's *Rules of Practice and Procedure*, this order calls for Clearspring and PEG "to confer with each other for the purposes of, among other things, narrowing issues and identifying the points on which their views differ or are in agreement." A joint report should then be issued by the consultants which "shall outline the key issues, and points of agreement and disagreement on these issues, and identify the portions of their respective reports on which Clearspring and PEG will continue to rely."

Summary of Current Recommendations After Narrowing of Issues

The conferring process has been productive. Both consultants revised their studies in response to the other's critique and ideas and reached points of agreement. Differences between the research methods and results narrowed materially. The following table provides the high-level summary of the revised recommendations of Clearspring and PEG regarding the parameters of Hydro One's CIR revenue escalation formulas.

Transmission CIR Revenue Escalation Parameters					
	X-Factor [A+B+C]	Productivity Growth Target [A]	Stretch Factor Resulting from Benchmark Results [B]	Supplemental Incentive Adjustment to Stretch Factor [C]	Extra CIR Capital Stretch Factor
Clearspring	Total: ≤0.0%	Total: ≤0.0%, (MFP = -1.05%)	0.00%	Not Warranted	Company's Proposed Supplemental SF of 0.15%
PEG	OM&A: +0.33%, Capital: -0.60%	Total: -0.99%, OM&A: -0.12%, Capital: -1.05%	0.15%	0.30%	Company's Proposed Supplemental SF of 0.15%
Distribution CIR Revenue Escalation Parameters					
	X-Factor [A+B]	Productivity Growth Target [A]	Stretch Factor Resulting from Benchmark Results [B]	Supplemental Incentive Adjustment to Stretch Factor [C]	Extra CIR Capital Stretch Factor
Clearspring	0.45%	0.00%	0.45%	Not Warranted	Company's Proposed Supplemental SF of 0.15%
PEG	0.45%	0.00%	0.45%	Not Warranted	Company's Proposed Supplemental SF of 0.15%

*The Company's distribution revenue escalation formula does not include a customer growth term. PEG and Clearspring agree that not including a customer growth term serves as an added stretch factor on distribution OM&A for the Company.[1]

General Areas of Productivity and Benchmarking Agreement

Clearspring and PEG have long agreed on many issues pertaining to the use of statistical cost research in utility regulation. These include the following.

- Statistical productivity and benchmarking studies that use publicly available utility industry data can be useful tools in utility regulation.
- Econometric models are useful in benchmarking when large amounts of reliable and standardized data are available. In those cases, the econometric approach tends to be more accurate and fair than unit cost and other peer group-based approaches provided that the econometric model is well-specified.
- The United States and Ontario have both produced large amounts of standardized electric utility operating data which are useful in benchmarking and productivity research. Unusually within Organisation for Economic Co-operation and Development ("OECD") countries, these data permit total cost benchmarking and multifactor productivity ("MFP") studies to be conducted with reasonable accuracy as well as the benchmarking studies of utility operation, maintenance, and administrative ("OM&A") expenses which regulators consider in other countries (e.g., Australia).
- There has also been substantial agreement over general approaches to solving technical problems such as the measurement of capital cost and the appropriate functional forms for cost models.
- Utilities that, like Hydro One, face business conditions that differ markedly from sample norms are more difficult to benchmark accurately. Benchmarking results for such companies can be unusually sensitive to changes in model specification and other methodological choices.
- Negative productivity factors and X-factors should be considered reasonable parameter possibilities within incentive regulation plans if industry data support them.

Power Transmission

Areas of Agreement Resulting from Conferring

During this conferring process, Clearspring and PEG followed the direction of the OEB and made several revisions and upgrades to their research methods which narrowed differences in results compared to those from each consultant's original report in this proceeding. Each consultant acknowledges that the other identified some ways to upgrade their research methods.

[1] The Company forecasts customer growth of approximately 0.7% during the CIR period. Therefore, the implicit stretch factor on distribution OM&A is expected to be 0.7% if the revenue cap index has no customer growth term.

Research Upgrades for Power Transmission Research

PEG

- PEG inadvertently used the wrong value of the ratcheted peak demand variable for Hydro One in their transmission cost benchmarking work and has now corrected this.

- Using new data on the detailed OM&A expenses of Hydro One which Clearspring provided in their reply comments, PEG will add six companies to their transmission benchmarking study which they previously excluded.[2] However, after further examination when reviewing this change, PEG identified certain years with substantial cost increases due to wildfires for two California utilities. Accordingly, PEG will include the six utilities (including these two utilities) but not include some of the later years in the benchmarking sample for these two utilities due to expense data distortions resulting from wildfires.[3] Furthermore, data for these two utilities will be removed entirely from PEG's transmission MFP sample.

- PEG agrees with Clearspring that the construction cost index variable value for the Company should reflect where its transmission lines actually are rather than its full licensed service territory.

- PEG agrees with Clearspring that a nineteen-year MFP sample period is reasonable and will shorten its recommended MFP period to 2000 to 2019 and match that of Clearspring's.[4]

- For its transmission total cost and capital cost models, PEG has replaced its plant-based scope variable with a more defensible scope variable based on operation and maintenance ("O&M") expenses.

Clearspring

- Clearspring acknowledges that improvements suggested by PEG will provide a more accurate independent system operator ("ISO") variable in its transmission cost benchmarking work.

- Clearspring agrees with PEG that the transmission peak load variable more accurately measures transmission peaks and will use this variable in their transmission cost benchmarking research and, accordingly, shorten the start year to 2004 for the benchmarking dataset which aligns with PEG's start year for the transmission benchmark model.

- Clearspring agrees with PEG that the transmission total cost model should include a construction standards index and a forestation variable.

- Clearspring recommended in its Reply Comments that PEG add six companies and exclude transmission dispatching and miscellaneous expenses from the cost definition for both the

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[2] These six are Commonwealth Edison, Kansas Gas & Electric, Oklahoma Gas & Electric, PECO, San Diego Gas & Electric, and Southern California Edison.

[3] PEG will not include 2018 and 2019 for Southern California Edison ("SCE") and 2010 to 2019 for San Diego Gas and Electric ("SDG&E").

[4] Data from the 2000 to 2019 period are used to calculate the 19 changes in productivity, which are then averaged.

benchmarking and productivity samples. PEG has done this and, in turn, Clearspring will also remove those expenses from their cost definition.

- Clearspring reviewed PEG's analysis on the wildfire issue and agrees to remove the same observations in their transmission total cost benchmarking dataset for SCE and SDG&E which PEG has removed. These utilities will also be removed from Clearspring's productivity research.

- In reviewing the O&M transmission scope variable proposed by PEG during the conferring process, Clearspring has no principled objection to it relative to Clearspring and PEG's original plant-based scope variable. The new scope variable does have the advantage of having a higher t-statistic despite having a lower coefficient value than the plant-based scope variable and does have fewer endogeneity concerns. As such, Clearspring will also replace its plant-based scope variable with the O&M-based scope variable proposed by PEG during this process.

Revised Benchmarking and Productivity Results for Power Transmission Research

Here are the revised MFP trend and benchmarking results for the five years of the proposed CIR when each consultant implements all of the above-mentioned corrections and upgrades that have been agreed upon. The new results for both consultants include the inflationary-driven spending increases proposed by Hydro One, the changed peak demand forecasts, and updated inflation projections from the Conference Board of Canada.

PEG

- PEG's recommended transmission industry MFP trend becomes **-0.99%**. The corresponding O&M productivity trend is -0.12%. The corresponding capital productivity trend is -1.05%. Since CIR entails a separate and essentially cost of service treatment of capital cost, only the partial factor productivity trends would be used in the CIR plan design. -0.99% is not an appropriate base productivity growth target for OM&A revenue.

- PEG's total transmission cost benchmarking score for Hydro One is now **-14.1%**. The standard Ontario stretch factor that would be commensurate with this score is **0.15%.** PEG's revised transmission capital cost benchmarking score for the Company is -10.4%. Their revised transmission OM&A cost benchmarking score for Hydro One is -10.0%.

Clearspring

- Clearspring's recommended transmission industry MFP trend becomes **-1.05%**, a result that is similar to PEG's.

- Clearspring's total transmission cost benchmarking score for Hydro One is now **-31.6%**. The standard Ontario stretch factor that would be commensurate with Clearspring's total transmission cost benchmarking remains at **0.0%**.

Areas of Continuing Disagreement for Power Transmission Research

The following are consequential areas of continued disagreement in the transmission research.

Base Productivity Growth Target Should be Negative

PEG advocates for negative productivity growth targets in the transmission plan. Clearspring is recommending a productivity target equal to zero.

PEG's View

PEG believes that CIR for Hydro One's power transmission can reasonably reflect the negative productivity trend of the industry but there is one important caveat: there should be separate ratemaking treatment of OM&A and capital revenue. Based on our research, a -0.12% OM&A productivity growth target is warranted for OM&A revenue, whereas a -1.05% capital productivity growth target makes sense for capital revenue. This would greatly reduce the need for supplemental capital revenue while producing a reasonable X factor for OM&A revenue. Clearspring's alternative recommendation of a 0% MFP growth target leads immediately to the claim that it should have what amounts to cost of service treatment of capital cost. Similar treatment is not warranted on the distribution side because industry O&M and capital productivity trends are more similar there.

Clearspring's View

Clearspring does not disagree with PEG that a negative MFP growth factor should be considered and implemented in Hydro One's transmission escalation formula. A negative productivity target would best align the revenue cap index with the empirical research and economic theory. However, in examining past CIR precedents and OEB decisions, we see direction from the OEB that it is has not been inclined to set productivity factors below zero. Clearspring is of the view that a productivity factor set at zero, despite the negative industry MFP trend, is tantamount to a supplemental stretch factor placed on the utility. Clearspring has calculated this extra stretch factor to be equal to approximately 1.0%. This is an extraordinarily large stretch factor and productivity challenge placed upon the utility. Please see Section 6 of the Clearspring Report for a description of our methodology and findings for the transmission productivity target.[5]

Supplemental Stretch Factor

PEG is recommending a supplemental 0.3% stretch factor to be added to the transmission escalation formula. Clearspring recommends not including a 0.3% supplemental stretch factor.

PEG's View

PEG believes that the stretch factor for a utility should be based in part on how the incentive power of its IR plan compares to that which was typical of the regulatory systems under which utilities in the productivity study operated during the sample period of the study. We contend that, for the full sample period that we recommend, a supplemental stretch factor of 0.3% is warranted for Hydro One Transmission on the grounds that sampled U.S. transmitters operated under unusually weak performance incentives. The weak incentives resulted from special incentives (e.g., a premium rate of return, CWIP in rate base, and accelerated depreciation) for some kinds of transmission capex which are permitted under the Energy Policy Act of 2005 and the widespread and growing use of formula rates. In our response to M-Hydro One-5, we presented an extensive discussion of the calculations supporting our 0.30% supplemental stretch factor recommendation.

[5] The two changes made, due to conferring, from the original report are we have dropped SCE and SDG&E from the sample and excluded dispatching and miscellaneous transmission expenses from the cost definition.

Clearspring's View

Clearspring is of the view that a supplemental stretch factor beyond the Company's proposed 0.15% supplemental stretch factor on capital is not warranted. Clearspring's proposed productivity factor of 0.0% already contains a very large implicit stretch factor of 1.05%. This combined with the Company's proposed supplemental stretch factor of 0.15% on capital already provides an extraordinarily large supplemental stretch factor.

Even absent the presence of the large implicit stretch factor and the Company's proposed supplemental stretch factor, Clearspring is not convinced that a supplemental stretch factor would be warranted. Stretch factors are, ideally, a product of total cost benchmarking results and the Company is a very strong cost performer. Further, Hydro One has an upcoming productivity challenge relative to the U.S. industry due to its older transmission capital age. Please see page 8 of the Clearspring Reply Report for further discussion.

ISO Variable

PEG does not include an ISO variable in its transmission total cost model. Clearspring does include one.

PEG's View

An ISO dummy captures the net effect of all reasons, not adequately addressed by other variables in the econometric model, why costs of ISO members during the sample period tended to differ from sample norms. We acknowledge that the parameter estimate for the ISO is positive and highly significant in Clearspring's revised cost model. However, this could be so because ISO members were less efficient on average, or because variables included in the model measured business conditions poorly, or because other key cost drivers were excluded from the model. A positive estimate for the ISO parameter therefore does not necessarily indicate that American ISOs tend to drive costs of member transmitters higher. Even if they do have this impact, PEG is not convinced that the typical extra cost pressures that U.S. ISO members incurred apply to Hydro One prospectively as a member of Ontario's IESO. We acknowledge that we did use an ISO dummy in our recent Quebec benchmarking study, but only in our model for OM&A expenses. These expenses account for far less than half of total transmission costs.

It can also be argued that the benchmarking research should focus on the costs that will be addressed by the revenue that the revenue cap index actually escalates. In this regard, it is notable that, In addition to a Z factor, Hydro One's proposed CIR includes two variance accounts that might address costs of IESO-mandated construction. Additionally, the IESO bills distributors and not Hydro One for many of its expenses.

Clearspring's View

Both Clearspring and PEG have included an ISO variable in current and past models and cited it as a business condition that Hydro One faces that some other US transmitters do not. Including this variable enables the model to adjust for the cost challenges associated with being a member of an ISO. We note the t-statistic on this variable continues to be highly robust despite Clearspring eliminating dispatching and miscellaneous transmission expenses from the transmission total cost definition. Please see the Clearspring Report pages 16 - 17 and the Clearspring Reply Report on pages 1 - 2 for more discussion on the ISO variable.

Power Distribution

Areas of Agreement Resulting from Conferring

During this conferring process, Clearspring and PEG followed the direction of the OEB and made some revisions and upgrades to their distribution benchmarking methods which narrowed differences relative to each consultant's original report in this proceeding. Each consultant acknowledges that the other identified some ways to upgrade their research methods.

Research Upgrades for Power Distribution Research

PEG

- PEG inadvertently used the wrong value of the ratcheted peak demand variable for Hydro One in their distribution cost benchmarking work and has now corrected this.

- PEG does not accept all of Clearspring's criticisms of the customer dispersion proxy variable (miles of transmission lines) that PEG used in its initial study in this proceeding. Clearspring's alternative area variable is imperfect and the quest for a better variable should continue. PEG nonetheless acknowledges that, since more reasonable estimates of Hydro One's service territory have become available since they filed their January 2022 report, it would be preferable to use Clearspring's area data in the benchmarking research. A notable benefit of the switch is the ability to add numerous companies to PEG's distribution cost sample. PEG will now use the estimate of a 413,277 sq. km. service territory area for Hydro One which PEG developed in response to M-Hydro One-21 d).

- PEG decided to now ratchet peak loads beginning in 1994 using Clearspring's peak load data.

- PEG replaced its plant-based scope variable with an O&M-based scope variable that matches the definition of the new transmission scope variable in their total cost and capital cost models.

Clearspring

- Clearspring acknowledges that the new and lower 529,313 sq. km estimate of the area of Hydro One's service territory which was presented in their Reply Report is preferable to the one we used in our July 2021 report.

- Clearspring is also adopting the use of PEG's new O&M scope variable and including the variable in our total cost distribution model.

Revised Benchmarking Results

Here are the revised distribution cost benchmarking results for the five years of the proposed CIR when each consultant implements the above-mentioned corrections and upgrades that have been agreed upon. These results include the inflation-driven spending increases proposed by Hydro One, the changed peak demand forecasts, and updated inflation projections from the Conference Board of Canada.

PEG

PEG's total distribution cost benchmarking score for Hydro One is now **+23.2%.** The standard Ontario stretch factor that would be commensurate with the new score is **0.45%.** PEG's distribution capital cost benchmarking score for the Company is now +32.8%. Their distribution OM&A cost benchmarking score for Hydro One is now +10.0%.

Clearspring

Clearspring's total distribution cost benchmarking score for Hydro One is now **+13.1%**. The standard Ontario stretch factor that would be commensurate with the new score is **0.45%.**

Areas of Continued Disagreement in Power Distribution Research

The following areas are consequential areas of continued disagreement.

Service Territory Area

PEG uses a Hydro One service area of 413,277 sq. km for Hydro One which PEG developed in response to M-Hydro One-21 (d). Clearspring uses an estimate of 529,313 sq. km for Hydro One developed by Hydro One, with details provided in Clearspring's Reply Report. Both consultants have, in advocating these values, moved towards each other's positions during this conferring process. Both consultants acknowledge the difficulty and challenge in getting a perfect number for this variable.

PEG's View

PEG believes that Hydro One's new estimate of its service territory area is still overstated. The estimate is based on the area of circles surrounding the Company's substations. A single circle with a radius of 100 km has an area of 3.142 x (100 x 100) = 31,400 sq. km. This exceeds the land area of the state of Vermont. Some of the substations that Hydro One uses in these calculations may chiefly be designed to serve remote mining operations. The illustrative map that Clearspring provides indicates that the methodology assigns to Hydro One a distribution service area the size of Vermont in the largely roadless region between Cochrane and Moose Factory near the shore of Hudson Bay.

As for our own area estimate, we explained in our lengthy response to M-Hydro One-21 (d) that service territory area variables bias cost benchmarking studies in favor of rural utilities. Simply put, the area that is not really served increases with the degree of ruralness. Since many utilities in the sample have service territories that are not very rural and/or estimate the area that the serve with some accuracy, a statistical adjustment to the area estimate is needed to reduce bias in the benchmarking results. PEG's 413,277 sq. km estimate of Hydro One's service territory is based on such an adjustment, which is well-explained in the response. The adjustment has the goal of making the area unserved by Hydro One similar to the sample norm.

Clearspring's View

Clearspring believes that the new estimate provided by Hydro One provides a reasonable area that the Company could serve based on the presence of a distribution substation. While there are areas within that estimate where no customers yet exist, the U.S. sample also has plenty of areas where no customers yet exist either. We would expect Hydro One to have the lowest customer per sq. km in the sample since most of the cities and towns near its service territory are being served by other LDCs and Hydro One serving large portions of northern Ontario. The rest of the utilities in the sample do not have most of the cities and towns carved out of their service territory like Hydro One has. Yet despite this, Hydro One does not have the lowest customer density using Clearspring's 529,313 sq. km measure. Hydro One's customers per sq. km in 2019 is 2.5, whereas Montana Dakota Utilities ("MDU") is measured at 2.2. Clearspring is of the view that Hydro One having a slightly higher customer density than MDU is reasonable.

Clearspring also notes that serving such remote areas as Moose Factory requires far longer travel times and expenses, even requiring helicopter transportation at certain times. The area variable value should adequately account for these cost challenges.

In regard to PEG's estimate of 413,277 sq. km formulated in M-Hydro One-21 (d), Clearspring finds this estimate problematic. PEG uses an ambiguous "tight" sample estimate of 40% for utilities in the sample that chiefly serve towns and cities and a 60% "loose" sample estimate for utilities not in the first designation. It is not clear to Clearspring how PEG made the 40% estimate or why the composition of the sample regarding rural versus suburban utilities should have an impact on Hydro One's estimate for service territory. The estimate should be consistent with how other rural utilities in the sample have their areas estimated. Using a 40% weight based on the areas of other Ontario LDCs (which serve primarily cities and towns) to calculate Hydro One's area does not lead to a proper estimate. Hydro One's actual service territory that it actively serves should not be weighted as 40% of a suburban utility and then 60% as a rural utility. Hydro One's actually-served service territory is nearly all rural. Even if we assume Hydro One is 20% suburban and 80% rural (which is higher on the suburban side than is warranted in Clearspring's opinion), using PEG's calculations result in a service territory estimate of 532,625 sq. km, which is quite near the estimate Clearspring is using.

Please see pages 6-8, and 12 of the Clearspring Reply Report for more information on the 529,313 sq. km. service area estimate.

Transmission Productivity and Benchmarking Study

15 February 2021

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Executive Summary

Introduction

The Régie de l'énergie has authorized Hydro-Québec Transmission ("HQT") and intervenors in proceeding R-4058-2018 Phase 2 to prepare power transmission productivity and statistical benchmarking studies. These may be used to choose key terms in revenue cap index formulas of HQT's current *mécanisme de réglementation incitative* ("*MRI*") and any succeeding *MRI*. The *Association Québécoise des Consommateurs Industriels d'Électricité* and the *Conseil de l'Industrie Forestière du Québec* retained Pacific Economics Group Research LLC ("PEG") to prepare such studies on behalf of intervenors. This is our report on this work. The report also includes general discussions of principles and methods used in revenue cap index design and statistical benchmarking.

Revenue Cap Index Design

Rate and revenue cap indexes in North American *MRIs* are frequently designed with the aid of statistical research on the input price and productivity trends of utilities. This approach has a solid foundation in cost theory and index logic. Its use in North America has been facilitated by the extensive data that have been available for many years on the operations of numerous gas and electric utilities in the United States ("U.S.").

Productivity indexes are influenced by external business conditions and are not pure measures of cost efficiency. Productivity growth can, for example, be slowed by an increased need for replacement capital expenditures and can accelerate after the expenditure surge. A utility tends to be more capable of brisk productivity growth to the extent that it is currently inefficient.

Several "hot-button" issues have arisen concerning statistical cost research methods in recent *MRI* proceedings. One is the appropriate sample period for these studies. Another is the appropriate capital cost specification. A third is whether the X factor should be adjusted if some capital expenditures are accorded variance account treatment.

Statistical Benchmarking

Statistical benchmarking has been undertaken in many *MRI* proceedings. It is useful for setting initial rates and for choosing the stretch factor terms of revenue cap index formulas. The econometric approach to statistical benchmarking has been favored in Ontario and other jurisdictions in the English-speaking world. The stretch factors in *MRIs* of Ontario electric utilities are linked to the outcomes of econometric benchmarking studies.

Transmission Precedents

While *MRIs* are used for power transmission in many countries, few have had revenue cap index formulas designed with the aid of productivity research. The most notable precedent is the revenue cap index recently approved for transmission services of Hydro One Networks. Hydro One proposed and the Ontario Energy Board approved a 0% base productivity trend. In addition to productivity studies, witnesses for Hydro One and Ontario Energy Board staff both prepared econometric benchmarking studies which appraised the Company's recent historical and proposed future cost. The Board chose a 0.30% stretch factor. The *MRI* also provides substantial extra revenue to fund capital expenditures ("capex").

Developing a Research Plan

In October 2020, we submitted a detailed proposal to the Régie to update and upgrade their Ontario power transmission studies. Some of our proposed tasks have not been undertaken due to uncertainty about cost recovery. The benchmarking research proved difficult and PEG appreciates the Régie's deadline extensions. While HQT provided reasonable responses to information requests the process was cumbersome. New information and ideas may yet arise in this proceeding that prompt us to revise some of our results.

The U.S. Power Transmission Industry

The U.S. power transmission industry has experienced substantial change in the last 25 years. The Federal Energy Regulatory Commission tried to develop well-functioning bulk power markets. Utilities were encouraged to join independent system operators ("ISOs") or regional transmission organizations.[1] A growing number of utilities were regulated by formula rate plans that are essentially comprehensive variance accounts. The Energy Policy Act of 2005 sanctioned premium rates of return on equity to encourage transmission investment. Tax incentives and other state and federal policies

[1] Throughout this report we use the term ISOs to refer to regional transmission organizations as well as independent system operators.

encouraged development of wind farms. Growing membership in ISOs complicated the data reported to regulators.

Empirical Research

Productivity

We calculated the trends in the productivity of capital and *charges nettes d'exploitation* ("*CNE*") inputs as well as the multifactor productivity of 51 U.S. electric utilities in the provision of power transmission services.[2] The primary source of data used in the report was FERC Form 1 reports that are in the public domain. In our calculations, multidimensional output indexes were used which tracked trends in transmission line length and peak demand. The weights were drawn from econometric cost elasticity estimates. Capital costs and quantities were measured using a geometric decay specification.

We found that the growth in the multifactor transmission productivity of sampled U.S. utilities averaged a 2.26% annual decline over the most recent fifteen years of the sample period (2005-2019) but only a 0.62% annual decline over the full 24-year 1996-2019 sample period, during which the effects of formula rates and other recent changes in the U.S. transmission business were less pronounced. The productivity of *CNE* averaged a 1.74% annual decline over the last 15 years and a 0.68% annual decline over the full sample period. The productivity of transmission capital inputs averaged a 2.16% annual decline over the last fifteen years and a 0.46% annual decline over the full sample period. The remarkable productivity decline that began in 2005 reflects special circumstances that we discuss at some length.

Multidimensional Scale Escalators

We encourage the Régie to consider multidimensional output indexes of the kind we have developed as scale escalators in HQT's revenue cap index. The 58% ratcheted peak/42% line length weights used in our *multifactor* productivity research in this proceeding are appropriate for a *comprehensive* revenue cap index. In a revenue cap index applicable only to *CNE* revenue, 53% ratcheted peak/47% line length weights drawn from our *CNE* model are more pertinent.

[2] In this report we use the term *CNE* to reference all costs other than capital costs.

Benchmarking Results

The benchmarking work was complicated by differences in the ways that HQT and sampled US utilities calculate their costs. PEG lodged several rounds of information requests to better understand HQT's cost accounting. Having developed cost calculations that we hope permit "apples to apples" comparisons, we developed econometric models of total transmission cost, transmission capital cost, and *CNE*.[3] There were 46 U.S. utilities in the sample for the econometric research. The total cost and capital cost models had considerably more explanatory power than the *CNE* model.

Total Cost

We compared HQT's total cost thus calculated to the cost projected by our econometric total cost benchmarking model. From 2017-19, the three most recent years for which data are available, HQT's total cost was 67% above the benchmark value on average.[4] This is commensurate with a bottom quartile ranking for the U.S. sample.

Capital Cost

We compared HQT's capital cost to the cost projected by our econometric capital cost benchmarking model. From 2017 to 2019, HQT's capital cost exceeded the benchmarks by 55% on average. This is commensurate with a bottom quartile ranking.

CNE

We compared HQT's CNE to the cost projected by our econometric CNE benchmarking model. From 2017 to 2019, the CNE of HQT was 121% above the benchmark value on average. This is also commensurate with a bottom quartile ranking in the U.S. sample.

Implications for the MRIs

X Factors

The revenue cap index in HQT's current *MRI* applies to its *CNE* revenue. The X factor should then be based on productivity trends in the use of *CNE* inputs (e.g., labor, materials, and services). The options for X include the 1.74% annual decline in the *CNE* productivity of sampled utilities in the last

---

[3] A few costs were excluded from these studies, as discussed further in Section 5.

[4] All percentages are stated in logarithmic terms.

fifteen years and the 0.68% decline over the full sample period. The marked decline in *CNE* productivity over the last fifteen years may be due in part to short-term circumstances such as the establishment of new reliability standards. *CNE* productivity growth in the last nine years averaged a 0.57% decline.

The Régie has also evinced interest in the X factor that might be applicable to a future *comprehensive* revenue cap index. Here again choices include the fifteen-year *PMF* decline of 2.26% and a longer-term decline of 0.62%. The Régie should also consider the 0.0% *PMF* growth target that the Ontario Energy Board chose for Hydro One transmission services.

The choice between such numbers depends on other aspects of the *MRI*. A more negative number would help HQT fund more capex without weakening its incentive to contain capex. Capital revenue may in some years exceed HQT's capital cost. This is to be expected if the revenue cap index is to fund occasional capex surges. However, HQT should then have less ability to request extra revenue for these surges.

This report details several provisions for addressing this situation. One is to limit or eliminate eligibility for extra revenue. If supplemental revenue is permitted, provisions like the following merit consideration.

- The X factor could be raised to reduce expected double counting and give customers a better chance of receiving the benefits of industry productivity growth in the long run.
- Capital costs that occasion supplemental revenue could be subject to continued tracking in later plans. Customers would then receive the benefit of depreciation of the surge capex between plans.

Stretch Factors

The stretch factor term should reflect an expectation of how the productivity growth of the subject utility will differ from the base productivity growth target. This depends in part on the utility's operating efficiency at the start of the *MRI*. It should also depend on how the performance incentives generated by the *MRI* compare to those in the regulatory systems of utilities in productivity studies that are used to set the X factor. Incentive power research by PEG has produced tools that can be useful in comparing the incentive power of regulatory systems.

Our econometric *CNE* benchmarking research suggests that the stretch factor for the current *CNE* revenue cap index should be no less than 0.60%. Our current *total* cost benchmarking results suggest that the stretch factor for any future *comprehensive* revenue cap index would also be no less than 0.60%. These lower bounds are based on the Ontario Energy Board's approach to stretch factor determination. The Régie should consider more aggressive penalties for poor cost performance.

If there is a succeeding *MRI* the Régie may wish to update the benchmarking study in the year in which it is developed. A new study can consider forward test year costs that HQT proposes as well as additional years of historic costs.

The Régie should increase the stretch factor to reflect the unusually weak performance incentives in the U.S. power transmission industry over the sample period. We recommend a stretch factor adder of at least **0.1%** should the Régie base X on productivity results for the full sample period. We recommend an adder of at least **0.3%** if X is based on results for the most recent fifteen years.

1. Introduction

The Régie de l'énergie has been engaged for several years in the development of an *MRI* for power transmission services of HQT. In D-2018-001 (January 2020), the Régie chose the broad outlines of this mechanism. It featured a four-year term and an index formula (*formule d'indexation*) to escalate revenue for its *CNE*.[5] Under the formula, *CNE* revenue grows with inflation and a growth factor (*facteur de croissance*) but is potentially slowed by a productivity factor (X) and a stretch factor (*dividende de client* or *facteur S*).

A provisional X factor of 0.57% was chosen for the formula in D-2019-060. However, the Régie directed HQT to prepare a study of power transmission multifactor productivity [*productivité multifactorielle* ("*PMF*")] in the first three years of its MRI which can be used to reset X in the fourth year of the mechanism.[6] The current *formule d'indexation* also features a 0% *dividende de client* "*en l'absence de données d'études comparatives"*.[7] The *facteur de croissance* is based on gross plant additions related to the "*maintien et amélioration de la qualité du service*" and to the "*croissance des besoins de la clientèle*".[8]

In D-2019-047, the Régie opted for the preparation of two *PMF* studies, one by HQT's chosen expert and another by an expert chosen by intervenors to the proceeding.[9] The Régie made some decisions on the framework for this research in D-2020-028.

- The *PMF* study should be accompanied by a statistical benchmarking study (*étude statistique comparative*) which can be used to set the S factor. This study may use econometric methods and publicly available data on HQT's operations. The experts can request additional data from HQT.[10]

[5] *Décision* D-2018-001, p. 54, *paragraphe* 213.

[6] *Décision* D-2018-001, p. 32, *paragraphe* 111.

[7] *Décision* D-2019-060, p. 36, *paragraphe* 151.

[8] *Décision* D-2018-001, p. 74, *paragraphe* 301.

[9] *Décision* R-2019-047, p. 149, *paragraphe* 648.

[10] *Décision* D-2020-028, p. 24, *paragraphe* 92.

- The productivity and benchmarking studies should use data on operations of North American power transmitters.[11]
- The sample period for the *PMF* study should be at least 15 years.[12]
- The *PMF* study should be consistent with the approved *MRI.*[13]
- Capital as well as *CNE* efficiency should be considered in both the productivity and benchmarking studies. The best way to model capital cost in such studies should be addressed.[14]
- Details of the calculations should be presented in spreadsheet form.[15]
- The studies should be useful for setting just and reasonable tariffs.[16]

The *PMF* and benchmarking studies that the Régie has authorized are worthwhile for several reasons.

- Due to Québec's outsized reliance on low-cost but remote hydroelectric generation resources, transmission services account for a sizable portion of the charges that customers pay for power. Québec in effect has a transmission-intensive power supply technology.
- The *PMF* studies can provide the basis for X factors in this and any succeeding *MRI*.
- The benchmarking studies can provide the basis for S factors in this and any succeeding *MRI*. This can strengthen HQT's cost containment incentives.
- Whether or not there is a succeeding MRI, a statistical benchmarking study is a useful complement to the more traditional *balisage* studies that HQT has provided in its *dossiers tarifaires* to help the Régie appraise its performance.

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[11] *Décision* R-2019-047, p. 22, *paragraphe* 83.

[12] *Décision* D-2020-028, p. 28, *paragraphe* 106.

[13] Ibid, p. 31, *paragraphe* 121.

[14] Ibid, p. 26, *paragraphe* 96.

[15] Ibid, p. 24, *paragraphe* 92.

[16] Ibid, p. 8, *paragraphe* 19.

- Québec's regulatory community can gain expertise about statistical cost research which may prove useful in future *dossiers tarifaires* of Hydro-Québec Distribution and Énergir as well.
- The studies can aid HQT in its cost management.
- The studies may also provide the basis for an alternative growth factor in the *formule d'indexation* for *CNE* revenue and a possible future formula that also applies to capital revenue.

Pacific Economics Group Research LLC ("PEG") is North America's leading energy utility productivity and statistical benchmarking consultancy. We have done several power transmission productivity and benchmarking studies, including recent studies for Ontario Energy Board ("OEB") staff which helped the Board choose revenue cap indexes for transmission services of Hydro One Networks and Hydro One Sault Ste. Marie. The *Association Québécoise des Consommateurs Industriels d'Électricité* ("AQCIE") and the *Conseil de l'Industrie Forestière du Québec* ("CIFQ") have asked PEG to prepare a productivity and benchmarking study for this proceeding.

This is our report on this work. Section 2 provides pertinent transmission industry background. Section 3 discusses the use of statistical cost research in benchmarking and revenue cap index design. Section 4 discusses pertinent recent Ontario transmission research and how PEG developed a research plan for this proceeding. PEG's transmission empirical research for AQCIE-CIFQ is detailed in Section 5. We provide in Section 6 our stretch factor and X factor recommendations. Appendix A discusses various methodological topics in the study in more detail, while a brief discussion of PEG's credentials is provided in Appendix B.

2. Transmission Industry Background

2.1. The Power Transmission Business

The main task of a power transmitter is long distance movement of power. Power is received from generating stations and other transmission networks and delivered to load centers and other networks. Transmission is undertaken at high voltages to reduce line losses. Transmitters own and operate substations that reduce the voltage of the power they carry before it is delivered to load centers. Many transmitters also own substations that increase the voltage of power received from generators. The principal assets used in transmission are high-voltage power lines, the towers and underground facilities that carry them, and substations. Other notable transmission assets include circuit breakers, buildings, and land.

2.2. U.S. Power Transmission Industry

To gauge the relevance and interpret the results of statistical cost research using U.S. transmission data it is important to understand some key aspects of the U.S. transmitter operating environment. Regulation of U.S. power transmission rates is undertaken chiefly by the Federal Energy Regulatory Commission ("FERC"). Transmitter cost and productivity has been greatly affected by FERC regulation and state and federal policies.

Unbundling Transmission Service

Prior to the mid-1990s, U.S. power transmission regulation reflected the vertically-integrated structure of most investor-owned electric utilities in that era. These utilities typically owned the transmission and distribution systems in the areas they served, monopolized retail sales, and obtained most of their electricity from their own power plants. There were fewer bulk power sales and independent power producers using transmission services than there are today.

Since the 1970s, federal policy has increasingly encouraged third party generators and well-functioning bulk power markets. This increased the need for non-discriminatory tariffs for transmission services. In 1996, FERC Order 888 required transmitters to provide services under open access transmission tariffs ("OATTs"). Many details of the resultant functional unbundling of transmission services were addressed in FERC Order 889.

Bulk power markets were also expanded by the initiatives of many American states to restructure retail power markets. In these states, many utility generating assets were sold to IPPs or spun off. Utilities in a few states (e.g., Iowa, Michigan, Ohio, and Wisconsin) sold or spun off transmission assets.

ISOs and RTOs

As another means to promote development of bulk power markets and non-discriminatory transmission service, in 1996 the FERC encouraged electric utilities to transfer operation of their transmission facilities to an independent system operator ("ISO"). Transfer of control was voluntary and utilities retained ownership of most of their facilities. Several ISOs were formed between 1996 and 2000.

ISOs have scheduled transmission service, managed transmission facility maintenance, provided system information to potential customers, ensured short-term grid reliability, and considered remedies for network constraints. ISO services are provided under OATTs that recover ISO costs.

In 1999, the FERC pushed for further structural change in markets for transmission services by encouraging formation of regional transmission organizations ("RTOs"). These organizations typically have a larger footprint, serving multiple states while ISOs typically serve a single state. The FERC has approved applications for RTOs that serve much of the Northeast, East Central, and Great Plains regions of the U.S. The Midwest ISO (now called the Midcontinent ISO) and PJM Interconnection received an RTO status in 2001, while the Southwest Power Pool and ISO New England became RTOs in 2004. ISOs that are not RTOs still operate in New York, Texas, and California.[17] Many utilities in the southeastern and intermountain states are not ISO or RTO members.[18] Charges of transmission owners who are members of ISOs or RTOs may still be reset in periodic rate cases or formula rate plans.

Energy Policy Act of 2005

Beginning in the late 1970s, U.S. transmission capex trended downward in real terms. This was partly due to diminished need. Generation plant additions declined, especially in the 1990s. Another reason for the capex lull was difficulties in siting transmission lines. The grid did not always handle the demands placed on it by growing bulk power market transactions, and congestion occurred in some

[17] Transmitters in the Electricity Reliability Council of Texas are generally not subject to FERC regulation.

[18] In recent years, several South Central U.S. transmitters joined the MISO.

areas. This sparked concerns by the FERC and other policymakers that insufficient capex by transmitters could jeopardize the success of bulk power markets.

This is the context in which the Energy Policy Act of 2005 ("EPAct") was passed. It affected transmission capex and many other aspects of transmitter operations. The Act gave the FERC authority to establish mandatory transmission reliability standards and penalties. Development of these standards, now called Critical Infrastructure Protection ("CIP") standards, was largely delegated to the North American Electric Reliability Corporation ("NERC"), which oversees six regional reliability entities. Numerous NERC Reliability Standards were approved by the FERC in 2007. These standards are intended to prevent reliability problems resulting from numerous sources including operation and maintenance of the system, resource adequacy, cybersecurity, and cooperation between operators. Concerns about the siting of transmission lines were mitigated by a provision allowing the federal government to designate "national interest electric transmission corridors" to serve areas of significant transmission congestion.

Concerns about transmission owner incentives were addressed by the addition of a mandate for the FERC to incentivize both transmission capex and participation in an RTO or ISO. The Energy Policy Act required the FERC to adopt rules that would accomplish the following:

> (1) promote reliable and economically efficient transmission and generation of electricity **by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce**, regardless of the ownership of the facilities;
>
> (2) **provide a return on equity that attracts new investment in transmission facilities** (including related transmission technologies);
>
> (3) **encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities**; and
>
> (4) allow recovery of—
>
> > (A) all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to section 215; and

(B) all prudently incurred costs related to transmission infrastructure development pursuant to section 216.[19]

In FERC Orders 679 and 679-A, released in 2006, the FERC adopted a wide range of incentives to encourage transmission investment. Permissible incentives included the ability for a transmitter to include 100% of construction work in progress in rate base, ROE premiums for some plant additions, accelerated depreciation, full cost recovery for abandoned facilities and pre-operation costs, and cost tracking for individual projects. In addition, ROE premiums were permitted for transmitters who joined or remained in an RTO or ISO.

In this framework, a transmission operator would need to file an application and show that the requested incentives were appropriate. These applications could also be tied to a request by a transmitter to switch from a fixed rate adjusted only in a rate proceeding to a formula rate that is updated annually. Between 2006 and 2012 alone, the FERC reviewed more than 80 applications for incentives related to proposed transmission projects.

Formula Rates

Rates for transmission services can be set by the FERC in periodic rate cases. However, transmitters can also obtain mechanisms that reset rates annually to reflect the changing cost of their service following expedited reviews. These “formula rates” may rely on a transmitter’s historical cost and revenue data or on forward-looking cost and revenue data with a subsequent true up of forecasts to actual values. Formula rates involve what are essentially comprehensive cost variance accounts.

Formula rates have been used at the FERC and its predecessor, the Federal Power Commission, to regulate interstate services of gas and electric utilities since at least 1950.[20] Economies in regulatory cost have been an important reason for their use. Regulatory cost is a major consideration for a commission with jurisdiction over the transmission services of more than 100 electric utilities as well as dozens of interstate oil pipelines and natural gas pipelines.

[19] Energy Policy Act of 2005, Title XII, Sec. 1241 (b).

[20] A useful discussion of early precedents for formula rates at the FERC can be found in a March 1976 administrative law judge decision in Docket No. RP75-97 for Hampshire Gas.

Use of formula rates by the FERC was encouraged in the 1970s and early 1980s by rapid input price inflation. Despite slower inflation in more recent years, the FERC's use of formula rates has grown in the power transmission industry. Growing use of OATTs greatly increased the need to set rates for transmission services by some means. Formula rates were also encouraged by national energy policies such as the Energy Policy Act of 2005 which promoted transmission investment and increased attention to reliability. Early adopters of formula rates in power transmission included midwestern and New England utilities and the Southern Company. Many of the formula rate mechanisms approved by the FERC have been the product of settlements.

In 2004 about 15 of the 56 sampled U.S. transmitters in our econometric sample operated under formula rates. By 2016 fewer than 15 sampled transmitters *did not* operate under formula rates. PEG is not aware of any transmitters that abandoned formula rate plans during these years. Thus, about half of the U.S. transmitters in our sample received approval of formula rate plans during this period.

2.3. Canadian Power Transmission Industry

The services provided by Canadian power transmitters are broadly similar to those of their U.S. counterparts. Power market restructuring has been less pervasive than in the States, and independent system operators have been established only in Alberta and Ontario. However, many utilities trade power with the U.S. and abide by an array of US transmission regulations. One (Manitoba Hydro) is a member of a US RTO, and most are members of regional reliability councils and interconnections such as the Northeast Power Coordinating Council or the Western Interconnection. Transmission rates are regulated at the provincial rather than the federal level.

3. Revenue Cap Index Design

In this section of the report we discuss pertinent principles and methods for designing revenue cap indexes. We begin by discussing basic indexing concepts. There follow discussions of the use of indexing and statistical benchmarking research in revenue cap index design. We also discuss the capital cost specifications that are used in both kinds of research.

3.1. Basic Indexing Concepts

Input Price and Quantity Indexes

The cost of each input that a company uses is the product of a price and a quantity. The aggregate cost of many inputs is, analogously, the product of a cost-weighted input price index ("*Input Prices*") and input quantity index ("*Inputs*").

Cost = *Input Prices* x *Inputs.* [1]

These indexes can provide summary comparisons of the prices and quantities of the various inputs that a company uses. Depending on their design, these indexes can compare the *levels* of prices (and quantities) of different utilities in a given year, the *trends* in the prices (and quantities) of utilities over time, or *both.* Capital, labor, and miscellaneous materials and services are the major classes of inputs that are typically addressed by the base rates of gas and electric utilities. These are capital-intensive businesses, so heavy weights are placed on the capital subindexes.

The growth rate of a company's cost can be shown to be the sum of the growth in (properly designed) input price and quantity indexes.[21]

growth Cost = *growth Input Prices* + *growth Inputs.* [2]

Rearranging terms, it follows that input quantity trends can be measured by taking the difference between cost and input price trends.

growth Inputs = *growth Cost* - *growth Input Prices.* [3]

This greatly simplifies input quantity measurement.

[21] This result, which is due to the French economist François Divisia, holds for particular kinds of growth rates.

Productivity Indexes

The Basic Idea

A productivity index is the ratio of an output quantity (or scale) index ("*Outputs*") to an input quantity index.

$$Productivity = \frac{Outputs}{Inputs}. \qquad [4]$$

Indexes of this kind are used to measure the efficiency with which firms convert production inputs into the goods and services that they provide. Productivity indexes can compare productivity levels of different companies in a given year, measure productivity *trends*, or do both. The growth of a productivity trend index can be shown to be the difference between the growth of the output and input quantity indexes.[22]

$$growth\ Productivity = growth\ Outputs - growth\ Inputs. \qquad [5]$$

Productivity grows when the output index rises more rapidly (or falls less rapidly) than the input index. Productivity can be volatile for various reasons that include fluctuations in output and/or the uneven timing of certain expenditures. The volatility of productivity growth tends to be greater for individual companies than the average for a group of companies.

The scope of a productivity index depends on the array of inputs that are addressed by the input quantity index. A *multifactor* productivity index measures productivity in the use of multiple inputs. These are sometimes call *total* factor productivity indexes even though they rarely address all inputs. Some indexes measure productivity in the use of a single input class (e.g., labor or capital.) These indexes are sometimes called *partial* factor productivity indexes.

Output Indexes

The output quantity (trend) index of a firm summarizes growth in its outputs or operating scale. If output is multidimensional in character, its trend can be measured by a multidimensional output index. Growth in each output dimension that is itemized is measured by a sub-index, and growth in the summary index is a weighted average of the growth in the sub-indices.

[22] This result holds true for particular kinds of growth rates.

In designing an output index, choices concerning sub-indices and weights should depend on the way the index is to be used. One possible objective of output research is to study the impact of output growth on *cost.*[23] In that event, the index should be constructed from one or more output variables that measure the "workload" that drives cost. If there is more than one output variable, the weights for these variables should reflect their relative cost impacts.

The sensitivity of cost to a small change in the value of an output or any other business condition variable is commonly measured by its cost "elasticity."[24] Cost elasticities can be estimated econometrically using data on the costs of utilities and on outputs and other business conditions that drive these costs. Such estimates provide the basis for elasticity-weighted output indexes.[25] A productivity index calculated using a cost-based output index ("$Outputs^C$") will be denoted as $Productivity^C$.

$$growth\ Productivity^C = growth\ Outputs^C - growth\ Inputs. \qquad [6]$$

Sources of Productivity Growth

Economists have studied the drivers of productivity growth using mathematical theory and empirical methods.[26] This research has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit firms to produce given output quantities with fewer inputs.

A second important source of productivity growth is output growth. In the short run, output growth can spur a company's productivity growth to the extent that it has excess capacity. In the longer run, economies of scale can be realized even if capacity additions are required provided that output growth exceeds its impact on cost. Scale economies will typically be lower the slower is output growth.

[23] Another possible objective is to measure the impact of output growth on *revenue*. In that event, the sub-indices should measure trends in *billing determinants* and the weight for each itemized determinant should reflect its share of *revenue*.

[24] The cost elasticity of output *i* is the effect on cost of 1% growth in that output.

[25] An early discussion of elasticity-weighted output indexes is found in Denny, Michael, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

[26] The seminal paper on this topic is Denny, Fuss and Waverman, *Ibid.*

Incremental scale economies may also depend on the current scale of an enterprise. For example, larger utilities may be less able to achieve incremental scale economies.

Productivity growth is also driven by changes in X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum possible efficiency. Productivity growth will increase to the extent that X inefficiency diminishes. A company's potential for future productivity growth from this source is greater the lower is its current efficiency.

Technological change, scale economies, and X inefficiency are generally considered to be dimensions of operating efficiency. This has encouraged the use of productivity indexes to measure operating efficiency. However, theoretical and empirical research reveals that productivity index growth is also affected by changes in miscellaneous external business conditions, other than input price inflation and output growth, which also drive cost. One example for a power transmitter is the extent to which facilities must be underground. If growth in the urban areas served by a utility requires it to increase transmission system undergrounding, its productivity growth will be slowed.

System age is another business condition that affects productivity. Productivity growth tends to be greater to the extent that the current capital stock is large relative to the need to refurbish or replace aging plant. If a utility requires unusually high replacement capital expenditures (sometimes called "repex"), cost growth surges and productivity growth can be unusually slow and even decline. Highly depreciated facilities are replaced by facilities that are designed to last for decades and may need to comply with new performance standards. On the other hand, cost growth slackens and productivity growth can accelerate after a period of unusually high capex.

This analysis has some noteworthy implications. One is that productivity indexes are imperfect measures of operating efficiency. Productivity can fall (or rise) for reasons other than deteriorating (improving) efficiency. Our analysis also suggests that productivity growth can differ between utilities, and over time for the same utility, for reasons that are beyond their control. For example, a utility with unusually slow output growth and an unusually high number of assets needing replacement can have unusually slow productivity growth.

3.2. Use of Indexing in Revenue Cap Index Design

Revenue Cap Indexes

Cost theory and index logic support the design of revenue cap indexes. Consider first the following basic result of cost theory:

growth Cost = growth Input Prices – growth Productivity^C *+ growth Outputs*^{C}.[27] [7]

The growth in the cost of a company is the difference between the growth in its input price and productivity indexes plus the growth in a consistent cost-based output index. This result provides the basis for a revenue cap index of general form:

growth Allowed Revenue^{Utility} *= growth Input Prices* – (*X + S*) *+ growth Scale*^{Utility} [7a]

where:

$X = \overline{Productivity^C}$. [7b]

S = stretch factor or consumer dividend

Here X, the productivity or X factor, reflects a base growth target ("$\overline{Productivity^C}$") which is typically the average trend in the productivity of a regional or national sample of utilities. A consistent cost-based output index is used in the supportive productivity research. A stretch factor is often added to the formula which slows revenue cap index growth in a manner that shares with customers the financial benefits of performance improvements which are expected under the *MRI.*

An alternative basis for a revenue cap index can be found in index logic. Recall from [2] that growth in the cost of an enterprise is the sum of the growth in an appropriately-designed input price index and input quantity index.[28] It then follows that

growth Cost = growth Input Prices + growth Outputs^C

- (*growth Outputs*^{C} – *growth Input Quantities*)

= *growth Input Prices – growth Productivity*^{C} *+ growth Outputs*^{C} [8]

[27] See Denny, Fuss, and Waverman, *op. cit.*

[28] This result is also due to François Divisia.

Simple vs. Size-Weighted Averages

In calculating industry productivity trends, a choice must be made between simple and size-weighted averages of results for individual utilities. The arguments for size-weighted averages include the following.

- This is a better measure of the *industry* productivity trend.
- To the extent that productivity growth depends on a utility's size, size-weighted results are more pertinent in X factor studies for larger utilities.

Arguments for even-weighted averages include the following.

- Absent evidence that size affects productivity trends, the results for individual utilities are equally important. Econometric cost research places the same weight on all observations.
- Size-weighted averages are sometimes unduly sensitive to results for a few utilities.
- Even if size does affect productivity trends, even-weighted averages are more pertinent in X factor studies for smaller utilities.

PEG typically uses size-weighted (even-weighted) averages in X factor studies applicable to larger (smaller) utilities.

Dealing with Cost Exclusions

General Considerations

It is important to note that relation [8] applies to *subsets* of cost as well as to total cost. Thus, a revenue cap index designed to escalate only *CNE* revenue can reasonably take the form

$$growth\ Revenue^{CNE} = Inflation - (X + S) + \text{growth}\ Scale^{CNE}$$

where

$$X = \overline{Productivity}^{CNE}.$$

Here X is the trend in the productivity of a group of utilities in the management of *CNE* inputs. The scale escalator involves one or more output variables that drive *CNE*.

If the *MRI* provides for certain costs to be addressed by variance accounts, relation [8] similarly provides the rationale for excluding these costs from the X factor research. This principle is widely (if not unanimously) accepted, and certain costs that are frequently accorded variance account treatment in *MRIs* (e.g., costs of energy, demand-side management, and pension programs) are frequently excluded from the supportive X factor studies.

Capital Cost Exclusions

This reasoning is important when considering how to combine a revenue cap index with *MRI* provisions that furnish extra funding for capex.[29] Many *MRIs* with indexed rate or revenue caps have had provisions for supplemental capital revenue. The rationale is that the index formula cannot by itself provide reasonable compensation for capex surges. Reasons that such surges might be needed include "lumpy" plant additions or a surge in plant that has reached replacement age. Provisions for funding capex often involve variance accounts that effectively exempt capital revenue or a portion thereof from indexing. In Ontario, for example, a "C factor" is sometimes added to a revenue (or price) cap index formula that helps capital revenue grow at a rate that is close to that of forecasted capital cost.

Capital cost variance accounts can require customers to fully compensate the utility for expected capital revenue *shortfalls* when capital cost growth is unusually rapid for reasons beyond its control even though the utility is not required to return any *surplus* capital revenue, in the current or future plan, if capital cost growth is unusually slow for reasons beyond its control.[30] Over multiple plans, the revenue escalation between rate cases would then not guarantee customers the full benefit of the industry's *PMF* trend, even when it is achievable.

A related concern is that most of the capex addressed by capital cost variance accounts (as well as Z factors) would be similar in kind to that incurred by transmitters sampled in past and future productivity studies that are used to calculate the company's X factors.[31] The company can then be compensated twice for the same capex: once via the variance account and then again by low X factors in past, present, and future *MRIs*. Capital variance accounts also weaken performance incentives and can

[29] Notable hearings where this controversy has arisen are discussed below.

[30] Slow capital cost growth may very well occur in the future for reasons other than good cost management. For example, depreciation of recent and prospective surge capex will tend to slow future capital cost growth and accelerate productivity growth.

[31] This is also true of Z factors.

encourage companies to exaggerate their capex needs and to bunch their capex in a way that bolsters supplemental revenue.

Given the inherent unfairness to customers of asymmetrically funding only capital revenue shortfalls, the utility's weak incentive to contain capex when afforded variance account treatment, and its incentive to exaggerate capex requirements and bunch capex in ways that bolster extra revenue, regulators and intervenors must be especially vigilant about the utility's capex proposal. The utility may be asked to periodically file a multiyear capex plan. This can raise regulatory cost considerably, and yet the regulator and intervenors will inevitably struggle to effectively challenge the company's capex proposal.

Informed by our research and testimony in several *MRI* proceedings, PEG has detailed a number of possible adjustments to *MRIs* that combine a capital cost variance account and a revenue (or price) cap index. Here are some examples.

- The X factor could be raised mechanistically, in the instant and/or future *MRIs*, to reduce expected double counting and give customers a better chance of receiving the benefits of industry productivity growth in the long run.
- The eligibility of capex for supplemental capital revenue can be contained by various means. In the fourth-generation *MRI* currently used by most Ontario power distributors, for instance, a share of otherwise-eligible capex (typically around 5%) is deemed ineligible for supplemental funding between rate cases. Alternatively, eligible capex can be limited to major plant additions.
- Capital costs that occasion supplemental revenue could be subject to continued tracking in later plans. Customers would then receive the benefit of depreciation of the surge capex between plans.

Salient Precedents

The "double counting" issue has been debated in several *MRI* proceedings and no consensus has been established. Most regulators have eschewed X factor adjustments and based X factors on *PMF* trends. However, the Hawaii Public Utilities Commission ruled, in a recent *MRI* proceeding, that X factors in revenue cap indexes for the three Hawaiian Electric companies should be set at zero, despite evidence that they should be materially negative, due in part to the fact that their major plant additions will be eligible for cost tracking. In British Columbia, *MRIs* for the Fortis companies have tracked the cost of *all* older capital.

Scale Escalators

Formula [7a] raises the issue of the appropriate scale escalator for a revenue cap index. For gas and electric power distributors, the number of customers served is a sensible component of a revenue cap index scale escalator, for several reasons. The customers served variable often has the highest estimated cost elasticity amongst the scale variables studied in econometric research on distributor cost. The number of customers clearly drives costs of connections, meters, and customer services and has a high positive correlation with peak load and delivery capacity. Consider also that a scale escalator that includes volumes or peak demand as output variables diminishes a utility's incentive to promote demand side management. This is an argument for excluding these system-use variables from a revenue cap index scale escalator.[32]

In power transmission no single scale variable is dominant. A multidimensional scale index with weights based on econometric research on transmission cost is therefore more appropriate.

Revenue cap indexes do not always include explicit scale escalators. A revenue cap index of general form

$$growth\ Revenue^{Allowed} = growth\ GDP\ IPI - X \qquad [9a]$$

where

$$X = \overline{PMF}^{C}_{Industry} + Stretch.$$

is equivalent to the following:

$$growth\ Revenue^{Allowed} = growth\ GDP\ IPI - X + Stretch^{Augmented} + \text{Expected}\ growth\ Scale_{Utility} \qquad [9b]$$

where

$$X = \overline{PMF}^{C}_{Industry}$$

[32] In choosing a scale escalator for a North American power distributor, it is also pertinent that data on miles of distribution line, another important distribution cost driver, are not readily available for most U.S. power distributors. This bolsters the arguments for using the number of customers as the sole scale variable in an RCI for a U.S. power distributor.

$$Stretch = \textit{Expected growth Scale}_{Utility} + Stretch^{Normal}. \qquad [9c]$$

It can be seen that if the *MRI* does not otherwise compensate the utility for growth in its operating scale, the expected scale index growth of the utility is an implicit stretch factor. The value of this implicit stretch factor will be larger the more rapid is the utility's expected scale index growth.

Inflation Issues

If a macroeconomic inflation index, such as the GDPIPI, is used as the inflation measure in a revenue cap index, Relation [7] can be restated as:

$$\begin{aligned}\textit{growth Cost} &= \textit{growth Input Prices} - \textit{growth Productivity}^{C} + \textit{growth Outputs}^{C} \\ &\quad + \textit{growth GDPIPI} - \textit{growth GDPIPI} \\ &= \textit{growth GDPIPI} - [\textit{growth Productivity}^{C} + (\textit{growth GDPIPI - growth Input Prices})]. \\ &\quad + \textit{growth Outputs}^{C}. \qquad [10]\end{aligned}$$

Relation [10] shows that cost growth depends on GDPIPI inflation, growth in operating scale and productivity, and on the difference between GDPIPI and utility input price inflation (which is sometimes called the "inflation differential".)

The GDPIPI is the Canadian government's featured index of inflation in the prices of the economy's final goods and services.[33] It can then be shown that the trend in the GDPIPI equals the difference between the trends in the economy's input price and (multifactor) productivity indexes.

$$\textit{growth GDPIPI} = \textit{growth Input Prices}^{Economy} - \textit{growth PMF}^{Economy}. \qquad [11]$$

The formula for the X factor can then be restated as:

$$X = [(\overline{Productivity}^{C} - \overline{PMF}^{Economy}) + (\overline{\textit{Input Prices}}^{Economy} - \overline{\textit{Input Prices}}^{Industry})]. \qquad [12]$$

Here, the first term in parentheses is called the "productivity differential." It is the difference between the productivity trends of the industry and the economy. The second term in parentheses is called the "input price differential." It is the difference between the input price trends of the economy and the industry.

[33] Final goods and services include consumer products, government services, and exports.

Relation [12] has been the basis for the design of several approved X factors in *MRI* plans in the United States.[34] Since the *PMF* growth of the U.S. economy has tended to be brisk it has resulted in substantially negative X factors in several American *MRIs* for energy distributors. PMF growth has historically been slower in Canada's economy, and macroeconomic price indexes are less frequently the sole inflation measures in revenue cap indexes.

Stretch Factors

Rationale

In prior direct testimony before the Régie, PEG stated that

> the stretch factor term… should reflect an expectation of how the productivity growth of the subject utility will differ from the base productivity growth target. This depends in part on how the performance incentives generated by the plan compare to those in the regulatory systems of utilities in productivity studies that are used to set the base productivity trend. It also depends on the utility's operating efficiency at the start of the MRI.
>
> Initial operating efficiency is often assessed in MRI proceedings by statistical benchmarking studies. The methods used in these studies run the gamut from crude unit cost metrics to sophisticated econometric modelling and data envelopment analysis. In succeeding MRIs, the linkage of the stretch factor to statistical benchmarking of the utility's forward test year cost proposal can serve as an efficiency carryover mechanism that rewards the utility for achieving lasting performance gains and can penalize the utility for a failure to do so.[35]

Incentive Power

In another piece of prior testimony, PEG presented results of some incentive power research that it had previously prepared.[36] Results of this research were published by Lawrence Berkeley National Laboratory.[37] We showed that the incentive power of regulatory systems can be increased by efficiency carryover mechanisms and less frequent rate cases and reduced by earnings sharing

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[34] This approach has, for example, been approved in Massachusetts on several occasions. See, for example, D.P.U. 96-50, D.T.E. 03-40, D.T.E. 05-27, D.P.U. 17-05, and D.P.U. 18-150.

[35] Mark Newton Lowry, "Outstanding Issues in the Design of an MRI for Hydro-Québec Transmission," 9 November 2018, p. 27.

[36] Mark Newton Lowry and Matt Makos, "Incentive Regulation for the Transmission and Distributor Services of Hydro-Québec," Revised HQT Draft 24 February 2017 pp. 136-145.

[37] Mark Newton Lowry, J. Deason, and Matthew Makos, "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," Lawrence Berkeley National Laboratory, July 2017.

mechanisms. We can then consider how the frequency of rate cases, the prevalence of earnings sharing, and other aspects of ratemaking for sampled utilities compares to the *MRI* of the subject utility.

<u>Precedents</u>

Most power distributors in Ontario operate under an *MRI* called the 4th Generation Incentive Ratemaking Mechanism. The X factor term of the price cap index includes a base productivity growth target and a stretch factor. The base productivity growth target is linked to the *PMF* trends of Ontario distributors. As detailed in the table below, the stretch factor varies with the outcome of an econometric total cost benchmarking study that is updated annually. The best performers get a stretch factor of zero whereas the worst get a stretch factor of 0.6%.[38] No explicit consideration is paid to how the incentive power of the *MRI* differs from that of utilities in the productivity study. The stretch factor the Board chose for the current MRI for transmission services of Hydro One Networks was informed by statistical benchmarking studies, as discussed further below.

Ontario Energy Board Stretch Factor Assignments

Cost Performance in Econometric Model	Assigned Stretch Factor
Actual costs 25% or more below model's prediction	0.00%
Actual costs 10-25% below model's prediction	0.15%
Actual costs within +/-10% of model's prediction	0.30%
Actual costs 10-25% above model's prediction	0.45%
Actual Costs 25% or more above model's prediction	0.60%

3.3. Statistical Benchmarking

What is Benchmarking?

The word benchmark originally comes from the field of surveying. The *Oxford English Dictionary* defines a benchmark as:

> A fixed point (esp. a cut or mark in a wall, building, etc.), used by a surveyor as a reference in measuring elevations.[39]

[38] Ontario Energy Board (2013), *EB-2010-0379 Report of the Board Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, p. 21.

[39] "benchmark, n. and adj." OED Online. Oxford University Press.

The term has subsequently been used more generally to indicate something that can be used as a point of comparison in performance appraisals.

A quantitative benchmarking exercise involves one or more activity measures. These are sometimes called key performance indicators. The value of each indicator achieved by an entity under scrutiny is compared to a benchmark value that reflects a performance standard. Given data on the cost of HQT and a certain cost benchmark we might, for instance, measure its cost performance by taking the ratio of the two values:

$$Cost\ Performance = Cost^{HQT}/Cost^{Benchmark}.$$

Benchmarks are often developed statistically using data on the operations of agents engaged in the same activity. Various performance standards can be used in benchmarking, and these often reflect statistical concepts. One sensible standard is the average performance of the utilities in the sample. An alternative standard is the performance that would define the margin of the top quartile of performers. An approach to benchmarking that uses statistical methods is called statistical benchmarking.

These concepts are usefully illustrated by the process through which decisions are made to elect athletes to the Hockey Hall of Fame. Statistical benchmarking plays a major (if informal) role in player selection. Players, for example, are evaluated using multiple performance indicators. The values typically achieved by Hall of Fame members are useful benchmarks. These values reflect a Hall of Fame performance standard.

External Business Conditions

When appraising the relative performance of two sprinters, comparing their times in the 100-meter dash when one runs uphill and the other runs on a level surface is not ideal since runner speed is influenced by the slope of the surface. In comparing the costs of utilities, it is similarly recognized that differences in their costs depend in part on differences in the external business conditions they face. These conditions are sometimes called cost "drivers." The cost performance of a company depends on the cost it achieves (or, in the case of a forward test year, *proposes*) given the business conditions it faces. Benchmarks must, therefore, reflect external business conditions.

Economic theory is useful in identifying cost drivers and controlling for their influence in benchmarking. Under certain reasonable assumptions, cost "functions" exist that relate the cost of a utility to the business conditions in its service territory. When the focus of benchmarking is total costs, theory reveals that the relevant business conditions include the prices of all inputs and the operating scale of the company. Miscellaneous other business conditions may also drive cost.

Economic theory allows for the existence of multiple output variables in cost functions. The cost of a power distributor depends, for instance, on the number of customers it serves and on the length of its lines.

Benchmarking Methods

In this section, two benchmarking methods commonly used in North American proceedings, econometric and indexing, are discussed.

Econometric Modeling

We noted above that simply comparing the results of a 100-meter sprinter racing uphill to a runner racing on a level course is not ideal for measuring the relative performance of the athletes. Statistics can sharpen our understanding of each runner's performance. For example, a mathematical model could be developed in which time in the 100-meter dash is a function of track conditions like wind speed, racing surface, and gradient. The parameters corresponding to each track condition would quantify their impact on times. The samples of times turned in by runners, under the varying track conditions, could be used to estimate model parameters. The resultant run time model could then be used to predict the typical performance of the runners given the track conditions they faced.

The relationship between the cost of utilities and the business conditions they face (sometimes called the "structure" of cost) can also be estimated statistically. A branch of statistics called econometrics has developed procedures for estimating economic model parameters using historical data on the variables.[40] The parameters of a utility cost function can be estimated using historical data on the costs incurred by a group of utilities and the business conditions they faced. The sample used in model estimation can be a time series consisting of data over several years for a single company, a cross section consisting of one observation for each of several companies, or a "panel" data set that pools time series data for several companies.

Economic theory can guide the specification of cost models. As noted above, cost is a function of input prices and output quantities. Multiple output quantity variables may be pertinent. If panel

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[40] The estimation of model parameters is sometimes called regression.

data are used in model estimation, the input price indexes in such a study should be able to compare price levels at each point in time as well as price trends over time.

Basic Assumptions Econometric research involves certain critical assumptions. The most important assumption, perhaps, is that the values of some economic variables (called dependent or left-hand side variables) are functions of certain other variables (called explanatory or right-hand side variables) and error terms. In an econometric cost model, cost is the dependent variable and the cost drivers are the explanatory variables. The explanatory variables are generally assumed to be independent in the sense that their values are not influenced by the values of dependent variables.

The error term in an econometric cost model is the difference between actual cost and the cost predicted by the model. Error terms are a means of modelling the reality that the cost model is unlikely to provide a full explanation of the variation in the costs of sampled utilities. The limitations of the model may include mismeasurement of cost and the external business conditions, the exclusion from the model of relevant business conditions, and the failure of the model to capture the true form of the underlying functional relationship. It is customary to assume that error terms are random variables drawn from probability distributions with measurable parameters.

Statistical theory is useful for selecting the business conditions used in cost models. Tests can be constructed for the hypothesis that the parameter for a business condition variable under consideration equals zero. A variable can be deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence.

Cost Predictions and Performance Appraisals A cost function fitted with econometric parameter estimates is called an econometric cost model. Such models can be used to predict a company's cost given local values for the business condition variables.[41] These predictions are econometric

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[41] Suppose, for example, that you want to benchmark the cost of a hypothetical transmission utility called Eastern Transmission. You could predict the cost of Eastern Transmission in period *t* using the following model:

$$\hat{C}_{Eastern,t} = \hat{a}_0 + \hat{a}_1 \cdot P_{Eastern,t} + \hat{a}_2 \cdot L_{Eastern,t}.$$

Here, $\hat{C}_{Eastern,t}$ denotes the predicted cost of the company, $P_{Eastern,t}$ is the peak demand that Eastern experiences, and $L_{Eastern,t}$ equals the length of its transmission line. The $\hat{a}_0$, $\hat{a}_1$, and $\hat{a}_2$ terms are parameter estimates. Cost performance might then be measured using a formula such as:

$$Performance = ln\left(C_{Eastern,t} / \hat{C}_{Eastern,t}\right)$$

benchmarks. Cost performance is measured by comparing a company's cost in year *t* to the cost projected for that year by the econometric model. The year in question can be in the past or the future.

Accuracy of Benchmarking Results A cost prediction like that generated in the manner just described is our best single guess of the company's cost given the business conditions that it faces. This is an example of a point prediction. This prediction is apt to differ from the true expectation of cost due, for example, to the exclusion from the model of relevant business conditions.

Statistical theory provides useful guidance regarding the accuracy of such benchmarks. One important result is that an econometric model can yield biased predictions if relevant business condition variables are excluded from the cost model. A model used to benchmark the cost of a power distributor with extensive undergrounding, for example, yields biased cost predictions if it excludes an indicator of this condition. It is therefore desirable to include in the model all cost drivers for which data are available at reasonable cost, are believed to be relevant, and which have plausible and statistically significant parameter estimates.

In addition, statistical theory provides the foundation for the construction of confidence intervals that represent the full range of possible cost model predictions that are consistent with the data at a given level of confidence. Wider confidence intervals suggesting reduced benchmarking precision are likely to the extent that:

- the model is less successful in explaining the variation in the historical cost data used to estimate the model's parameters;
- the sample size used in model estimation is smaller;
- the number of business condition variables included in the model is larger;
- the business conditions of sample companies are less varied; and
- the business conditions of the subject utility are less similar to those of the typical firm in the sample.

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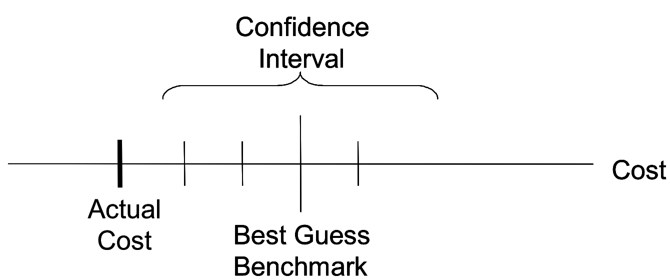
where ln indicates a natural logarithm.

These results have important implications for benchmarking. For example, the results suggest that we can often improve the precision of an econometric benchmarking model by pooling data for sampled companies over multiple years rather than using only a cross-section of data for a single year. In fact, the precision of an econometric benchmarking exercise is actually *enhanced* by using data from companies with diverse operating conditions. For example, to capture the impact of variables that measure the ruralization of a service territory it is useful to have data for utilities that operate under urban as well as rural conditions.

Testing Efficiency Hypotheses Confidence intervals developed from econometric results not only provide us with indications of the accuracy of a benchmarking exercise but also permit us to test hypotheses regarding cost efficiency. Suppose, for example, that we use a sample average efficiency standard and compute the confidence interval for the benchmark that corresponds to the 90 percent confidence level. It is possible to test the hypothesis that the company has attained the benchmark standard of efficiency. If, for example, the company's actual cost is below the best guess benchmark generated by the model, but nonetheless lies within the confidence interval, the aforementioned hypothesis cannot be rejected. In other words, the company is not a *significantly* superior cost performer.

An important advantage of efficiency hypothesis tests is that they take into account the accuracy of the benchmarking exercise. But there is uncertainty involved in the prediction of benchmarks. These uncertainties are properly reflected in the confidence interval that surrounds the point estimate (best single guess) of the benchmark value. The confidence interval will be greater the greater the uncertainty is regarding the true benchmark value. If uncertainty is great, our ability to draw conclusions about operating efficiency is hampered.



Econometric Benchmarking Precedents There are numerous precedents for the use of econometric benchmarking in regulation. The Ontario Energy Board has the most extensive experience in North

America. Most Ontario power distributors operate under *MRIs* that feature price cap indexes. The index formulas in third- and fourth-generation plans have had stretch factors that varied between utilities based on results of econometric cost benchmarking studies commissioned by the Board.[42] The benchmarking in the current (fourth generation) *MRI* uses an econometric model of total cost. The model is used to update the performance scores and stretch factors of distributors annually. Additionally, distributors are required to use this model to benchmark their forward test year cost proposals in rate cases.

Benchmarking is also used in Ontario "Custom" *MRI* proceedings for some of the larger power distributors (e.g., Toronto Hydro-Electric) and the main power transmitter. These utilities frequently benchmark their proposed cost in each year of their proposed *MRIs*. Ontario's benchmarking program effectively serves as an efficiency carryover mechanism since distributors achieving long-term cost savings will have better benchmarking scores, which translates to more rapid revenue growth.

PEG personnel have also provided econometric benchmarking evidence in several other North American proceedings. In Massachusetts, for example, we have used it to support stretch factor proposals in *MRI* proceedings for Bay State Gas, Boston Gas, and NSTAR Gas.[43] We have filed testimony on the cost performance of San Diego Gas & Electric and Southern California Gas on several occasions.[44] In some Colorado PUC proceedings, we used econometric benchmarking to appraise the forward test year cost proposals for the gas and electric services of Public Service of Colorado.[45] In Vermont, PEG benchmarked the cost performance of Central Vermont Public Service in the provision of power

[42] PEG performed these studies for the OEB.

[43] See Massachusetts D.P.U. proceedings 96-50 and 03-40 (Boston Gas); 05-27 (Bay State Gas); and 19-120 (NSTAR Gas).

[44] See for example, California Public Utilities Commission Application Nos. 02-12-027, 02-12-028 and 06-12-009, and 06-12-010.

[45] See for example, Colorado Public Utilities Commission Proceedings 09AL-299E, 10AL-963G, 17AL-0363G, and 17AL-0649E.

distributor services. This study provided the basis for an article in *The Energy Journal.*[46] Econometric benchmarking has also been used by regulators in Australia and Great Britain.[47]

<u>Indexing</u>

In their internal reviews of operating performance utilities tend to employ index approaches to benchmarking rather than the econometric approach just described. Benchmarking indexes are also used occasionally in regulatory submissions. We begin our discussion with a review of index basics and then consider unit cost indexes.

Index Basics An index is defined in one dictionary as "a ratio or other number derived from a series of observations and used as an indicator or measure (as of a condition, property, or phenomenon)."[48] In utility-performance benchmarking, indexing typically involves the calculation of ratios of the values of performance metrics for a subject utility to the corresponding values for a sample of utilities. The companies for which sample data have been drawn are sometimes called a peer group.

We have noted that a simple comparison of the costs of utilities reveals little about their cost performances to the extent that there are large differences in the cost drivers they face. In index-based benchmarking, it is therefore common to use as cost metrics the ratios of their cost to one or more important cost drivers. The operating scale of utilities is typically the greatest source of difference in their cost. It makes sense then to compare ratios of cost to operating scale. Such a ratio is sometimes described as the cost per unit of operating scale or unit cost. In comparing the unit cost of a utility to the average for a peer group, we introduce an automatic control for differences between the companies in their operating scale. This permits us to include companies with more varied operating scales in the peer group.

A unit cost index is the ratio of a cost index to a scale index.

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[46] Mark N. Lowry, Lullit Getachew, and David Hovde. *Econometric Benchmarking of Cost Performance: The Case of U.S. Power Distributors*, THE ENERGY JOURNAL 26 (3), at 75-92 (2005).

[47] See for example, Ofgem, RIIO-ED1 Final determinations for the slow-track electricity distribution companies Business Plan expenditure assessment (2014) and Australian Energy Regulator, Final Decision EvoEnergy Distribution Determination 2019 to 2024 Attachment 6 Operating Expenditure (2019).

[48] Webster's Third New International Dictionary of the English Language Unabridged, Volume 2, p. 1148. (Chicago: G. and C. Merriam and Co. 1966).

$$Unit\ Cost = Cost/Scale. \quad [13]$$

Each index compares the value of the metric to the average for a peer group.[49] The scale index can be multidimensional if it is desirable to measure operating scale using multiple scale variables.

Unit cost indexes do not control for differences in the other cost drivers that are known to vary between utilities. We have noted that cost depends on input prices and miscellaneous other business conditions in addition to operating scale. The accuracy of unit cost benchmarking thus depends on the extent to which the cost pressures placed on the peer group by these additional business conditions are similar on balance to those facing the subject utility.

One sensible upgrade to unit cost indexes is to adjust them for differences in the input prices that utilities face. The formula for real (inflation-adjusted) unit cost is

$$Unit\ Cost^{Real} = \frac{Cost\,/\,Input\ Prices}{Scale}. \quad [14]$$

Recollecting that cost is the product of properly-designed input price and quantity indexes

$$Cost = Input\ Prices \cdot Input\ Quantities$$

it follows that

$$Unit\ Cost^{Real} = \frac{Input\ Quantities}{Scale} = 1/Productivity \quad [15]$$

Thus, a real unit cost index will yield the same benchmarking results as a productivity index.

Custom Productivity Growth Benchmarks

We have seen that the cost of an enterprise is a function of input prices, outputs, and miscellaneous other external business condition variables ("*Other Variables*"). This relationship may be expressed in general terms as

$$Cost = \mathrm{f}(Input\ Prices, Outputs, Other\ Variables, Time). \quad [16]$$

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[49] A unit cost index for Eastern Transmission, for instance, would have the general form

$$Unit\ Cost_t^{Eastern} = \frac{(Cost_t^{Eastern}/Cost_t^{Peers})}{(Scale^{Eastern}/\,Scale_t^{Peers})}.$$

We can measure the impacts of business conditions on utility cost by positing a specific form for the cost function and then estimating model parameters using econometric methods and historical data on utility operations. Here is a simple example of an econometric cost model.

$$\ln Cost^{Real} = \hat{\beta}_0 + \hat{\beta}_1 \times \ln Output_1 + \hat{\beta}_2 \times \ln Output_2$$
$$+ \hat{\beta}_3 \times \ln Other_1 + \hat{\beta}_4 \times \ln Other_2 + \hat{\beta}_T \times Trend \qquad [17]$$

Here, $Cost^{Real}$ is real cost, the ratio of cost to an input price index. The $\hat{\beta}$ terms are econometric estimates of model parameters. This model has a double log functional form in which cost and the values of business condition variables are logged. With this form, parameters $\hat{\beta}_1$ to $\hat{\beta}_4$ are also estimates of the elasticities of cost with respect to the four business condition variables. The term $\hat{\beta}_T$ is an estimate of the parameter for the trend variable in the model. This parameter would capture the typical net effect on utility cost trends of technological progress and changes in cost driver variables that are excluded from the model.

Econometric cost research has several uses in the determination of X factors for HQT. In the case of our illustrative model, econometric estimates of output variable parameters can be used to construct an output quantity index with the following formula:

$$growth\ Outputs = [\hat{\beta}_1/(\hat{\beta}_1 + \hat{\beta}_2)] \times growth\ Output_1 + [\hat{\beta}_2/(\hat{\beta}_1 + \hat{\beta}_2)] \times growth\ Output_2. \qquad [18]$$

This formula states that output index growth is an elasticity-weighted average of the growth in the two output variables. An index of this kind can be used in the *PMF* research. It can also serve as the scale escalator of the revenue cap index.

Denny, Fuss, and Waverman provided the additional useful result that, for a cost model like [17], growth in a company's *productivity* can be decomposed as follows. [50]

$$growth\ Productivity = [1 - (\hat{\beta}_1 + \hat{\beta}_2)] \times growth\ Outputs + \hat{\beta}_3 \times growth\ Other_1$$
$$+ \hat{\beta}_3 \times growth\ Other_2 - \hat{\beta}_T. \qquad [19]$$

The first term in [19] represents the component of productivity growth that is realized due to economies of scale when output grows. These economies are greater the smaller is the sum of the cost elasticities

[50] Denny, Fuss, and Waverman, *op. cit*.

with respect to output ($\hat{\beta}_1$ + $\hat{\beta}_2$) and the greater is output index growth. Relation [19] also shows that if a change in the value of a business condition variable like *Other₁* raises cost it also slows *PMF* growth. If the trend variable parameter estimate has a negative (positive) value it would to that extent raise (lower) productivity growth. Formulas like [19] can be generalized to models with additional (or fewer) outputs and other business condition variables.

Econometric cost research and an equation like [19] can be used to identify *PMF* growth drivers and estimate their impact. Given forecasts of the change in output and other business conditions, an equation like [19] can also provide the basis for *PMF* growth benchmarks that are specific to the business conditions of a utility that will be operating under an *MRI*. For example, we can make projections that are specific to HQT during the four likely indexing years (e.g., 2024-2027) of any succeeding *MRI*. These are effectively projections of the *PMF* growth of typical utility managers if faced with HQT's expected business conditions.

For the simple model detailed in equation [19] the productivity growth projection formula would be

$$trend\ \widehat{Productivity}^{C}_{HQT} = [1-(\hat{\beta}_1+\hat{\beta}_2)] \times trend\ \widehat{Outputs}_{HQT} + \hat{\beta}_3 \times trend\ \widehat{Other}_{1,HQT} + \hat{\beta}_4 \times trend\ \widehat{Other}_{2,HQT}) - \hat{\beta}_T. \quad [20]$$ [51]

Here $trend\ \widehat{Productivity}^{C}_{HQT}$ is the projected annual productivity growth trend (average annual growth rate) for HQT during the final four years of its next *MRI*. The variable $trend\ \widehat{Outputs}_{HQT}$ is the expected trend in HQT's output index. $trend\ \widehat{Other}_{l,HQT}$ is the expected trend for HQT in each external business condition that is included in the model.

In an application to Canadian telecommunications Denny, Fuss, and Waverman, *op. cit.*, were the first to use econometric research and a formula like [19] to decompose *PMF* growth. The method

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[51] Here is a more general formula.

$$trend\ Productivity^{C}_{HQT} = \left(1-\sum_i \hat{\beta}_i\right) \cdot E\left(trend\ \overline{Outputs^{C}_{HQT}}\right) - \sum_l \widehat{\beta}_l \cdot \mathrm{E}\left(trend\ \overline{Others_{l,HQT}}\right) - \widehat{\beta}_T$$

Here $\hat{\beta}_i$ is the econometric parameter estimate for each output variable i while $\hat{\beta}_l$ is the parameter estimate for each other business condition l that is included in the model.

was also used several times in California proceedings.[52] In work for the Ontario Energy Board, PEG used this method in an Ontario gas *MRI* proceeding to project the *PMF* trends of two large gas utilities and published a paper on the work in the *Review of Network Economics.*[53] These projections were useful because the productivity drivers facing these utilities (e.g., rapid growth in Toronto and Ottawa) were very different from those facing gas utilities in adjacent American states.

Productivity growth projections have several advantages in the design of an X factor for HQT. They are useful for ascertaining the reasonableness of an X factor which is based on more conventional industry cost trend research. Moreover, the projection can pertain to the specific costs that the revenue cap index will address. Despite being customized to HQT's business conditions, the use of these projections would not weaken HQT's cost containment incentives since they reflect only the estimated cost impact of external business conditions.

3.4. Capital Cost Issues

Capital Cost, Prices, and Quantities

Since the technologies of energy transmitters and distributors are capital-intensive, the capital cost specification is important in benchmarking and productivity studies. A discussion of sensible specifications might begin by noting that the annual cost of capital that a utility incurs includes depreciation expenses, a return on investment, and certain taxes. If the price (unit value) of older assets changes over time, the annual cost may also be net of any capital gains or losses. Annual capital cost is different from the capex or gross plant additions that are added each year to the rate base.

The quantity of capital has several aspects. These include the service flow that the assets provide, their capacity or potential service flow (which may be higher), and the stock of present and future capacity/service flows that are possible. Each of these notions of quantity has a corresponding price. Rental prices are prices for the use of capacity (e.g., the use of a car or hotel room for a day). There are also prices to gain ownership of capital assets (e.g., new and used automobiles).

[52] See, for example, California Public Utilities Commission A.98-01-014.

[53] See Lowry, M.N., and Getachew, L., *Review of Network Economics*, "Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry" Vol. 8, Issue 4, December 2009.

Potential and actual service flows from assets may decay as they age and ultimately end. This causes the values of the assets to depreciate. Depreciation is normal, even if the annual capacity/service flow is constant until retirement.

Depreciation and service lives matter, especially in capital-intensive industries. One reason is that opportunity cost accounts for a sizable share of the cost of asset ownership. Depreciation reduces opportunity cost over time and can be an important driver of cost trends. Following a capex surge, for instance, depreciation in the value of a utility's assets may materially slow cost growth. This may be followed later by a period of rapid cost growth when surge assets of decades past need replacement.

The service lives of assets can be an important consideration in the choice between assets. For example, utilities have some ability to extend the service lives of aging assets by increasing *CNE*. This is tantamount to choosing between an old asset with a low opportunity cost of ownership and a new asset that contains a large stock of future service flows but also has a high opportunity cost. Buyers also choose between assets with different service lives in other markets (e.g., those for consumer durables). New assets (e.g., vacuum cleaners) have varied service lives, and there are markets for used assets. In markets of both kinds, asset prices and opportunity costs vary with expected service lives.

Monetary Capital Cost Specifications

The Basic Idea

Monetary approaches to measurement of capital prices and quantities are conventionally used in statistical research on the productivity and cost performance of North American utilities. In these approaches, capital cost ("*CK*") is the product of a consistent capital price index ("*WK*") and capital quantity index ("*XK*").

$$CK = WK \times XK. \qquad [21]$$

The growth rate of capital cost can then be shown to be the sum of the growth rates of these indexes.[54] This decomposition facilitates productivity and econometric cost research.

Construction of capital quantity indexes involves deflation, using asset price indexes, of reported values of gross plant additions. These quantities are then subjected to a standardized decay

[54] This result is specific to certain growth rate measures.

specification.[55] In research on the productivity and cost performances of U.S. energy utilities, Handy Whitman utility construction cost indexes ("HWIs") have traditionally been used as the asset price indexes. Statistics Canada used to compute credible electric utility construction cost indexes but these have been discontinued.

Since some of the plant a utility owns may be 40-60 years old, it is desirable in these calculations to have gross plant addition data for many years into the past. For earlier years, however, the desired gross plant addition data are frequently unavailable. Consequently, it is customary to begin the calculation of a capital quantity index by considering the remaining value of all plant at the end of the limited-data period and then to estimate the quantity of capital that it reflects using data on asset prices in earlier years. This initial year of the capital quantity index is sometimes called the "benchmark year". Since the estimate of the capital quantity in the benchmark year is inexact, it is preferable to base capital and total cost research on a sample period that begins many years after the benchmark year. If this is not done, research on capital and total cost will be less accurate, especially in the early years of the sample period.

Capital Service Flows and Service Prices

A capital good provides a stream of services over some period of time. In rigorous statistical cost research, it is often assumed that the capital quantity index measures the annual flow. A companion capital price index is then chosen that measures the hypothetical price of a unit of capital service. This is sometimes called a "service" price. The design of capital service price indexes should be consistent with the assumption about the decay in the service flow. The product of the capital service price index and the capital quantity index is interpreted as the annual cost of using the flow of services. This is sometimes called the user cost of capital.

[55] Utilities have various methods for calculating depreciation expenses that they report to regulators and retire their assets at different times. Consequently, when calculating capital quantities using a monetary method, it is desirable to rely on the reporting companies chiefly for the values of their gross plant additions and to use a standardized decay specification for all companies.

Popular Monetary Capital Cost Specifications

Several monetary methods have been established for measuring capital price and quantity trends. A key issue in the choice between these methods is the pattern of decay in the quantity from each year's plant additions. This pattern is sometimes called the age-efficiency profile.

Another issue in the choice between monetary methods is whether plant is valued in historical or replacement (i.e., current) dollars. Historical valuations (sometimes called "book" valuations) are commonly used in North American utility cost accounting. When plant is valued in replacement dollars, utilities experience capital gains if the value of older plant appreciates, and this reduces the cost of capital.

Three monetary methods for calculating capital cost have been used extensively in utility cost benchmarking and X factor research: geometric decay, one-hoss shay, and cost of service. We discuss these methods in turn.

1. Geometric Decay Under this method, the quantity of capital from each group of plant additions to which it is applied declines at a constant rate ("*d*") over time. The capital quantity at the end of each period *t* ("XK_t") is related to the quantity at the end of the *last* period and the quantity of gross plant additions ("XKA_t") by the following equation:[56]

$$XK_t = XK_{t-1} \cdot (1-d) + XKA_t \qquad [22a]$$

$$= XK_{t-1} \cdot (1-d) + \frac{VKA_t}{WKA_t}. \qquad [22b]$$

The assumed constant rate of depreciation is accelerated relative to straight-line depreciation in the early years of an asset's service life but is less rapid in later years. Note that the quantity of gross plant additions is calculated as the ratio of their value to an asset price index ("WKA").

The geometric decay method assumes a replacement valuation of plant. Cost is thus computed net of capital gains. The companion capital price is a service price.

[56] Equations of this kind are sometimes called "perpetual inventory equations."

2. <u>One-Hoss-Shay</u>[57] Under the one hoss shay method, the quantity of capital from each group of capital assets to which it is applied is assumed to be constant until the end of its average service life, when it abruptly falls to zero. This decay pattern is typical of an incandescent light bulb. However, in utility cost research this constant-flow assumption is usually applied to the total plant additions each year.

   The quantity of plant at the end of year *t* is the sum of the quantity at the end of the prior year ("XK_{t-1}") plus the quantity of gross plant additions ("XKA_t") less the quantity of plant retirements ("XKR_t"):

$$XK_t = XK_{t-1} + XKA_t - XKR_t \qquad [23a]$$

$$= XK_{t-1} + \frac{VKA_t}{WKA_t} - \frac{VKR_t}{WKA_{t-s}}. \qquad [23b]$$

   Since reported utility retirements are valued in historical dollars, the quantity of retirements in year *t* is calculated by dividing the reported value of retirements by the value of the asset price index for the (earlier) year when the retired assets were added.

   Plant is once again valued at replacement cost. The annual cost of capital is then computed net of capital gains. The companion capital price is once again a capital service price.

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[57] Wikipedia provides the origin of this term (https://en.wikipedia.org/wiki/One-horse_shay),

> A **one-horse shay** is a light, covered, two-wheeled carriage for two persons, drawn by a single horse. The body is chairlike in shape and has one seat for passengers positioned above the axle which is hung by leather braces from wooden springs connected to the shafts. "One-horse shay" is an American adaptation, originating in Union, Maine, of the French *chaise*. The one-horse shay is colloquially known in the US as a 'one-hoss shay'.
>
> American writer Oliver Wendell Holmes Sr. memorialized the shay in his satirical poem "The Deacon's Masterpiece *or* The Wonderful One-Hoss Shay". In the poem, a fictional deacon crafts the titular wonderful one-hoss shay in such a logical way that it could not break down. The shay is constructed from the very best of materials so that each part is as strong as every other part. In Holmes' humorous, yet "logical", twist, the shay endures for a hundred years (amazingly to the precise moment of the 100th anniversary of the Lisbon earthquake shock) then it "went to pieces all at once, and nothing first, — just as bubbles do when they burst". It was built in such a "logical way" that it ran for exactly one hundred years to the day.
>
> In economics, the term "one-hoss shay" is used, following the scenario in Holmes' poem, to describe a model of depreciation, in which a durable product delivers the same services throughout its lifetime before failing with zero scrap value. A chair is a common example of such a product.

3. Cost of Service ("COS"). The geometric decay and one hoss shay approaches for calculating capital cost use assumptions that differ from those used to calculate capital cost in traditional cost of service ratemaking.[58] With both approaches, we have seen that the trend in capital cost is a simulation of the trend in cost incurred for purchasing capital services in a competitive rental market. The derivation of a revenue cap index using index logic does not require a service price/service flow treatment of capital cost and can in principle use more familiar capital cost accounting provided that capital cost can still be decomposed into price and quantity indexes.

   The alternative COS approach to measuring capital cost achieves this decomposition and uses a simplified version of COS accounting. Plant is valued in historical dollars and straight-line depreciation of asset values is applied. Capital cost is not intended to simulate the cost of purchasing capital services in a competitive rental market, and the capital price is not a simulation of a capital service price. The formulae are complicated, however, making them more difficult to code and review.

Two other methods for calculating capital cost also warrant discussion – hyperbolic decay and the Kahn method:

4. Hyperbolic Decay Hyperbolic decay has rarely if ever been used in North American X factor or utility benchmarking studies but merits consideration in these applications. Under this approach the quantity of capital from groups of assets to which it is applied is assumed to decline at a rate that may vary as they age. This is appealing because the service flow from many utility assets seems to decline more markedly as they age.

   Like one-hoss shay and geometric decay, a hyperbolic decay specification typically entails a replacement valuation of plant. The annual cost of capital is therefore computed net of capital gains. The capital price is a service price which reflects these assumptions.

5. Kahn Method. An X factor can also be calculated using the simpler Kahn Method. This method was developed by Alfred Kahn, the distinguished regulatory economist who was a professor at Cornell University. It has been used by the FERC to set the X factors in *MRIs* for interstate oil pipelines. PEG has upgraded the method that Dr. Kahn used to better approximate cost of service capital cost

[58] The OHS assumptions are more markedly different.

accounting. The PEG approach was recently embraced by the Régie in choosing the provisional X factor in the *formule d'indexation* for the *CNE* revenue of HQT. PEG used this method in recent Massachusetts and Hawaii *MRI* proceedings.[59]

In this proceeding, the Kahn Method might involve calculating trends in the cost of base rate inputs of a sample of U.S. power transmitters using an approximation to traditional capital cost accounting and then solve for the value of X which would cause the trend in transmitter cost to equal the trend in a revenue cap index with a formula like:

$$\textit{growth Allowed Base Revenue}^{Utility} = \textit{growth GDPPI} - X + \textit{growth Outputs}^{C}. \qquad [24]$$

The X factor resulting from such a calculation reflects the inflation differential that we discussed in Section 3.2 above as well as the productivity trends of sampled utilities. This is a problem in an application to HQT since the inflation differential for a U.S. utility may differ considerably from that which is pertinent in Canada. Meanwhile, we don't have the data for multiple utilities that would permit us to compute a Kahn X specific to Canada.

Choosing the Right Monetary Approach

The relative merits of alternative monetary approaches to measuring capital cost have been debated in several *MRI* proceedings.[60] Based on PEG's experience in debates of this nature we believe that the following considerations are particularly relevant.

<u>The Goal of X Factor Research is to Find a Just and Reasonable Means to Adjust Rates Between Rate Cases.</u>

Statistical cost research has many uses, and the best capital cost specification for one application may not be best for another. One use of such research is to measure a utility's operating efficiency. Another use is to determine the X factor in a rate or revenue cap index.

Revenue cap indexes used in utility *MRIs* are intended to adjust allowed revenue between general rate cases that employ a cost-of-service approach to capital cost measurement. In North

[59] See Massachusetts DPU 18-150, Exhibits. AG-MNL, pp. 15-16 and AG-MNL-2, pp. 39-40, and Hawaii PUC 2018-0088, Initial Comprehensive Proposal of the Hawaiian Electric Companies, Exhibit A, *Designing Revenue Adjustment Indexes for Hawaiian Electric Companies*, August 14, 2019, pp. 19-20.

[60] See, for example, Exhibit M2, Tab 11.1, Schedule OPG-002, Att. A of the Ontario Energy Board's recent proceeding on Ontario Power Generation Payments Amounts (EB-2016-0152).

America, the calculation of capital cost in rate cases typically involves an historical valuation of plant and straight-line depreciation. Absent a rise in the target rate of return, the cost of the assets that sampled utilities add in a given year shrinks over time as depreciation reduces their net plant value and the return on rate base. Capital cost can rise rapidly in a period of high repex.

When a macroeconomic inflation measure like the GDP-IPI is the revenue (or price) cap index inflation measure, the input price trend of utilities becomes an issue as well as the productivity trend in X factor determination. The capital price index then becomes a criterion in the choice of the capital cost specification as well as the productivity index since an input price differential must be chosen. Some capital cost specifications have volatile capital prices. X factor witnesses often try to downplay this volatility, but more recently the X factor witness for power distributors National Grid (D.P.U. 18-150) and Eversource (D.P.U. 17-05) has touted the appropriateness of a large negative input price differential that benefitted its client, and the Massachusetts regulator embraced their analysis. Large input price differentials do not always favor utilities. In a proceeding to approve a price cap index for Central Maine Power, a witness for consumer interests asked for a large *positive* input price differential.[61]

One Hoss Shay Pros and Cons

One Hoss Shay Advantages The one hoss shay specification is sometimes argued to better fit the service flows of individual utility assets than geometric decay. The argument is that many assets, once installed, provide a fairly constant service flow for many years. One hoss shay has for this reason been used in some productivity studies filed in proceedings to determine X factors.

Another advantage of one hoss shay is that the data are unavailable in some applications to accurately calculate capital quantities using monetary methods. In these applications, the assumption of a one hoss shay service flow legitimizes using available data on capacity (e.g., line miles) as a capital quantity metric.[62]

One Hoss Shay Disadvantages Other considerations suggest that the one hoss shay specification is disadvantageous. Notable problems include the following.

[61] Maine PUC Docket 1999-00666

[62] However, capacity data are then unavailable as measures of output.

- Individual utility assets frequently do not exhibit a constant service flow until their retirement. For example, many assets tend to have diminished reliability, require more maintenance and safety inspections, and/or do more environmental damage as they age. For example, HQT stated in response to an information request from PEG that

> **Dans le dossier tarifaire 2013 et 2014**, **le Transporteur a expliqué que le vieillissement de son parc d'actifs entraîne des pressions à la hausse sur ses charges. D'une part, il a précisé que les activités de maintenance corrective ou préventive requises sont par nature plus significatives et augmentent ainsi les coûts de maintenance. D'autre part, le Transporteur a indiqué qu'il procède à des interventions ciblées et de réhabilitation ayant pour but de diminuer le risque de défaillance majeure d'équipements et d'éviter d'importants investissements pour les remplacer. Il a également expliqué que la forte sollicitation du réseau entraîne également une pression accrue sur le coût des interventions.**
>
> **Dans le dossier tarifaire 2016, le Transporteur a indiqué que les analyses sur ses travaux de maintenance passées démontrent que plus l'âge d'un actif augmente, plus le risque de bris et de défaillance augmente.**
>
> **Finalement, dans le dossier tarifaire 2017, le Transporteur a démontré que l`âge moyen du parc entraîne des effets importants sur la maintenance en précisant que l'effort de maintenance augmente de manière significative une fois passé le 50 % de la durée de vie utile d'un équipement.**[63]

- In productivity studies, capital quantity trends are not calculated for *individual* assets. Instead, they are typically calculated from data on the total value of *all* of the additions to (and, in the case of one hoss shay, retirements of) the various kinds of assets that a utility uses. Even if each individual asset did have a constant service flow, the flow from total plant additions could be poorly approximated by one-hoss shay[64] for several reasons.

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[63] B-0265 (HQT-16, Document 1), p. 9.

[64] Consistent with these remarks, the authors of a capital research manual for the Organization of Economic Cooperation and Development stated in the Executive Summary that:

> In practice, cohorts of assets are considered for measurement, not single assets. Also, asset groups are never truly homogenous but combine similar types of assets. When dealing with cohorts, retirement distributions must be invoked because it is implausible that all capital goods of the same cohort retire at the same moment in time. Thus, it is not enough to reason in terms of a

a. Different kinds of assets can have markedly different service lives.

b. Assets of the same kind have varied service lives. Identical light bulbs installed by Québec homeowners on June 1 in a given year, for instance, will burn out at different times. In power transmission and distribution, the service lives of assets vary due to casualty losses (e.g., due to severe storms).

c. Individual assets sometimes have components with different service lives. The fixtures on a transmission tower, for example, might need replacement before the tower itself.

- The value of assets with one hoss shay service flows depreciate as they age because of diminution in their expected future service flows. However, the simple one hoss shay approach abstracts from asset value depreciation since the service flow from the asset is assumed constant and the price of capital services is one that is commensurate with a competitive rental market. This matters for several reasons.
  - Depreciation reduces the opportunity cost of owning assets, and this is a material consideration when benchmarking utility cost. Using a simple one hoss shay approach in a benchmarking study, a utility's effort to delay replacement of assets will not be recognized. On the other hand, a capital cost specification that is more sensitive to age complicates modelling by raising the need for an appropriate age variable.
  - Depreciation can materially affect utility cost trends in the short and medium term, and its effect merits consideration in X factor selection. For example, we might want X to be less (more) positive if the subject utility and utility industry are both in a period of high (low) capex.
  - Depreciation is another reason why the quantity of a group of assets declines as they age. For example, as the asset ages, the utility obtains a constant service flow from a

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single asset but age efficiency and age-price profiles have to be combined with retirement patterns to measure productive and wealth stocks and depreciation for cohorts of asset classes.

OECD, *Measuring Capital OECD Manual 2009*, 2nd ed., at 12.

33-year-old asset one year and from a cheaper 34-year-old asset the next. This is arguably a quantity decline.

- One hoss shay is more difficult to implement accurately than other capital cost specifications. To understand this point, consider first that all monetary methods require deflation of gross plant *additions*. These calculations are facilitated by the fact that the years in which given additions are made are known exactly, so that it is easy to choose the matching value of the asset price deflator. The challenge with one hoss shay is that it also requires deflation of plant *retirements*, and the vintages of reported retirements are not readily available for a large number of utilities. One hoss shay practitioners commonly address this challenge by deflating the value of retirements by the value of an asset price index for a year in the past which reflects the assumed average service life of the assets. Deflations by this means can be well off the mark.

- One hoss shay has given rise to methodological controversies in *MRI* proceedings. The biggest controversy has concerned the average service life of assets. PEG's empirical research suggests that productivity results using one hoss shay are quite sensitive to the average service life assumption. Since the average service life is used to match a value for the asset price index to the retirements value, and retirements reduce the capital quantity, a higher average service life tends to slow measured capital quantity growth and thereby accelerate *PMF* growth. The average service life can then be a "fudge factor" in an X factor study.

  To better understand why this is important, consider that the recent popularity of one hoss shay in X factor studies was triggered by its use in the first Alberta generic *MRI* proceeding (2010-2012). The Alberta Utilities Commission hired National Economic Research Associates ("NERA") to study U.S. power distribution productivity. The sample period for their study (1975-2009) was unusually long. NERA found that the *PMF* of sampled U.S. distributors rose briskly in the first half of their full sample period and fell briskly in the second half. In this and the Alberta's second generic *MRI* proceeding utility consultants (e.g., the Brattle Group and Christensen Associates) largely embraced NERA's methods but argued that the X factor should, contrary to NERA's recommendation, be based on results for a more recent sample period, when *PMF* was declining.

Now, NERA used a constant average service life in its capital quantity calculations whereas the actual average service life of U.S. power distributors rose in the second half of the sample period and materially exceeded the NERA assumption. While Brattle and Christensen defended one hoss shay using the constant service flow argument, PEG as witness for an Alberta consumer group argued that their finding of negative productivity growth was due in part to an average service life assumption that was inappropriate for the truncated sample period they advocated. With a more realistic service life assumption, PEG found that *PMF* growth was considerably higher, and similar to that produced using geometric decay.

With one hoss shay as the new *cri de guerre* of utility productivity witnesses, London Economics International ("LEI" another one hoss shay proponent) and Christensen Associates won contracts to provide productivity research and testimony for Massachusetts energy distributors and used one hoss shay capital cost specifications. Due in part to data limitations, the average service lives that they used in two studies for gas distributors were appropriate for their sample periods rather than too low. Both studies found *positive PMF* growth trends for the full U.S. sample. [65]

- For various reasons, one hoss shay studies sometimes produce negative capital quantities. In the second generic *MRI* proceeding in Alberta, for instance, Christensen reported in response to an information request that if they raised the average service life to a level more similar to that actually reported by utilities during their chosen sample period it produced negative capital quantities for some utilities. Christensen and LEI encountered the same problem when they tried to use Handy Whitman gas utility construction cost indexes as asset price deflators in their recent Massachusetts studies. Both consultants instead used a producer price index to deflate asset values.

[65] Both witnesses argued in Massachusetts that the X factors for their gas distribution clients should be based on the *PMF* trends of the subset of sampled distributors serving northeastern states, where *PMF* growth was slower. In Alberta, where a regional sample produced more *rapid* productivity growth, Christensen Associates (and Brattle) favored a U.S. sample.

Geometric Decay Pros and Cons

Geometric Decay Advantages

- Geometric decay takes some account of the depreciation and decline in capital quantities that result over time from a cohort of diverse assets.
- In an X factor study, geometric decay is therefore more sensitive to any capex cycle that an industry might display. It is also more sensitive to system age in a benchmarking study. A remarkable effort by a utility to extend asset life can be recognized.
- The price and quantity formulas are simple and intuitively appealing.
- Calculation of retirement quantities is not required.
- Results are less sensitive to the average service life assumption.

Geometric Decay Disadvantages

- The assumption of constant decay means that initial decay is considerably greater than that which actually occurs. Some have argued that one hoss shay is a closer approximation to actual service flows than geometric decay even if it is imperfect.
- Some practitioners seek TFP trends that are relatively insensitive to capex surges.

Popularity of Alternative Capital Cost Specifications

Here is some evidence on the popularity of alternative capital cost specifications in productivity research.

- The U.S. Bureau of Labor Statistics, Australian Bureau of Statistics, and Statistics New Zealand use hyperbolic decay in their *PMF* studies of the economy and important sectors thereof.[66] Statistics Canada uses geometric decay in such studies.

[66] See for example, Bureau of Labor Statistics, Multifactor Productivity, *Technical Information About the BLS Multifactor Productivity Measures,* at 3 (September 26, 2007).

- Table 1 reports capital cost specifications used in North American energy utility productivity studies. It shows that geometric decay was by far the most common method used in these studies. In Ontario, for example, geometric decay is routinely used today in most productivity and benchmarking studies that are filed by OEB staff and utility witnesses. PEG's 2017 study of power distributor productivity for Lawrence Berkeley National Laboratory also used geometric decay.[67]

  It is also notable that Christensen Associates used geometric decay in virtually all of their numerous studies of telecommunications and cable television productivity, as well as in energy distribution productivity studies that they prepared before their Alberta and Massachusetts engagements. Concentric Energy Advisors used the Kahn method in testimony for HQT and geometric decay in a gas utility productivity study for Enbridge Gas Distribution in Ontario.[68] Table 1 also shows that the cost of service and Kahn methods have both been used more frequently than one hoss shay. However, there has been an uptick in recent years in (utility-funded) studies using one hoss shay. In addition to the two Massachusetts *gas* distributor studies noted above, there have been two Massachusetts *power* distributor studies. Furthermore, the Massachusetts Department of Public Utilities ("DPU") has embraced the one hoss shay specification explicitly. PEG used one hoss shay in its recent Massachusetts gas distributor productivity study due in part to the DPU's stance and in part due to budgetary limitations.

Conclusions

The cost-of-service capital cost specification has many advantages in X factor studies. However, the math is complicated, and the assumption of historical plant valuations is not ideal for a benchmarking study. Hyperbolic decay may make the most sense for benchmarking, but its use in utility applications has not been funded. Geometric decay is a serviceable alternative for both X factor research and benchmarking, especially in Canada where inflation differentials are not a major issue.

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[67] Mark N. Lowry, Jeff Deason, and Matt Makos (2017), *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, LAWRENCE BERKELEY NATIONAL LABORATORY, at B. 19-20 (July 2017).

[68] James Coyne, James Simpson, and Melissa Bartos, *Incentive Ratemaking Report* (prepared for Enbridge Gas Distribution), OEB Proceeding EB-2012-0459, Exh. A2, Tab 9, Sch. 1, p. B-11 (June 28, 2013).

Table 1

Capital Cost Specifications Used in North American Energy Utility Productivity Evidence[69]

Power Industry Studies

Year	Jurisdiction	Author	Client	Industry Studied	Capital Cost Specification
1994	Maine	PEG personnel[1]	Utility	Northeast Bundled Power Service	Geometric Decay
1995	New York	PEG personnel[1]	Utility	US Bundled Power Service	Geometric Decay
1998	California	PEG personnel[1]	Utility	US Power Distributors	Geometric Decay
1999	Hawaii	PEG	Utility	US Bundled Power Service	Geometric Decay
1999	Maine	NERA	Utility	Northeast Power Distributors	One Hoss Shay
2000	Alberta	NERA	Utility	Western Power Distributors	One Hoss Shay
2001	Maine	PEG	Utility	Northeast Power Distributors	Geometric Decay
2002	California	PEG	Utility	US Power Distributors	Geometric Decay
2004	California	PEG	Utility	US Power Distributors	Geometric Decay
2005	Massachusetts	PEG	Utility	Northeast Power Distributors	Geometric Decay
2006	California	PEG	Utility	US Power Distributors	Geometric Decay
2006	Kansas	Christensen Associates	Utility	US Power Distributors	Geometric Decay
2006	Kansas	Christensen Associates	Utility	US Bundled Power Service	Geometric Decay
2006	Kansas	Christensen Associates	Utility	US Power Generation	Geometric Decay
2006	Kansas	Christensen Associates	Utility	US Power Transmission	Geometric Decay
2007	Maine	PEG	Utility	Northeast Power Distributors	Cost of Service
2008	Maine	Christensen Associates	Regulator	Northeast Power Distributors	Geometric Decay
2008	Vermont	PEG	Utility	US Power Distributors	Cost of Service
2008	Ontario	PEG	Commission	Ontario Power Distributors	Cost of Service
2008	Ontario	LEI	Utility	Ontario Power Distributors	One Hoss Shay (Physical Asset)
2010	California	PEG	Utility	US Power Distributors	Geometric Decay
2010	Alberta	NERA	Commission	US Power Distributors	One Hoss Shay
2011	District of Columbia	PEG	Utility	Northeast Power Distributors	Cost of Service
2011	Maryland	PEG	Utility	Northeast Power Distributors	Cost of Service
2011	Maryland	PEG	Utility	Northeast Power Distributors	Cost of Service
2011	New Jersey	PEG	Utility	Northeast Power Distributors	Cost of Service
2011	Alberta	LEI	Utility	Ontario Power Distributors	One Hoss Shay (Physical Asset)
2012	Delaware	PEG	Utility	Northeast Power Distributors	Cost of Service
2013	British Columbia	Black & Veatch	Utility	US Power Distributors	Kahn Variant
2013	British Columbia	PEG	Consumer Advocate	US Power Distributors	Cost of Service
2013	Massachusetts	PEG	Utility	Northeast Power Distributors	Cost of Service
2013	Massachusetts	Acadian Consulting	Consumer Advocate	Northeast Power Distributors	Cost of Service
2013	Maine	PEG	CMP	Northeast Power Distributors	Cost of Service
2013	Ontario	PEG	Regulator	Ontario Power Distributors	Geometric Decay
2015	Alberta	Brattle Group	Utility	US Power Distributors	One Hoss Shay
2015	Alberta	PEG	Consumer Advocate	US Power Distributors	Geometric Decay
2015	Alberta	Christensen Associates	Utility	US Power Distributors	One Hoss Shay
2016	Ontario	LEI	Utility	US Hydro-electric Generation	One Hoss Shay (Physical Asset)
2016	Ontario	PEG	Regulator	US Hydro-electric Generation	Geometric Decay
2017	Massachusetts	Christensen Associates	Utility	US Power Distributors	One Hoss Shay
2018	Massachusetts	Acadian Consulting	Consumer Advocate	US Power Distributors	Geometric Decay
2017	US	PEG	Government	US Power Distributors	Geometric Decay
2017	Ontario	NERA	Utility	US Power Distribution	One Hoss Shay
2018	Massachusetts	Christensen Associates	Utility	US Power Distributors	One Hoss Shay
2019	Massachusetts	PEG	Attorney General	US Power Distributors	Geometric Decay and Kahn Variant
2018	Ontario	Power Systems Engineering	Utility	US Power Transmitters	Geometric Decay
2019	Ontario	PEG	Regulator	US Power Transmitters	Geometric Decay
2019	Ontario	Power Systems Engineering	Utility	US Power Transmitters	Geometric Decay
2019	Ontario	PEG	Regulator	US Power Transmitters	Geometric Decay
2019	Hawaii	PEG	Utility	US Bundled Power Service	Kahn Variant
2020	Hawaii	Binz	Environmentalist	US Bundled Power Service	Kahn Variant

[69] As filed in Massachusetts D.P.U. 19-120, Exhibit AG-MNL-Surrebuttal, filed May 8, 2020, p. 9.

Table 1 (continued)

Capital Cost Specifications Used in North American Energy Utility Productivity Evidence

Gas Industry Studies

Year	Jurisdiction	Author	Client	Industry Studied	Capital Cost Specification
1995	California	PEG personnel[1]	Utility	US Gas Utilities	Geometric Decay
1996	Massachusetts	PEG personnel[1]	Utility	US Gas Utilities	Geometric Decay
1997	British Columbia	PEG personnel[1]	Utility	US Gas Utilities	Geometric Decay
1997	Georgia	PEG personnel[1]	Utility	US Gas Utilities	Geometric Decay
1998	California	PEG personnel[1]	Utility	US Gas Utilities	Geometric Decay
1999	Ontario	Christensen Associates	Utility	Company-specific	Geometric Decay
2002	California	PEG	Utility	US Gas Utilities	Geometric Decay
2003	Massachusetts	PEG	Utility	Northeast Gas Distributors	Geometric Decay
2004	California	PEG	Utility	US Gas Utilities	Geometric Decay
2006	California	PEG	Utility	US Gas Utilities	Geometric Decay
2007	Ontario	PEG	Regulator	US Gas Utilities	Cost of Service & Geometric Decay
2010	California	PEG	Utility	US Gas Utilities	Geometric Decay
2011	Quebec	PEG	Utility and Consumer Adv	US Gas Utilities	Cost of Service
2011	Ontario	PEG	Regulator	Gas Utilities	Cost of Service
2012	Quebec	PEG	Utility	US Gas Utilities	Cost of Service
2013	British Columbia	PEG	Consumer Advocate	US Gas Utilities	Cost of Service
2013	British Columbia	Black & Veatch	Utility	US Gas Utilities	Kahn Variant
2013	Ontario	Concentric Energy Advisors	Utility	US Gas Utilities	Geometric Decay
2018	Ontario	PEG	Regulator	US Gas Utilities	Geometric Decay
2019	Massachusetts	LEI	Utility	US Gas Distributors	One Hoss Shay
2020	Massachusetts	PEG	Attorney General	US Gas Distributors	One Hoss Shay

Oil Pipeline Industry Studies

Year	Jurisdiction	Author	Client	Industry Studied	Capital Cost Specification
1993	US	Klick	Utility	US Oil Pipelines	Kahn
1993	US	NERA	Consumers	US Oil Pipelines	Kahn
2000	US	FERC Staff	Regulator	US Oil Pipelines	Kahn
2000	US	NERA	Utility	US Oil Pipelines	Kahn
2000	US	Shippers	Consumers	US Oil Pipelines	Kahn
2005	US	Innovation and Information	Consumers	US Oil Pipelines	Kahn
2005	US	NERA	Utility	US Oil Pipelines	Kahn
2010	US	NERA	Utility	US Oil Pipelines	Kahn
2010	US	Brattle	Consumers	US Oil Pipelines	Kahn
2015	US	FERC Staff	Regulator	US Oil Pipelines	Kahn
2015	US	NERA	Utility	US Oil Pipelines	Kahn
2015	US	Brattle	Consumers	US Oil Pipelines	Kahn

[1] Economists now affiliated with PEG prepared these studies when they worked for Christensen Associates.

4. Developing a Research Plan

Having established a foundation for understanding key methodological issues in X factor and benchmarking research, we discuss in this section how we developed a research plan for this project. We begin by discussing the power transmission productivity and benchmarking studies submitted in two recent Ontario Energy Board proceedings. These studies are especially germane because they were undertaken recently, in the jurisdiction of an experienced *MRI* practitioner, to determine the base productivity trend and stretch factors for power transmitters. We then explain our proposal to upgrade this research and how our research plan evolved in response to Régie commentary and HQT's responses to information requests.

4.1. The Hydro One Proceedings

The first of these proceedings (EB-2018-0218) considered an *MRI* for Hydro One Sault Ste. Marie, a small transmission subsidiary of Toronto-based Hydro One Networks which serves a region on the eastern shore of Lake Superior. The second proceeding (EB-2019-0082) concerned an *MRI* for Hydro One's main transmission business. In both proceedings, Hydro One proposed a revenue cap index that would apply to capital cost as well as *CNE*. However, a C factor term in the formula would correct for any difference between forecasted capital cost and the capital revenue that would otherwise be provided by the revenue cap index. Hydro One proposed a 0% base productivity trend and stretch factor and no growth factor.[70]

To support these proposals, Hydro One presented in evidence an econometric total transmission cost benchmarking study and calculations of transmission productivity trends of Hydro One and a large sample of U.S. electric utilities.[71] Both studies were prepared by Power Systems Engineering ("PSE"), a

[70] In June 2019, the Board in Decision and Order EB-2018-0218 chose a 0% productivity factor and a 0.3% stretch factor for Hydro One Sault Ste. Marie. In April 2020, the Board in Decision and Order EB-2019-0082 chose a 0% base productivity trend and a 0.3% stretch factor for transmission services of Hydro One Networks.

[71] Power Systems Engineering, *Transmission Study for Hydro One Networks: Recommended CIR Parameters and Productivity Comparisons*, 24 January 2019, filed as Exhibit A-4-1 Attachment 1 in EB-2019-0082 and Power Systems Engineering, *Transmission Study for Hydro One Networks: Recommended CIR Parameters and Productivity Comparisons*, 23 May, 2018, filed as Exhibit D-1-1 Attachment 1 in EB-2018-0218.

consulting firm based in Madison, Wisconsin.[72] Board staff retained PEG to appraise PSE's work and prepare independent transmission productivity and benchmarking studies.[73]

Several aspects of these studies merit note.

- Both consultants developed econometric cost models and used them to benchmark Hydro One's historical cost over the 2004-2016 period and its forecasted cost over the 2017-2022 period.
- Both consultants also used multidimensional output indexes in their productivity calculations. These indexes featured two scale variables: transmission line km and ratcheted peak demand. Each consultant used weights for these subindexes which were drawn from their econometric cost research. Econometric cost research thus played a dual role in the Ontario studies.
- PSE used data from 48 utilities (47 U.S. utilities plus Hydro One) in its productivity study and from 57 utilities (56 U.S. utilities plus Hydro One) in its econometric cost benchmarking study.[74] The sizes of these samples were reduced by miscellaneous data problems that included mergers and acquisitions, spinoffs of transmission operations, and the non-availability of some transmission system and output data.
- The companies in PEG's samples were similar to those in PSE's samples because PEG, with a limited budget, wished to use some of the business condition variables that PSE had developed for its econometric model. These variables included indexes of the relative price levels of labor and capital in the service territories of sampled utilities.[75] These price level indexes were for a more recent year than those that PEG had previously calculated, and values had been calculated

[72] The principal investigator of PSE's studies for Hydro One was a former employee of PEG.

[73] Mark Newton Lowry, *Incentive Regulation for Hydro One Transmission*, EB-2019-0082 Exhibit M1, September 2019 p. 36.

[74] The econometric sample was larger because a "balanced" panel (i.e., a sample with the same number of observations for each company) is not required.

[75] Due to the substantial work involved in calculating price level indexes for use in econometric cost studies, they are typically calculated only occasionally for X factor and benchmarking studies. Input prices in other years are obtained by trending these index levels.

for Hydro One as well as the sampled U.S. utilities.[76] PSE had also developed a construction standards index that measures how the minimum requirements for the strength of transmission structures varies with weather in various geographic regions.

- The sample period for PSE's productivity and benchmarking studies was 2004 to 2016. PEG instead used the twenty-one-year period from 1996 to 2016. Productivity results proved to be quite sensitive to the choice of the sample period. For example, PEG reported that *PMF* tended to rise briskly from 1996 to 2006 but to fall briskly from 2008 to 2016. *PMF* averaged a -1.02% average annual decline over the last 15 years of PEG's sample period (2002-2016). Over its full 21-year sample period, PEG found that *PMF* growth averaged only a 0.25% annual decline.
- An informal review identified several possible reasons for the recent decline in U.S. transmission *PMF* growth. These included 1) higher capex in order to access remote renewable resources, increase capacity to serve growing economies (e.g., in the sunbelt states), eliminate load "pockets" in bulk power markets, and replace aging facilities 2) new service quality standards, 3) the Energy Policy Act of 2005 which, as noted in Section 2.2, authorized the FERC to provide special incentives for transmission capex, and 4) increased use by the FERC of formula rate plans for power transmission, which weakened utility cost containment incentives.
- Controversy emerged over the appropriate sample period for establishing the base *PMF* trend. Hydro One's consultant proposed to use the thirteen-year 2004-2016 period when *PMF* averaged a -1.45% decline. PSE reported a -0.18% *PMF* trend for Hydro One over this same period.
- Another area of controversy was whether the *PMF* trend of the industry was pertinent for setting X considering that the Company was asking for supplemental capital revenue.
- A third area of controversy was the appropriate econometric method for estimating cost model parameters.
- Both consultants employed geometric decay capital cost specifications in their studies.

[76] PSE had calculated a labor price level index for the year 2010 and a capital price level index for the year 2011. PEG at that time had labor and capital price level indexes for 2008. All of these indexes are now quite dated.

- PSE purchased rights to most of the transmission operating data that it used in these studies from SNL Financial, a commercial vendor that is a unit of S&P Global Market Intelligence. Subscriptions to SNL data are costly and must typically be renewed annually. PEG used data that it had gathered from the FERC and other publicly-available sources.

4.2. Implications for this Proceeding

The recent Ontario studies illuminate the path forward for the transmission productivity and benchmarking studies in this proceeding. It is clearly feasible to undertake productivity and econometric total cost benchmarking studies for power transmission utilities which are like the studies used in other North American *MRI* proceedings. Data on transmission operations are available for a sizable sample of U.S. electric utilities and also for Hydro One Networks, a sensible Canadian peer for HQT.

However, these studies are now dated. Moreover, PSE had no prior experience preparing transmission productivity and benchmarking studies, and the budgets provided by the Ontario Energy Board for PEG's studies were limited.[77] The Ontario studies can thus be updated and upgraded to increase their quality and relevance to the situation of HQT.

- The biggest single task is to benchmark the cost of HQT. Benchmarking HQT's cost using data from U.S. utilities (and possibly also Hydro One) is quite challenging for reasons that include different approaches to cost accounting and the need to compare U.S. and Québec input prices.
- Another large task is to develop cost benchmarking models for *CNE* and capital cost.
- U.S. transmission operating data are now available for three additional years (2017-2019). Adding these data to the sample is desirable to sharpen our understanding of recent trends and to make econometric model parameter estimates more precise and appropriate for current conditions.
- There is more to learn about the causes of recent transmission productivity declines. This is important given the sensitivity of transmission productivity trends to the sample period. HQT

[77] At Board staff's request, PEG devoted a lot of its effort in the second Hydro One transmission *MRI* proceeding to considering alternative mechanisms for providing extra capital revenue. Upgrades to the empirical studies were discouraged.

may not be experiencing cost pressures or cost containment incentives like those that U.S. transmission utilities experienced in the last 10-15 years. Ideally, we would like to know the productivity growth that should be expected of transmitters facing cost pressures like those that HQT is expected to face in the near future. Econometric research can quantify the relative importance of various productivity growth drivers, and the results can be used to fashion custom productivity growth benchmarks for HQT.

- The productivity and econometric benchmarking methods can be upgraded in various ways. For example, new business condition variables merit consideration in the econometric cost benchmarking model.
- The productivity and benchmarking methods that we used in Ontario have to be revised to reflect certain limitations of HQT's data.
- Since PEG's current labor and capital price level indexes are for 2008, it would be desirable to calculate new labor and capital price level indexes that reflect more recent (e.g., 2019) prices in Québec and the various service territories of the sampled U.S. companies.
- PEG uses its own FERC Form 1 data. We must therefore incur the cost of adding three years of data but need not purchase costly data from a commercial vendor such as SNL Financial. However, it is more efficient to purchase the right to use some business condition variables developed by PSE. PSE's construction standards index seems to be particularly pertinent in a study to benchmark HQT, which operates under severe winter weather conditions. PSE has also developed a useful forestation variable.
- HQT indicated in response to information request 5.3 of B-0265 (HQT-16, Document 1) that the Brattle Group was considering the use of a one hoss shay capital cost specification in its studies. Because one hoss shay has been used less often than other specifications in X factor studies, some issues concerning the usefulness and proper use of one hoss shay in X factor and benchmarking studies are unresolved and merit additional reflection. To obtain consultation on some of these issues, PEG retained the services of Dr. Jean-Paul Chavas, a distinguished microeconomist and chaired professor in the Department of Agricultural and Applied Economics at the University of Wisconsin.

- *CNE* and capital cost performance and productivity trends are issues in this proceeding as well as total cost performance and *PMF* trends. Calculations of *CNE* productivity merit close attention since these may be used to revise the X factor in HQT's current *MRI*. The *CNE* and capital cost of HQT should be benchmarked, as well as its total cost.[78]
- It is possible to expand the sample to include more companies which face business conditions similar to HQT's.
- Use of the alternative hyperbolic decay capital cost specification warrants consideration.
- There is no guarantee that Brattle will prepare an econometric total cost benchmarking study like those that regulators in Ontario and Massachusetts consider in choosing stretch factors.

4.3. Project Proposal and the Régie's Response

On 9 October 2020, the Régie sent AQCIE-CIFQ a request for an estimate of the cost of PEG's research. To afford the Régie some say in the direction of the research and reduce the risk of cost underrecovery, PEG submitted a detailed project proposal as well as a budget estimate. This proposal had the following core objectives.

1. Update the U.S. sample that PEG used in its recent Ontario transmission *MRI* proceedings to include 2017-2019 data.
2. Calculate 2019 labor and capital price level indexes.
3. Consider new business condition variables for the benchmarking study.
4. Use the upgraded and updated data set to develop econometric models of transmission *CNE*, capital cost, and total cost.
5. Calculate the *CNE*, capital, and multifactor transmission productivity trends of U.S. utilities in the Ontario sample.
6. Even though PEG uses code to calculate costs and productivity trends, another objective was to prepare working papers that include such calculations in Microsoft Excel spreadsheets.

[78] These costs were not separately benchmarked by either consultant in the Ontario studies.

7. Examine drivers of U.S. transmission productivity growth more closely and use these findings to consider 1) the appropriate sample period for choosing HQT's X factor and 2) the appropriate stretch factor.
8. Consider alternatives to the scale escalator in HQT's current *formule d'indexation* for *CNE* revenue and appropriate escalators for future formulas which can apply to capital as well as *CNE* revenue.
9. Process HQT data and use the econometric models to benchmark the *CNE*, capital, and total cost of HQT in recent years.
10. Since the Régie has little experience with studies of this kind, we proposed to include in the report a thoughtful discussion of appropriate methods for X factor and benchmarking studies, including the pros and cons of alternative capital cost specifications.
11. With the help of Dr. Chavas, consider some unresolved issues concerning the appropriateness and proper use of the one hoss shay specification.
12. Perform any tasks requested by the Régie in any later stages of the proceeding.[79] The additional tasks in these stages could include participation in a technical conference, preparation of information requests to Brattle and responses to theirs, and oral testimony.

In addition to these core tasks, PEG proposed some optional tasks for the Régie's consideration.

1. Add data for Hydro One transmission to the sample. This is also a sizable task because we cannot use the Hydro One data from the Ontario proceedings, which were obtained pursuant to a confidentiality agreement, and would have to gather these data from scratch.
2. Expand the sample from PEG's Ontario study to include some additional U.S. power transmitters that face business conditions that are similar to HQT's (e.g., Central Maine Power).
3. Develop a hyperbolic decay capital cost specification and use it to recalculate benchmarking (and possibly also productivity) results.

AQCIE-CIFQ transmitted PEG's research and cost proposal to the Régie on 30 October 2020. In its response to the proposal on 4 December, the Régie declined to approve a specific budget for the

[79] Subsequent stages have not as yet been announced.

work or to comment on the appropriate scope of the PEG study. The Régie's *Guide de Paiement de Frais* was cited as a reference for acceptable hourly rates. In light of the Régie's response, PEG is exposed to material financial risk in undertaking this multitask empirical study, which took several staff members several months to prepare.

4.4. Information Requests to HQT

PEG submitted four tranches of information requests (*demandes de renseignements* or *DDRs*) to HQT, including several follow-up questions. The correspondence was cordial, and the responses to our questions were generally fulsome. Some of the *DDR* responses influenced our research plan.

- Even though HQT has adopted a *modèle de gestion d'actifs*, it did not provide detailed data on the age of its system which could be used in cost benchmarking or the development of custom productivity growth benchmarks.[80]
- HQT's responses indicated that its retirements data are unsuitable for the use of a one hoss shay capital cost specification when benchmarking the company.[81][82]
- HQT's inability to provide an estimate of its dispatching expenses that is consistent with FERC Form 1 prompted us to spend a great deal of time considering possible fixes.

4.5. Revised Research Plan

We accordingly decided to trim certain tasks from the research plan we presented to the Régie. Here are some examples.

- A hyperbolic decay capital cost specification was not developed.
- Hydro One Networks was not included in the sample.
- No econometric productivity growth benchmarks were developed.
- No new work was done to determine the drivers of recent negative productivity growth in the transmission industry.

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[80] See, for example, B-0268 (HQT-16, Document 2), Response 5.1.

[81] See, for example, B-0265 (HQT-16, Document 1), Response 5.3 and B-0268 (HQT-16, Document 2), Response 8.1.

[82] One hoss shay could still be used in the productivity research.

- The hours for the work of Dr. Chavas were scaled back.
- Ironically, the heightened uncertainty about cost recovery prompted us to spend *more* time preparing questions for HQT in order to increase the relevance of our study to its situation.

4.6. Research Challenges

PEG has found power transmission benchmarking and productivity studies to be particularly difficult due to industry change, idiosyncratic data, and the limited number of prior studies in the public domain. Benchmarking the cost performance of HQT, with its different cost accounting, posed additional complications. Under these circumstances, PEG appreciates the Régie's deadline extensions. While HQT provided reasonable responses to information requests the process was cumbersome. New information may arise in later stages of this proceeding which prompts us to revise our benchmarking results.

5. Empirical Research

5.1. U.S. vs. Canadian Transmission Data

U.S. Data

Power transmission in the United States is performed chiefly by investor-owned utilities.[83] Most of these companies also distribute power, and many generate power. Transmission services of other utilities are often used, especially by utilities still engaged in generation. The division between generation, transmission, and distribution systems varies somewhat across the industry. Utilities typically count the substations associated with power plants that they own as transmission facilities. They frequently do not own substations associated with independently-owned power plants.

Advantages

U.S. data have material advantages in transmission cost and productivity research.

- The U.S. government has gathered detailed, standardized data for decades on the operations of dozens of major investor-owned utilities that transmit power. The primary source of these data is FERC Form 1. Most costs attributable to transmission are itemized on this form. The transmission services provided by these utilities are similar to those that HQT provides. FERC Form 1 data are also available on important characteristics of transmission networks (e.g., the length of transmission lines and the capacity of substations).
- Transmission costs are further itemized, and this permits some useful customization of cost studies. For example, the cost of using transmission systems of other utilities is itemized for easy removal.
- PEG has gathered data, from FERC Form 1 and antecedent forms, on the net value of transmission plant (and other kinds of plant) in 1964 and the corresponding gross plant additions since that year. This increases the accuracy of using monetary methods to measure capital costs and quantities.

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[83] Some federal utilities and rural electric cooperatives also provide power transmission services in the States. A notable example is the Bonneville Power Administration.

- Regional Handy Whitman indexes are available on trends in the costs of transmission plant construction.

These advantages make U.S. data the best in the world for calculation of the costs and price and quantity indexes that are needed to calculate transmission *CNE*, capital, and multifactor productivity trends and to develop econometric benchmarking models for *CNE*, capital cost, and total transmission cost.

Disadvantages

There are also some notable disadvantages to using U.S. data in transmission cost and productivity research.

ISO Complications We noted in Section 2.2 above that, between 1996 and 2005, many U.S. utilities (mostly located in California, Texas, other south-central, north-central, and northeastern states) became (and have generally remained) ISO members while others (mostly located in northwest, mountain-west, and southeastern states) have not.[84] These organizations perform certain activities (e.g., dispatching) which were previously performed by their members. Members permit the organization to use some of their assets and may also provide it with operation and maintenance services. Members also purchase their transmission services from the organization. The organization bills members for its own costs (e.g., costs incurred for dispatching) and for costs of services it purchases from transmission owners.

This restructuring of the transmission industry in certain regions complicates statistical cost research using U.S. data. For example, the costs that utilities incurred for services that they previously provided (e.g., dispatching) could decline after they joined because these activities were now performed by the organization, and these costs could be lower than those of transmitters that were not ISO members. ISO members may, on the other hand, face new cost pressures. For example, tasks that the organization takes over may become more difficult, organizations may perform new tasks (e.g., market monitoring), and members may be charged for these new and expanded tasks. ISO members may also be encouraged by their ISOs to incur higher costs on certain tasks (e.g., maintenance). Costs may then grow more rapidly for members and exceed those of transmitters who are not members.

[84] We will use the term ISOs to encompass regional transmission organizations as well.

Restructuring has also caused members to report some costs differently than they did in the past. For example, costs of capital (e.g., computer hardware and software, communications equipment, and structures) which ISOs incur in system operation and bill to utilities will be recorded by the utilities as *CNE,* whereas utilities treat costs for these kinds of capital as capital costs when they are the owners. Many vertically-integrated utilities have in the last two decades increased their reliance on unbundled transmission services to obtain power supplies. Changes in how these costs were reported can affect research results.

FERC Order 668 in December 2005 changed reporting guidelines for transmission costs. Here are some examples.

- New accounts have been established for (the gross value of) Regional Transmission and Market Operation Plant. The new categories include computer hardware (382), computer software (383), communications equipment (384), and miscellaneous plant (385). Accounts 569.1-569.4 were established, under transmission load dispatching, for maintenance of these same assets. These accounts were intended chiefly for use by ISOs but some utilities may have elected to start reporting costs in these same accounts.
- Accounts 575 and 576 were established for regional market *CNE*. [85]
- Transmission dispatching expenses (in Account 560) were itemized, and three subaccounts were established to report utility payments for costs that ISOs bill to them:
    - 561.4 Scheduling, System Control, and Dispatching;
    - 561.8 Reliability Planning and Standards Development; and
    - 575.7 Market Facilitation, Monitoring and Compliance.

Data problems posed by transmission sector restructuring could be mitigated if reported transmission costs were appropriately itemized and utilities reported these costs consistently. However, data problems have been observed.

- The new data guidelines occasioned by FERC Order 668 did not occur until many California, Midwestern, New York, and New England utilities had been ISO members for several years.

[85] These costs are generally small.

This has produced some shifts in where ISO costs are reported. As one example, a utility might have initially reported certain ISO costs as transmission by others expenses (which are excluded from our calculations) and then reported them as dispatching expenses.

- Utilities seem to have reported ISO costs incurred *before* FERC Order 668 inconsistently, with some reporting them as transmission by others expenses and others reporting them as miscellaneous transmission expenses.
- ISO members do not seem to have reported their ISO costs consistently since the implementation of FERC Order 668. For example, while many members have consistently reported sizable costs for ISO services in accounts like 561.8, as directed by Order 668, many have not.[86] This may be due in part to varied ISO policies and the peculiarities of formula rate plans.
- Some utilities seem to have reported, as miscellaneous transmission or dispatching expenses, sizable costs that other utilities report as transmission by others expenses.
- Whether or not utilities are ISO members, they have some discretion as to whether to report dispatch expenses in FERC Account 561 (Load Dispatching) under Transmission Expenses or FERC Account 556 (System Control and Load Dispatching) under Other Power Supply Expenses.

Since power transmission is a highly capital-intensive business, these data problems occasioned by restructuring of the sector might not matter greatly if the focus of X factor and benchmarking work is *total* transmission cost. However, *CNE* is a particular focus of this proceeding due to the design of the transmission *MRI.*

Other Problems Here are some other problems with U.S. transmission data.

- Peak demand data are idiosyncratic, as discussed further below.
- It is difficult to adjust capital cost calculations for sales and spinoffs of *postes de départ* that resulted from the restructuring of power markets.

[86] Most of the companies in our sample that did not are members of PJM or the New York ISO.

- FERC Form 1 does not itemize some costs by U.S. electric utilities between their production, transmission, distribution, and customer services. The values of transmission-related computer hardware, telecommunications equipment, and structures typically are included in general plant, and the value of computer software is in intangible plant.
- Since most U.S. investor-owned utilities, like Hydro-Québec, are engaged in other electric services, they incur certain general costs that are difficult to accurately allocate between these services.

Canadian Data

Power transmission in Canada is performed chiefly by Crown corporations that provide most or all transmission services in an entire province. Like Hydro-Québec, many of these utilities also have extensive generation and distribution operations.

Advantages

Canadian transmission cost data have the major advantage of being denominated in Canadian dollars. The challenging task of comparing U.S. and Canadian input price levels accurately can therefore be sidestepped. Transmitters in other provinces, like their U.S. counterparts, appear to play a role similar to that of HQT.

Disadvantages

Data on transmission operations of utilities in the various provinces of Canada are not standardized, one reason being that rate regulation occurs at the provincial level. The many years of consistent data needed for monetary capital cost specifications are available in just a few provinces (e.g., Ontario), and even in these provinces are generally not available before 2000. In its Ontario study for Hydro One, PSE invited nine transmission utilities in other provinces to participate but none did so.

Resolution

Given the many advantages of U.S. transmission data, the problems with Canadian data, and the budget uncertainties in this project, we decided to base our productivity and econometric cost research solely on U.S. data. PSE took the same approach in its studies for Hydro One Networks.

5.2. Data Sources Used in This Study

FERC Form 1 was the source of data on transmission costs, network characteristics, and peak demand of U.S. electric utilities which we used in our research. Data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Selected Form 1 data were for many years published by the U.S. Energy Information Administration ("EIA").[87] More recently, these data have been available electronically in raw form from the FERC and in more processed forms from commercial vendors such as SNL Financial.

Data on U.S. salary and wage prices were obtained from the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor. The gross domestic product price index ("GDPPI") that we used to deflate material and service ("M&S") expenses of U.S. transmitters was calculated by the Bureau of Economic Analysis of the U.S. Department of Commerce. Data on the *levels* of heavy construction costs in various U.S., and Québec locations were obtained from RSMeans. Data on U.S. electric utility construction cost *trends* were drawn from the *Handy Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates. Two of the business condition variables we used in our econometric cost research were obtained from PSE.

5.3. Sample

Data for 51 U.S. power transmitters were used in our productivity trend research. Data for 46 U.S. transmitters were used in our econometric research. A larger sample is possible for the productivity research because data are not required for all of the business condition variables. Table 2 lists the sampled utilities.

Various problems limited the size of the sample. Some utilities were involved in mergers or acquisitions, and some sold or spun off transmission assets that came to be owned by "transcos." These transactions complicate monetary capital cost and quantity calculations. Some had missing or implausible data (e.g., unusual ways to report ISO costs.)

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[87] This publication series had several titles over the years. The most recent title is *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*.

Table 2

Utilities Sampled in PEG's Studies

Alabama Power	*Kansas Gas and Electric*
ALLETE (Minnesota Power)	Kentucky Utilities
Arizona Public Service	Louisville Gas and Electric
Atlantic City Electric	Mississippi Power
Avista	Monongahela Power
Baltimore Gas and Electric	New York State Electric & Gas
Central Hudson Gas & Electric	Niagara Mohawk Power
Cleco Power	Northern States Power - MN
Commonwealth Edison	Oklahoma Gas and Electric
Connecticut Light and Power	Orange and Rockland Utilities
Consolidated Edison of New York	PacifiCorp
Delmarva Power & Light	*PECO Energy*
Duke Energy Carolinas	Potomac Electric Power
Duke Energy Florida	Public Service Company of Colorado
Duke Energy Indiana	Public Service Electric and Gas
Duke Energy Ohio	Rochester Gas and Electric
Duke Energy Progress	*San Diego Gas & Electric*
Duquesne Light	South Carolina Electric & Gas
El Paso Electric	*Southern California Edison*
Empire District Electric	Southern Indiana Gas and Electric
Florida Power & Light	Southwestern Public Service
Gulf Power	Tampa Electric
Idaho Power	Tucson Electric Power
Indianapolis Power & Light	Union Electric
Jersey Central Power & Light	West Penn Power
Kansas City Power & Light	

Notes:
Italicized companies are only included in the productivity research.

The sample period for our econometric cost research was 2004-2019 due to data limitations. Most notably, this was the first year for which data were available for our preferred peak demand variable in this research. The full sample period for our productivity research was 1996-2019.

5.4. Variables Used in the Empirical Research

Costs

The cost of power transmission considered in our productivity and econometric studies was the sum of applicable capital costs and *CNE*. We employed a monetary approach to capital cost, price, and quantity measurement which featured a geometric decay specification. Capital cost was the sum of depreciation expenses and a return on net plant value less capital gains.[88] Plant was valued in current dollars. In addition to costs of *transmission* plant ownership, we included a sensible share of the costs of *general* plant ownership. Taxes (and franchise fees) were excluded, and no provisions were made for tax-related accelerated depreciation.

CNE that we considered comprised applicable transmission *CNE* and a sensible share of applicable administrative and general *CNE.*[89] We excluded some categories of transmission *CNE* from our *productivity trend* calculations out of concern that 1) they were sensitive to the restructuring of the transmission industry and 2) this restructuring is of limited relevance to an *MRI* for HQT. The FERC Form 1 categories excluded on these grounds were Transmission of Electricity by Others (account 565), Load Dispatching (accounts 561.1-561.8), Miscellaneous Transmission Expenses (566), and Regional Market Expenses (accounts 575 and 576). Small differences in the cost exclusions that we made for the econometric benchmarking model are discussed in Section 5.7 below.

Administrative and general expenses that we considered included those for the following categories:

- administrative and general salaries and office supplies and expenses less administrative expenses transferred;
- outside services employed;
- property insurance;

[88] Further details of our capital cost calculations are provided in Appendix section A.1.

[89] We apportioned to transmission cost a share of each American utility's general costs equal to the share of included transmission *CNE* in its net *CNE*. Since general costs are tied to the management of labor, in calculating net *CNE* we excluded some *CNE* that are large relative to their labor cost component. Examples of these excluded expenses include those for energy, transmission by others, and uncollectible bills.

- injuries and damages;
- regulatory commission expenses;
- general advertising expenses;
- miscellaneous general expenses;
- rents; and
- general plant maintenance;

Pension and other benefit expenses were excluded from both studies, as they were from our recent Ontario transmission studies. One reason is that pension expenses can be sensitive to volatile external business conditions such as stock prices. Another is that such expenses receive Y factor treatment in the *MRI* of HQT. The health insurance obligations of U.S. and Canadian utilities can differ considerably. In Canada, an additional problem with including pension and benefit expenses is the lack of federal labor price indexes that correspond to them as well as to salaries and wages. Pension and benefit (e.g., health care) expenses are reported on a consolidated basis on FERC Form 1, so it is not possible to exclude pension expenses and include other benefit expenses. We also excluded from both studies reported costs that the U.S. utilities incurred for power production and procurement, power distribution, customer accounts, customer service and information, sales, and gas utility services.

Input Prices

The input price indexes used in our study were designed to compare the price *levels* of utilities at each point in time as well as the price *trends* over time. This capability was needed because these indexes were used in both the econometric cost research (where differences between utilities in the level of input prices in a given year matter) and the productivity index research (where they do not).

<u>*CNE*</u>

Labor For the year 2019 we calculated indexes of labor price levels for HQT and the sampled U.S. utilities. Occupational Employment Statistics ("OES") survey data from the U.S. Bureau of Labor Statistics were used to calculate wage rate indexes as weighted averages of comparisons of the hourly wage rates, for various job categories established in the occupational classification code, using cost share weights that correspond to the electric utility industry. These data were available for numerous metropolitan statistical areas, and we computed an average of the results for the areas in each service territory using population weights.

To calculate a comparable wage rate index value for HQT in 2019, we compared U.S. and Québec wage rates for pertinent job categories. These calculations used, in addition to U.S. Bureau of Labor Statistics data, data from Statistics Canada on hourly wage rates that were itemized by job category using the National Occupational Classification ("NOC").

For other years of the sample period, values of each company's wage rate index were calculated by adjusting these levels for changes in labor price trend indexes. For the U.S. utilities we used regionalized indexes of employment cost trends for the utilities sector of the economy. These indexes were constructed from BLS Employment Cost Indexes. For HQT, we calculated the wage rate trend using the average hourly earnings for Québec industry reported by Statistics Canada.

Materials and Services The prices that U.S. utilities pay for materials and services were assumed to be the same in a given year but to inflate over time at the rate of the U.S. gross domestic product price index. This is the U.S. government's featured index of inflation in prices of the economy's final goods and services. Final goods and services include consumer products, business equipment, and exports. For the material and service price inflation of HQT we used Statistics Canada's gross domestic product implicit price index for final domestic demand. This is preferable to the more comprehensive GDPIPI because the latter is quite sensitive to volatile prices of Canada's sizable commodity exports. Material and service prices in the U.S. and Canada were patched using U.S./Canadian purchasing power parities ("PPPs") for gross domestic product. PPPs summarize the relative prices of a wide range of products included in the gross domestic product.

The summary *CNE* price indexes used in our research featured subindexes for labor and materials and services.[90] Growth in each summary index was a weighted average of the growth of the two subindexes. In these calculations we used company-specific, time-varying cost-share weights that we calculated from FERC Form 1 and HQT data.

[90] The formulas for our input price indexes are discussed further in Appendix A.1.

Capital

A monetary approach to the calculation of capital cost was used in both the productivity and benchmarking research. As discussed in Section 3.4 above, this required us to construct capital (service) price indexes from asset price indexes and rates of return on capital. A multistep process was used in these calculations. We first calculated an index of construction cost levels which varied between the service territories of sampled utilities in 2019 in proportion to the relative cost of local construction as measured by total (material and installation) heavy construction cost indexes published by RSMeans.[91] Index values are available for multiple cities in the service territories of most sampled utilities. For these utilities, we computed a weighted average of these values using as weights the approximate populations of the pertinent cities.[92] For HQT, we used only the construction cost index value for Montréal (the highest reported for Québec) out of concern that RS Means reported no values for remote areas that HQT serves which might have higher construction costs.

To obtain asset price index values for other years, we trended the values for 2019 using asset price trend indexes. As asset price trend indexes for U.S. utilities we used the applicable regional Handy Whitman Indexes of Public Utility Construction Costs for Total Transmission Plant. As general plant asset price indexes for these utilities we used the applicable regional Handy Whitman Indexes of Public Utility Construction Costs for reinforced concrete building construction.

For HQT we developed an asset price trend index from the average annual growth rates of two indexes. One was the product of the Handy Whitman Indexes of Public Utility Construction Costs for Total Transmission Plant in the North Atlantic region and the PPP for gross domestic product. The other was Statistics Canada's implicit capital stock deflator for the utility sector of Québec. Statistics Canada includes in the utility sector power generation and distribution, gas distribution, and water and sewer utilities as well as power transmission. We assigned equal weights to the trends in these two indexes.

For the rates of return of U.S. utilities we calculated 50/50 averages of rates of return for debt and equity.[93] For debt we used the embedded average interest rate on long-term debt of a large group

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[91] *Heavy Construction Costs with RSMeans Data*, Gordian Publishers, 34th annual edition, 2020.

[92] When multiple utilities served a city, we counted only a portion of the population.

[93] This calculation was made solely for the purpose of measuring productivity trends and benchmarking cost performance and does not prescribe appropriate rate of return *levels* for utilities.

of electric utilities as calculated from FERC Form 1 data. For equity we used the average allowed ROE approved in electric utility rate cases as reported by the Edison Electric Institute.[94] For HQT, we employed the approved weighted average cost of capital that is reported in their *revenu requis* tables.

The construction of capital service prices from these components is discussed further in Appendix A.

Multifactor

The summary multifactor input price indexes that we used in the econometric cost research were constructed for each transmitter by combining the summary capital and *CNE* price indexes using company-specific, time-varying cost share weights.

Output Variables

Two output variables were used in our research: length of transmission line and ratcheted maximum peak demand. We ratcheted the peak load data by using in each year the highest value yet attained since the start of the sample period. This is a proxy for the expected maximum peak demand that we believe drives transmission cost.

U.S. line length data were drawn from the Transmission Line Statistics on page 422 of FERC Form 1. Two sources of peak demand data are available on FERC Form 1.

- **Monthly Transmission System Peak Load** (page 400) comprises firm network service, long-term firm point-to-point, other long-term firm, short-term firm point-to-point, and other. Most of these categories are firm service. These data have been gathered since 2004.
- **Monthly Peak Load** (page 401b) is not expressly a *transmission* system peak and seems instead to have been intended originally as a measure of peak power *supply* to retail and requirements sales for resale customers (e.g., munis and cooperatives). It expressly excluded the demand at the peak which is associated with non-requirements sales for resale. However, the definition has changed and is now is less clear.

The peak demand data available for HQT are drawn from response 1.23 of HQT-16 Document 1 (the first tranche of data requests). These data pertain to *demandes de pointes du reseau de transport*,

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[94] The Edison Electric Institute is the principal trade association of U.S. electric utilities. The ROE data we used in the study were drawn from the backup data to the *EEI Rate Case Summary* quarterly reports.

which HQT translates as “peaks coinciding at network peak demand”. These peaks are decomposed with respect to “native load” (*charge locale*) and “point to point” services. HQT’s point-to-point load at the peak (which occurs in the winter) is quite variable and typically ranges between 5-15% of the total. Most of it is firm.

The two peak demand variables available on Form 1 each have advantages in transmission benchmarking and X factor studies for HQT.

Arguments for Transmission System Peak Load

- This is the more accurate measure of *transmission* system peak loads.
- It matches up better with HQT’s peak load data.
- Monthly peak load data are sensitive to the restructuring of the US electric utility industry since, for some companies, the sale or spin off of generation reduced requirements sales for resale.

Arguments for Monthly Peak Load

- Data are available for a considerably longer sample period, thereby permitting calculation of longer-term productivity trends that should interest the Régie.
- The longer sample period also facilitates use of a ratcheted peak demand variable.
- Data are also available for a few more utilities.
- Some companies report *transmission* peaks only for a multi-utility *system*, and it is difficult to apportion these between the constituent companies accurately.
- While restructuring may have caused the monthly peak demand growth of some companies to slow as requirements sales for resale were suspended, many companies did not have many requirements sales for resale before restructuring. Also, ratcheting peak demand mitigates this problem.
- Transmission peak may include some non-firm load that shouldn’t drive cost.

Based on these considerations, we decided to use the *monthly* system peak data in the *productivity* research and the *transmission* system peak data in the *econometric* research.

We accorded the two scale variables in our econometric models a translog treatment by adding quadratic and interaction (aka "second-order") terms for these variables to the econometric cost model. To reduce controversies over functional forms, no second-order terms were included for the other variables in the model. Functional form issues are discussed further in Appendix A.2.

Other Business Condition Variables

Five other business condition variables were included in our econometric total cost model. Three of these address characteristics of the transmission system. These variables were substation capacity (measured in MVA) per substation, substations per line mile, and the share of overhead assets in the gross value of transmission line assets.[95] The U.S. data for these variables were obtained from FERC Form 1. Analogous data for HQT were provided by the Company in response to information requests. We expect the parameters of the first two variables to have positive signs, while that for the third variable should have a negative sign because undergrounding of transmission facilities is especially costly.

The model also includes the construction standards index for transmission tower construction which PSE developed[96] in the Hydro One proceeding and the share of transmission plant in the utility's non-general gross plant value. The former variable indicates how construction standards vary with weather in a transmitter's service territory. The latter variable should indicate the extent to which the utility was unable to realize economies of scope from the joint provision of transmission and distribution (and in some cases generation) services. We expect both of these variables to have positive parameters.

Our model also contains a trend variable. This permits predicted cost to shift over time for reasons other than changes in the business conditions that are specified in the cost model. Trend variables thereby capture the net effect on cost of changes in diverse conditions, such as technology and X inefficiency, which are otherwise excluded from the model. Parameters for such variables often have

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[95] For the sampled U.S. utilities, the extent of transmission plant overheading was measured as the share of overhead plant in the gross value of overhead and underground transmission conductor, device, and structure (pole, tower, and conduit) plant. System overheading typically involves lower capital costs. Since transmission is capital-intensive, high overheading should generally lower total cost.

[96] See Appendix A3 for details on PSE's variables.

a negative sign in econometric research on utility cost. However, the expected value of the trend variable parameter in a cost model is *a priori* indeterminate.

The *CNE* model includes the same scale variables, MVA per substation, the scope economies variable, a variable indicating ISO membership, and a variable that PSE developed which measures the extent of forestation in each company's service territory.[97] We expect all of these variables to have positive parameters save the scope economies variable.

Our capital cost model contains all of the variables in the total cost model. This is unsurprising since transmission is highly capital-intensive. We expect the parameters of these variables to have the same signs.

5.5. Econometric Research

Total Cost

The dependent variable in our econometric total cost research was *real* total cost: the ratio of total cost to the multifactor input price index. This specification enforces a key result of cost theory.[98]

Results of our econometric total cost research are reported in Table 3. This table includes parameter estimates and their associated asymptotic t-statistics and p-values. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero can be rejected at a high level of confidence. These significance tests were used in model development.

Examining the results in the table, it can be seen that the parameter estimates of the business condition variables in the model all have plausible values.[99] Our research indicates that the transmission costs tended to be higher to the extent that sampled utilities had

- higher ratcheted maximum peak demand;
- longer transmission lines;
- more capacity per substation;

[97] To save money we used the value for the forestation variable which PSE had assigned to Hydro One Networks in the Hydro One transmission *MRI* proceeding. See Appendix A3 for details on PSE's variables.

[98] Theory predicts that 1% growth in a multifactor input price index should produce 1% growth in cost.

[99] This remark pertains to the "first order" terms in the model, and not to the parameters of the second-order (quadratic and interaction) terms.

Table 3

Econometric Model of Transmission Total Cost

VARIABLE KEY

ym = Miles of transmission line
ym2 = ym squared
yptx = Transmission peak
yptx2 = yptx squared
ymyptx = ym · yptx
mva0919pernsub0919 = Substation capacity per number of stations
nsub0919perym = Number of substations per miles of transmission line
load_tx = Construction standards index
pctpoh = Percent of transmission plant that is overhead
pctptx = Percent of plant transmission
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
ym	0.402	14.50	0.000
ym2	0.171	5.45	0.000
yptx	0.549	21.31	0.000
yptx2	0.207	6.78	0.000
ymyptx	-0.168	-8.20	0.000
mva0919pernsub0919	0.150	7.60	0.000
nsub0919perym	0.077	4.17	0.000
load_tx	0.174	4.65	0.000
pctpoh	-0.437	-10.86	0.000
pctptx	0.341	15.86	0.000
trend	0.013	8.57	0.000
Constant	19.028	960.87	0.000

System Rbar-Squared	0.948
Sample Period	2004-2019
Number of Observations	711

- more substations per line mile;
- higher construction standards due to weather challenges;
- more transmission assets underground; and
- transmission plant that constituted a larger share of total non-general plant.

The parameter estimates for the two scale variables indicate that ratcheted peak demand had a long-run cost elasticity of 0.549% whereas that for transmission line length was 0.402%. All three second-order (quadratic and squared) output variables had highly significant parameter estimates.

The parameter estimate for the trend variable suggests that transmission cost tended to *rise* over the full sample period by about 1.28% annually for reasons that aren't explained by the business condition variables in the model. The 0.948 adjusted R-squared for the model indicates that it has substantial explanatory power.

Capital Cost

The dependent variable in our econometric capital cost research was *real* capital cost: the ratio of capital cost to a capital input price index. Results of our econometric capital cost research are reported in Table 4. Examining the results in the table, it can be seen that the parameter estimates of all of the business condition variables in this model also have plausible values.[100] Our research indicates that transmission capital *cost* tended to be higher to the extent that sampled utilities had

- higher ratcheted peak demand;
- more transmission miles;
- more substation capacity per substation;
- more substations per line mile;
- more transmission plant underground;

[100] This remark pertains to the "first" order terms in the model, and not to the parameters of the second-order (quadratic and interaction) terms.

Table 4

Econometric Model of Capital Cost

VARIABLE KEY

ym =	Miles of transmission line
ym2 =	ym squared
yptx =	Transmission peak
yptx2 =	yptx squared
ymyptx =	ym · yptx
mva0919pernsub0919 =	Substation capacity per number of stations
pctpoh =	Percent of transmission plant that is overhead
pctptx =	Percent of plant transmission
nsub0919perym =	Number of substations per miles of transmission line
load_tx =	Construction standards index
trend =	Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
ym	0.396	13.78	0.000
ym2	0.048	1.58	0.115
yptx	0.614	23.38	0.000
yptx2	0.183	6.24	0.000
ymyptx	-0.092	-4.70	0.000
mva0919pernsub0919	0.159	7.78	0.000
pctpoh	-0.435	-12.45	0.000
pctptx	0.390	17.80	0.000
nsub0919perym	0.082	4.54	0.000
load_tx	0.260	7.14	0.000
trend	0.009	6.07	0.000
Constant	14.196	533.10	0.000
System Rbar-Squared	0.957		
Sample Period	2004-2019		
Number of Observations	711		

- more transmission plant relative to generation and distribution plant; and
- higher construction standards due to severe weather.

The parameter estimates for the scale variables in this model indicate that ratcheted peak demand had a long-run cost elasticity of 0.614% whereas that for transmission line length was 0.396%. Two of the three second-order output variables had highly significant parameter estimates.

The parameter estimate for the trend variable suggests that transmission cost tended to rise over the full sample period by 0.85% annually for reasons that aren't explained by the business condition variables in the model. The 0.957 adjusted R-squared for the model is similar to that for the total cost model and remarkably high.

CNE

The dependent variable in our econometric *CNE* research was *real CNE*: the ratio of *CNE* to the *CNE* input price index. Results of our econometric *CNE* research are reported in Table 5. Examining the results in the table, it can be seen that the parameter estimates of all of the business condition variables in this model are also plausible.[101] Our research indicates that transmission *CNE* tended to be higher to the extent that sampled utilities had

- higher ratcheted maximum peak demand;
- longer transmission lines;
- more substation capacity per substation;
- more transmission plant relative to generation and distribution plant;
- more service territory forestation; and
- ISO membership.

The parameter estimates for the scale variables in this model indicate that ratcheted peak demand had a long-run cost elasticity of 0.423% whereas that for transmission line length was 0.372%. All of the second-order terms had highly significant parameter estimates. Thus, the relationship of cost

[101] This remark once again pertains to the "first order" terms in the model, and not to the parameters of the second-order (quadratic and interaction) terms.

Table 5

Econometric Model of Transmission *CNE*

VARIABLE KEY

ym = Miles of transmission line
ym2 = ym squared
yptx = Transmission peak
yptx2 = yptx squared
ymyptx = ym · yptx
mva0919pernsub0919 = Substation capacity per number of stations
pctptx = Percent of plant transmission
pforgis1 = Percent forestation in service territory
rto = Binary variable indicates RTO/ISO member
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
ym	0.372	10.06	0.000
ym2	0.664	14.37	0.000
yptx	0.423	12.37	0.000
yptx2	0.463	7.87	0.000
ymyptx	-0.584	-20.84	0.000
mva0919pernsub0919	0.072	2.64	0.009
pctptx	0.231	7.41	0.000
pforgis1	0.046	5.11	0.000
rto	0.189	5.69	0.000
trend	0.021	6.88	0.000
Constant	17.314	485.72	0.000

System Rbar-Squared	0.796
Sample Period	2004-2019
Number of Observations	711

to output was highly nonlinear. The parameter estimate for the trend variable suggests that transmission cost tended to rise over the full sample period by a brisk 2.1% annually for reasons that aren't explained by the business condition variables in the model. This result was likely influenced by the EPAct.

The 0.796 adjusted R-squared for the model is considerably lower than those of the total cost and capital cost models. This gives us less confidence in the appropriateness of our econometric *CNE* benchmarks. *CNE* is affected by numerous business conditions that are difficult to model accurately. These include ice storms, tornados, hurricanes, wildfires, reliability standards, system age, and maintenance cycles.

5.6. Productivity Research

Methodology

We calculated indexes of the *CNE*, capital, and multifactor transmission productivity of each U.S. utility in our sample. The annual productivity growth rate of each transmitter was calculated as the difference between the growth of its output and input quantity indexes. Size-weighted averages of these growth rates were then calculated. As noted in Section 3.1, size weighting makes particular sense in research to determine the X factor of a large utility like HQT.

To measure output growth we used multidimensional indexes with cost elasticity weights as discussed in Section 3.1. The output variables were the two that we identified in our econometric research: line length and ratcheted maximum peak demand. The estimated cost elasticities for these two variables from our econometric total cost research were used to establish weights. These weights were about 58% for ratcheted maximum peak demand and 42% for line length.

We encourage the Régie to consider multidimensional output indexes of this kind as a scale escalator in HQT's revenue cap indexes. The 58/42 weights are appropriate for a comprehensive revenue cap index. In a revenue cap index applicable only to *CNE* revenue, the 53% ratcheted peak/47% line length weights from our *CNE* model are more pertinent.

In calculating input quantity indexes for the U.S. utilities, we broke down their applicable costs into those for transmission capital, general capital, labor, and material and service inputs. Each of these input groups had its own quantity subindex. We calculated *summary CNE* and capital quantity indexes using company-specific time-varying cost-share weights. The trend in each company's multifactor input quantity index was a cost-weighted average of the trends in the labor, M&S and capital subindexes.

Industry Trends

Table 6 reports results of our productivity calculations for the full sample. We found that the growth in the transmission *PMF* of sampled U.S. utilities averaged a 2.26% annual decline over the fifteen-year 2005-2019 sample period but a more positive 0.62% average annual decline over the full 24-year 1996-2019 sample period, during which the effects of formula rates and other recent changes in the U.S. transmission business were less pronounced. *CNE* productivity averaged a 1.74% annual decline over the last 15 years and a 0.68% annual decline over the full sample period. The productivity of transmission capital averaged a 2.16% annual decline over the last fifteen years and a 0.46% annual decline over the full sample period.

Our estimates of transmission output do not reflect any possible improvements in transmission reliability, bulk power market performance, or increased reliance on renewable resources that may have occurred during the sample period. Reliability is treated as an output variable in transmission productivity research commissioned by the Australian Energy Regulator. [102]

5.7. Cost Benchmarking

HQT Background

We begin this section by discussing key aspects of HQT's situation which should be considered in appraising its costs.

<u>Overview</u>

Hydro-Québec is a crown corporation that generates, transmits, and distributes most electricity in the province of Québec. HQT is the Company's transmission division. Québec has Canada's second largest provincial economy and a population and transmission service territory area comparable to that of Arizona, of Colorado, Wyoming, and Montana combined, or of Minnesota, the Dakotas, and the upper peninsula of Michigan combined.

[102] Denis Lawrence, Tim Coelli and John Kain, *Economic Benchmarking Results for the Australian Energy Regulator's 2020 TNSP Annual Benchmarking Report*, prepared for the Australian Energy Regulator, October 15, 2020, pp. 6-7.

Table 6

U.S. Transmission Productivity Results: Cost-Weighted Averages

(Growth Rates)[1]

Year	Scale Index	Input Quantity Index: Summary	Input Quantity Index: O&M	Input Quantity Index: Transmission Capital	Input Quantity Index: Allocated General Plant	Productivity: MFP	Productivity: O&M	Productivity: Transmission Capital	Productivity: Allocated General Plant
1996	1.2%	-0.5%	0.4%	-0.9%	1.2%	1.7%	0.8%	2.2%	0.0%
1997	0.9%	-1.4%	-0.5%	-1.2%	-4.4%	2.3%	1.4%	2.1%	5.3%
1998	2.2%	-0.4%	3.9%	-1.9%	2.1%	2.6%	-1.7%	4.2%	0.1%
1999	2.8%	-2.1%	-4.3%	-1.9%	-2.3%	4.9%	7.1%	4.6%	5.1%
2000	0.4%	-0.1%	6.3%	-1.3%	10.5%	0.5%	-5.9%	1.7%	-10.1%
2001	1.8%	-0.6%	-0.8%	-0.9%	13.4%	2.4%	2.6%	2.6%	-11.6%
2002	0.7%	-1.7%	-6.2%	-0.4%	-4.3%	2.4%	6.9%	1.0%	4.9%
2003	1.4%	-0.2%	3.0%	-0.7%	1.2%	1.5%	-1.6%	2.0%	0.2%
2004	0.6%	-0.1%	0.5%	-0.2%	-1.5%	0.7%	0.1%	0.9%	2.1%
2005	2.7%	0.9%	4.6%	0.1%	-1.8%	1.8%	-1.8%	2.7%	4.5%
2006	2.3%	1.4%	3.3%	0.4%	-0.8%	0.9%	-1.0%	1.9%	3.1%
2007	0.0%	2.9%	6.1%	1.4%	0.2%	-2.8%	-6.1%	-1.3%	-0.2%
2008	0.3%	1.9%	3.5%	1.2%	1.0%	-1.6%	-3.2%	-0.9%	-0.7%
2009	-0.1%	3.1%	4.2%	2.5%	2.2%	-3.2%	-4.3%	-2.6%	-2.3%
2010	0.7%	2.9%	5.4%	2.2%	-1.4%	-2.2%	-4.7%	-1.5%	2.0%
2011	0.3%	2.3%	1.1%	2.9%	2.9%	-2.0%	-0.8%	-2.5%	-2.6%
2012	0.4%	1.8%	2.0%	2.1%	5.5%	-1.4%	-1.6%	-1.7%	-5.1%
2013	0.3%	4.3%	2.1%	4.9%	6.2%	-4.0%	-1.7%	-4.6%	-5.9%
2014	1.2%	4.2%	-1.5%	5.0%	0.4%	-3.0%	2.7%	-3.8%	0.9%
2015	0.4%	4.5%	-2.8%	5.9%	1.3%	-4.2%	3.1%	-5.5%	-0.9%
2016	0.8%	5.0%	5.9%	4.7%	9.6%	-4.2%	-5.1%	-3.9%	-8.8%
2017	0.1%	3.1%	-0.8%	3.7%	2.2%	-3.0%	0.9%	-3.6%	-2.2%
2018	0.8%	4.3%	7.2%	3.1%	3.9%	-3.4%	-6.3%	-2.3%	-3.1%
2019	0.7%	2.3%	-3.0%	3.4%	6.6%	-1.6%	3.7%	-2.7%	-5.9%
Average Annual Growth Rate									
1996-2019 (24 Years)	**0.96%**	**1.58%**	**1.64%**	**1.42%**	**2.25%**	**-0.62%**	**-0.68%**	**-0.46%**	**-1.29%**
2005-2019 (15 Years)	**0.74%**	**3.00%**	**2.48%**	**2.90%**	**2.54%**	**-2.26%**	**-1.74%**	**-2.16%**	**-1.80%**

[1] All growth rates are calculated logarithmically.

HQT's provincial loads lie chiefly south of the Laurentian Plateau and are concentrated in the St. Lawrence Valley. The low-cost hydroelectric resources that are used to supply most power are meanwhile scattered across the plateau. HQT also accesses power from more than 40 wind farms and from small hydro, biomass and biogas cogeneration stations that are owned by independent producers (*producteurs privés*). The totality of generation volumes that HQT handles well exceed provincial loads, and around 20% of power deliveries are outside Québec. The transmission system has recently expanded to access new hydroelectric and wind resources in eastern Québec and to strengthen transmission capacity to the growing Montréal area. Facilities under construction will increase capacity to receive power from generators in eastern Québec and to deliver power to the States.

As a transporter of large power quantities over long distances, HQT has North America's most extensive transmission system, with more than 30,000 km of lines and more than 500 substations (*postes*). Transmission accounts for about 1/3 of Hydro-Québec's net plant value, substantially larger than the share of distribution. This is the reverse of the typical pattern of investor-owned utilities in the States.[103]

Transmission of large amounts of power over long distances has over the years encouraged HQT to use unusual and innovative technologies. These include 735 kV alternating current ("AC") lines, a high-voltage direct current ("DC") line, new tower designs, and remote monitoring systems. HQT also owns an extensive telecommunications system with thousands of km of fibre-optic cables and high-capacity microwave links. This is used for system control and for voice and data transmission via mobile radio communications for jobsites and work crews.

HQT operates asynchronously from North America's Eastern Interconnection. Its system therefore constitutes a separate interconnection, like that of the Electric Reliability Council of Texas. Special converters are used to export power to other provinces and the United States.

A sizable portion of HQT's access to transmission corridors has been achieved by easements rather than land ownership. At the end of 2019, land accounted for less than 1% of HQT's net plant value. Roughly 69% of the land that HQT owns is used as sites for *postes* rather than *lignes*.[104]

<u>Cost Challenges and Cost Advantages</u>

Challenges In addition to the great distances over which power must be carried, HQT faces other special challenges.

- The receipt points for a great deal of the power transmitted are remote. Many facilities are distant from good roads. Thus, HQT confronts special logistical challenges.

[103] These utilities typically own both transmission and distribution ("T&D") plant, as noted above, and the value of distribution plant is much larger.

[104] B-0268 (HQT-16, Document 2) *response* 3.1.

- Hard rock is close to or at the surface on much of the plateau, making it especially difficult to establish footings for structures.
- Transmission lines must traverse terrain that is hilly, forested, and/or incised by sizable lakes and rivers that include the broad St. Lawrence.
- Winters are cold throughout the region served, and ice storms have in the past caused major disruptions of transmission service. *Postes* are sometimes housed in structures.
- Substations at Hydro-Québec's generation facilities are owned by HQT. Since HQP owns most of the massive generating capacity in the province, these *postes de départ* are unusually numerous. The *postes de départ* of *producteurs privés* are typically owned and operated by the producers. However, for reasons of equity and in conformance with the *Tarifs et conditions des services de transport d'Hydro-Québec*, HQT reimburses these producers for these costs.[105] Costs of these *remboursements* are capitalized.
- Montréal is a large metropolitan area with a population similar to that of Minneapolis-St. Paul in the States. Costly undergrounding of some transmission facilities is required.
- Many of HQT's assets are approaching replacement age. HQT has adopted a *modèle de gestion d'actifs* to optimize the age of assets. This has placed upward pressure on its *CNE*.
- The need for special converters to export power has been noted.

Advantages HQT also has some cost advantages.

- Its large operating scale has permitted the realization of scale economies.
- Since the James Bay project roughly doubled the size of HQT's network, growth of the system has been gradual. Even sizable system expansions like the Romaine project in eastern Québec tend to be modest in percentage terms.
- Hydro-Québec's extensive involvement in generation and distribution as well as transmission should permit the realization of scope economies.

[105] HQT-16, Document 1, *reponse* 1.7.

- Ownership by the provincial government permits Hydro-Québec to borrow money at low rates.
- Hydro-Québec pays no income taxes. These taxes can account for more than 20% of capital cost.

Corporate Structure

Special features of Hydro-Québec's corporate structure merit note.

- HQT was established as a separate business unit (*unité d'affaires*) in 1997. This move, which FERC Order 888 encouraged, helped to separate Hydro-Québec's transmission operations from its generation and distribution.[106] A Transmission Provider Code of Conduct governs relations between HQT and other Hydro-Québec *unités d'affaires* and is intended to prevent preferential treatment or cross-subsidization.[107]
- HQT's *Direction principale – Contrôle des mouvements d'énergie et exploitation du réseau* ("DPCMEER") provides many services for the Québec Interconnection which would fall under the dispatch heading on FERC Form 1. DPCMEER has five divisions.
    - *La direction – contrôle des mouvements d'énergie* ("*DCMÉ*") balances loads and operates the main transmission network.
    - *La direction – exploitation du réseau* ("*DER*") comprises three divisions, two that operate regional networks and a third that supports the first 2 divisions.
    - *La direction – normes de fiabilité et conformité réglementaire* ("*DNFCR*") addresses transmission reliability standards and regulatory compliance.

  A Reliability Coordinator Code of Conduct discourages *DCMÉ* from providing preferential treatment to other Hydro-Québec business units.

[106] This move helped Hydro-Québec obtain a license to sell electricity at unregulated prices in U.S. bulk power markets.

[107] One reason that these arrangements matter is that independent generators and marketers also use HQT's system.

- Hydro-Québec's *Innovation, équipement et services partagés* division provides HQT with design and construction services.

- Miscellaneous services that HQT uses are provided by other Hydro-Québec divisions.

Accounting Idiosyncrasies

PEG expended a great deal of effort in this project, via information requests and document perusals, to learn about idiosyncrasies in HQT's accounting which should be addressed in the benchmarking study. The notable idiosyncrasies include the following.

- U.S. GAAP accounting has been used by the Company only since July 2015[108].

- HQT does not itemize its costs consistently with the FERC's Uniform System of Accounts or Form 1. Certain costs that PEG has excluded from past transmission cost studies using U.S. data nonetheless are itemized consistently by HQT for easy removal. These include costs of the retirement program (*régime de retraite*), other benefits (*autres avantages sociaux*), and transmission by others (*achats de service de transport*). However, HQT does not itemize certain costs that we removed from our productivity study and might wish to remove from the benchmarking study. These include costs of dispatching and miscellaneous transmission *CNE.*[109]

- HQT's status as a division of a vertically-integrated utility affects its cost accounting. Assets devoted chiefly to the provision of transmission service are deemed transmission assets and included in the transmission *base de tarification* (rate base). In addition to *postes* and *lignes*, these assets include land, buildings, and control centers. Since decision D-2008-019, these assets have also included most of Hydro-Québec's telecommunications assets.[110]

  The Company is billed for certain goods and services provided to it by other *unités d'affaires*. These charges are reported as *charges de services partagés*, a component of *CNE* in HQT's *revenus requis* summary tables. Included are charges for information,

[108] B-0265 (HQT-16, Document 1), response 1.9.

[109] In B-0265 (HQT-16, Document 1, response 4.1), HQT did report the *charges brutes directes* for the *DCMÉ* from 2015 to 2019.

[110] Ibid, *response* 1.4.

communications, purchasing, building, transportation, materials handling, and corporate services. These charges may include a return on the assets that Hydro-Québec has assigned to the supplying units. Also included in HQT's *revenus requis* are certain *frais corporatifs* for corporate service costs that are divided between business units using rules of thumb ("*règles d'imputation*").

- HQT in turn bills other *unités d'affaires* for services that it provides to them. Charges for many services HQT provides to other divisions are billed as *facturation interne émise.* Charges for costs of telecommunications assets are reported as *autres revenus de facturation interne.*
- Since any administrative and general expenses or costs of general plant which are assigned to HQT take the form of *coûts de services partagés* and *frais corporatifs*, we cannot assign to HQT a share of these costs using formulas as we do when calculating the (loaded) transmission costs of U.S. utilities.
- HQT reported in response 4.3 of B-0265 (HQT-16, document 1) that itemized costs of its telecommunications assets were not readily available and did not report these costs in a form that facilitated their removal.
- Data on the gross and net value of HQT's transmission plant and the value of its gross plant additions are readily available only since 2001.[111] These data make it possible to compute HQT's capital cost using a monetary approach such as geometric (or hyperbolic) decay. However, the benchmark year for these calculations is fairly recent. This reduces the accuracy of capital and total cost benchmarking, especially in the years before 2010.
- A change in HQT's accounting for the value of its asset retirements in 2009 which makes it difficult to compute its capital cost using the one-hoss shay method was noted above.[112]

[111] Ibid, *response* 5.2.

[112] Ibid, *response* 5.3.

Benchmarking Details

Calculating HQT's Costs

Our calculation of HQT's cost has the following notable features.

- Capital cost was calculated using a geometric decay (monetary) specification, and was thus the product of consistent capital price and quantity indexes. In these calculations we considered the costs of tangible transmission plant in service (*immobilisations corporelles en exploitation*) but not the (much smaller) costs of intangible plant (*actifs incorporels*), regulatory assets (*actifs réglementaires*), government reimbursements (*remboursement gouvernemental*), working capital (*fonds de roulement*), or taxes. The capital quantity at the end of the first year calculated (2001) was the inflation-adjusted net plant value. Values of the capital quantity index in later years were calculated using inflation-adjusted data on the gross value of additions to tangible plant in service (*mises en exploitation*) less the value of *contributions internes et autres* and of reimbursements to independent power producers.

- *CNE* were computed using the formula

$$(Masse\ salariale - Avantages\ Sociaux + Autres\ Charges\ Directes + Charges\ de\ Services\ Partagés) * \left[1 - \frac{\text{Coûts Capitalisés}}{(\ Charges\ Brutes\ Directes + Charges\ de\ Services\ Partagés))}\right] + Frais\ Corporatifs\ - (Facturation\ Interne\ \text{émise}\ +\ Autres\ Revenus\ de\ Facturation\ Interne)$$

Note that we adjusted *coûts capitalis*és for the removal of *avantages sociaux.* Our *CNE* calculations did not include costs of electricity or transmission services that HQT purchased or adjustments for *compte d'écarts et de reports, interêt relié au remboursement gouvernemental,* or *facturation externe.*

Calculating U.S. Transmission Costs

The idiosyncrasies in HQT's data which we just discussed prompted us to calculate the *CNE* of U.S. utilities a little differently than we did in the productivity study. As in the productivity study, we excluded costs of transmission by others. We did *not* exclude dispatching expenses or miscellaneous transmission expenses because HQT did not consistently itemize these expenses. However, we did remove some companies from the sample which reported uncommonly large dispatching or miscellaneous transmission expenses which we suspect other companies would have reported as transmission by other expenses. All of the anomalies occurred during years when these companies were ISO members. This is the main reason for differences in the econometric and productivity samples.

Sample Period

We used our three econometric transmission cost models to benchmark the transmission costs of HQT during the years for which suitable data on its operations are available. We focused on the 2017-2019 period for several reasons.

- Due to data limitations, capital cost could not be calculated before 2001. When using a monetary method it is desirable to benchmark costs that are at least ten years older than the first year for which they are calculated.
- Consistent data on the *CNE* of HQT are only available starting in 2007.
- HQT has used U.S. GAAP accounting only since 2015.
- The recent years are more relevant for setting the stretch factor.
- We lack forecasts of future costs and business conditions which would permit us to benchmark such costs. However, this can in principle be done in HQT's next *demande tarifaire*.

How HQT Compares to Sampled U.S. Utilities

Table 7 compares the costs and business conditions of HQT to those of sampled U.S. utilities. Average values for HQT are compared to sample mean averages for the utilities in our econometric sample. The following results of these comparisons are salient.

- HQT's *CNE*, capital cost, and total cost (in Canadian dollars) were all about twelve times higher than the U.S. sample mean (in American dollars).[113]
- One of the reasons for the higher costs was that HQT's transmission line miles and ratcheted peak demand were both roughly five times higher than the mean.

[113] Capital cost differs from that which HQT uses in *dossiers tarifaires*.

Table 7

How HQT's Recent Costs and Business Conditions Compare to 2019 Sample Norms

Costs and Business Conditions		Units	HQT 2017	HQT 2018	HQT 2019	HQT Average 2017-2019 [A]	U.S. Sample Mean (2019) [B]	HQT Ave / 2019 Sample Mean [C=A/B]	ln (C)	Comments
Costs										
Total Cost	[D]	Canadian Dollars for HQT	3,740,586,670	3,921,977,277	3,720,385,075	3,794,316,341	304,469,798	12.46	2.52	
CNE	[E]	Canadian Dollars for HQT	703,823,300	773,058,813	756,724,251	744,535,455	64,162,086	11.60	2.45	
Capital Cost	[F]	Canadian Dollars for HQT	3,036,763,369	3,148,918,463	2,963,660,823	3,049,780,885	240,307,713	12.69	2.54	
Outputs										
Transmission Line Miles		Miles	21,256	21,183	21,457	21,299	3,969	5.37	1.68	
Ratcheted Peak Demand	[G]	MW	40,812	40,812	40,812	40,812	8,204	4.97	1.60	
Cost/MW										
Total Cost	[H=D/G]	Canadian Dollars for HQT	91,654	96,099	91,159	92,971	37,112	2.51	0.92	
CNE	[I=E/G]	Canadian Dollars for HQT	17,245	18,942	18,542	18,243	7,821	2.33	0.85	
Capital Cost	[J=F/G]	Canadian Dollars for HQT	74,409	77,157	72,617	74,728	29,291	2.55	0.94	
Input Prices										
Total Factor	[K]	Index Number	1.24	1.26	1.20	1.23	0.99	1.24	0.22	
CNE	[L]	Index Number	1.11	1.13	1.17	1.14	1.00	1.14	0.13	
Capital	[M]	Index Number	120	121	114	118	92.92	1.27	0.24	
Real Unit Cost										
Total Factor	[N=(D/K)/G]	Index Number	74,046	76,461	75,883	75,464	37,424	2.02	0.70	
CNE	[O=(E/L)/G]	Index Number	15,514	16,753	15,915	16,062	7,818	2.05	0.72	
Capital	[P=(F/M)/G]	Index Number	622	635	637	631	315	2.00	0.69	
Productivity (output = peak)										
Total Factor	[K/(D/G)]	Index Number	0.501	0.485	0.489	0.492	0.99	0.50	-0.70	
CNE	[L/(E/G)]	Index Number	0.504	0.467	0.491	0.487	1.00	0.49	-0.72	
Capital	[M/(F/G)]	Index Number	47.108	46.110	45.956	46.391	92.92	0.50	-0.69	
MVA per Substation		Ratio	449	452	457	453	371	1.23		Cost Disadvantage
Substations per Line Mile		Ratio	0.02	0.02	0.02	0.024	0.02	1.17		Cost Disadvantage
Percentage of Line Plant that is Overhead		Percent	0.95	0.95	0.95	95%	89%	1.07		Cost Advantage
Percentage of Plant that is Transmission		Percent	0.33	0.34	0.35	34%	21%	1.67		Cost Disadvantage
Percentage of Service Territory Forested		Percent	0.74	0.74	0.74	74%	61%	1.22		Cost Disadvantage
Construction Standards Index		N/A	0.87	0.87	0.87	0.87	0.68	1.28		Cost Disadvantage
Regional Transmission Organization (binary variable)		N/A	0.00	0.00	0.00	0.00	0.57	0.00		Cost Advantage

- Simple unit cost comparisons can be obtained by dividing each of the three costs by ratcheted peak demand. It can be seen that all three unit costs are roughly 2.5 times the mean.
- Input prices are modestly higher for HQT than the U.S. sample.
- Real unit cost and productivity metrics have been computed, as discussed in Section 3.3, which take account of input price differences as well as differences in operating scale. It can be seen that HQT's real unit cost metrics were all roughly twice the mean. The CNE, capital, and total factor productivity of HQT are all roughly 50% of the mean.
- HQT faces an array of other business conditions that are in general less favorable than sample norms. For example, HQT must deal with higher forestation, MVA per substation, and substations per line mile, and construction standards. On the other hand, HQT is not an ISO member.

Econometric Benchmarking Results

Total Cost

We compared HQT's total cost thus calculated to the cost projected by our econometric total cost benchmarking model. From 2017-19, the three most recent years for which data are available, HQT's total cost was 67% above the benchmark value.[114] This is commensurate with a bottom quartile ranking for the U.S. sample.

Capital Cost

We compared HQT's capital cost to the cost projected by our econometric capital cost benchmarking model. From 2017 to 2019, HQT's capital cost exceeded the benchmarks by about 55% on average. This is commensurate with a bottom quartile ranking.

[114] All percentages are calculated logarithmically.

CNE

We compared HQT's *CNE* to the cost projected by our econometric *CNE* benchmarking model. From 2017 to 2019, the *CNE* of HQT exceeded the benchmark by an extraordinary 121%. This is commensurate with a bottom quartile ranking in the U.S. sample.

Several possible reasons may be advanced for the poor *CNE* performance score of HQT in our research.

- Our *CNE* model does not have a high explanatory power.
- HQT is an extreme outlier with respect to the interaction term (Line length x Ratcheted Peak Demand), which has a negative and highly significant parameter estimate.
- HQT also has unusually large substation operations, and we have had a difficult time developing variables that measure the *CNE* challenge of substation operations and have high statistical significance.
- HQT has adopted a *modele de gestion d'actifs* which requires high *CNE* to prolong system age.
- HQT may have been assigned an unusually high share of Hydro-Québec's general costs.
- HQT incurs as *CNE* costs of general plant which, in our calculations for U.S. utilities, are treated as capital costs.
- The *CNE* of HQT may be noncomparable to those of U.S. utilities in ways that we don't understand despite numerous information requests.

6. Implications for *MRIs*

In this section of the report we consider the implications of our research for the X factor and S factor terms of HQT revenue cap indexes. In addition to the implications for the *CNE* revenue cap index, we consider the implications for a possible comprehensive revenue cap index in any succeeding *MRI*.

6.1. X Factors

The revenue cap index for HQT's current *MRI* applies to *CNE* revenue. The X factor should then be based on productivity trends in the use of *CNE* inputs (e.g., labor and materials). The Régie could base X on the **1.74%** annual decline in *CNE* productivity over the fifteen most recent years of the sample period or the **0.68%** decline over the full sample period. The decline in *CNE* productivity may be due in part to short-term circumstances such as the enforcement of new reliability standards. In this regard, it is notable that the decline in *CNE* productivity decline was especially pronounced from 2007 to 2010, shortly after passage of the EPAct. In the nine years from 2011 to 2019 *CNE* productivity growth has averaged a 0.57% decline, which is similar to that for the full-sample trend. PEG reported 0.83% average annual *growth* in the *CNE* productivity of Hydro One transmission in its recent *MRI* proceeding.[115] The Régie should also consider the 0% productivity growth target which Ontario regulators have chosen.

The Régie has also evinced interest in the X factor that might be applicable to a future comprehensive revenue cap index. Here again there are choices, which this time include a fifteen-year *PMF* decline of **2.26%**, a longer-term decline of **0.62%**, and the 0% target that the Ontario Energy Board chose. Recollecting our discussion in Section 2 of the special circumstances of U.S. transmitters in recent years, we lack the evidence at this time to conclude that the unusually negative *PMF* growth of U.S. transmitters will be applicable to HQT in the five years of any succeeding *MRI.*

The choice between such numbers would also depend on other aspects of the *MRI*. A more negative number would help HQT fund more capex. Capital revenue may in some years exceed HQT's capital cost. HQT should then have less need for extra revenue for capex surges.

[115] Mark Newton Lowry, *Incentive Regulation for Hydro One Transmission*, EB-2019-0082 Exhibit M1, September 2019 p. 36.

Our report has detailed several provisions for addressing this situation. One is to contain or eliminate eligibility for extra revenue. If supplemental revenue is nonetheless permitted, provisions like the following merit consideration.

- The X factor could be raised to reduce expected double counting and give customers a better chance of receiving the benefits of industry productivity growth in the long run.
- Capital costs that occasion supplemental revenue could be subject to continued tracking in later plans. Customers would then receive the benefit of depreciation of the surge capex between plans.

6.2. Stretch Factors

Our econometric benchmarking research for AQCIE-CIFQ suggests that the stretch factor for the current *CNE* revenue cap index should be no less than **0.60%.** This is the stretch factor that would be chosen in Ontario based on a similar benchmarking score. Our current results suggest that the stretch factor for any future *comprehensive* revenue cap index would also be no less than **0.60%.** The Régie is, of course, under no obligation to base its stretch factors on the Ontario Energy Board's schedule.

The Régie may wish to update the benchmarking study in the year in which such an *MRI* is developed. A new study can consider forward test year costs that HQT proposes as well as additional years of historic costs. Alternatively, the models developed here could be used with minimal modification.

The Régie should increase the stretch factor to reflect the unusually weak performance incentives in the U.S. power transmission industry over the sample period. The incentive power of the proposed plan is not remarkably strong due to the comparatively short four-year term and the earnings sharing mechanism. However, we have seen that the incentive power of U.S. transmission regulation was significantly weakened by the FERC's use of ROE premia and formula rate plans.

Based on our incentive power research, we recommend a stretch factor adder of at least **0.1%** should the Régie base X on productivity results for the full sample period. An adder of at least **0.3%** is recommended if X is based on results for the most recent fifteen years.

Appendix A: Additional Information on Research Methods

A.1 Technical Details of PEG's Empirical Research

This section contains more technical details of our empirical research. We first discuss our input quantity and productivity indexes. We then address our methods for calculating input price inflation and capital cost.

Input Quantity Indexes

The growth rate of a summary (multidimensional) input quantity index is defined by a formula that involves subindexes measuring growth in the quantities of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and quantity subindexes.

Index Form

We have constructed summary *CNE*, capital, and multifactor input quantity trend indexes. Each of these indexes has a chain-weighted Törnqvist form.[116] This means that its annual growth rate is determined by the following general formula:

$$\ln\left(\frac{Inputs_t}{Inputs_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1} \right) \cdot \ln\left(\frac{X_{j,t}}{X_{j,t-1}} \right). \qquad \text{[A1]}$$

Here in each year *t*,

$Inputs_t$ = Summary input quantity index

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

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

It can be seen that the growth rate of the index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the natural logarithm of the ratio of the quantities in successive years. Calculations of the average shares of each input in the applicable cost of each utility in the current and prior years serve as weights.

[116] For seminal discussions of this index form see Törnqvist (1936) and Theil (1965).

Productivity Growth Rates and Trends

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

$$\ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right) = \ln\left(\frac{Outputs_t}{Outputs_{t-1}}\right) - \ln\left(\frac{Inputs_t}{Inputs_{t-1}}\right). \qquad [A2]$$

The trend in each productivity index was calculated as its average annual growth rate over the sample period.

Capital Cost and Quantity Specification

A monetary approach was used to measure the capital cost of each utility. Recall from Section 3.4 that under this approach capital cost is the product of a capital quantity index and a capital price index.

$$CK = WKS \cdot XK.$$

Geometric decay was assumed in the construction of both of these indexes.

Data previously processed by PEG permitted us to use 1964 as the initial year for the U.S. capital cost and quantity calculations. The value of each capital quantity index for each U.S. utility in 1964 depends on the net ("book") value of the (transmission or general) plant that it and any predecessor utilities reported. We estimated the quantities of capital in that year by dividing these values, respectively, by triangularized weighted averages of 47 consecutive values of a regional Handy Whitman Index of power transmission construction cost and 16 values of a regional Handy Whitman Index of reinforced concrete building construction cost for periods ending in the benchmark year. A triangularized weighted average places a greater weight on more recent values of the construction cost index. This makes sense intuitively since more recent plant additions are less depreciated and to that extent tend to have a bigger impact on net plant value.

The following geometric decay perpetual inventory equation was used to compute values of each capital quantity index in subsequent years. For any asset category j,

$$XK_{j,t} = (1-d) \cdot XK_{j,t-1} + \frac{VKA_{j,t}}{WKA_{j,t}}. \qquad [A3]$$

Here, the parameter d is the (constant) economic depreciation rate and $VKA_{j,t}$ is the value of gross additions to utility plant. The assumed 47-year average service life for transmission plant, 16-year average service life for general plant, 1.65 declining balance rate for equipment, and 0.91 declining balance rate for structures were used to set *d*.

The formula for the corresponding capital service price indexes used in the research was

$$WKS_{j,t} = d \cdot WKA_{j,t} + r_t \cdot WKA_{j,t-1} + (WKA_{j,t} - WKA_{j,t-1}). \quad [A4]$$

The first term corresponds to the cost of depreciation. The second term corresponds to the return on capital. The term in parentheses corresponds to capital gains.

A.2 Econometric Research Methods

This section of the Appendix provides additional and more technical details of our econometric research. We begin by discussing the choice of a form for the econometric benchmarking models. There follow discussions of econometric methods.

Form of the Econometric Cost Model

Specific forms must be chosen for cost functions used in econometric research. Forms commonly employed by scholars include the linear, double log, and translog. Here is a simple example of a *linear* cost model:

$$C_{h,t} = a_0 + a_1 \cdot L_{h,t} + a_2 \cdot D_{h,t}. \quad [A5]$$

Here, for each company *h* in year *t*, $C_{h,t}$ is cost, *L* is the length of transmission lines, and *D* is ratcheted peak demand. Here is an analogous cost model of *double log* form:

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln L_{h,t} + a_2 \cdot \ln D_{h,t}. \quad [A6]$$

The double log model is so-called because right- and left-hand side variables in the equation are logged.[117] This specification makes the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, parameter a_1 indicates the percentage change in cost resulting from 1% growth in the length of transmission lines. Elasticity estimates are informative and make it easier to assess the reasonableness of model results. It is also noteworthy that, in a double log model, elasticities are *constant* in the sense that they are the same for every value that

[117] In other words, the variable is used in the equation in natural logarithmic form, as ln(X) instead of X.

the cost and business condition variables might assume. This feature is restrictive and may be inconsistent with the true form of the cost relationship we are trying to model.

Here is an analogous model of *translog* form:

$$\ln C_{h,t} = a_o + a_1 \cdot \ln L_{h,t} + a_2 \cdot \ln D_{h,t} + a_3 \cdot \ln L_{h,t} \cdot \ln L_{h,t} + a_4 \cdot \ln D_{h,t} \cdot \ln D_{h,t} + a_5 \cdot \ln L_{h,t} \cdot \ln D_{h,t} \quad [A7]$$

This form differs from the double log form in the addition of quadratic and interaction terms. These are sometimes called second-order terms. Quadratic terms like $\ln D_{h,t} \cdot \ln D_{h,t}$ permit the elasticity of cost with respect to a business condition variable to vary with the value of the variable. The elasticity of cost with respect to a scale variable may, for example, be lower for a small utility than for a large utility. Interaction terms like $\ln L_{h,t} \cdot \ln D_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable. For example, the elasticity of cost with respect to growth in peak load may depend on the length of a transmitter's transmission lines.

The translog form is a "flexible" functional form. Flexible forms can accommodate a greater variety of the possible functional relationships between cost and the business condition variables. A disadvantage of the translog form is that it involves more variables than simpler forms like the double log. As the number of variables accorded translog treatment increases, statistical theory suggests that the precision of a model's parameter estimates and cost predictions falls. It is therefore common in econometric cost research to limit the number of variables accorded translog treatment. Most commonly, only output and any input price variables are translogged.

In our econometric work for this proceeding, we have chosen a functional form that has second-order terms only for the two scale variables. This preserves degrees of freedom but permits the model to recognize some nonlinearities. All of the second-order terms in our model had statistically significant parameter estimates.

Econometric Model Estimation

A variety of parameter estimation procedures are used by econometricians. The appropriateness of each procedure depends on the distribution of the error terms in the cost model. The estimation procedure that is best known, ordinary least squares ("OLS"), is readily available in commercial econometric software. It has good statistical properties under simple assumptions about the structure of the data and the error terms. These assumptions are often violated by real world economic data.

A common problem in econometric cost research is autocorrelation of error terms. Autocorrelation, also known as serial correlation, occurs when data from one year are correlated to the data in subsequent years. This reduces the precision of parameter estimates and debases estimates of the error terms that are used in tests of the statistical significance of parameter estimates. This can complicate model development.

Several econometric methods have been developed to address autocorrelation. One class of estimators, called generalized least squares, adjusts the parameters using estimates of the autocorrelation pattern and improves the accuracy of the estimated standard errors. We have in past studies frequently used a generalized least squares estimator with an AR1 process in our research. Another class of estimators, called robust standard errors estimators, improves the accuracy of the estimated standard errors but uses OLS to estimate model parameters.

The choice between these approaches has been debated several times in recent Ontario Energy Board proceedings. To diffuse controversy in this proceeding, we have adopted in this study the general approach that has been favored by utility witnesses in Ontario. Specifically, we have used an OLS estimator with robust standard errors available in the Stata statistical software package.

A.3 Details of PSE's Forestation and Construction Standards Variables

Forestation Variable

PSE has used its forestation variable in several power distribution benchmarking studies. It is inefficient to develop a variable of similar quality when its use in this proceeding can be purchased at a reasonable price from PSE. To save money we used the value for the forestation variable which PSE had assigned to Hydro One Networks in a distribution *MRI* proceeding.

Here is PSE's discussion of its forestation variable from a recent Ontario report. [118]

The **percentage of forestation** variable is based on GIS (geographic information system) land cover maps. PSE used the GlobCover 2009 product processed and produced by the European Space Agency ("ESA") and the Université Catholique de Louvain. These maps are matched with the areas served by each utility to create the forestation variable. We would expect that the higher the level of forestation,

[118] Fenrick, Steve, Power System Engineering, "Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry," OEB Proceeding EB-2017-0049, Exhibit A-3-2, Attachment 1, November 4, 2016, p. 10.

the higher OM&A costs required for right-of-way clearing and service restoration activities. GIS variable data is available for all sampled U.S. utilities and for Hydro One.

Construction Standards Index

PSE developed its construction standards index for use in its Hydro One Transmission benchmarking study. To save money we used the value for the construction standards index which PSE had assigned to Hydro One Networks in that study.

Here is PSE's discussion of its construction standards index from a report in the recent Hydro One Transmission *MRI* proceeding. [119]

The **construction standards index (or loading)** variable measures the minimum requirements for strength of transmission structures, which vary by geographic region. Transmission lines constructed in different regions must withstand different combinations of ice and wind due to local weather. A line designed for harsher loading conditions is more expensive to construct because it may require higher class poles, greater set depth, specialized insulators, and/or stronger hardware.

The loading variable is a way to quantify the expense associated with transmission line construction based on local weather conditions and the resultant regulatory requirements. This is accomplished by evaluating the percentage of strength capacity utilized under required load cases for a base transmission structure in different regions. The process and reasoning behind this variable are included in Appendix A. We would expect that a higher minimum construction requirement for a utility would result in higher total costs.

Here is the referenced discussion in the Appendix of that report.

This Appendix explains the theory and data behind the transmission loading variable discussed [above] (also known as the construction standards index). Per the Canadian Standards Association (CSA) and the National Electrical Safety Code (NESC), overhead transmission lines constructed throughout Ontario, Canada and the United States must withstand a minimum combination of accumulated ice and wind based on local extreme historical weather conditions. As a result, the required minimum design/build structural strength for an overhead transmission line is dependent on the physical location of the line.

This minimum structural strength requirement has a direct influence on the overall capital cost a utility must devote to its overhead transmission plant. For example, a transmission structure designed for harsher loading conditions is more expensive to construct because it may require larger diameter poles, greater setting or foundation depth, specialized insulators, and/or stronger hardware.

[119] Fenrick, Steve, and Sonju, Erik, Power System Engineering, "Transmission Study for Hydro One Networks: Recommended CIR Parameters and Productivity Comparisons," OEB Proceeding EB-2019-0082, Exhibit A-4-1, Attachment 1, January 24, 2019, pp. 28, 55-59.

Furthermore, since these minimum strength requirements are developed from documented historical weather conditions, they provide an indirect indication of the severity of extreme ice and wind storms that overhead transmission lines are exposed to, which can influence operational and maintenance costs.

To account for the influence of CSA and NESC minimum overhead transmission line structure strength requirements and associated extreme weather conditions as they relate to total cost benchmarking, Power System Engineering's transmission line design engineers developed a related variable for statistical analysis. This was accomplished by evaluating the percentage of utilized strength capacity, under required CSA and NESC load cases, for a base transmission structure in different zones.

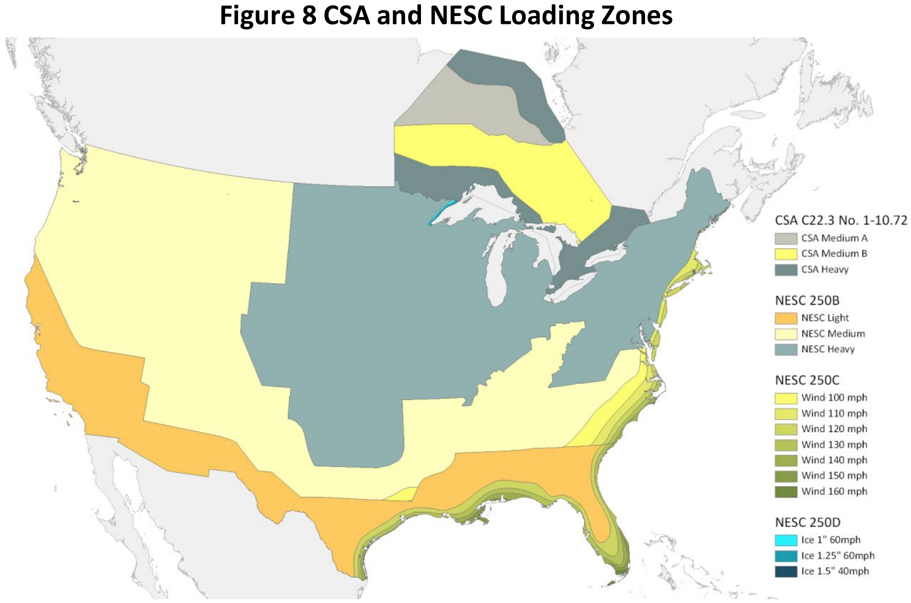
"Percentage of utilized strength capacity" is the percentage of the load resulting from specific design criteria (e.g., this line was designed to meet winds of X mph and ice of Y thickness) as a function of the overall maximum strength of the structure. The variable is a way to quantify the expense associated with transmission line construction based on local weather conditions. There were three main steps in developing the variable, as described below.

Development of Variable

1. Zones specified by the CSA and NESC were mapped and overlaid with utility service territories.

Industry standards in Canada and the United States dictate minimum requirements for strength of transmission structures, which vary by geographic zone. During design, ice and wind loads are applied to a structure model to analyze strength in terms of percentage of strength capacity used. The zone boundaries and the required ice and wind load cases are outlined in the Canadian Standards Association (CSA) Overhead Systems Standard C22.3 No. 1-10 for Canada, and the National Electrical Safety Code (NESC) for the United States. The loading zones are illustrated in Figure 8.

Figure 8 CSA and NESC Loading Zones



Utility service territories were overlaid with the above loading zone map. GIS analysis revealed the percentage of a given utility's service territory that fell into each loading zone.

2. Loading capacity was evaluated for a base structure in each zone.

A base transmission structure was identified to represent a typical application throughout the industry. Specifications are outlined in Table 13. Although this structure cannot represent an exact base structure for every utility, it is reasonable for side-by-side comparison of relative structure loading values for utilities in each zone.

Thus, Table 14 represents the loads as a percentage of the maximum allowable for the base transmission structure. For example, the design criteria for CSA 7.2 zone "Medium A" is 73.3% of the maximum load strength of the base structure described in Table 13. The design criteria required for a structure in CSA 7.2 zone "Severe" is 148.9% of the maximum load strength of the base structure described in Table 13, indicating that the base transmission structure would fail in those conditions.

Industry best practice is to consider local historical weather data for transmission line designs, but the deterministic load cases defined by the CSA and NESC provide minimum requirements for each zone. Therefore, the load cases identified in CSA C22.3 No. 1-20 7.2 and NESC Rules 250B, 250C, and 250D were used for analysis. Loading zones with the same names in Canada and the United States are not equivalent, e.g. the CSA "Heavy" zone specifies different accumulated ice and wind loads than the NESC "Heavy" zone. Multipliers, including strength factors for structure components and load factors for ice and wind loads, are also specified in each code and were included in this analysis. PLS-CADD Lite, an engineering modeling software application for transmission and distribution structures, was used to complete nonlinear analysis of the base structure for each zonal load case, outlined in Table 14.

Table 13 Base Transmission Structure Specifications

	Metric		English	
Pole Material	wood			
Pole Length	22.9	m	75	ft
Pole Class	H2			
Span Length	106.7	m	350	ft
Framing	TP-115			
Voltage	115 kV			
Construction Grade	NESC Grade B / CSA Grade 1			
Transmission Conductor Material	795 (26/7) ACSR			
Transmission Design Tension	6000	lb	26.7	kN
Shield Wire Material	3/8" EHS Steel			
Shield Wire Design Tension	2700	lb	12.0	kN

Table 14 Loading Capacity Usage Percentages by Loading Zone

CSA 7.2	**Zone**		**Loading [%]**
	Medium A		73.3
	Medium B		81.5
	Heavy		103.5
	Severe		148.9
NESC 250B	**Zone**		**Loading [%]**
	Light		75.3
	Medium		49.7
	Heavy		66.2
NESC 250C	**Wind [mph]**		**Loading [%]**
	85		43.1
	90		48.2
	100		59.1
	110		71.1
	120		84.1
	130		98.1
	140		113.1
	150		128.9
	160		145.5
NESC 250D	**Ice [in]**	**Wind [mph]**	**Loading [%]**
	1.5	30	33.7
	0.75	40	29.2
	1	40	36.2
	1.25	40	44.3
	1.5	40	53.7
	0.5	50	34.7
	0.75	50	43.9
	1	50	54.1
	0.5	60	48.9
	0.75	60	61.7
	1	60	75.9
	1.25	60	91.7

3. Loading values were calculated for each utility based on the area and loading percentages.

The area percentages derived from the zone map and utility service territory map were multiplied by loading value percentages from PLS-CADD analysis for each loading zone present in a given utility service territory. These values were summed to produce an overall loading value for each utility. This overall loading value represents (roughly) the minimum design/build structural strength required for the utility's service territory.

Data Sources

1. United States load cases: National Electrical Safety Code (NESC) Rules 250B, 250C, and 250D
2. Canadian load cases: Canadian Standards Association (CSA) Overhead Systems C22.3 No. 1-10 7.2
3. Nonlinear loading models: PLS-CADD Lite Version 15.00

4. GIS mapping software: ArcGIS Pro v2.1, ArcGIS Server 10.5, SQL Server 2014
5. Utility service territories: S&P Global – Platts and Power System Engineering acquired service territories <https://www.platts.com/maps-geospatial>

PLS-CADD Lite Model Inputs

Zonal weather criteria are defined in NESC 250B and CSA 22.3 No. 1-10 7.2 and summarized in Table 15 below. The NESC set includes two additional sets of load cases which do not have counterparts in the CSA. These are Rule 250C: extreme wind loading and Rule 250D: extreme ice with concurrent wind loading. Separate zones were identified for these rules as well.

Table 15 Weather Criteria

		Wire Ice Density		Air Density Factor		Wind Pressure		Wire Ice Thickness		Ambient Temp		NESC Constant	
		[kg/m^3]	[lbs/ft^3]	[Pa/(m/s)^2]	[psf/mph^2]	[Pa]	[psf]	[mm]	[in]	[°C]	[°F]	[N/m]	[lb/ft]
NESC	Heavy	913	57.0	0.613	0.00256	190.5	4	12.7	0.5	-17.8	0	4.38	0.3
	Medium					190.5	4	6.4	0.25	-9.4	15	2.92	0.2
	Light					428.6	9	0.0	0	-1.1	30	0.73	0.05
	Warm Islands (<9000 ft)					428.6	9	0.0	0	10.0	50	0.73	0.05
	Warm Islands (>9000 ft)					190.5	4	6.4	0.25	-9.4	15	2.92	0.2
CSA	Severe	900	56.2	0.613	0.00256	400	8.40	19.0	0.75	-20	-4	N/A	
	Heavy					400	8.40	12.5	0.49	-20	-4		
	Medium A					400	8.40	6.5	0.26	-20	-4		
	Medium B					300	6.30	12.5	0.49	-20	-4		

Load factors and strength factors are summarized in Tables 16 and 17, respectively.

Table 16 Load Factors

	NESC Grade B	CSA Grade 1
Vertical	1.50	4.00
Tansverse - wind	2.50	2.00
Transverse - wire tensions	1.65	2.00
Longitudinal - at deadends (with terminations or tension changes)	1.65	2.00
Longitudinal - general (without terminations or tension changes)	1.10	1.30

Table 17 Strength Factors

	NESC 250B Grade B	CSA Grade 1
Wood Structures	0.65	not specified - accounted for in load factors
Wood Crossarms & Braces	0.65	
Support Hardware	1.0	
Guy Wire	0.9	
Guy Anchor and Foundation	1.0	

Appendix B: PEG Credentials

PEG is an economic consulting firm with headquarters in Madison, Wisconsin USA. We are a leading consultancy on incentive regulation and statistical research on energy utility productivity trends on cost performance. Our personnel have over sixty years of experience in these fields, which share a common foundation in economic statistics. Work for a mix of utilities, regulators, government agencies, and consumer and environmental groups has given us a reputation for objectivity. Our practice is international in scope and has included dozens of projects in Canada.

Mark Newton Lowry, the author of this report and principal investigator for this project, is the President of PEG. He has over thirty years of experience as an industry economist, most of which have been spent addressing utility issues. He has prepared productivity and benchmarking research and testimony in more than 30 separate proceedings. Author of dozens of professional publications, Dr. Lowry has also spoken at numerous conferences on utility regulation and statistical performance measurement. He recently coauthored two influential white papers on incentive regulation for Lawrence Berkeley National Laboratory. In the last five years, he has played a prominent role in incentive regulation proceedings in Alberta, British Columbia, Colorado, Hawaii, Minnesota, and Ontario as well as Québec. He holds a PhD in applied economics from the University of Wisconsin.

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Custom Incentive Rate Mechanism Design for Hydro Ottawa

June 19, 2020

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1. Introduction and Summary

1.1. Introduction

Hydro Ottawa Ltd. ("Hydro Ottawa" or "the Company") proposed a Custom Incentive Rate-Setting ("Custom IR") mechanism for its power distributor services in a February 2020 application.[1] The mechanism is a multiyear rate plan ("MRP") for 2021 to 2025 that is similar to that which the Ontario Energy Board ("OEB" or "the Board") approved for the Company in 2015 for the 2016-2020 period.[2] After a conventional rebasing of revenue in 2021 using a forecasted test year, a formula-driven Custom Price Escalation Factor ("CPEF") would apply to revenue for operation, maintenance, and administration ("OM&A") expenses for the subsequent four years of the plan. Escalation by the CPEF would depend on an inflation measure, the Company's customer growth, and a two-part X factor consisting of a base total factor productivity ("TFP") trend and a stretch factor. Mr. Steven Fenrick of Clearspring Energy Advisors LLC ("Clearspring") prepared cost and reliability benchmarking research and testimony for the Company which is germane to the choice of the stretch factor.[3]

The revenue requirement for capital would be based on a multiyear cost forecast/proposal. A capital variance account would return to customers any revenue requirement savings due to capex underspends over the plan period. Z factor treatment would be available, subject to OEB review and approval, for unforeseen and externally-driven capex and opex that exceeds a materiality threshold.

Hydro Ottawa is one of Ontario's larger electricity distributors. Its proposed plan raises many of the concerns that the OEB has expressed with respect to other recent Custom IR applications. Careful appraisal of the Company's IR proposal and the supportive statistical cost research is thus warranted. Controversial technical work and proposed IR provisions should be identified and, where warranted, challenged to avoid undesirable precedents for the Company and other Ontario utilities in the future.

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[1] EB-2019-0261, Hydro Ottawa Limited Electricity Distribution Rate Application, filed February 10, 2020.

[2] Ontario Energy Board, *Decision and Rate Order*, EB-2015-0004, December 22, 2015.

[3] Steve Fenrick, Clearspring Energy Advisors LLC, *Econometric Benchmarking Study of Hydro Ottawa's Total Cost and Reliability*, September 30, 2019.

The OEB has constructively commented on plan design and statistical cost research in its past multiyear IR decisions.

OEB staff retained Pacific Economics Group Research LLC ("PEG") to appraise and comment on Clearspring's cost benchmarking work and, if needed, to prepare an alternative study. We were also asked to consider other aspects of the Company's Custom IR proposal. This is the report on our work.

Following a brief summary of our findings, we provide pertinent background information in Section 2. There follows a critique of Clearspring's research and testimony and the presentation of some results of empirical research using our preferred methods and data. We conclude by discussing other features of the Company's Custom IR proposal. An Appendix addresses some of the more technical issues in more detail.

1.2. Summary

Stretch Factor

The X factor in Hydro Ottawa's proposed CPEF formula is the sum of a 0% base productivity trend and a 0.15% custom stretch factor. The stretch factor proposal is informed by Clearspring's total cost benchmarking work. Using an econometric total cost benchmarking model developed for the study, Clearspring found that the Company's projected/proposed costs over the five years (2021-2025) of the new plan were 7.1% below the model's predictions on average. Clearspring recommends a stretch factor of 0.30%.[4] Excluding two large construction projects, the Company's score during the years of the proposed plan would average a more favorable -12.5%.[5] In a response to interrogatories, Clearspring stated that this alternative analysis was done at the request of Hydro Ottawa. Using guidelines established by the OEB for Price Cap IR stretch factors, the Company's proposal for a 0.15% stretch factor is commensurate with the latter result.

Mr. Fenrick uses benchmarking methods are in many respects like our own. In work for several clients, he has developed some business condition variables that are useful in power distributor benchmarking. Further, his study for this proceeding is free of several concerns that we have raised

[4] Exhibit 1/Tab 1/Schedule 12/Attachment A, p. 8. See also 1.0-VECC-8, OEB-10 b) and OEB-13.

[5] 1.0-VECC-8 and OEB-10 b).

about his work in other recent OEB proceedings. This greatly reduces the scope of controversy concerning benchmarking methods in this proceeding. Clearspring's benchmarking results are fairly stable with respect to changes in the model specification.

We nonetheless disagree with some of the methods Clearspring used in this study. Here are some of our larger concerns.

- The benchmarking model still does not properly address the complex issue of density.
- Ontario data from pre-MIFRS years are included in the sample.
- The calculation of capital costs for the utilities in the econometric study sample is inaccurate.
- We believe that it desirable to go beyond econometric total cost benchmarking in Custom IR proceedings by benchmarking major cost sub-aggregates such as operation, maintenance, and administration ("OM&A") expenses ("opex") and capital cost.

PEG developed an alternative total cost benchmarking model using our preferred methods. We found that Hydro Ottawa's total cost was about 4.5% below the benchmark on average from 2016 to 2018. This is very close to an average performance. The projected/proposed total cost is about 5% above our model's prediction on average in the five years from 2021 to 2025.

PEG also developed models to evaluate Hydro Ottawa's projected/proposed opex and capital cost. These models are sensible (e.g., in terms of explanatory variables, coefficient signs and functional forms) and generate results that should be informative to the OEB and the Company alike. During the term of the proposed plan, the Company's projected/proposed OM&A expenses would be about 0.5% *below* the model's predictions while the Company's capital cost would be about 12.2% *above* the predictions.

On the basis of our research, we believe that a 0.30% stretch factor is appropriate for Hydro Ottawa, provided that the OEB is comfortable fixing the stretch factor for the full plan term. We do not believe, as a matter of principle, that the stretch factor should be based on a study of costs that exclude major plant additions. The geometric decay capital cost specification that PEG and Clearspring both use in benchmarking is sensitive to the age of plant. This strengthens incentives for utilities to postpone plant additions until they are really needed. Analogous exclusions for once in a generation projects were not made for other companies in the sample.

Productivity Growth Target

Hydro Ottawa's proposal to set the productivity growth target in the CPEF formula at 0% is controversial. This target is based on a study of Ontario power distributor total factor productivity ("TFP") trends which is now many years old and was complicated by the transition of most of these distributors to MIFRS accounting. Furthermore, the proposed CPEF applies only to OM&A expenses. The trend in the OM&A productivity of the US distributors in our sample over the full sample period was 0.27%. In the event that the CPEF applies only to OM&A revenue we believe that this trend should be the base productivity growth target in the CPEF formula.

Scale Escalator

Cost theory and index logic support use of a scale escalator in a revenue cap index.[6]

Fixed vs. Variable CPEF

The ability to adjust revenue growth to changing business conditions without weakening utility incentives is one of the chief advantages of indexed attrition relief mechanisms. The COVID-19 pandemic has made inflation and customer growth in the next few years especially difficult to accurately predict. We accordingly recommend that the Board not approve a fixed CPEF for Hydro Ottawa for the plan term.

CPEF Summary

If the Board accepts Hydro Ottawa's proposal to base capital revenue solely on the approved multiyear capital cost, our recommended CPEF formula is Inflation – 0.57% + G where the X factor is the sum of a 0.27% trend in OM&A base productivity and a 0.3% stretch factor. If, alternatively, the Board opts for a Capital-factor (C factor) approach,, similar to what the OEB has approved for Custom IR plans

[6] Since Hydro Ottawa's proposal is that the CPEF escalates aggregate OM&A expenses, which are then added to the capital-related revenue requirement based on the forecasted rate base, to form each plan year's revenue requirement, the CPEF is akin to a revenue cap adjustment.

for Hydro One distribution[7] and Toronto Hydro,[8] our recommended CPEF formula is Inflation – 0.3% + growth Customers, where the X factor is the sum of a 0% base TFP growth trend and a 0.3% stretch factor.

Other Plan Design Features

We are also concerned with the provisions for supplemental funding of capital in Hydro Ottawa's proposal. The plan is modelled on one which was approved before the OEB issued additional Custom IR guidelines in the *Rate Handbook* and is, in our view, inconsistent with those guidelines. It is also contrary to the spirit of some recent OEB rulings on Custom IR proposals.

The proposed ratemaking treatment of capital cost is especially problematic.

- The capital variance account would greatly weaken the incentives to contain capex. The Company would be perversely incented to spend excessive amounts on capex that slows the growth of its OM&A expenses.
- The capital variance account reduces but does not eliminate the Company's incentive to exaggerate its need for extra capital revenue and to bunch capex in ways that bolster such revenue.
- The OEB and stakeholders are compelled to judge the prudence of several years of forecasted/proposed capital spending. It is difficult and resource-intensive to perform this task well.
- Hydro Ottawa may be overcompensated for its capex. The kinds of capex accorded forecast and variance account treatment are, for the most part, conventional distribution capex that are similar to that incurred by distributors in studies used to calibrate the base productivity trend. Capital cost growth would be fully funded when it is rapid for reasons beyond the Company's control but there would be no counterbalancing obligation for the Company to operate with slower revenue growth if and when its capital cost growth was slow for reasons beyond its control. Thus, customers would never receive the benefit of industry TFP

[7] EB-2017-0049

[8] EB-2018-0165

growth between rate cases, even in the long run and even if it is achievable. The stretch factor would apply only to OM&A revenue.

We discuss in the report several alternative capital cost treatments. A C factor treatment with a supplemental stretch factor like those which the OEB has recently approved for Toronto Hydro and Hydro One Networks is certainly one option worth careful consideration. However, the OEB has shown increasing concern about this approach and some alternative approaches also merit consideration. We provide some discussion of various ratemaking treatments of capital in other jurisdictions.

It seems desirable to consider how to make Custom IR more streamlined, incentivizing, and fair to customers while still ensuring that it is reasonably compensatory over time for efficient distributors. Utilities should be encouraged to <u>not</u> stay on Custom IR indefinitely.[9] Regulators in other jurisdictions (e.g., Alberta and Britain) who championed IR but found themselves saddled with a system that retained too many cost of service features have reconsidered and reformed IR at the end of each round of plans.

The other reforms discussed in the report range from evolutionary measures such as an incentivized capital variance account to larger departures from the Board's recent Custom IR approaches, such as those used in Alberta and California.

1.3. PEG Credentials

PEG is an economic consulting firm with home offices on Capitol Square in Madison, Wisconsin USA. We are a leading consultancy on IR and statistical research on energy utility performance. Our personnel have over sixty years of experience in these fields, which share a common foundation in economic statistics. The University of Wisconsin has trained most of our staff and is renowned for its

[9] See EB-2018-0165, Decision and Order, December 19, 2019. While approving Toronto Hydro's Custom IR plan for 2020-2024, the OEB stated:

> Toronto Hydro indicated that intervenors are asking the OEB panel to either make changes to generic policy through a particular utility's rate application or to fetter the discretion of a future panel. Toronto Hydro also submitted that its proposed ratemaking formula is structurally the same as the one approved in its 2015-2019 Custom IR proceeding. The OEB notes that the Custom IR approach taken has required extensive evidence and time to consider the details provided. Toronto Hydro is encouraged to consider an alternative approach in the future that might be more efficient in establishing the revenue requirement for the base year and following years as well as meeting OEB RRF objectives, and improving the balance of risk between customers and the utility. Toronto Hydro should not assume that future panels will continue to accept Toronto Hydro's current proposed Custom IR framework. (p. 24)

economic statistics program. Work for a mix of utilities, regulators, government agencies, and consumer and environmental groups has given PEG a reputation for objectivity and dedication to good research methods. Our practice is international in scope and has included dozens of projects in Canada.

Mark Newton Lowry, the author of this report and principal investigator for the project, is the President of PEG. He has over thirty years of experience as an industry economist, most spent on energy utility issues. Author of numerous professional publications, Dr. Lowry has also chaired several conferences on performance measurement and utility regulation. He has provided productivity, benchmarking, and other statistical cost research and testimony in over 30 proceedings. A recent study on the productivity trends of U.S. power distributors was published in 2017 by Lawrence Berkeley National Laboratory ("Berkeley Lab").[10] In Canada, Dr. Lowry has played a prominent role in IR proceedings in Alberta, British Columbia, and Québec as well as Ontario. He holds a PhD in applied economics from the University of Wisconsin.

[10] Mark Newton Lowry, Matt Makos, and Jeff Deason, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, Lawrence Berkeley National Laboratory, July 2017.

2. Background on Ontario Regulation

In this section of the report we summarize in one place notable aspects of the OEB's evolving approach to incentive rate-setting ("IR"). This review is useful background for the discussions of empirical research and other plan design issues that follow. In particular, it pulls together statements that could guide further reforms to Custom IR.

2.1 Renewed Regulatory Framework

The Renewed Regulatory Framework ("RRF") (initially known as the Renewed Regulatory Framework for Electricity or "RRFE") resulted from initiatives the OEB began in 2010 to review their policies in the areas of ratemaking, distribution system planning, and performance measurement. The Board stated that the goal of the RRF is

> to support cost-effective modernization of the network while at the same time controlling rate and/or bill impacts on consumers.[11]

The Board provided three ratemaking options under the RRF: the fourth-generation standard incentive ratemaking mechanism (now called "Price Cap IR"), the Annual IR index, and Custom IR. Each distributor can request its preferred ratemaking approach. The Board stated regarding these options that

> [Price Cap IR] is most appropriate for distributors that anticipate some incremental investment needs will arise during the plan term. The Board expects that this method will be appropriate for most distributors.
>
> Distributors with relatively steady state investment needs (i.e., primarily sustainment), may prefer the Annual Incentive Rate-setting Index.
>
> The Custom Incentive Rate-setting ("Custom IR") method may be appropriate for distributors with significantly large multi-year or highly variable investment commitments with relatively certain timing and level of associated expenditures.[12]

The OEB noted that these three options would have many similarities.

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[11] Ontario Energy Board, *Renewed Regulatory Framework for Electricity Frequently Asked Questions*, filed in Ontario Energy Board Case EB-2010-0379, November 8, 2011, p. 1.

[12] Ontario Energy Board, *Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,* October 18, 2012, p. 14.

All three rate-setting methods are based on a multi-year IR mechanism. Each rate method will be supported by: the fundamental principles of good asset management; coordinated, longer-term optimized planning; a common set of performance expectations; and benchmarking. Rate applications will be supported by a five-year capital plan that includes consideration of regional infrastructure planning.

The Board stated that this more flexible approach to rate-setting will:

- enhance predictability necessary to facilitate planning and decision-making by customers and distributors;
- better align rate-setting with distributor planning horizons;
- facilitate the cost-effective and efficient implementation of distributor multi-year plans that have been developed to achieve the outcomes for customer service and cost performance; and
- help to manage the pace of rate increases for customers.[13]

The OEB issued a *Handbook for Utility Rate Applications* ("*Rate Handbook*") in 2016, expanding the rate-setting principles and options, as the RRF, to all energy sector rate-regulated entities in Ontario,[14]

2.2 Price Cap IR

Many aspects of what is now called Price Cap IR are holdovers from the third generation incentive ratemaking mechanism.[15] These include periodic rate rebasings based on a forward test year, use of a price cap index to escalate rates between rebasings, opportunities for distributors to obtain supplemental revenue for capex, and an off-ramp to address significant earnings variances or unacceptable performances. Some costs are addressed by variance accounts.

The price cap index ("PCI") formula includes an inflation measure, an X factor, and a Z factor. The X factor is the sum of a 0% TFP trend and a stretch factor ranging from 0 to 0.6% which depends on the outcome of an annual total cost benchmarking assessment.

[13] *Ibid*., p. 10

[14] Ontario Energy Board, *Handbook for Utility Rate Applications*, October 13, 2016.

[15] Price Cap IR was previously called the fourth-generation incentive ratesetting mechanism ("4GIRM").

Z factor adjustments to PCI growth may be requested for certain changes in costs which result from unforeseen events that are "generally external to the regulatory regime and beyond the control of management."[16] To obtain Z factor treatment a distributor must prove that the costs for which it requests recovery are related to the Z factor event, not already reflected in its base rates, prudently incurred, and in excess of the Board's materiality threshold. The threshold:

> will be differentiated based on the relative magnitude of the revenue requirement in order to maintain the concept of relative materiality across diverse distributors. Specifically, the materiality threshold will be as follows:
>
> - $50 thousand for distributors with a distribution revenue requirement less than or equal to $10 million;
> - 0.5% of distribution revenue requirement for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million; and
> - $1 million for distributors with a distribution revenue requirement of more than $200 million.

The threshold applies to individual events.[17] If a cost impact is deemed eligible, the entirety of the impact can be funded.

Supplemental funding for capital expenditures ("capex") is available from two Price Cap IR provisions: advanced capital modules ("ACMs") and incremental capital modules ("ICMs"). An ACM may be requested only during rebasing rate cases and addresses projects outlined in the applicant's distribution system plan ("DSP"). An ICM may be requested between rebasing rate cases to address projects not included in a distributor's DSP, projects which have increased substantially in size and/or scope since the approval of the DSP, and projects whose eligibility could not be determined during the rebasing.

The ACM was developed to address concerns that distributors were strategically bunching capex around the year of the rebasing and not in accordance with a prudent asset management program. The Board in its decision discussed the advantages of the ACM.

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[16] Ontario Energy Board, *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, EB-2007-0673, July 14, 2008, p. 35.

[17] *Ibid,* p. 36.

> Advancing the reviews of eligible discrete capital projects, included as part of a distributor's Distribution System Plan and scheduled to go into service during the IR term, is expected to facilitate **enhanced pacing and smoothing of rate impacts**, as the distributor, the Board and other stakeholders will be examining the capital projects over the five-year horizon of the DSP.
>
> The ACM approach should also facilitate regulatory efficiency by placing the requirement to establish the need and prudence for any additional incremental capital spending within a cost of service proceeding. This is well suited to such forms of review and when the five-year DSP is tested. Consequently, largely mathematical calculations of ACM/ICM-related matters, such as the determination of the rate riders, will remain part of the streamlined IR applications in subsequent years.
>
> When coupled with the requirement for five-year DSPs and other policies that impose discipline upon distributors in their planning, the ACM should **reduce incentives for clustering capital projects around the rebasing year.** Further, this also provides options for distributors to recover costs for discrete capital projects when they are needed throughout the Price Cap IR cycle….
>
> The ACM approach will also assist in large part to preserve the **regulatory efficiency** of IR applications, as many qualifying capital projects should be identifiable through the DSP. More importantly, it provides **greater assurance of recovery for prudent and appropriately prioritized capital projects** regardless of when the investments might be made. The Board would also expect **improved performance with respect to capital forecasting** both in terms of timing of and the level of projects, taking into account bill impacts on customers as well on the financial, human and other resources of the utility to carry out its capital projects as planned.[18] [Emphasis added]

For either type of capital module, distributors must demonstrate that the capex driving the supplemental funding request is prudently incurred, material, and the most cost-effective option for ratepayers. Distributors overearning by more than 300 basis points cannot request a capital module.

To demonstrate materiality, the total amount of capex needed must exceed a materiality threshold determined by a Board-approved formula. Supplemental funding is not provided for capex below the materiality threshold. There is thus a dead band in the eligibility of capex for supplemental funding which varies by utility.[19]

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[18] Ontario Energy Board, *Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module,* EB-2014-0219, September 18, 2014, pp. 11-12.

[19] PEG estimated in a recent Toronto Hydro proceeding that its markdown would be about 3% under an ICM.

The initially approved materiality threshold calculation required a distributor's capex to otherwise exceed the threshold by 20%. The Board provided the following discussion of this provision:

> Certain participants suggested that there should be a dead band added to the calculated materiality threshold to prevent marginal applications. The suggested levels ranged from adding 10 percent to 50 percent to the calculated percentage thresholds. The Board finds merit in the suggestion of adding a dead band. However, a high adder may be unreasonably prohibitive for distributors genuinely in need of incremental CAPEX during the term of 3rd Generation IR, as it would connote a regime that is not related to revenue requirement considerations. The Board is satisfied that a 20 percent adder is sufficient at this time.[20]

In 2016 the percentage by which capex must exceed the materiality threshold was reduced from 20% to 10% as part of a series of changes made to the materiality threshold formula, including revisions that would allow the materiality threshold to be calculated more easily over a multiyear period. The Board explained this reduction as follows:

> [T]he OEB considers that **a dead band remains an appropriate means to allow for appropriate funding for qualifying ACM/ICM projects, while discouraging numerous applications for marginal amounts that the utility would be expected to manage under the RRFE and Price Cap IR framework**. However, maintaining the dead band at 20% may not be responsive to the OEB's RRFE objectives of enhanced distributor planning and effective access to available regulatory tools to facilitate pacing and prioritizing needed capital investments. Furthermore, with the adoption of the multi-year formula…, the OEB concurs that the dead band should decrease.
>
> The OEB has determined that a dead band of 10% is more appropriate in light of the changes being made to the materiality threshold formula, and balancing the need for appropriately funding necessary incremental capital investments while **avoiding numerous marginal applications and providing some protection that amounts are not already in rates**.[21] [Emphasis added]

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[20] Ontario Energy Board, *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, EB-2007-0673, September 17, 2008, p. 33.

[21] Ontario Energy Board*, Report of the OEB New Policy Options for the Funding of Capital Investments: Supplemental Report*, EB-2014-0219, January 22, 2016, pp. 17-18.

2.3 Annual IR Index

Under this option, a utility could operate for more than five years under a price cap index. The base TFP trend in the index would be zero but the stretch factor would be set at 0.60%. This is the high end of the Price Cap IR stretch factor range. Utilities selecting this option would not be able to seek supplemental funding through a capital module.

2.4 Custom IR

Under the Custom IR approach, a distributor-specific rate trend is determined by the Board that is

> informed by: (1) the distributor's forecasts (revenue and costs, inflation, productivity); (2) the Board's inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor's forecasts.[22]

Further,

> The Board expects that a distributor that applies under this method will file robust evidence of its cost and revenue forecasts over a five year horizon, as well as detailed infrastructure investment plans over that same time frame.[23]

and

> planned capital spending is expected to be an important element of the rates distributors will be seeking, and hence will be subjected to thorough reviews by parties to the proceeding. Once rates have been approved, the Board will monitor capital spending against the approved plan by requiring distributors to report annually on actual amounts spent. If actual spending is significantly different from the level reflected in a distributor's plan, the Board will investigate the matter and could, if necessary, terminate the distributor's rate-setting method. A distributor on the Custom IR method will have its rate base adjusted prospectively to reflect actual spend at the end of the term, when it commences a new rate-setting cycle.[24]

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[22] OEB, *Renewed Regulatory Framework*, *op. cit*., p. 13.

[23] *Ibid*., p. 19.

[24] *Ibid.*, p. 20.

The OEB acknowledged that "The adjudication of an application under the Custom IR method will require the expenditure of significant resources by both the Board and the applicant."[25]

Since Custom IR plans were sanctioned, the OEB has approved eight plans for transmitters and distributors, rejected 2 outright, and substantially modified another. The designs of attrition relief mechanisms ("ARMs")[26] in these plans fall into three categories: fully forecasted ARMs[27], hybrid ARMs where OM&A revenue is indexed and capital revenue is proposed/projected, and indexation applied to both OM&A and capital revenue but with a provision for extra capital revenue via a C factor. Plans of the first two kinds have typically been outlined in settlements, while the latter category resulted from litigated proceedings.

All three kinds of ARMs have usually been combined with capital cost variance accounts and provisions to asymmetrically return to customers most or all of any revenue requirement savings made possible by capex underspends. The prevalence of these "clawback" mechanisms has been somewhat surprising since they were not a mandated in the Custom IR guidelines. A plan for Enbridge Gas Distribution didn't feature a clawback, though some kinds of capex were tracked.[28]

Early History

The first approved Custom IR plan featured an ARM based entirely on company projections/proposals. This approach, together with the clawback of capex underspends, is similar to that used to regulate power distributors in New York state. The approach subsequently fell from favor in Ontario due, in part, to concerns highlighted by the Board in its 2015 rejection of a Hydro One Networks Custom IR proposal.

> **The OEB expects Custom IR rate setting to include expectations for benchmark productivity and efficiency gains that are external to the company.** The OEB does not equate Hydro One's embedded annual savings with productivity and efficiency

[25] *Ibid*., p. 19.

[26] Our use of the "ARM" term is an attempt to finesse the fact that some plans have *price* caps and others have *revenue* caps. The ARM term originated in California regulation.

[27] The word "forecasted" is something of a misnomer since distributor capex will frequently be lower if their capex forecasts are not accepted.

[28] Ontario Energy Board, *Decision with Reasons,* EB-2012-0459, July 17, 2014.

> incentives. **Incentive-based or performance-based rates are set to provide companies with strong incentives to continuously seek efficiencies in their businesses.**
>
> The OEB does not believe that Hydro One's plan contains adequate efficiency incentives to drive year-over-year continuous improvement in the company. Furthermore, the plan lacks measurement of increased efficiency year-over-year, that is in a form indicating trending and that is transparent.[29] [**Emphasis added]**

The Board expressed similar concerns in its decision to reject a similar Custom IR proposal brought forward by PowerStream in 2016.[30]

First Hydro Ottawa Plan

Hydro Ottawa currently operates under a Custom IR plan detailed in a settlement that the OEB approved in December 2015. A conventional rebasing established rates for 2016. Allowed revenue in subsequent years of the plan has been escalated by a hybrid mechanism.[31] Revenue for OM&A expenses has been escalated by a formula that includes an inflation factor, a 0.14% growth factor, and a -0.30% productivity factor. Capital revenue has instead been based on projections/proposals. A capital investment variance account will asymmetrically return to customers the entirety of cumulative revenue requirement reductions that result from any underspends in system renewal and service, system access, and general plant capex. An Efficiency Adjustment Mechanism acts as a proxy stretch factor if the Company's cost performance as measured using the OEB's econometric total cost benchmarking model materially worsens during the plan. An earnings sharing mechanism ("ESM") asymmetrically shares only surplus earnings and has no dead band. The term of the plan is the five years from 2016 to 2020.

The Efficiency Adjustment Mechanism has been triggered during the plan, as Hydro Ottawa's cost performance slipped in the OEB's benchmarking from Group III to Group IV.[32] During the term of the first Custom IR plan, Hydro Ottawa also transitioned to fixed pricing for residential customers.

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[29] Ontario Energy Board, *Decision,* EB-2013-0416/EB-2014-0247*,* March 12, 2015, p. 14.

[30] Oshawa PUC Networks' proposal for a Custom IR plan based entirely on forecasts was modified to include a reopener after the third year.

[31] A plan with a hybrid ARM was also approved in 2015 for Kingston Hydro. To the best of PEG's knowledge, there have been no subsequent Custom IR proposals that featured this kind of ARM prior to the current proceeding.

[32] See Interrogatory OEB-4, Table 1-Staff-4-1. Moving between Group III and Group IV in the OEB's benchmarking under 4thGIRM is associated with a 0.15% increase in the stretch factor. The amount recorded in the efficiency

In its rate application, the Company explained how a need for many years of high capex encouraged it to propose Custom IR, stating that

> Hydro Ottawa's capital expenditure plan for the 2016-2020 period proposes an average gross annual expenditure of $130 million per year. Hydro Ottawa fully expects this level of annual capital expenditure will be sustained, if not increased through the decade from 2020-2030.
>
> The proposed annual expenditure level is significantly greater than annual expenditure levels set out in previous Hydro Ottawa rate applications but is consistent with the 2013- 2015 capital spend levels for distribution plant… By comparison, between 2006 and 2009, Hydro Ottawa's average annual net expenditure level was approximately $60 million per year (gross expenditure average was $75 million per year).[33]

The Company listed several unique challenges it was facing that drove the need for high capex. These challenges included climate, aging assets, "intensification of development within the urban core and continued suburban growth in the east, west, and southern regions of its service territory."[34] The Company reported that approximately 30% of its assets had reached or exceeded their expected useful life.[35]

As part of the settlement approval process for Hydro Ottawa, Staff made a submission appraising the settlement. While Staff believed that the overall settlement was reasonable, it expressed concerns about Hydro Ottawa's Custom IR ratemaking framework:

> The approach to capital spending, however, does not necessarily accord so clearly with a performance-based rate form: costs to customers associated with capital investments are proposed to be recovered on a cost-of-service basis, based on a used or useful principle, forecast against a rate base agreed-upon for every year of the plan term. The capital expenditure related component of rates is excluded from an explicit stretch or productivity commitment and is not subject to an index approach that has been informed by the company's investment plan commitments.
>
> Such asymmetry between the treatment of OM&A and capital expenses was not the intent of the Custom IR option. Instead, with the onset of the RRFE, the OEB has advocated comprehensive, total cost incentive rate-setting, on the grounds that it

adjustment mechanism was 0.15% of the service revenue requirement for each year that the mechanism was triggered.

[33] EB-2015-0004, Exhibit A, Tab 2, Schedule 1, p. 10.

[34] *Ibid*, p. 4-5.

[35] EB-2015-0004, Exhibit A, Tab 2, Schedule 1, Updated June 29, 2015, p. 4.

> creates stronger and more balanced incentives. As has been argued elsewhere, including during RRFE consultations, an asymmetrical I-X framework applied to OM&A but not to capital may distort incentives, promote sub-optimal investments and alter a distributor's response to cost and revenue changes.[36]

Rate Handbook Guidelines

Subsequent to approving Hydro Ottawa's plan the Board issued the *Rate Handbook* that provides further guidance on the "minimum standards" for Custom IR applications.[37] The Board stated that "there is **no threshold test or eligibility requirement** for a Custom IR application."[38] However, the application must advance the OEB's RRF goals and meet certain standards that include the following.

> **The annual rate adjustment must be based on a custom index** supported by empirical evidence (using third party and/or internal resources) that can be tested. **Custom IR is not a multi-year cost of service; <u>explicit financial incentives</u> for continuous improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction** over the term of the plan (not built into the cost forecast)…
>
> **If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service…**
>
> **It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications**. **Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.**[39] [Emphasis added]

[36] *OEB Staff Submission on the Settlement Proposal,* EB-2015-0004, pp. 5-6.

[37] *Rate Handbook*, *op. cit*., pp. 18-19 and 24-28.

[38] *Ibid*, p. 25.

[39] *Ibid*., pp. 25-26.

Recent Custom IR Developments

C Factor ARMs

The third approved type of ARM used in Custom IR has been featured in two Toronto Hydro-Electric Ltd. ("Toronto Hydro") plans and plans for transmission and distribution ("T&D") services of Hydro One Networks. This type of ARM nominally escalates capital as well as OM&A revenue using an index. However, a C-factor term in the escalation formula provides supplemental capital revenue. The C factor effectively compensates the utility for most of the difference between its forecasted capital cost growth and the capital revenue growth that the formula otherwise provides. As approved by the Board in Toronto Hydro's first plan, this effectively permitted the Company to obtain capital revenue growth equal to the approved rate of capital cost growth less the base TFP trend and the stretch factor.

The OEB in its decision approving Toronto Hydro's first Custom IR plan expressed some qualms about the heavy reliance on detailed capital cost forecasts, stating that

> The record in this case is one of the largest that the OEB has ever seen. It is important to strike a balance between the amount of evidence necessary to evaluate the Application and the goal of striving for regulatory efficiency. It is important to note that it is not the OEB's role, nor the intervenors, to manage the utility or substitute their judgment in place of the applicant's management. That is the job of the utility. The OEB has established a renewed regulatory framework for electricity (RRFE) which places a greater emphasis on outcomes and less of an emphasis on a review of individual line items in an application.[40]

With capital revenue still being addressed on a largely cost of service basis, the OEB, its Staff, and various parties have expressed concerns about regulatory cost and incentives with this approach. In its decision in the Hydro One distribution proceeding the Board stated that:

> Hydro One has argued that the 0.45% stretch factor inherent in the (I – X) adjustment is applied to the revenue requirement, and therefore applies to both OM&A and capital. The difference between the treatment of OM&A and capital with Hydro One's proposal is that funding for OM&A is not based on a forecast of OM&A costs. For OM&A, Hydro One is expected to manage within an increase of less than inflation (I – X) each year, regardless of its forecast costs. This is to incent the company to find productivity improvements. For capital, however, Hydro One has forecast capital expenditures for

[40] Ontario Energy Board, *Decision and Order*, EB-2014-0116, December 29, 2015, p. 2.

> each year of the term, and is seeking funding for any incremental capital not funded by the (I – X) adjustment.
>
> **The OEB expects Hydro One to stretch itself more to find additional initiatives and to consider new approaches to its business. The OEB is therefore imposing an additional stretch factor for the capital factor of 0.15% to incent further productivity improvements throughout the term, and to provide customers the benefit from these additional improvements upfront**.[41]

The OEB subsequently adopted Custom IR plans with C factors and supplemental stretch factors in decisions on new Custom IR plans for Toronto Hydro and the transmission services of Hydro One. Nevertheless, the Board expressed concerns about this revised approach to Custom IR in their most recent THESL decision.

> The RRF objectives of customer-focused outcomes and continuous improvement were not particularly well serviced under Toronto Hydro's 2015-2019 Custom IR framework. Toronto Hydro made significant investments in its system resulting in increases to rates and declining cost performance. The OEB will be making several changes to Toronto Hydro's Custom IR proposal to increase compliance with the objectives set out in the Renewed Regulatory Framework….
>
> **The OEB notes that the Custom IR approach taken has required extensive evidence and time to consider the details provided. Toronto Hydro is encouraged to consider an alternative approach in the future that might be more efficient in establishing the revenue requirement for the base year and following years as well as meeting OEB RRF objectives, and improving the balance of risk between customers and the utility. Toronto Hydro should not assume that future panels will continue to accept Toronto Hydro's current proposed Custom IR framework**. [42] (emphasis added)

Incentivized Capital Variance Accounts

Capital cost variance accounts in the current Custom IR plans for T&D services of Hydro One have incentive features. One feature allows the company to retain the cumulative revenue requirement savings that result from the first 2% of underspends in each year. This is essentially a dead band that is analogous to the dead bands sometimes seen in ESMs.

[41] Ontario Energy Board, *Decision and Order* EB-2017-0049 Hydro One Networks Inc., March 7, 2019, pp. 32-33.

[42] Ontario Energy Board, *Decision and Order EB-2018-0165 Toronto Hydro-Electric System Limited,* December 19, 2019, pp. 23-24.

Another incentivizing provision allows the company to retain all of the revenue requirement savings resulting from any underspends that can be attributed to verifiable productivity gains until the next rebasing. Verifiable productivity gains are the sum of capital productivity gains and capital-allocated corporate costs; are incremental to productivity initiatives incorporated in the Company's Custom IR plan filing; and must result from a productivity initiative that was approved by Hydro One's management. The resulting underspends must be confirmed by the Board as legitimate productivity gains at rebasing.

The Board discussed these mechanisms in the Hydro One Networks Transmission Custom IR decision.

> The [capital cost variance] account was established to protect customers from potential underspending of Hydro One's capital plan**. The OEB finds it reasonable to have a threshold at 98% to allow Hydro One to manage its operations without a potential penalty from underspending.** The OEB also finds it acceptable during this three-year term to allow Hydro One to adjust the account for identifiable productivity improvements, in order to encourage continuous improvement. The OEB agrees with Hydro One that the OEB panel for its next rebasing application can review these adjustments to determine whether they were true productivity savings and reasonable. The OEB panel for that proceeding can also determine whether the [capital cost variance] account should continue, and if so, whether these productivity adjustments add too much complexity to the account and should be discontinued.[43]

2.5 Hydro Ottawa's New Proposal

Hydro Ottawa's new Custom IR proposal is broadly similar to its expiring plan.[44] The term of the plan would be the five-year 2021-2025 period. Rates for 2021 would be established by a traditional rebasing process that uses a forecasted test year. A hybrid ARM would escalate allowed revenue in subsequent years. OM&A revenue would be escalated formulaically using an index while capital revenue would be based on a multiyear projection/proposal of capital cost.

A Custom Price Escalation Factor for OM&A revenue would be based on a formula that includes a custom inflation factor ("I"), a productivity factor ("X"), and a growth factor ("G").

$$CPEF = I - X + G.$$

[43] Ontario Energy Board, *Decision and Order EB-2019-0082*. April 23, 2020, pp. 172-173.

[44] We use the term distributor services to encompass distribution and customer (e.g., billing and collection) services.

The proposed inflation measure is similar to that which the OEB adopted for Price Cap IR. Measured inflation measure would be a cost-weighted average of the growth in two inflation subindexes: Canada's gross domestic product implicit price index for final domestic demand ("$GDPIPIFDD^{Canada}$") and the average weekly earnings for all employees in Ontario ("$AWE^{Ontario}$"). Hydro Ottawa has proposed to change the weights for these two subindexes from the 70/30 in the Price Cap IR to 44.5%/55.5% based on an analysis of the labor/non-labor shares of the Company's gross OM&A expenses for the 2016-2020 period. The Company has also proposed to calculate the inflation factor using historical and projected data for the 2017-2025 period from the Conference Board of Canada. The inflation measure would not be updated during the plan, instead being fixed at 2.26%.[45]

The proposed X factor would be fixed as the sum of a 0% total factor productivity ("TFP") component and a 0.15% stretch factor component. The 0% TFP factor would be based on the OEB's Price Cap IR decision and a more recent OEB precedent. The 0.15% stretch factor is based on a Clearspring benchmarking exercise that excluded costs of the sizable Company's Facilities Renewal Program ("FRP") and Cambrian Municipal Transformer Station ("MTS") projects, which the Company notes "do not occur on a regular basis."[46] Clearspring instead recommended a 0.30% stretch factor based on a benchmarking run that retained these costs.[47]

The G factor would compensate Hydro Ottawa for "the increased costs associated with its substantial and steady customer growth."[48] The Company's proposal to fix the value of G at 0.40 is based on the 1.34% growth trend in its historical and forecasted customer count from 2013 to 2020 and the fact that approved customer growth escalators in two Canadian jurisdictions have been marked down.[49]

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[45] See Interrogatory Response to OEB-5. Hydro Ottawa acknowledged some errors in calculations, and provided a corrected measure of 2.33%. However, Hydro Ottawa proposed to maintain the 2.26% forecast as being favorable to customers.

[46] EB-2019-0261, Exhibit 1 Tab 1 Schedule 10, p. 19

[47] Clearspring Report and IRRs 1.0-VECC-8a, OEB-10 b) and OEB-13, *op. cit.*

[48] EB-2019-0261, Exhibit 1 Tab 1 Schedule 10, p. 20.

[49] EB-2019-0261, Exhibit 1 Tab 1 Schedule 10, pp. 20-24.

Hydro Ottawa proposes to freeze the value of the CPEF at 2.51% during the plan. This would reflect the fixed 2.25% inflation factor less the 0.15% X factor plus the 0.40% G factor.

Several of the Company's costs would be addressed by variance accounts. These would include expenses for pensions and other post-employment benefits. Most costs of conservation and demand management ("CDM") programs would continue to be funded by Ontario's Independent Electricity System Operator rather than through rates.[50] A lost revenue adjustment mechanism would compensate Hydro Ottawa for load losses due to CDM programs.

A capital variance account would separately track variances in the cumulative revenue requirement arising from four kinds of capex: System Access, System Services, System Renewal, and General Plant.[51] Reductions in the cumulative revenue requirement would be passed through to customers at the end of the plan. The depreciated balance of any capex overspends would be considered for recovery in the next rate case.

Hydro Ottawa would retain the option to request Z factor adjustments to its revenue if qualifying events occur, based on the OEB's existing Z factor policy. Qualifying events must be difficult to foresee, outside the Company's control, and have a cost impact that exceeds a materiality threshold. The threshold for Hydro Ottawa would be $1 million or more per event.

An ESM would asymmetrically share surplus earnings when the ROE exceeded the Board-approved target by more than 150 basis points. This proposed mechanism adds a 150 basis point dead band to the Company's current ESM. For each year, the ratepayer share (50%) of any overearnings would be calculated and added to a deferral account. At the end of the plan term, the deferral account balance would be refunded to customers.

Hydro Ottawa has also proposed to apply the OEB's existing off-ramp policy. An off-ramp would be triggered if earnings variances exceed the OEB-approved rate of return on equity by more than 300 basis points in a single year. If an off-ramp is triggered, a regulatory review may be initiated. This

[50] The current CDM framework is set to expire at the end of 2020.

[51] A symmetric variance sub-account for system access capex is rationalized on the grounds that "capital spending in this category is driven by customer requests and is therefore difficult to predict, as the level of required expenditure is outside Hydro Ottawa's control.

review would be prospective in nature and could result in modifications to the plan, the plan continuing without changes, or the termination of the plan.

The Company proposes to add 16 metrics to its existing performance scorecard. Each of these metrics is associated with a target, which may be to monitor, improve, or maintain performance. Hydro Ottawa has proposed to terminate its asymmetric efficiency adjustment mechanism.

3. Principles for Revenue Cap Index Design

Revenue cap indexes featuring productivity offsets play a key role in both Hydro Ottawa's proposed approach to Custom IR and the alternative "C factor" approach used by other distributors. This section of the report considers some technical and theoretical issues in research to develop revenue cap indexes and productivity growth targets.

3.1 Productivity Research and its Use in Regulation

Productivity Indexes

A productivity index is the ratio of an output (quantity) index ("Outputs") to an input index ("Inputs"). Growth in a productivity trend index is then the difference between output and input growth:

$$\textit{growth Productivity} = \textit{growth Outputs} - \textit{growth Inputs}. \qquad [1]$$

Productivity grows when output rises more rapidly than inputs.

The scope of a productivity index depends on the array of inputs addressed by the Inputs. *Partial* factor productivity indexes measure productivity in the use of certain inputs such as capital or labor. A *multifactor* productivity index ("MFP") measures productivity in the use of multiple inputs. In Ontario, these are usually called *total* factor productivity indexes even though indexes calculated for ratemaking in Ontario have never to our knowledge addressed the productivity of all inputs.

The output index of a company measures growth in its output. If the index is multidimensional, the growth in each output dimension which is itemized is measured by a subindex, and growth in the summary index is a weighted average of growth in the subindices. In designing an output index, choices concerning subindices and weights should depend on the way the index is to be used. One possible objective of output research is to measure the impact of output growth on *cost.*[52] In that event, the index should be constructed from one or more output variables that measure dimensions of the

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[52] Another possible objective is to measure the impact of output growth on *revenue*. In that event, the subindices should measure trends in *billing determinants* and the weight for each itemized determinant should reflect its share of revenue.

"workload" that drive cost. A productivity index calculated using a cost-based output index ("*Outputs*^{C}") will be denoted as *Productivity*^{C}.

If there is more than one output variable in an *Outputs*^{C} index, the weights for these variables should reflect their relative cost impacts. The sensitivity of cost to a small change in the value of a business condition variable is commonly measured by its cost "elasticity." Cost elasticities can be estimated econometrically using data on the operations of utilities. Such estimates provide the basis for elasticity-weighted output indexes.

Sources of Productivity Growth

Economists have studied the drivers of productivity growth using mathematical theory and econometric cost research. A classic study by Denny, Fuss, and Waverman has been influential in this literature.[53] This team included a University of Toronto economics professor.

Research has found the sources of utility productivity growth to be diverse. One important productivity driver is technological change. New technologies permit an industry to produce given output quantities with fewer inputs. A second important productivity growth driver is economies of scale. These economies are realized in the longer run if inputs tend to grow less rapidly than operating scale. Incremental scale economies (and thus productivity growth) will typically be lower when output growth is slower. Incremental scale economies may also depend on the current scale of an enterprise. For example, there may be diminishing incremental returns to scale as an enterprise grows beyond a certain point.

A third driver of productivity growth is X inefficiency --- the degree to which a company fails to operate at the maximum possible efficiency. Productivity growth will increase to the extent that X inefficiency diminishes. A company's potential for future productivity growth from this source is greater the higher is its current inefficiency.

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[53] See Michael Denny, Melvyn A. Fuss, and Leonard Waverman, *The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications*, in PRODUCTIVITY MEASUREMENT IN REGULATED INDUSTRIES, at 172-218 (May 12, 1981).

Technological change, scale economies, and X inefficiency are generally considered to be dimensions of operating efficiency. Productivity indexes are, therefore, sometimes considered to be measures of efficiency. However, theoretical and empirical research reveals that productivity index growth is also affected by changes in miscellaneous business conditions other than input price inflation and output growth which drive cost.[54] A clear example for a power distributor is forestation. If forestation increases in a distributor's service territory due, for example, to a decline in the acreage of open fields[55], more inputs are needed for line clearance. Cost growth will then accelerate and productivity growth will slow.

System age is another business condition that affects productivity. Productivity growth tends to be greater to the extent that the current capital stock is large relative to the need to replace aging plant. If a utility requires unusually high replacement capex (a.k.a. "repex"), productivity growth can be unusually slow and even decline. MFP growth of gas and electric power distributors is especially sensitive to repex for several reasons.

- Distribution technology is capital-intensive.
- Highly depreciated assets valued in historical dollars are typically replaced with assets designed to last for decades which must conform to the latest performance standards. These standards typically exceed any that were previously applicable and may incorporate new technologies. Contributions in aid of construction are usually not provided for repex.
- Under the cost of service accounting traditionally used in North American ratemaking, the cost impact of repex is magnified. Assets are valued in historical dollars.
- There is typically no counterbalancing growth in measured output.

On the other hand, productivity growth can accelerate after a multiyear surge in repex as the replacement assets depreciate and growth in the rate of return component of capital cost slows.

[54] To better understand this result, consider that a productivity index is the ratio of an output index to an input index. The quantity of inputs that a utility uses depends on various external business conditions as well as its efficiency. Thus, productivity growth is sensitive to changes in business conditions as well as to changes in efficiency.

[55] Acreage may decline due to suburbanization and the declining competitiveness of agriculture in a district.

This analysis has some notable implications. One is that productivity trends of individual utilities can differ from industry norms for reasons that are beyond their control. Another implication is that productivity indexes are not pure measures of operating efficiency. Productivity can decline for reasons other than declining efficiency.[56] A distributor's efficiency can continuously improve despite negative productivity growth. This could occur, for example, if TFP growth averaged -0.4% annually for several years when a typical distributor would achieve -0.8% growth. A further implication is that regulators need not restrict productivity growth targets in ARM formulas to be non-negative when achievable productivity trends are likely to be negative for external reasons. A more realistic goal is that productivity growth decline by the typical amount expected under adverse business conditions.

Use of Index Research in Regulation

Revenue Cap Indexes

Cost theory and index logic support the design of RCIs. Consider first the following basic result of cost theory:

$$\textit{growth Cost} = \textit{growth Input Prices} - \textit{growth Productivity}^{C} + \textit{growth Scale}^{C}.^{57} \qquad [2]$$

The growth in the cost of a company is the difference between the growth in the company's input price and productivity indexes plus the trend in a consistent cost-based output index. This result provides the basis for a revenue cap escalator of general form:

$$\textit{growth RCI}^{Utility} = \textit{growth Input Prices} - X + \textit{growth Scale}^{Utility} \qquad [3a]$$

where:

$$X = \overline{TFP^{C}} + \text{Stretch}. \qquad [3b]$$

[56] The ratio of outputs to inputs intuitively *does* seem like a pure efficiency measure. Outputs are, after all, an important driver of cost and productivity will rise if efficiency improves. However, outputs are not the only external business conditions that drive cost. Suppose for example that utility cost is also a function of the number of trees in the service territory. We could then hypothetically measure efficiency by taking the ratio of trees to the quantity of inputs. More efficient utilities would tend to have higher scores. However, this metric would not control for the large differences that exist in the output of utilities in the sample.

[57] *See, e.g.*, Denny, Fuss, and Waverman, *op. cit.*

Here RCI is the revenue cap index. *Scale*^{C} is the scale escalator. X, the "X factor," reflects a base TFP growth target ("$\overline{TFP}$") that is typically the recent historical trend in the *TFP*^{C} of a regional or national sample of utilities. Notably, a consistent cost-based output index should be used in the supportive productivity research. A stretch factor is often added to the formula which slows RCI growth in a manner that shares with customers the financial benefits of performance improvements which are expected under the MRP.[58]

An alternative basis for an RCI can be found in index logic. It can be shown that growth in the cost of an enterprise is the sum of the growth in an appropriately designed input price index and input quantity index ("Input Quantities"):[59]

growth Cost = growth Input Prices + growth Input Quantities. [4]

We can then obtain the same result as [2] since

growth Cost = growth Input Prices + growth Scale^C - (*growth Scale*^{C} – *growth Input Quantities*)
= *growth Input Prices – growth Productivity*^{C} + *growth Scale*^{C}*.*

Note that both of these formulas can apply to *components* of total cost. The trend in OM&A expenses, for example, can be decomposed as

growth Cost$^{OM\&A}$ = *growth Input Prices* $^{OM\&A}$
– *growth Productivity* $^{OM\&A}$ + *growth Scale* $^{OM\&A}$. [5]

Scale Escalators

These results suggest that RCIs should by some means reflect actual or expected growth in the output of each subject utility. This matters more to the extent that the subject utility is experiencing rapid growth. Growth in scale can be addressed by an explicit scale escalator or an X factor adjustment for expected growth in scale. If the RCI does not compensate the utility for growth in its operating scale, the expected scale index growth of the utility is an implicit stretch factor in the formula.

Some readers may find an alternative demonstration of the relevance of output growth to the design of ARA formulas persuasive. Equation [4] suggests that, if a revenue cap index compensates a

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[58] In some jurisdictions (e.g., Massachusetts) the X factor and stretch factor terms are separate.

[59] This result is due to the French engineer and economist Francois Divisia (1889-1964).

utility only for input price inflation less productivity growth, it will generally not provide sufficient compensation for input *quantity* growth even if the productivity growth trend is zero since input quantity growth also depends on output growth.

Formula [3a] raises the issue of the appropriate scale escalator for an RCI. One issue in the development of a scale escalator is which scale variable(s) to use. For gas and electric power distributors, the number of customers served is a sensible component of an RCI scale escalator, for several reasons. The customers variable usually has the highest estimated cost elasticity amongst the scale variables modelled in econometric research on distributor cost. The number of customers served clearly drives costs of connections (e.g., meters and services) and customer services (e.g., billing and collection) and has traditionally been highly correlated with peak load and delivery capacity. Consider also that a scale escalator that includes volumes or peak demand as output variables diminishes a utility's incentive to promote CDM. This is an argument for excluding these two system use variables from an RCI scale escalator. In choosing a scale escalator for a North American power distributor, it is also pertinent that data on miles of distribution line, another candidate for inclusion in the scale index. are not readily available for most U.S. power distributors.

Relation [4] can be expanded to obtain the following result:

$$\begin{aligned} \textit{growth Cost} &= \textit{growth Input Prices} + \textit{growth Input Quantities} + (\textit{growth Customers} - \textit{growth Customers}) \\ &= \textit{growth Input Prices} - (\textit{growth Customers} - \textit{growth Inputs}) + \textit{growth Customers} \\ &= \textit{growth Input Prices} - \textit{growth Productivity}^{N} + \textit{growth Customers.} \end{aligned}$$

Here $Productivity^{N}$ is a productivity index that uses the number of customers to measure output. This result provides the rationale for the following RCI formula:

$$\textit{growth Revenue}^{Allowed} = \textit{growth Input Prices} - X + \textit{growth Customers} \quad [6a]$$

where:

$$X = \overline{TFP}^{N} + Stretch.^{60} \quad [6b]$$

[60] A mathematically equivalent formula is:

$$\textit{growth Revenue} - \textit{growth Customers} = \textit{growth}\ (\textit{Revenue/Customer}) = \textit{growth Input Prices} - X. \quad [6c]$$

Table 1 details North American RCI precedents. It can be seen that twelve of the twenty-one approved RCIs that we identified have had explicit scale escalators. Most of these RCIs have applied to energy distributor services. The number of customers has been used in all of these escalators and was used exclusively in 10 of the twelve. Three of the twelve escalators have featured a percentage markdown on customer growth. These applied to utilities in BC and Québec.

Since, additionally, Hydro Ottawa has proposed a sizable markdown of its customer growth the rationale for markdowns merits some discussion. One rationale is that output growth is multidimensional and growth in some outputs is expected to be flat during the MRP term. For example, growth in peak demand might be flat, due to a large CDM program, despite customer growth. Another rationale is that output growth has a bigger impact on cost in the long run than in the short run. Customer growth has less cost impact to the extent that it doesn't occasion expansion of the distribution grid.

This is sometimes called a "revenue per customer" index.

Table 1

Summary of Approved Revenue Cap Indexes Informed by Cost Trend Research

Applicable Services	Utility	Jurisdiction	Plan Term	Scale Escalator(s)
Gas Distribution	Southern California Gas	California	1997-2002	Customers
Gas Distribution	BC Gas	British Columbia	1998-2000	Customers, Service Line Additions, etc.[2]
Power Distribution	Southern California Edison	California	2001-2003	Customers
Bundled Power Service and Gas Distribution	Pacific Gas and Electric	California	2004-2006	None
Gas Distribution	Southern California Gas	California	2005-2007	None
Gas Distribution	Gaziféré	Québec	2006-2010	Customers
Gas Distribution	Vermont Gas Systems	Vermont	2006-2009, extended to 2015	Customers
Gas Distribution	Enbridge Gas	Ontario	2008-2012	Customers
Power Distribution	Central Vermont Public Service	Vermont	2009-2011, extended to 2013	None
Power Distribution	Green Mountain Power	Vermont	2010-2013	None
Gas Distribution	Gaziféré	Québec	2011-2015	Customers
Gas Distribution	All Distributors	Alberta	2013-2017	Customers
Bundled Power Service	FortisBC	British Columbia	2014-2019	Customers * 0.5
Gas Distribution	FortisBC Energy	British Columbia	2014-2019	0.5* Customers, 0.5* Service Line Additions[2]
Gas Distribution	All Distributors	Alberta	2018-2022	Customers
Power Distribution	Eversource Energy	Massachusetts	2018-2023	None
Power Distribution	Hydro-Québec	Québec	2018-2022, Terminated in 2019	Customers * 0.75
Power Distribution	Hydro One Networks	Ontario	2018-2022	None
Power Transmission	Hydro One Sault Ste. Marie	Ontario	2019-2026	None
Power Distribution	National Grid	Massachusetts	2019-2024	None
Power Transmission	Hydro One Networks	Ontario	2020-2022	None

[1] Shaded plans have expired.

[2] There are separate revenue cap indexes for O&M expenses and various kinds of capex in these plans that in some instances have different scale escalators. For example, the annual scale escalator for services capex is the number of service additions.

4. Clearspring's Benchmarking Research

4.1. Summary of Clearspring's Work

Clearspring benchmarked the total cost of Hydro Ottawa's base rate inputs. The study appraised the Company's historical total costs over the 13-year period from 2006 to 2018 and its projected/proposed costs for the 2019-25 period. The component OM&A expenses, capital costs (e.g., depreciation and return on plant value), and capex were not separately benchmarked.

An econometric model provided the cost benchmarks. Clearspring developed this model using data on power distributor operations of 81 investor-owned utilities ("IOUs") in the United States and of Hydro Ottawa and six other large Ontario distributors that serve urban areas. The sample period for the U.S. utilities was 2002-17 while the sample period for the Ontario utilities was 2006-17. The model has two scale variables: the number of customers served and ratcheted maximum peak demand. Differences in the wage levels and construction costs that utilities in the sample faced were considered in the construction of the input price indexes.

The model also contained the following variables that measure several other drivers of distributor cost.

- share of the service territory area that has urban congestion;
- share of customers with advanced metering infrastructure ("AMI");
- customer density (number of customers/service territory area);
- prevalence of extreme temperatures;
- share of electric customers in the sum of gas and electric customers served;
- estimated share of the service territory that is forested; and
- standard deviation of service territory elevation.

The model also contains a trend variable.

With respect to the form of Clearspring's cost model, the model contains a full complement of quadratic and interaction terms (e.g., Customers^2 and Customers x Ratcheted Peak Demand) for the two scale variables in addition to their first-order terms (Customers and Ratcheted Peak Demand). This form is common in econometric cost models. Clearspring also adds quadratic terms for the congested urban and rural density variables. All parameter estimates are highly significant and those for the first order terms have plausible signs. The estimate of the trend variable parameter suggests that cost was *falling* by about 0.4% annually over the sample period for reasons other than changes in the values of the included business condition variables.

Clearspring reported that Hydro Ottawa's total costs were well below the benchmarks yielded by its model in the early years considered (e.g., 2006 to 2010). However, the Company's cost performance eroded steadily. Cost was 10.4% below the model's prediction in 2015, the last year prior to the start of Hydro Ottawa's current Custom IR plan, and is forecasted to be 5.6% below the model's prediction in 2020, the last year of the plan. Projected/proposed costs would be only 7.1% below the model's predictions on average during the five years of the new plan. The cost performance would actually improve slightly to -8.9% in the last year of the plan.

At the Company's request, Clearspring also benchmarked the residual cost resulting if annual costs of two sizable capex projects, the Facilities Renewal Program and the South Nepean Transformer Station, were excluded. Cost would be 12.5% below the model's prediction on average during the years of the plan. On this basis, and in conformance with the OEB's Price Cap IR guidelines, Hydro Ottawa has proposed a fixed 0.15% stretch factor during the full term of the plan, although Clearspring recommended a 0.30% stretch factor.[61]

Clearspring also benchmarked Hydro Ottawa's reliability. Econometric models were developed for the System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI") using U.S. data. These models control for various business conditions, such as forestation and undergrounding, which affect reliability. The models were developed using data from utility reports to state regulators, Form EIA 861, and the OEB. Benchmarking work using these models suggests that the Company was for many years a markedly inferior SAIFI performer but a superior CAIDI performer. SAIFI performance improved noticeably during the first three years of the current IR plan.

[61] See discussion on page 2 and footnotes 4 and 5.

4.2. Critique

Clearspring Cost Benchmarking

Mr. Fenrick uses benchmarking methods that are in many respects like PEG's. For example, we both favor the econometric approach to benchmarking and believe that total cost benchmarking using a geometric decay approach to the measurement of capital cost is worthwhile in rate applications. Mr. Fenrick has attempted, over several Ontario projects, to develop some useful business condition variables.

In this study for Hydro Ottawa, it is also notable that Mr. Fenrick has changed his benchmarking methodology in ways that address various concerns that we have raised with his work in recent Ontario proceedings.

- The number of quadratic and interaction terms has been reduced.
- Attention to urban and rural cost challenges is more balanced.
- The model does not contain a system undergrounding variable.
- The construction cost was levelized in the correct year.

We nonetheless disagree with some of the methods Clearspring used in this study. Our concerns range from "medium-sized" to concerns that are small but nonetheless notable. We discuss our larger concerns first to facilitate the Panel's review since some panel members may not have an interest in smaller issues.

<u>Medium-Sized Concerns</u>

Capital Cost Power distribution technology is capital-intensive, so the treatment of capital is a major issue when benchmarking total cost. Clearspring, like PEG, used a "monetary" approach to the calculation of capital cost.[62] This uses price indexes to deflate the asset values utilities report (e.g., their gross plant additions). Clearspring used regional American Handy Whitman Electric Utility Construction Cost Indexes ("HWIs") for power distribution for the U.S. and Ontario utilities alike.[63] They attempted to

[62] Monetary approaches to measuring capital cost are discussed further in Appendix Section A.1.

[63] The HWI applied to Ontario was that for the North Atlantic region.

make HWIs more relevant to Ontario by adjusting each value for U.S./Canadian purchasing power parities ("PPPs") obtained from the Organization for Economic Cooperation and Development ("OECD").

The appropriate asset price deflator to use in Ontario utility cost research has become an important issue. One reason is that Statistics Canada stopped computing Electric Utility Construction Price Indexes ("EUCPIs") after 2014. These had been available for power distribution and substation assets. The trends in the EUCPIs in the decade prior to 2014 were implausible.

PEG had used the EUCPIs in a number of cost studies for the OEB and spent considerable time and effort during the recent Hydro One distribution IR proceeding reviewing alternative replacement asset price deflators.[64] We found that HWIs and EUCPIs have both had drawbacks. Both indexes were designed many years ago and have cost-share weights and inflation subindexes that are now inappropriate. The labor price component of the distribution system EUCPI grew quite slowly in the later years of its calculation. However, trends in the prices of labor and construction in the North Atlantic states may not be appropriate for Hydro Ottawa and other Ontario utilities. For example, the HWI would be sensitive to a surge in power transmission capex that put upward pressure on distribution construction costs in the North Atlantic region. Purchasing power parities ("PPPs") calculated for the entire economy may not satisfactorily adjust for differences in Ontario and northeast U.S. construction cost trends.

Alternative asset price indexes are available. Based on our review, our professional opinion is that the most promising replacement for the EUCPI in Ontario energy distributor cost research is Statistics Canada's implicit capital stock deflator ("ICSD") for the Canadian utility sector.[65] This is readily computed from Statistics Canada's data on Flows and Stocks of Fixed Non-Residential Capital. This data collection program measures trends in the quantities of various capital assets using a monetary method. Statistics Canada generates this dataset by gathering investment data from various sources including the Capital Repair and Expenditures Survey. Our research showed that this index tracked the EUCPI in its good years better than the HWI with a PPP adjustment.

[64] EB-2017-0049, Exhibit L1, Tab 8, Schedule HONI-14 Attachment.

[65] Statistics Canada, 36-10-0096-01, Flows and Stocks of Fixed Non-Residential Capital, CANSIM. The implicit price index is calculated as the ratio of current value of net stock to the corresponding quantity index.

However, the utility sector of Canada's economy includes power generation and transmission, gas distribution, and water and sewage utilities as well as power distributors. We acknowledge that the growth trends in power distribution HWIs and the Canadian ICSD for the utility sector have differed markedly in some recent years. For the purpose of this transnational benchmarking project, which relies chiefly on U.S. data, we accordingly assume that power distributor asset price inflation in Ontario is a simple average of the inflation of the power distribution HWI for the North Atlantic states and the Canadian ICSD for the utility sector.

We discuss in the Appendix how the accuracy of statistical cost research using "monetary" capital cost specifications is increased by using an early "benchmark" year to begin calculating capital cost. Clearspring used a 2002 "benchmark" year to calculate the capital costs of Hydro Ottawa and the other Ontario distributors, even though a 1989 benchmark year is feasible for these distributors. This reduces the accuracy of their benchmarking work, especially in the early years of the sample period.

Density Issues Clearspring uses an urban congestion variable in its model. We prefer to call this an "urban challenge" variable because the cost of urban service is materially raised by high reliability requirements in office districts as well as by congestion problems. Our other concerns about the variable that Clearspring developed include the following.

- Toronto Hydro Electric and Consolidated Edison of New York ("Con Ed") have by far the highest values for Clearspring's urban challenge variable. If these two companies have unusually poor cost performances the variable's parameter estimate would reflect this.
- The area of the service territory is a legitimate candidate for treatment as an output variable with a full complement of second order terms (e.g., area x area and area x customers). This can capture the cost impact of high and low customer density. When this treatment is added to the model it receives strong statistical support and the %CU parameter estimate is much less significant.
- It seems equally sensible to use the estimated urban area as the variable in a cost model since cost will clearly be higher the larger is the urban area served. However, when we tried this in models the parameter estimate was negatively signed.

Other Major Concerns Here are some other major concerns that we have with Clearspring's benchmarking work in this proceeding.

- Data going back to 2006 are used from the Ontario distributors, but all but one of these distributors transitioned to MIFRS accounting between 2011 and 2015. The change from Canadian GAAP to MIFRS materially raised their OM&A expenses but did not have a commensurately large (offsetting) effect on capital cost.

- Total cost benchmarking does not shed light on the sources of high and low costs that utilities incur. Knowledge of strengths and weaknesses in more granular management of major cost categories such as OM&A expenses is useful to utilities and regulators alike. OM&A benchmarking is especially pertinent inasmuch as the CPEF applies only to OM&A expenses.

- Statistical tests revealed the presence of first-order autocorrelation in the data. This reduces the "efficiency" of parameter estimates – their tendency to be close to the true parameter values. In the econometric literature, efficiency is considered to be an important criterion for choosing an estimation procedure (aka "estimator") along with bias. The minimum variance linear unbiased estimator, for example, is called the *best* linear unbiased estimator. Clearspring did not correct its estimates of model parameters for autocorrelation. Its procedure for estimating model parameters was therefore inefficient.

Smaller Concerns

Here are some smaller concerns we have with Clearspring's benchmarking study. We do not believe that these problems individually had a major impact on the benchmarking results. However, future benchmarking studies, for Hydro Ottawa and other utilities, which steer clear of these problems will have more credibility.

- Clearspring used a 1989 benchmark year to begin calculation of the capital cost of all U.S. utilities in the econometric cost sample even though a 1964 benchmark year is feasible for the U.S. distributors. The cost of gathering the requisite U.S. capital data for a 1964 benchmark year is non-negligible, but Clearspring has expended effort to develop several complicated business condition variables over several proceedings.

- The forestation variable Clearspring used was poorly documented and used a different definition of area than the density variable. As well, this variable is sensitive to forestation in the rural areas that surround the urban areas where most of a distributor's customers frequently live. The cost impact of forestation depends on the extent to which lines are overhead. The exercise was performed for 2009, and the extent of forestation can change a fair bit over the years.

- The service territory area ascribed to Hydro One is implausibly large. This could materially impact the estimate of the area (or Clearspring's density) variable parameter because Hydro One serves a large area and has been found in prior total cost benchmarking studies to be inefficient.
- Numbers of gas customers served were missing from the data for several sampled utilities, which were evidently not recognized as providers of gas services.
- The service territory area of Kansas City Power and Light was, in our view, also implausibly large.
- Fixed 70/30 weights were assigned to labor and material and service expenses in the OM&A price index for all sampled utilities, even though company-specific weights can be computed for Hydro Ottawa and the American IOUs in the sample and the labor cost share is typically well below 70% for these companies. Thus, the OM&A input price indexes for most distributors in the study were unnecessarily inaccurate.
- Clearspring used the U.S. gross domestic product price index, converted to Canadian dollars using PPPs, as the material and services ("M&S") price index for the Ontario utilities even though Hydro Ottawa proposes to use Canada's gross domestic product implicit price index for final domestic demand as a CPEF inflation measure. Clearspring used as the Ontario labor price trend a U.S. employment cost index x PPP when the Company proposes to use the average weekly earnings ("AWE") for Ontario as its other CPEF inflation measure.
- Pension and benefit expenses were included in the calculations even though the Company proposes a variance account for pension expenses in its Custom IR plan and pension expenses can be volatile and difficult to benchmark accurately.
- There is no control in the study for differences in the health care obligations of U.S. and Ontario utilities. While this is a source of possible bias *favoring* the Company, there are other sources of bias that cut the other way. Most notably, the peak loads of U.S. utilities

may be overstated. Also, Clearspring levelizes its labor and construction cost indexes using only data for headquarters cities. This likely overstates the price levels of many sampled U.S. utilities.

- Data are frequently mean-scaled in econometric cost studies. This ensures that elasticities are calculated at sample mean values of the business condition variables. Clearspring's data were incorrectly mean-scaled.
- Clearspring removed *structure* maintenance expenses from the calculation when they should have removed the (typically larger) *streetlight* maintenance expenses.
- Clearspring's benchmarking of Hydro Ottawa's cost from 2021 to 2025 is problematic in several respects.
    - The formula used to escalate OM&A expenses was I – X rather than I - X + G.
    - The Company's latest forecast of capex was not used.
    - The Conference Board inflation forecasts used to benchmark Hydro Ottawa's future costs were dated (spring of 2019).

0% TFP Target

We also wish to challenge the notion that a 0% base productivity target is necessarily appropriate for Hydro Ottawa. Ontario data have many limitations for the accurate measurement of productivity trends. These include the recent benchmark year for capital cost calculations, the recent transition of many utilities to MIFRS accounting, and the fact that pension and benefit expenses are not readily excluded from such studies. The CPEF is designed to apply only to OM&A expenses. As well, Custom IR guidelines speak of an X factor that is as high or higher than that used in Price Cap IR.

PEG calculated the MFP trends of a large sample of U.S. power distributors in a recent study on multiyear rate plans for Berkeley Lab.[66] We reported TFP trends of 0.45% for the full 1980-2014 sample period and of 0.39% for the more recent 1996-2014 sample period. In recent testimony for the

[66] Lowry, Makos, and Deason, *op. cit*., p. B.15.

Massachusetts Attorney General's office, PEG reported a TFP trend of 0.33% for a large sample of U.S. power distributors over the 21 years from 1997 to 2017.

Clearspring Reliability Benchmarking

We believe that Clearspring has, with the Company's sponsorship, done a service to Ontario's regulatory community by continuing to make progress in the area of reliability benchmarking. Cost benchmarking should ideally be combined with reliability benchmarking to gain a balanced view of performance, and reliability performance is germane when considering requests for supplemental capex funding. Clearspring has gathered a respectable sample of publicly available U.S. data that span the years 2010-2017. Major event days have been excluded, if not with fully consistent definitions. The models presented by Clearspring are a good starting point for further improvements.

5. Alternative Research by PEG

5.1 Business Conditions Facing Hydro Ottawa

The external business conditions faced by Hydro Ottawa should be considered in the development of benchmarking models. The Company is an electric utility based in Ottawa and owned by the city. It provides power distributor services (e.g. distribution and customer services) but not power transmission or natural gas services. This limits its opportunities to realize scope economies. A subsidiary company, now called Portage Power, is engaged in small-scale renewable power generation in Ottawa and the surrounding region.

Power is distributed to most of the Ottawa-Gatineau metropolitan area.[67] In 2019, this area had a population of 1.44 million residents after years of brisk growth. The area includes Canada's national capital, two large universities, and a sizable information technology industry. Comparable North American metro areas include Edmonton ALTA, Salt Lake City, UT, Raleigh-Durham NC, and Oklahoma City. There are concentrations of office buildings in suburban Ottawa (e.g., Nepean, Gloucester, Kanata) as well as the downtown area where the capitol complex is located.

All customers now have AMI. The service territory includes a portion of the Rideau River and the Ottawa River valley but this produces little variation in the elevation of the service territory. Much of the surrounding region is forested.

Table 2 compares Hydro Ottawa's cost and external business conditions to the sample mean values in 2017. The following results are notable.

- Hydro Ottawa's cost was 32% of the sample mean.
- The Company's customer count was 34% of the mean while peak demand was 28%.

[67] The Company also serves the Village of Casselman Ontario. It does not serve the Quèbec side of the Ottawa River or some outlying areas of the city (e.g., Marlborough, Osgoode, and Huntley).

Table 2

Comparison of Hydro Ottawa's Business Conditions in 2017 to Full Sample Norms

Business Condition	Units	Hydro Ottawa Values, 2017 [A]	Sample Mean, 2017 [B]	Values / Sample Mean [A/B]
Total Cost($000 Dollars)	Dollars	217,373	675,817	0.32
Number of Retail Customers	Count	331,777	970,483	0.34
Rolling 5 Year Ratcheted Peak Demand	MW	1,430	5,082	0.28
Standard Deviation of Elevation		17	138	0.13
Percentage of Service Territory Forested	Percent	58.46%	57.27%	1.02
Percentage of Service Territory Congested Urban	Percent	0.12%	0.09%	1.23
Percentage of Customers with AMI meters	Percent	100.00%	43.58%	2.29
Percent of Total Customers that are Electric	Percent	100.00%	88.49%	1.13
Service Territory Area	Square Kilometers	1,116	28,019	0.04
Price Index for Capital Inputs	2017 Dollars	12.90	11.41	1.13
Price Index for O&M Inputs	2017 Dollars	1.47	1.16	1.27

- The share of the service territory that was congested urban and the share of customers with AMI were well above the mean.
- The company has no gas customers.
- The standard deviation of elevation was far below the mean.
- The share of the service territory forested was close to the mean.

5.2 Econometric Cost Research

Like Clearspring, we developed an econometric model of the total cost of power distributor base rate inputs. We also developed econometric models of two major components of total cost: OM&A expenses ("opex") and capital cost. Estimation results for all four models are reported in Tables 3-6. These tables include parameter estimates and their associated asymptotic t values and p-statistics. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. These significance tests were used in model development. A t test requires selection of a critical value for the asymptotic t ratio. We employed a critical value that is appropriate for a 75% confidence level.[68] In all of these models, all of the parameter estimates for the first-order terms of the business condition variables were statistically significant and plausible as to sign and magnitude.

Differences from the Clearspring Methodology

The following methods that we used in model development differed from Clearspring's.

- Instead of a 2002 benchmark year to begin computation of Hydro Ottawa's capital cost we used 1989.[69]
- Instead of using only the Handy Whitman Index of Power Distribution Construction Costs in the Northeast US as the asset price deflator for Ontario distributors we assumed that the growth of the Ontario asset price index was a 50/50 average of the growth of this HWI and the growth of the ICSD for the Canadian utility sector.
- Instead of using the US GDPPI as the material and service price subindex for the Ontario distributors we used Canada's gross domestic product implicit price deflator for final domestic demand ("GDP-IPI").
- Instead of using the US employment cost index as the labor price trend index for the Ontario distributors we used the AWE of Ontario workers.
- The OM&A input price index used company specific cost share weights for Hydro Ottawa and the US distributors in the sample.[70] The cost share weights for the other Ontario distributors were fixed at 70/30.
- We assumed that Hydro Ottawa's OM&A expenses would grow at the same rate as their proposed CPEF, updated to reflect the latest inflation and customer forecasts.

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[68] A one-tailed test was appropriate for most first order terms in the model. Two-tailed tests were appropriate for the quadratic and interaction terms associated with the scale variables.

[69] We did not have the time or budget to do this for the other Ontario utilities.

[70] For the U.S. utilities, these cost share weights were also time-varying.

- We treated the service territory area as a third scale variable where data supported this treatment and added quadratic and interaction terms.
- Instead of a stand-alone forestation variable we interacted the share of service territory forested with a variable measuring the share of distribution assets that were overhead.
- We corrected for missing data on the gas customers served by several sampled utilities and used a more accurate estimate of Hydro One's service area. We excluded the data for Kansas City Power and Light from the sample.
- We corrected the mean-scaling.
- We corrected the parameter estimates for first order autocorrelation using a standard method found in Stata, a popular econometric software package, in an effort to improve their precision. Statistical tests provided strong evidence of autocorrelation in the total cost and capital cost models.
- We did not use pre-2013 Ontario data in model estimation, except in the capital cost model.
- We benchmarked the opex and capital cost of Hydro Ottawa as well as its total cost.

Econometric Results

Econometric results for the total cost model are presented in Table 3. Here are some salient results.

- The parameter estimates for the number of customers, ratcheted peak demand, and area variables are all highly significant and positive. The parameter estimates for all but one of the quadratic and interaction terms associated with these three scale variables were also highly significant. The relationship of cost to the three scale variables was therefore significantly nonlinear.
- Total cost was also higher the higher was the share of the service territory that was urban, the share of distribution assets overhead x the share of service territory area forested, AMI penetration, the standard deviation of elevation, and the share of electric plus any gas customers that were electric.

Table 3

Econometric Model of Total Cost

VARIABLE KEY

N = Number of customers
D = 5 year ratcheted maximum peak demand
A = Service territory area
PCTELEC = % electric customers
ELEVSTD = Elevation standard deviation
PCTOH * PFOREST = % of overhead assets times the percent forested
PCTCU = % service territory congested urban
PCTAMI = % of customers with AMI meters
Trend = Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.655	16.61	0.000
N*N	0.531	6.89	0.000
D	0.282	7.20	0.000
D*D	0.600	5.74	0.000
D*N	-1.066	-6.35	0.000
A	0.068	6.20	0.000
A*A	0.026	4.66	0.000
A*N	0.011	0.52	0.606
A*D	-0.058	-2.80	0.005
PCTELEC	0.173	5.18	0.000
ELEVSTD	0.020	1.89	0.059
PCTOH*PCTFOREST	0.045	5.76	0.000
PCTCU	9.969	3.07	0.002
PCTAMI	0.018	1.10	0.274
Trend	-0.002	-1.15	0.250
Constant	13.130	238.12	0.000

Adjusted R^2 0.997

Sample Period 2002-2017

Number of Observations 1302

Pacific Economics Group Research, LLC

- The estimate of the trend variable parameter suggests that cost was falling by about 0.2% annually for reasons other than changes in the values of the included business condition variables.

The adjusted R^2 for the model was 0.997. This suggests that the model had a high level of explanatory power.

OM&A Expenses

Results for the opex cost model are presented in Table 4. Please note the following.

- The parameter estimates for the number of customers and ratcheted peak demand were both significant and positive.[71] Notice that the number of customers had a much greater impact than in the total cost model, while peak demand had a much smaller impact. This makes sense since OM&A expenses include many customer-driven expenses like those for metering, billing, and collection. The area variable and its related second-order terms did not have sufficiently strong statistical support to warrant inclusion in the model.
- The parameter estimates for the additional quadratic and interaction terms associated with the two included scale variables were also highly significant. This suggests that the relationship of cost to the two scale variables was significantly nonlinear.
- Opex was higher the greater was the share of the service territory that was congested and urban. A quadratic urban congestion variable was added and its parameter estimate was also highly significant.
- Opex was also higher the higher was system overheading, share overhead x share forestation, and the standard deviation of elevation.
- The trend variable parameter estimate indicates a 0.7% annual decline in opex for reasons other than changes in the values of included business condition variables. This decline is considerably more rapid than that in the total cost model.

[71] Ratcheted peak demand was significant using a one-tailed test.

Table 4

Econometric Model of OM&A Expenses

VARIABLE KEY

N = Number of customers
D = 5 year ratcheted maximum peak demand
ELEVSTD = Elevation standard deviation
PCTOH * PFOREST = % of overhead assets times the percent forested
PCTCU = % service territory congested urban
PCTPOH = % of plant overhead
Trend = Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.883	11.94	0.000
N*N	0.609	3.96	0.000
D	0.106	1.38	0.167
D*D	0.467	2.31	0.021
D*N	-1.026	-3.10	0.000
ELEVSTD	0.051	3.03	0.002
PCTOH*PCTFOREST	0.057	4.38	0.000
PCTCU	86.017	4.85	0.000
PCTCU*PCTCU	-2295.294	-3.70	0.000
PCTPOH	1.388	7.05	0.000
Trend	-0.007	-2.62	0.009
Constant	10.792	57.42	0.000

Adjusted R^2	0.981
Sample Period	2002-2017
Number of Observations	1305

- Table 4 also reports a 0.981% adjusted R^2 statistic for the opex model. This is just a little below that for the total cost and capital cost models.

Capital Cost

Econometric results for the capital cost model are presented in Table 5. Here are some key results.

- The parameter estimates for the number of customers, ratcheted peak demand, and the area variable were all highly significant and positive. All but one of the parameter estimates for the extra quadratic and interaction terms for the output variables were also highly significant. This suggests that the relationship of capital cost to the three output variables is significantly nonlinear.
- Capital cost was also higher the greater was the share of the area served that was congested and urban, share forestation x share overhead, AMI penetration, and the ratio of electric customers to the sum of gas and electric customers.
- The estimate of the trend variable parameter indicates a 0.2% annual increase in capital cost for reasons other than changes in the values of the model's business condition variables.
- The 0.998 value of the adjusted R^2 model was very similar to that for the total cost model.

Table 5

Econometric Model of Capital Cost

VARIABLE KEY

N = Number of customers
D = 5 year ratcheted maximum peak demand
A = Service territory area
PCTELEC = % electric customers
PCTOH * PFOREST = % of overhead assets times the percent forested
PCTCU = % service territory congested urban
PCTAMI = % of customers with AMI meters
Trend = Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.702	32.96	0.000
N*N	0.332	6.94	0.000
D	0.229	10.83	0.000
D*D	0.325	5.31	0.000
D*N	-0.596	-6.11	0.000
A	0.100	12.76	0.000
A*A	0.023	5.49	0.000
A*N	-0.028	-1.95	0.051
A*D	-0.014	-1.28	0.202
PCTELEC	0.170	5.73	0.000
PCTOH*PCTFOREST	0.024	3.63	0.000
PCTCU	11.665	3.87	0.000
PCTAMI	0.023	3.30	0.001
Trend	0.002	2.48	0.013
Constant	10.476	797.10	0.000

Adjusted R^2	0.998
Sample Period	2002-2017
Number of Observations	1351

5.3 Econometric Benchmarking Results

We benchmarked the opex, capital cost, and total cost of Hydro Ottawa in each year of the historical 2013-2018 period as well as in the 2019-2025 period for which the Company has provided proposals/projections. For the capital cost model we were also able to benchmark the 2006-2012 period because we have less concern about the inconsistency of pre-MIFRS data. All benchmarks were based on our econometric model parameter estimates and values for the business condition variables which are appropriate for the Company in each historical and future year.

Tables 6-8 and Figures 1-3 report results of this benchmarking work. For each cost considered, we provide results for each year as well as average results for the last three historical years (2016-2018) and the five years of the proposed new Custom IR plan (2021-25).[72]

Table 6 and Figure 1 show results of our econometric *total* cost benchmarking. It can be seen that the company's total cost was about 13% below model predictions in 2013. The Company's scores gradually deteriorated thereafter. Cost efficiency will decline modestly during the Company's current IR plan but is projected to stabilize during the next plan after a drop in 2021. On average, projected/proposed total cost during the new plan will exceed the benchmarks by 5.0% during the 2021-25 term of the Custom IR plan.

Table 7 and Figure 2 show results of our econometric opex benchmarking. It can be seen that Hydro Ottawa's total cost was a considerable 18% below model predictions in 2013. The Company's scores gradually deteriorated thereafter. OM&A efficiency will decline modestly during the Company's current IR plan but is projected to stabilize during the next plan. On average, projected/proposed total cost during the new plan will be 0.5% below the benchmarks during the 2021-25 Custom IR term. This would essentially be an average cost performance.

[72] Recollecting the recent benchmark years for estimating capital cost in Ontario, the capital cost and total cost benchmarking results are likely to be more accurate in these three years.

Table 6

Year by Year Total Cost Benchmarking Results

Year	Percent Difference[1]
2013	-13.3%
2014	-9.3%
2015	-6.0%
2016	-5.6%
2017	-5.6%
2018	-2.2%
2019	*3.3%*
2020	*2.3%*
2021	*4.9%*
2022	*5.8%*
2023	*5.0%*
2024	*4.4%*
2025	*5.0%*
Annual Averages	
2013-2018	**-7.0%**
2016-2018	**-4.5%**
2021-2025	**5.0%**

[1] Formula for benchmark comparison is $\ln(Cost^{HOL}/Cost^{Bench})$.

Note: Italicized numbers are projections/proposals.

Figure 1

Hydro Ottawa's Total Cost Benchmarking Scores

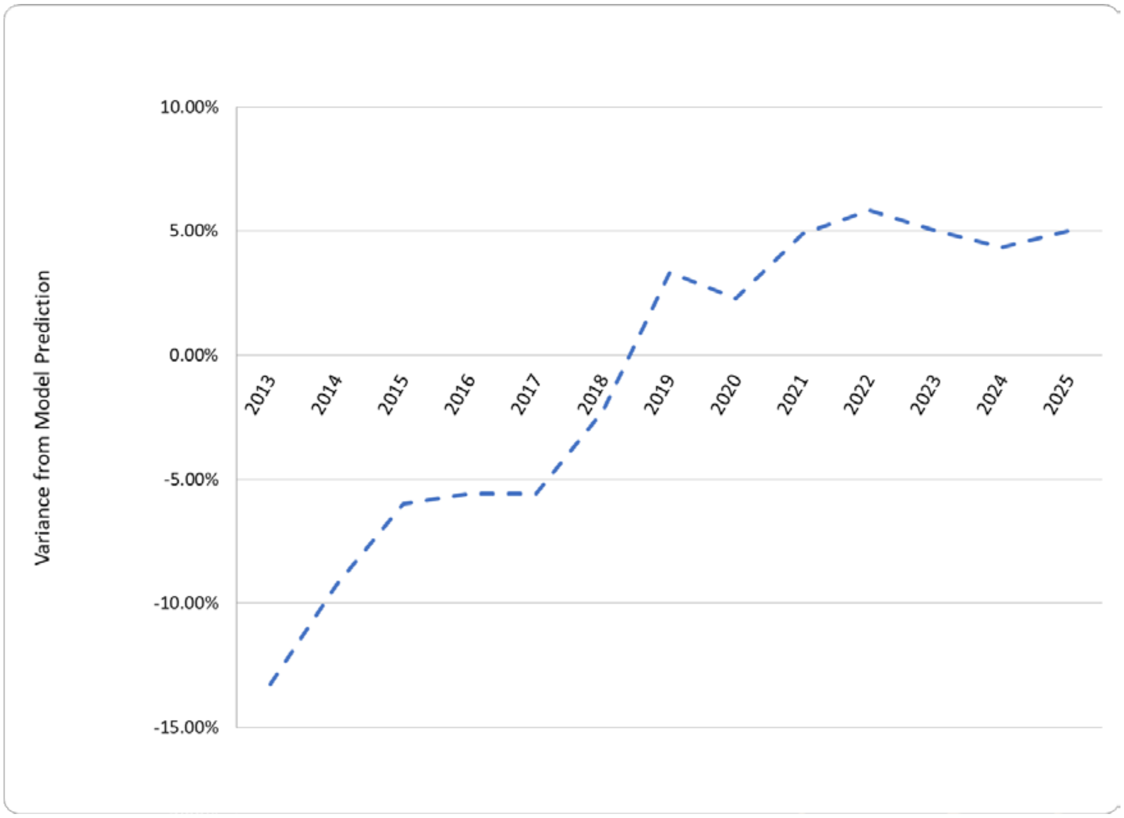


Table 7

Year by Year OM&A Cost Benchmarking Results

Year	Percent Difference[1]
2013	-18.2%
2014	-11.3%
2015	-5.9%
2016	-7.2%
2017	-9.1%
2018	-0.5%
2019	*0.1%*
2020	*-1.6%*
2021	*-0.9%*
2022	*-0.8%*
2023	*-0.6%*
2024	*-0.3%*
2025	*0.0%*
Annual Averages	
2013-2018	**-8.7%**
2016-2018	**-5.6%**
2021-2025	**-0.5%**

[1] Formula for benchmark comparison is $\ln(Cost^{HOL}/Cost^{Bench})$.

Note: Italicized numbers are projections/proposals.

Figure 2

Hydro Ottawa's OM&A Cost Benchmarking Scores

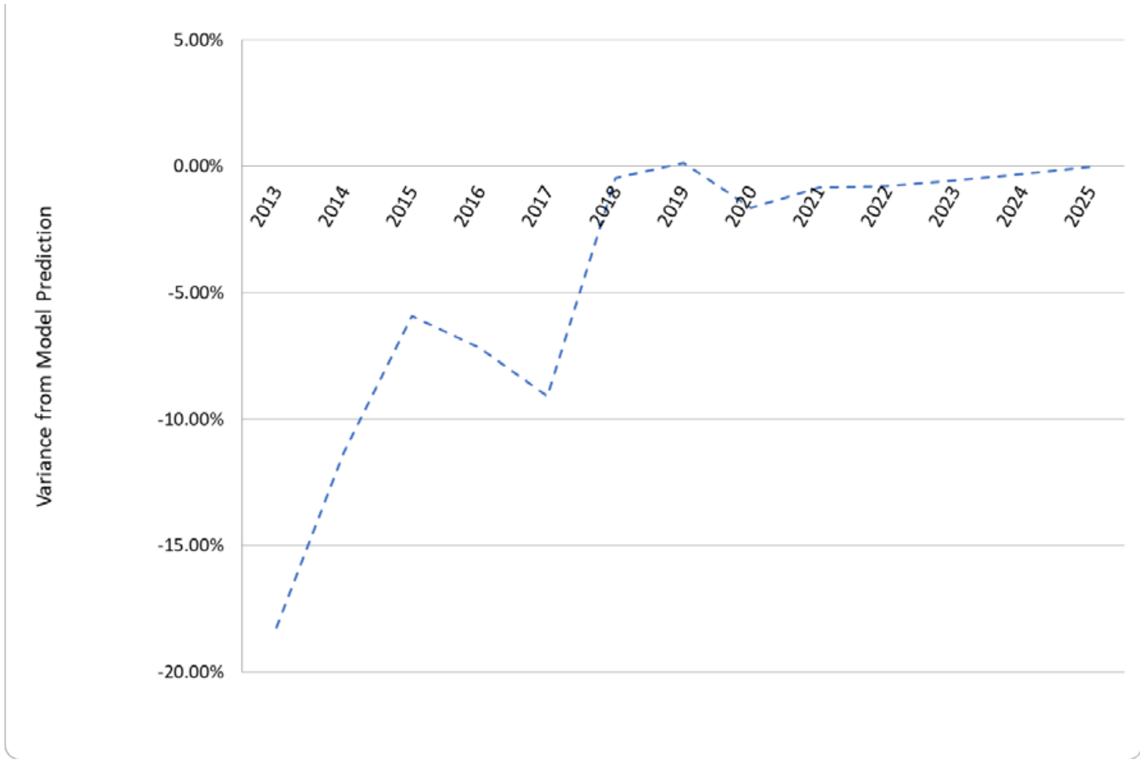


Table 8 and Figure 3 show results of our econometric *capital* cost benchmarking. It can be seen that Hydro Ottawa's capital cost was about 6% below model predictions in 2013. The Company's scores gradually deteriorated thereafter. Capital cost performance will decline considerably during the Company's current IR plan but is projected to stabilize during the next plan after a decline in 2021. On average, projected/proposed total cost during the new plan will be 12.2% above the benchmarks for the 2021-25 period.

Table 8

Year by Year Capital Cost Benchmarking Results

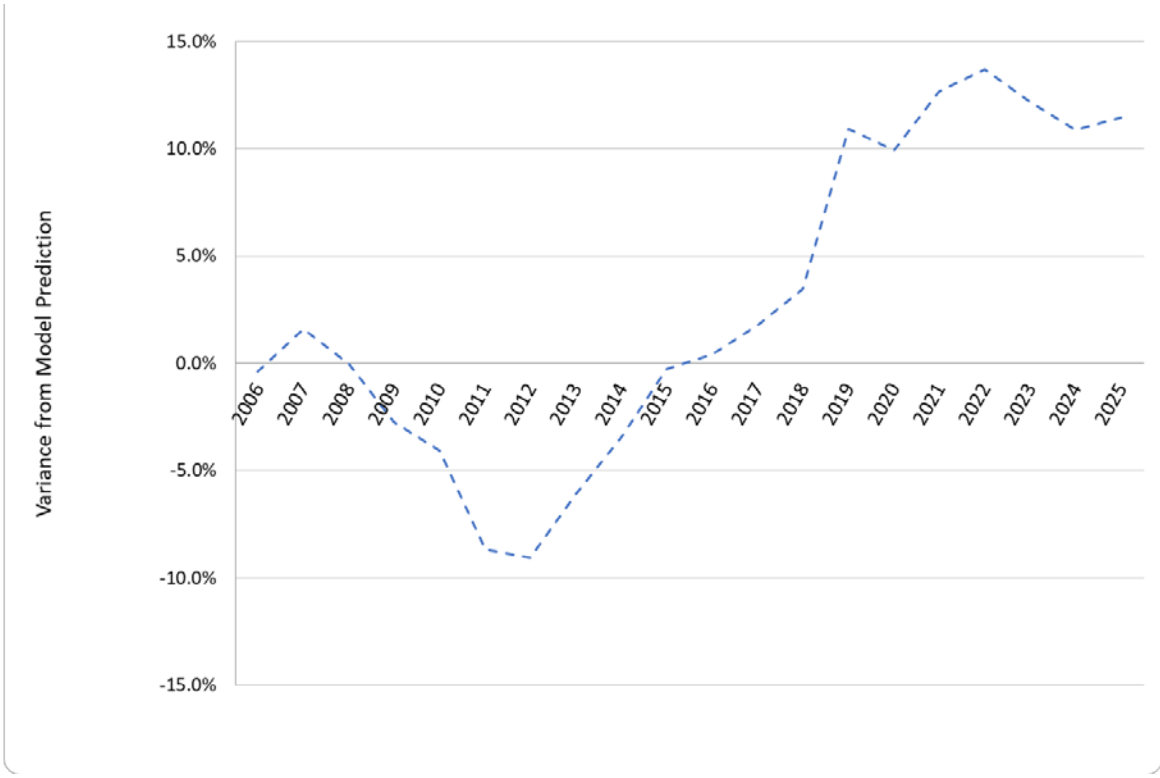
Year	Percent Difference[1]
2006	-0.4%
2007	1.6%
2008	0.0%
2009	-2.8%
2010	-4.1%
2011	-8.7%
2012	-9.1%
2013	-6.1%
2014	-3.4%
2015	-0.3%
2016	0.4%
2017	1.8%
2018	3.5%
2019	*10.9%*
2020	*9.9%*
2021	*12.7%*
2022	*13.7%*
2023	*12.2%*
2024	*10.9%*
2025	*11.4%*
Annual Averages	
2006-2018	**-2.1%**
2016-2018	**1.9%**
2021-2025	**12.2%**

[1] Formula for benchmark comparison is $\ln(\text{Cost}^{HOL}/\text{Cost}^{Bench})$.

Note: Italicized numbers are projections/proposals.

Figure 3

Hydro Ottawa's Capital Cost Benchmarking Scores



5.4 Stretch Factor

The stretch factor should be based on the total cost of Hydro Ottawa's base rate inputs. The cost of the two major capex projects that the Company has taken should not be excluded. Major plant additions may to some degree be driven by external business conditions but they are also to some degree optional (especially with regard to timing). New construction has the disadvantage of tying up funds in the ownership of assets that are especially valuable because they will last for many years. The geometric decay approach to measuring capital cost that PEG and Clearspring both use in benchmarking captures this disadvantage. Utilities are thereby incentivized to postpone plant additions until they are really needed. Analogous exclusions were not made for the costs of other companies in the sample.

Hydro Ottawa's 5.0% average total cost benchmarking score over the 2021-25 sample period would be commensurate with a 0.30% stretch factor under Price Cap IR conventions. On the basis of our research, we believe that a 0.30% stretch factor is indicated for Hydro Ottawa. We recommend this stretch factor if the Board is comfortable fixing the stretch factor for the full plan term.

5.5 Base Productivity Trend

Hydro One's proposed CPEF would apply only to the Company's OM&A revenue. Should the Board wish to adopt this approach, the question of an appropriate productivity growth target arises. As we noted in Section 2 above, the OEB states in the Rate Handbook that

> Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.[73]

In recent testimony for the Massachusetts AGO, PEG found that the OM&A productivity growth of a large sample of U.S. power distributors averaged 0.39% over the eleven year 2007-2017 sample period. The number of customers was the sole output variable in this calculation.

Early RRF guidelines called for Custom IR ARMs to reflect "the Board's inflation and productivity analyses." OEB Staff has asked PEG, as part of the engagement, to calculate the OM&A productivity trend of U.S. utilities for this proceeding. Pursuant to this request, we calculated the trend in the OM&A productivity of U.S. distributors in the Clearspring sample. The sample consisted of all of the U.S. distributors included in the sample that had good data for all years of the sample period. Florida Power & Light was excluded due to the recognition in 2017 of a large amount of deferred storm damage cost, which resulted in an atypical end point that cannot be relied upon for a trend analysis. We also added Kansas City Power & Light to the sample, as its area data problem did not affect the OM&A PFP calculations.

In this exercise, output growth was an elasticity-weighted average of the growth in customers and ratcheted peak demand. OM&A input quantity growth was calculated as the difference between the growth in OM&A expenses and an OM&A input price index we developed using company-specific and time-varying cost share weights for labor and other OM&A inputs.

Results of this exercise can be found in Table 9. It can be seen that, over the full 2007-2017 sample period considered, the OM&A productivity of the sampled U.S. distributors averaged 0.27%. The scale index averaged 0.51% growth while OM&A input quantity growth averaged 0.24%.

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[73] *Rate Handbook*., pp. 25-26.

Table 9

US Power Distributor OM&A Productivity Trend[1]

(Growth Rates)

Year	Scale Index	O&M Input Quantity Index	O&M Productivity Index
2007	1.03%	6.35%	-5.32%
2008	0.57%	-1.59%	2.16%
2009	0.24%	-1.43%	1.67%
2010	0.33%	0.89%	-0.57%
2011	0.20%	2.30%	-2.11%
2012	0.27%	-0.59%	0.86%
2013	0.42%	-6.51%	6.94%
2014	0.49%	4.83%	-4.34%
2015	0.69%	-3.85%	4.54%
2016	0.78%	3.77%	-2.99%
2017	0.62%	-1.48%	2.10%
Average Annual Growth Rate 2007-2017	**0.51%**	**0.24%**	**0.27%**

[1]All growth rates are calculated logarthmically.

Scale Escalator

We showed in Section 3 of the report that cost theory and index logic suggest that the RCI should provide an allowance for growth in the operating scale of the subject utility. This matters more for a utility that will be experiencing brisk growth in scale. The output growth of Hydro Ottawa in the next four years is clouded by the current pandemic challenge, but has traditionally been brisk. We accordingly support the proposed customer growth escalator.

Fixed vs. Variable CPEF

Given the uncertainty that the COVID-19 pandemic has triggered surrounding inflation and customer growth in the next five years, we recommend that the OEB not approve a fixed CPEF for Hydro

Ottawa. The ability to adjust revenue growth to changing business conditions without weakening utility incentives is one of the chief advantages of indexed attrition relief mechanisms.

CPEF Summary

If the CPEF applies only to OM&A revenue, as proposed by Hydro Ottawa, our recommended CPEF formula is Inflation – 0.57% + G where the X factor is the sum of a 0.27% base OM&A productivity trend and a 0.3% stretch factor. If CPEF applies to *all* revenue (i.e., OM&A and capital) in a rate adjustment formula similar to what the OEB has approved for Hydro One and Toronto Hydro in 2019 decisions, we recommend a 0.30% X factor consisting of 0% base TFP trend and a 0.3% stretch factor.[74]

[74] EB-2017-0049, March 7, 2019 for Hydro One distribution and EB-2018-0165, December 19, 2019 for Toronto Hydro.

6. Other Plan Design Issues

The other provisions of the Custom IR plan proposed by Hydro Ottawa are in some respects uncontroversial. We have noted that the plan is similar to the expiring one, which was detailed in a Board-approved settlement. There are some customer protections since an ESM would asymmetrically share only surplus earnings and the capital variance account would asymmetrically return capital revenue requirement savings to customers. We are nonetheless concerned about some other features of the Company's proposal.

6.1 Capital Cost Concerns

Basic Concerns

The ratemaking treatment of capital is our chief concern about the other plan provisions. We begin by acknowledging that utilities operating under indexed ARMs based on industry cost (e.g., price and productivity) trends sometimes do need extra capital revenue. We noted in Section 3 that productivity growth drivers vary between utilities and, for individual utilities, over time. Some kinds of capex are lumpy and capex, once incurred, raises costs recoverable from customers based on in-service asset values, for many years. Index research used to design ARMs may, furthermore, fail to properly capture utility cost trends.[75] MRPs with ARMs based on cost trends have, for these and other reasons, had provisions for supplemental capital revenue in Ontario and several other jurisdictions (e.g., Alberta, British Columbia, and Hawaii).

The fairness of supplemental revenue provisions is magnified if the subject utility has either not previously operated under MRPs or *has* operated under such plans but prior ARMs were under-compensatory. On a net present value basis, *under*-compensation in the early years of operation under MRPs will tend to outweigh any possible *over*-compensation in future years. MRPs with under-compensatory ARMs would, under these circumstances, tend to be unfair to the utility as well as increasing its risk and the cost of accessing funds in capital markets.

[75] The research might, for example, not capture the cost impact of repex which utilities experience.

While extra capex funding is sometimes needed, provisions for such supplements can nevertheless be controversial and greatly complicate MRP design and execution. Legitimate concerns can arise as to capex containment incentives, over-compensation, and regulatory cost. All of these concerns arise with Hydro Ottawa's proposed plan.

Weak Incentives

Under Hydro Ottawa's plan, growth in its capital revenue requirement would be based on a projection/proposal of its total capital cost. This projection would, if approved, be fully funded without even a stretch factor markdown. The entirety of any cumulative revenue requirement reduction that occurred due to capex *under*spends would be returned to ratepayers. The ongoing annual capital cost of the depreciated balance of any capex *over*spends could possibly be added to required revenue in future rebasings. The Company could also recover, through the Z factor (or similar mechanisms), the entirety of material capex incurred due to some unforeseen external events. Capital revenue would thus be determined on a largely cost of service basis while OM&A revenue would be indexed.

These provisions would greatly reduce Hydro Ottawa's capex containment incentive.[76] There would, for instance, be an incentive to spend too much on capital that reduces OM&A business expenses.[77] The Company's capital cost has grown rapidly under the provisions of its current Custom IR plan, which is its first. For example, the Company has undertaken a "once in a generation" building project and plans another big project during its next plan for 2021-2025. On balance, this approach to Custom IR has such weak incentive power that it may not seriously merit an IR characterization.

Despite the proposed claw back of all capital cost savings, Hydro Ottawa would still have some incentive to exaggerate its capex needs since exaggerations strengthen the case for Custom IR, which affords the Company extra revenue and preapproval of capex budgets and reduces pressure to contain

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[76] It is important to emphasize that the pass-through of all capital cost savings is the chief, though not the only, incentive problem with Hydro Ottawa's proposal.

[77] There is, for example, an extra incentive to underground lines. The tendency for over-capitalization is a well-known issue referred to as the Averch-Johnson effect. See Averch, Harvey and Leland L. Johnson (1962). "Behavior of the Firm Under Regulatory Constraint". *American Economic Review*. 52 (5): 1052–1069

capex and the risk that too little was requested.[78] Hydro Ottawa would also still have some incentive to "bunch" deferrable capex, in this and similar future plans, in ways that bolster extra revenue. [79] If, for example, the Company could change, after 2025, the timing of its capex so that $I - X + G$ escalation of its first-year revenue requirement was compensatory throughout the plan it would not qualify for extra revenue. There is also a temptation to change the mix of capex projects during the plan so that there remain some projects that justify continuation of Custom IR. Continual operation under Custom IR has joined the bunching of capex around the rebasing year as a serious concern.

Overcompensation

An overcompensation problem arises if a utility receives more funding than it needs for a given capex surge. Overfunding may occur during a plan and/or over multiple plans. Hydro Ottawa's proposed plan raises several overfunding concerns.

Consider first that most of the capex that occasions supplemental revenue is similar in kind to that incurred by distributors sampled in productivity studies used to set X factors. For example, distributors occasionally build, replace, or substantially expand transformer stations and office buildings. To the extent that this capex slows their productivity growth, the X factor will be lower and ARMs will have grown faster in previous IR plans, the current plan, and future plans. The OEB has been setting base TFP trends at 0% for several years, and the capex of Ontario distributors has doubtless reduced provincial TFP growth. Hydro Ottawa can then be compensated twice for some of the same capex: once via full funding of its projected/proposed capital budget and then again by low X factors in past, present, and future IR plans.

A related overcompensation concern is that, while customers would be asked to fully compensate Hydro Ottawa when its capital cost growth is *brisk* for reasons beyond its control, the Company can in the future switch to Price Cap IR and avoid commensurately reducing its capital revenue

[78] Exaggeration of capex needs may reduce the credibility of Hydro Ottawa's forecasts in future proceedings. However, the Company can always claim that it "discovered" ways to economize. British distributors operating under several generations of IR with revenue requirements based on cost forecasts have repeatedly spent less on capex than they forecasted.

[79] While an incentive to bunch would exist, the optimal bunching strategy for Hydro One is not obvious since spreading out high capex creates a rationale for continuing Custom IR.

if capital cost growth is unusually *slow* for reasons beyond its control.[80] Slow capital cost growth in the future could very well occur for reasons other than good management. For example, depreciation of recent and prospective surge capex like that for the South Nepean MTS will tend to slow the Company's capital cost growth in the future as its net plant value gradually depreciates. The Company acknowledged in response to an interrogatory[81] that "accumulated depreciation reduces the rate base and capital cost growth. Given the same amount of capital spending, all else equal, when the rate base starts at a higher level the capital cost growth will be lower." To the extent that capex has been bunched during Custom IR, there may be less need for it afterwards. While a capex surge and the resultant short-term productivity slowdown and revenue shortfall are easily discerned, productivity growth that modestly exceeds the peer group norm which may precede or follow the surge is likely to be attributed to good management.

Under Hydro Ottawa's proposal, customers therefore would never receive the full benefit of the industry's TFP trend, even in the long run and even when it is achievable.[82] The Company would, by the same token, manage to skirt the challenge of having to match industry TFP growth in the long run in order to achieve the target rate of return between rate cases. These problems illustrate how hard it is to design good IR plans when the premise is accepted that expected revenue shortfalls in one plan should be fully funded without consideration of previous and subsequent plans.

Note also that no consideration has been paid, in the Company's past or current plan, to any special *advantages* Hydro Ottawa has in managing its costs. These advantages have included in the past, and may in the future continue to include, comparatively brisk customer growth that increases opportunities to realize scale economies. The Board's 0% base productivity trend applies to all Ontario utilities and is effectively an industry standard.

[80] If the Company embraced the Annual IR Index option, the X factor would be higher.

[81] Hydro Ottawa Interrogatory Response to OEB-34 a).

[82] It is possible, of course, that a utility could experience an inordinately large number of (or inordinately large) unfavorable events that make it difficult to achieve the MFP trend of the peer group in the short run or long run. For example, a distributor directly hit by a hurricane may deserve supplemental compensation even though few utilities in the productivity sample used to calibrate X have been similarly afflicted. A utility ordered to replace all wooden poles with cement poles could, similarly, argue that this has rarely been asked of peer group utilities. However, the degree to which peer group productivity trends reflect various kinds of unfavorable events is difficult to assess.

Still another overcompensation concern is that, due to the specific hybrid design of the revenue cap, the stretch factor term in the CPEF would apply only to the Hydro Ottawa's OM&A revenue. This is less than half of the Company's total revenue requirement.[83]

High Regulatory Cost

Hydro Ottawa's weak incentive to contain capex and its incentives to exaggerate its capex needs and strategically manage capex in order to bolster extra revenue all give stakeholders and the Board extra reasons to scrutinize the Company's multiyear capex proposal. Careful oversight of capex plans raises regulatory cost and has proven increasingly taxing to the OEB and stakeholders as most of Ontario's larger utilities queue up for Custom IR. Regulatory cost is an important consideration in Ontario, which has large gas and electric utility industries and an unusually large number of power distributors to regulate.[84] Containment of regulatory cost is part of the rationale for using indexed ARMs and statistical benchmarking in Ontario. The Board has used the regulatory cost argument to rationalize materiality thresholds to limit use of Z factors, ACMs, and ICMs.

Despite the extra effort, the OEB and stakeholders naturally struggle with the difficult task of effectively reviewing distributor capex proposals for multiyear plans. In essence, the Board has sanctioned British (forecast-based) approaches to determining multiyear capital revenue requirements but has not made investments that British and Australian regulators have in the capability for appraising multiyear capex proposals. Both of these regulators have, for example, commissioned statistical benchmarking and engineering models to produce independent estimates of capex needs. The British regulator Ofgem's own view of a power distributor's required cost growth is assigned a 75% weight in IR proceedings.[85] Ofgem has also devised a complicated Information Quality Incentive to encourage truthful cost forecasts. Ofgem also has spent considerable sums on engineering consultants.

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[83] We noted in Section 5.5 above the additional concern that the X factor in the CPEF formula would be based on total factor productivity growth.

[84] It should also be noted that the analogous regulators in American states do not have primary jurisdiction over power transmission rates and services.

[85] Ofgem (2014), RIIO-ED1: *Final determinations for the slow-track electricity distribution companies Overview Final Decision*, November 28, p. 22.

Excessive Use of Custom IR

It is also notable that the full funding of its capital cost growth which Hydro Ottawa proposes is more remunerative than that available under Price Cap IR. We noted in Section 2.2 that ACMs and ICMs feature a materiality threshold with a meaningful dead band before projected capital revenue shortfalls are funded.[86] The disparity in expected returns encourages distributors to choose Custom IR instead of Price Cap IR or an Annual IR Index. Some distributors may now or in the future choose Custom IR, with its weaker performance incentives and higher regulatory cost, even though efficient and compensatory operation under Price Cap IR or an Annual IR Index is feasible.

Conformance with Board Policy

Partly for the reasons just discussed, the proposed plan does not conform well to the Board's policies and recent decisions concerning Custom IR. We noted in Section 2 that Hydro Ottawa's prior plan was approved before the Board issued its *Rate Handbook* in 2016. The Handbook states that

> Custom IR is not a multi-year cost of service; explicit financial incentives for continued improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast).[87]

Only the proposed ratemaking treatment of OM&A expenses satisfies these guidelines, and these expenses account for less than half of the Company's revenue requirement. Hence, the proposed plan is conformant with the Handbook only if these guidelines are construed as not necessarily intended to apply to most of an applicant's costs.

Alberta Experience

Other regulators have sought to balance a need to make IR reasonably compensatory with the high regulatory cost and weak cost containment incentives that can result from such efforts. This has

[86] The Board rationalized these thresholds chiefly (and in the cast of Z factors entirely) on the grounds of reducing regulatory cost even though they make sense for other reasons.

[87] *Rate Handbook*, *op. cit*., p. 25.

sparked periodic reconsideration of IR and new IR approaches. The RIIO approach to regulation in Great Britain is one such outcome.

In this section we discuss the deliberations of the Alberta Utilities Commission ("AUC"). The AUC has, in generic proceedings, developed two generations of MRPs for large gas and electric power distributors. In each generation of plans, rates or (for gas distributors) revenue per customer have been escalated by I-X formulas designed using evidence on industry cost trends. In both proceedings, jurisdictional distributors claimed an outsized need for capex due in part to the "boom and bust" nature of Alberta's economy. This led to provisions for extra capex funding in both generations of MRPs. The AUC has addressed many of the issues that the OEB has grappled with.[88]

In the first-generation plans supplemental funding was provided, via "capital trackers," for *individual categories* of capital cost if an "accounting test" convincingly demonstrated that the funding otherwise provided by the ARM was insufficient. The resultant percentage adjustments to rates were called "K factors." All benefits of capex underspends were passed back to customers. A great deal of capex proved to be tracker-eligible. A further generic proceeding was required just to clarify tracker policy. Regulatory cost was high and incentives to contain capex were weak.

The AUC stated the following about its experience with this plan.

> The Commission considers that **finding a mechanism that achieves the balance between providing incremental funding for capital while maintaining the incentives to improve productivity and lower costs inherent in the PBR plans, without double-counting, has been challenging during the first PBR term**… many highly complex issues involving the interpretation and application of the capital tracker criteria, including grouping issues, the establishment of the accounting test to determine the amount of funding available under I-X, and project assessment to confirm the need for a project, have arisen in the various capital tracker proceedings. The number and complexity of these issues far outstrip any other issues that have arisen from the implementation of the PBR plans.
>
> Accordingly, **the Commission considers that it is reasonable to consider whether modifications to, or substitutes for, the capital tracker mechanism can be made in the next generation PBR plans to improve regulatory efficiency** while achieving the balance of objectives identified in Decision 2012-237. **These modifications could include**, as

[88] For example, The AUC stated in D-2012-237 that "A capital factor must be carefully designed in order to maintain the efficiency incentives of PBR, and also to avoid double-counting." (p. 115).

> suggested by AltaGas, **streamlining options**, particularly for multi-year capital tracker programs.[89] **[Emphasis added]**

The mentions of regulatory efficiency and streamlining are notable given the Board's stated concerns with Custom IR.

Conclusions

The OEB has evinced mounting frustration with the cumbersome Custom IR option that most large Ontario utilities now request. It is notable that high regulatory cost has been a major concern since this was not emphasized in the OEB's Custom IR guideline discussions. It seems desirable to consider how to make Custom IR more mechanistic, incentivizing, and fair to customers while still ensuring that it is reasonably compensatory over time for efficient distributors. Custom IR should be streamlined and/or used less frequently. Regulators in other jurisdictions (e.g., Alberta and Britain) who championed IR but found themselves saddled with a system that retained too many cost of service features have reconsidered and reformed IR at the end of each round of plans.

6.2 Alternative Ratemaking Treatments for Capital

Absent a comprehensive generic proceeding to reconsider the RRF, we have, with a limited budget aligned with aims of our work in reviewing Hydro Ottawa's Custom IR proposal in this application, extended the analysis of possible reforms to the ratemaking treatment of capital which we have provided in some other recent Custom IR proceedings. We believe that the following alternatives to Hydro Ottawa's proposed ratemaking treatment of capital merit consideration by the Board and other parties to this proceeding. We group the alternatives into: 1) smaller reforms that are evolutionary in character; and 2) more sweeping changes to Custom IR. All of the options should be appraised for their ability to strengthen utility performance incentives, reduce regulatory cost, and ensure customers a reasonable share of IR benefits.

[89] Alberta Utilities Commission Final Issues List in Alberta Utilities Commission Proceeding 20414, August 21, 2015, p. 9.

Smaller Reforms

C Factor and S Factor

The most obvious alternative to Hydro Ottawa's proposal is that approved by the OEB in recent Custom IR decisions for THESL and Hydro One.[90] The CPEF would nominally apply to capital as well as OM&A revenue. A C factor would be added to the CPEF formula which escalates revenue for a portion of any positive difference between the approved growth in the Company's total capital cost and the capital revenue growth that the CPEF would otherwise provide. The capital cost growth eligible for recovery would be reduced by the TFP growth target, the stretch factor, and a supplemental stretch factor (aka S factor) for capital. This is, effectively, a materiality threshold that includes a dead band.

The capital revenue requirement in the first indexing year can be represented formulaically as

$$RK_1 = \{CK_o \times [1 + [I - (TFP + Stretch) + G)]\} + \{CK_1 - CK_0 \times [1 + (I + G) + S]\} \quad [7a]$$

$$= CK_o \times [1 + (I + G)] - CK_o \times (TFP + Stretch) + CK_1 - CK_0 \times (1 + G) - CK_0 \times S \quad [7b]$$

$$= CK_1 - (TFP + Stretch + S) \times CK_0. \quad [7c]$$

where

RK = allowed capital revenue

CK_t = capital revenue requirement in year t

I = growth in the inflation measure

TFP = base TFP trend

Stretch = stretch factor

G = growth factor

Compared to Hydro Ottawa's proposal, this approach would strengthen capex containment incentives, reduce overcompensation concerns, and conform better with the OEB's Custom IR Guidelines with only a small increase in regulatory cost.[91] Since a portion of *capital cost growth* would be ineligible for funding, a portion of the *capex* (which utilities control during the plan) would also be

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[90] OEB, *Decision and Order*, EB-2017-0049, March 7, 2019 and *Decision and Rate Order*, EB-2018-0165, February 20, 2020.

[91] The chief incremental regulatory cost is deciding on the S factor.

ineligible. The stretch factor would apply to capital as well as to OM&A revenue. This approach also has the merit of not binding future Board panels that must approve new regulatory systems.

On the other hand, gains from this approach would be modest at the low values for X and S which the OEB has recently approved. Incentives and the likelihood that a capex plan would be ineligible for Custom IR depend on the base TFP trend, which the Board has for several years been setting at zero. There would not be a meaningful materiality threshold for Custom IR even though the arguments for such a threshold apply to Custom IR just as they do to ACMs, ICMs, and Z factors.

It should also be noted that the THESL and Hydro One plans are compliant more with the letter than with the spirit of the Board's Custom IR guidelines.[92] When the base TFP trend is set at zero, such plans are particularly close to violating the *Rate Handbook* standard that "it is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications." The incremental capital stretch factor of 0.15% barely achieves compliance. As noted in Section 2.4, the Board indicated in its recent THESL decision a lack of enthusiasm for considering additional plans with these features.

The benefits from the C factor approach would be increased were the S factor raised substantially from the 0.15% level recently approved for Hydro One Transmission. A higher S merits contemplation for several reasons.

- An S of 0.15% is unlikely to establish parity with the ACM and ICM capex markdowns.
- The OEB has rationalized materiality thresholds (and, in the case of the ACM and ICM, dead bands) chiefly on the grounds of reducing regulatory cost. Yet we have noted two other rationales for markdowns: stronger capex containment incentives and lessened overcompensation concerns.
- The markdown in the ACM and ICM materiality thresholds is actually far less than 10%.

[92] This approach conforms to the Board's Custom IR guidelines in the Rate Handbook in the same sense that a restaurant offers a lobster dinner if it offers a dinner featuring lobster plus a chef's special "menu surprise," where the surprise is that 60% of the lobster is replaced with poor man's lobster in the form of previously-frozen haddock.

- A higher markdown could, over time, materially reduce the number of capex plans eligible for Custom IR. It could particularly discourage continuation of Custom IR when utilities are approaching the end of a period of high capex.
- A higher S conforms to the OEB's guideline that, for a Custom IR plan, X be higher than and certainly no lower than what it would be under Price Cap IR.

Utilities may respond to a higher markdown by asserting a need for higher capex and/or bunching more capex to attain eligibility. To the extent that a higher markdown is rationalized on the grounds of overcompensation in *future* IR plans, it should be noted that the future of IR in Ontario is unclear. MRPs with indexed ARMs based on industry cost trends may not continue. Higher markdowns therefore makes more sense to the extent that the Board is confident that regulation will continue to be broadly similar.

Also on the downside, the Board stated in the Rate Handbook that Custom IR did not involve a "threshold test." However, the Board's approved C factor approaches have effectively involved thresholds.[93] Regulatory cost would still be high and capex containment incentives would still be weak.

If the Board chooses the C factor approach for Hydro Ottawa, we believe that the S factor should be at least high enough that, together with the TFP target, it achieves parity with the capex markdowns in the ACM and ICM formulas. We further encourage the Board to consider an even higher S factor that is more likely to materially reduce the number of eligible Custom IR applications.

Variants on the C Factor Theme

Variants on the current C factor approach to Custom IR also merit consideration. One variant would be to calculate C using the (typically slower) productivity growth trend of capital, while the X factor for OM&A revenue would reflect the (typically faster) productivity trend of OM&A. This would modestly reduce the size of C factors and, combined with a meaningful materiality threshold, reduce the frequency of Custom IR plans. Escalation of OM&A revenue would better reflect industry OM&A cost

[93] The AUC, in its first generation PBR decision, approved a 40 basis point *cumulative* materiality threshold on projects eligible for tracking. A 4 basis point threshold was applied to individual projects. AUC Decision 2013-435, p. 86.

trends. There is precedent for separate indexing of O&M and capital revenue in British Columbia IR.[94] Unfortunately, there is no contestable recent research available to the panel in this proceeding on the capital productivity trends of power distributors.

Consider next that one reason why incentives are weak under the current C factor approach is that utilities have no incentive to contain their *incremental* capex once capital cost growth exceeds the threshold. The following alternative mechanism would provide an incentive to contain incremental capex.

$$RK_1 = CK_0 \; x \; \{1 + [(I - (TFP + Stretch) + G)]\} - \{[CK_1 \; x \; (1\text{-}S)] - CK_0 \; x \; [1 + (I{+}G)]\} \quad [8a]$$

$$= CK_1 - (S \; x \; CK_1 + (TFP + Stretch) \; x \; CK_0). \quad [8b]$$

An alternative approach with more complicated math would also accomplish this

$$RK_1 = CK_0 \; x \; \{1 + [(I - (TFP + Stretch) + G)]\}$$
$$- \{CK_1 - CK_0 \; x \; [1 + (I - (TFP + Stretch) + G)]\} \; x \; (1\text{-}S) \quad [9]$$

Formula [8b] would not establish a materiality threshold. Desirable attributes of both approaches could be combined by using [7c] to establish the materiality threshold and then using [8b] to determine the exact amount of eligible capital cost. In other words, if proposed capital cost exceeded the materiality threshold, a percentage of *all* (or a wider range of) unfunded capital cost could be declared ineligible for C factoring. This would strengthen the Company's incentive to contain capex at the margin.

Consider next that, under the current mechanism, the choice of the S factor is tied to the base productivity trend. The appropriate value of S would likely be higher if X is 0% (or -0.3%) than if it is 0.3%. This complication in choosing S can be sidestepped by making the capital cost eligible for extra revenue independent of the base productivity trend. This can be achieved by the following formula.

$$RK_1 = CK_o \; x \; \{1 + [I - (TFP + Stretch) + G]\}$$
$$+ \{[CK_1 - CK_0 \; x \; [1 + (I - TFP + G) + S)]\} \quad [10a]$$
$$= CK_o \; x \; [1 + (I\text{-}TFP{+}G)] - CK_o \; x \; Stretch + CK_1 - CK_0 \; x \; [1 + (I\text{-}TFP{+}G)] - CK_0 \; x \; S \quad [10b]$$
$$= CK_1 - (Stretch + S) \; x \; CK_0. \quad [10c]$$

[94] See, for example, the recent plans of FortisBC (formerly West Kootenay Power) and FortisBC Energy (formerly Terasen Gas). Note that the base productivity trends have been the same for OM&A and capital revenue.

Consider finally that it is difficult to calculate a value for S that establishes parity with the markdown that ACMs and ICMs require. A straightforward way to sidestep this calculation is to abandon the current C factor mechanism entirely and to instead use the current ACM/ICM mechanism to determine the capex eligible for supplemental revenue. Alternatively, the ACM/ICM mechanism might be used to determine incremental capex eligible for supplemental revenue, which would then be used to determine the C-factor for the rate adjustment in each year. This might require some adjustments to the C factor formula to maintain parity with the ACM/ICM.

Alternative Eligibility Restrictions

Eligibility of capex for supplemental revenue could be scaled back by the alternative method of making certain *kinds* of capex ineligible. Some capex would then be addressed by the CPEF. Here are some possible exclusion criteria.

- Some approved MRPs with indexed ARMs based on cost trends permit variance account treatment only for plant additions that are major and/or unpredictably timed. The FRP and South Nepean MTS projects of Hydro Ottawa would likely qualify. This approach is featured in the recently expired MRPs of FortisBC and FortisBC Energy.[95] An example from Hawaii is discussed below.
- While distributors serving rapid-growth regions experience growth-related cost bumps, growth-related capex could be deemed ineligible for supplemental revenue (or certain *kinds* of supplements) on several grounds.[96] For example, a lot of growth-related capex is partially self-

[95] British Columbia Utilities Commission ("BCUC") (2014), *In the Matter of FortisBC Inc. Multi-Year Performance Based Ratemaking Plan for 2014 Through 2018 Decision*, September 15, pp. 170-175.

BCUC (2014), *In the Matter of FortisBC Energy Inc. Multi-Year Performance Based Ratemaking Plan for 2014 Through 2018 Decision*, September 15, pp. 176-181.

[96] The AUC stated in Decision 2012-237 that one of its capital tracker eligibility criteria

> excludes projects required to accommodate customer or demand growth because a certain amount of capital growth is expected to occur as the system grows and system growth generates new sources of revenue that offset the costs of the new capital. The new sources of revenue can come in the form of increased customers and load growth, and also through contributions in aid of construction.

However, in a later decision it revised this criterion. Capex eligible for tracker treatment must also exceed a materiality threshold. The Commission described its eligibility requirements as having a "targeted criteria-based financed by growth in billing determinants and contributions in aid of construction. Some kinds of growth-related capex (e.g., costs incurred due to construction of mass transit and highway infrastructure) are potentially eligible for Z factoring. Intensive use of CDM and distributed generation and power storage can reduce the need for substation and substransmission system capacity expansions.[97] Consider also that distributors in rapid-growth regions tend to have outsized opportunities to realize scale economies. Our research over the years has revealed that such distributors often experience rapid MFP growth.

- Capex in the last year of the plan term could be deemed ineligible for extra revenue because this involves only one year of underfunding.

This general approach would strengthen capex containment incentives and reduce overcompensation concerns despite a net *reduction* in regulatory cost. The freedom of OEB panels in future proceedings would not be fettered. On the other hand, to the extent that such eligibility restrictions are rationalized on the grounds of overcompensation in future IR plans, it should again be noted that the future of IR in Ontario is unclear. This approach therefore makes more sense to the extent that the Board is confident that regulation using ARMs based on industry cost trends will continue.

X Factor Adjustment

The X factor could be raised, in this and any future IR plans, by an amount sufficient to increase the likelihood that revenue cap indexes reflect industry productivity growth over multiple plans. This could be accomplished in several ways.

- One approach would be to recompute TFP growth removing a certain share of the capex made by sampled utilities. In a study for a British Columbia proceeding, PEG reported that, over the ten year 2002-2011 period, removing 10% of gross plant additions from the study increased the

nature" that "limits the number of projects that are outside the I-X mechanism, and as a result, the incentive properties of PBR are preserved to the greatest extent possible." (September 2012, pages 124 and 127).

[97] Encouragement of such non-wire alternatives ("NWAs") to load-related capex is a focus of IR today in some American states (e.g., New York). See, for example, the Brooklyn-Queens demand management project of Consolidated Edison of New York.

average annual TFP growth of a large sample of U.S. power distributors by 25 basis points.[98] A downside of this particular approach is that it is difficult to establish what share of capex should be removed from the productivity study. There is no contestable evidence on this matter in this proceeding.

- Another approach would be to require utilities seeking supplemental funding to borrow revenue escalation privileges from future plans. If, for example, customers were in one plan effectively asked to fund capital productivity growth that was 3.2% above the industry norm on average over the indexing years of a plan, the X factor could be SK x 0.4% or roughly 0.2% higher in this and the next 7 plans to make customers whole. Here SK would be the typical share of capital cost in total utility cost.

Several benefits of this general approach of adjusting the X-factor are notable. Overcompensation concerns would be reduced. The incremental regulatory cost is small. Knowledge that there is a price to be paid in the long run for asking for extra revenue now would strengthen Hydro Ottawa's capex containment incentives. X factor adjustments would continue only if a broadly similar form of IR with an indexed ARM based on industry cost trends was used in future plans.

One downside of this general approach is that the freedom of future Board panels may be fettered, or they may choose not to honor past commitments. If future growth in the ARM is slowed by this means, the utility is more likely to request supplemental capital revenue in future plans via Custom IR, ACMs, or ICMs.[99] However, this problem could be mitigated by having higher Custom IR, ACM, and ICM materiality thresholds.

Continued Tracking

Capital costs that occasion supplemental revenue could be subject to continued variance account treatment in later plans. Customers, having fully funded the initial cost of surge capex, would then receive the benefit of its depreciation between rate cases in later plans. This would reduce

[98] Lowry, M.N., Hovde, D.A., and Rebane, K. (2014), *X Factor Research for Fortis PBR Plans*, Submitted on behalf of Commercial Energy Consumers Association of British Columbia in British Columbia Utilities Commission Projects 3698715 and 3698719, January 7, pp. 35-37.

[99] This concern would, however, be lessened by a meaningful materiality threshold.

overcompensation concerns. The utility's revenue for surge capex would closely track the annual cost of the investment that the Board deemed prudent. Knowledge that there is a price to be paid in the long run for asking for extra revenue now would strengthen Hydro Ottawa's capex containment incentives. Tracking need continue only if a broadly-similar form of IR with an indexed ARM based on cost trend research continued.

On the downside, the regulatory burden of continuing to track the revenue requirement for old capex would be non-negligible. However, the recent MRPs for the Fortis companies in BC tracked the cost of *all* older capital.[100] The freedom of future regulators may be abridged and they may choose not to abide by the arrangement (e.g., they may instead role surge capex into the rate base addressed by the indexed ARM and not continue to track its cost).

A portion of depreciating older plant would be excluded from the cost that is addressed by the ARM in Price Cap IR or its successor. This would increase the likelihood that Hydro Ottawa would in the future claim a need for supplemental revenue in the form of an ACMs, ICMs, or Custom IR. However, this problem could be mitigated by having meaningful Custom IR, ACM, and ICM materiality thresholds.

<u>Incentivized Variance Account</u>

The capital variance account is the single leading cause of the weak capex containment incentives in Hydro Ottawa's proposed plan. In Ontario, these accounts were initially approved in proceedings where the ability of utilities to spend the high levels of capex which they proposed was questioned.[101] The ability of Ontario utilities to markedly increase their capex has been since been amply demonstrated.

One way to incentivize the capital variance account would be to permit Hydro Ottawa to keep a share of the revenue requirement impact of capex underspends.[102] The Company could, for example, be permitted to keep the revenue requirement impact resulting from the first X% of savings, as in the Hydro One Custom IR plans.

[100] These expiring plans indexed only the revenue requirements for OM&A expenses and routine capex.

[101] See, for example, Ontario Energy Board EB-2014-0140.

[102] A share of any revenue requirement overruns could, in principle, be deemed ineligible for rate basing.

This general approach would strengthen Hydro Ottawa's incentive to contain capex with little increase in regulatory cost. The freedom of future Boards would not be compromised. However, a reduction in overcompensation is not ensured since this approach would reduce customer clawbacks of underspends and increase the Company's incentive to exaggerate its capex needs.[103] Moreover, gains would be small under the sharing provisions that the OEB has thus far approved. Regulatory cost would still be high, capex containment incentives would still be weak, and even a plan with a C factor would still be compliant more with the letter than the spirit of the Board's guidelines.[104] The benefits from this approach would be increased were the Company's share of revenue requirement savings raised substantially. At the extreme, the plan could contain no capital cost variance account, like a previous Enbridge Gas Distribution plan.[105]

An exemption of underspends due to productivity gains also strengthens incentives to underspend but encourages strategic behavior by the utility. For example, the Company has an incentive to misrepresent the extent of true productivity gains and to hold back on productivity gains in its initial revenue requirement offer. Regulatory cost would be increased materially.

A third approach meriting consideration is to place a hard cap on the capital revenue requirement. The undepreciated balance of investment resulting from a capex overspend would then be ineligible for inclusion in rates in later rebasings. Alternatively, only a share of the overspend capex could be declared eligible.

Variants of the approaches to capital variance account incentivization used thus far in Ontario merit consideration. The dead band could be eliminated, or a range could be established where variances are shared. For example, customers could be permitted to keep the entirety of the first 10% of cumulative revenue requirement savings and 50% of any additional savings.

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[103] The AUC stated in its first generic PBR decision 2012-237 that "The use of long term forecasts as proposed by ATCO Electric for its K factor does create some efficiency incentives. However, in the absence of a true-up, the Commission considers the incentives for a company to exaggerate its capital needs…to be a major drawback to such an approach." p. 131.

[104] This approach conforms to the Board's Custom IR guidelines in the same sense that a restaurant offers a lobster dinner if it offers a dinner featuring lobster plus a chef's special "menu surprise" where the surprise is that 2/3 of the lobster is replaced with previously-frozen haddock.

[105] EB-2012-0459, *Decision with Reasons*, July 14, 2014.

Precedents for incentivized trackers in the regulation of other utilities shed light on their potential merit and possible designs. PEG has not undertaken a comprehensive survey of approved cost tracker sharing provisions but we are aware of several examples. Most notably, this type of mechanism has been approved for capex in California, Britain, and British Columbia.

Details of some approved capital tracker sharing mechanisms can be found in Table 10 below. Please note the following.

- The BCUC has approved Certificates of Public Convenience and Necessity for several large capex projects that were conditional on a mechanistic sharing of cost variances. Some of these mechanisms shared cost overruns or underspends that were outside of a +/- 10% band evenly between the utility's shareholders and customers. Notice that in the cited BC plans *customers* kept the entirety of the first 10% of variances.

- In the United States, Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison, and Southern California Gas obtained special ratemaking treatments to recover the cost of full AMI deployment. These treatments combined a preapproved multiyear capex forecast with a cost tracker. Recovery was allowed for capital costs net of OM&A savings. If each company's actual cost to deploy AMI was in line with the approved forecast, there would be no subsequent prudence review.

  Southern California Edison's AMI deployment tracker featured an asymmetric sharing mechanism wherein 90% of the first $100 million in excess of the approved forecast was absorbed by shareholders and 10% by customers without the need for a further prudence review. Exceptions to the cost caps were made for *force majeure* events, changes in the project's scope due to government or regulatory activity, and delays in Commission approval. The treatment of variances from forecasted cost for San Diego Gas & Electric was similar, as 90% of the first $50 million over the budget would be absorbed by shareholders without a further prudence review. San Diego Gas & Electric's AMI tracker also authorized a sharing of the first $50 million under the budget, with 10% going to the company. Southern California Gas' AMI tracker was similar to San Diego Gas & Electric's. The company would absorb 50% of the first $100 million above the budget and keep 10% of the first $100 million under the budget without a further prudence review.

Table 10

Details of Incentivized Capital Cost Trackers

Jurisdiction	Company Name	Services	Eligible Investments	Special Treatment of Cost Variances	Case Reference
BC	Terasen Gas (now FortisBC Energy)	Gas	Customer Care Enhancement Project	Customers receive/absorb 100% of variances within 10% of cap; Savings or costs beyond deadband split evenly between customers and company	Order C-1-10
BC	Terasen Gas Vancouver Island (now FortisBC Energy)	Gas	Gas pipeline lateral from Squamish to Whistler	Customers receive/absorb 100% of variances within 10% of cap; Savings or costs beyond deadband split evenly between customers and company	Orders G-53-06, G-76-06
BC	Terasen Gas Whistler (now FortisBC Energy)	Gas	Conversion of Whistler Gas system from propane to methane, meter/regulating station	Customers receive/absorb 100% of variances within 10% of cap; Savings or costs beyond deadband completely at company's risk	Order G-53-06
BC	BC Gas (now FortisBC Energy)	Gas	Southern Crossing Pipeline Project	Customers receive/absorb 100% of variances within 10% of cap; Savings or costs beyond deadband completely at company's risk.	Order G-51-99
BC	FortisBC	Bundled power service	Big White Supply Project	Customers receive/absorb 100% of variances within 10% of cap; Savings or costs beyond deadband completely at company's risk	Order C-17-06
CA	San Diego Gas & Electric	Power and Gas Distribution	Advanced metering infrastructure ("AMI")	No deadband. Asymmetrical mechanism wherein 90% of the first $50 million over the cap and 10% of first $50 million under the cap allocated to shareholders (No prudence review required)	Decision 07-04-043 (April 2007)
CA	Southern California Edison	Power Distribution	Deployment of AMI	No deadband. Asymmetrical Mechanism wherein 90% of first $100 million over the cap charged to customers (No prudence review required)	Decision 08-09-039 (September 2008)
CA	Southern California Gas	Gas	AMI	Overrun sharing mechanism: Up to $50 million to be paid by shareholders, calculated as 50% of first $100 million over total cost; Underrun sharing mechanism: Up to $10 million to be received by shareholders, calculated as 10% of first $100 million under total cost.	Decision 10-04-027 (April 2010)

- In Britain, energy utility revenue requirements are based on total (capital and operating) expenditures (aka "totex"). Utilities may share in both underspends and overspends of totex relative to approved amounts. The utility's share of totex variances is tied mechanistically to how reasonable the utility's expenditure forecast is deemed to be by Ofgem. This provision is part of Ofgem's complicated information quality incentive mechanism.

Incentivized cost trackers have also been approved in North America for energy (e.g., generation fuel) procurement costs and for other operating revenues. It should also be noted that many multiyear rate plans have been approved over the years in which utilities keep the benefits of *all* capex underspends or share them only through an ESM.

Custom IR Limits

Accumulating experience with Custom IR in Ontario (and analogous mechanisms elsewhere) suggests that it would be desirable to limit its usage. In addition to making its terms less favorable to utilities, the OEB should consider limiting the frequency with which utilities can use Custom IR. For example, the option could be made available in only three of each five (or two of each three) IR cycles. This would strengthen capex containment incentives and could substantially lower regulatory cost if utilities would otherwise likely opt for Custom IR continually.

However, utilities would be more likely under this restriction to bunch capex so that it occurs in years when Custom IR plans are permissible. Utilities denied the right to use Custom IR could make aggressive use of ACM, ICM, and Z factor provisions of Price Cap IR. This would increase the importance of DSP reviews. The freedom of future Board members could be abridged or they may refuse to abide by the arrangement.

Strengthen Reviews of Capex Prudence

The OEB should encourage greater effort to review capex prudence. Performance incentives can be strengthened thereby and overcompensation reduced. The Board has already taken a big step in this direction by requiring DSPs and learning how to review them. One the other hand, regulators will still struggle with the asymmetry of information.

Further upgrades to the prudence review process merit consideration. Engineering and econometric models could be commissioned to ascertain the need for repex, and variants on Ofgem's information quality incentive mechanism could be developed. Plans can be reviewed over periods longer than five years for their tendency to bunch capex in ways that bolster supplemental capital revenue. Inefficient bunching of capex should be discouraged, but so too should be strategies that unduly prolong Custom IR. Plans in the late stages of a capex surge merit special scrutiny. Excessive use of capex to reduce OM&A expenses is another special concern. For example, proposals to increase system undergrounding merit special scrutiny.

On the downside, conscientious reviews of capex are costly. The OEB will still operate at an information disadvantage. Thus, a mix of prudence reviews and IR mechanism will continue to be optimal.

Major Departures

The Board may also wish to consider more substantial departures from the capital cost treatments it has approved in prior Custom IR proceedings. The following alternative ratemaking treatments of capital in Alberta and California then merit consideration.

Alberta and California

California The California Public Utilities Commission ("CPUC") has required jurisdictional gas and electric utilities to operate under MRPs since the 1980s. Revenue decoupling has been common, so these plans have typically featured *revenue* caps, not *price* caps. Escalation of these caps between rate cases has often involved hybrid mechanisms with separate treatments of OM&A and capital revenue.[106] OM&A revenue has typically been indexed for inflation. The capital revenue requirement is calculated, using traditional cost accounting, under the assumption that a utility's gross plant additions in each year of the plan will equal its recent historical average or the approved test year additions. The Office of the

[106] *See, e.g.*, the current multiyear rate plan of Southern California Edison as approved in CPUC Decision 19-05-020.

Ratepayer Advocate has often expressed a reluctance to consider multiyear capex forecasts.[107] Gross plant additions are sometimes adjusted for inflation in later years of the plan.

These plans typically have not included capital variance accounts that returned benefits of most capex underspends to customers. Earnings sharing mechanisms have also been uncommon.

Hybrid revenue caps in California have sometimes been combined with capital cost trackers that are limited in scope but address major plant additions with hard to predict timing (e.g., AMI and generation facilities). Under a hybrid ARM, it is easier to ensure that capital costs are not double counted should the need for a capital cost tracker arise, as parties can identify whether or not the costs associated with a project are already addressed through the capital cost budget.

Alberta The second-generation Alberta MRPs[108] allow for two methods by which distributors may obtain extra capex funding. Trackers may fund material capex that is required by a third party or extraordinary. Supplemental funding for other kinds of capex is provided by the "K-bar." A base K-bar value was established for each distributor for the first year of the plan based on its recent *historical* capex, adjusted for growth in inflation, X, and billing determinant growth, which were not funded by base rates. [109] This process is repeated for subsequent years. These plans do not include ESMs or trackers that return the benefits of capital underspends to customers.

Appraisal The California and Alberta approaches to ARM design have notable selling points. Regulators need not sign off in advance on the prudence of detailed multiyear capex plans. There is less opportunity for utilities to exaggerate their capex needs. This can reduce regulatory cost considerably. Capex containment incentives are strengthened by the lack of an ESM or capex underspend clawback

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[107] It may be noted that these are large distributors, three of which serve over six million customers, and this has helped to stabilize capex requirements. A very large distributor might, for example, build or replace three substations every five years whereas a small Ontario distributor might build or replace one substation every forty years.

[108] PEG is not recommending this ratemaking treatment for Hydro Ottawa.

[109] For power distributors the change in billing determinants is calculated across all billing determinants including energy, demand, and the number of customers, while the billing determinants for gas distributors is calculated as the weighted average change in the number of customers among rate classes.

and by increased uncertainty about capex prudence reviews in the next rebasing.[110] Overcompensation is reduced if OM&A revenue escalation is not based on TFP trends. Other overcompensation concerns would remain, however, in an application to Ontario since Hydro Ottawa could return to Price Cap IR in a future plan.

On the other hand, this approach requires confidence that recent capex levels will continue during the plan term. DSPs are still needed to provide this confidence. It is possible that a utility's capex needs will change during the plan due to unforeseen circumstances such as a deep recession. Some OEB Custom IR guidelines are violated since the capital revenue requirement is unaffected by the industry productivity trend or stretch factor. However, the Board could modify the California approach in order to incorporate its rate-setting principles and policies as documented in the Rate Handbook.

Capex containment incentives can be weakened if this approach continues in future plans and the capital revenue requirement in these plans is again expected to be based on recent historical capex. For example, Hydro Ottawa's incentives would be weakened during its new plan if there was an expectation that its capex in the 2021-2025 period was going to be used to set the capex budget for the next plan. Research by PEG for Berkeley Lab found that the TFP growth of California distributors has been slower and not more rapid than the sample norm during their years of operation under MRPs.[111] In the case of Hydro Ottawa, this problem can be mitigated by using the same base capex levels in any third Custom IR plan. However, it seems doubtful that this strategy would be reasonable for more than one additional plan. An argument could be made for extending the new plan to seven years with an understanding that a return to Price Cap IR would follow.

Some parties may be concerned that this approach invites the utility to defer capex without sharing benefits and then argue that another high capex budget is needed in the next plan. An ESM or incentivized capital variance account can share benefits. Alternatively, any revenue requirement reduction from capex underspends can be reserved to fund future capex subject to the understanding

[110] The AUC stated in its first generic PBR decision (D-2012-237) that "The Commission recognizes that superior efficiency incentives would be created if the companies were required to make capital investment decisions and undertake the investment prior to applying for recovery of their costs by way of a capital tracker, p. 131.

[111] Lowry, Makos, Deason, *op. cit*., pp. 6.11-6.13.

that elevated capex budgets will not long be permitted. For example, Hydro Ottawa could be instructed that it is eligible for only one additional consecutive Custom IR plan.

The California approach to ARM design may seem to be inconsistent with some OEB Custom IR guidelines. However, a capital cost projection that is based on an annual budget for gross plant additions that is fixed in nominal or real terms can be used to make C factor calculations.

Econometric MFP Projections

In Hawaii, a generic proceeding is underway to develop a new performance-based regulation ("PBR") framework for the Hawaiian Electric Companies ("HECO") and two affiliates. These three vertically integrated electric utilities ("VIEUs") are chiefly engaged in T&D since most power in Hawaii is generated by third parties or customers. Like many Alberta and Ontario distributors, the HECO companies claim a need for high levels of repex.[112]

The Commission has decided that the new PBR framework will feature MRPs with revenue cap indexes that have I – X formulas designed using cost trend research.[113] Each plan will also have a major plant interim recovery cost tracker. Repex will, importantly, *not* be eligible for tracker treatment. The X factor thus has special importance in this proceeding. The challenge has been to use research on the cost trends of mainland VIEUs to determine an X factor that is suitable for the costs to which the revenue cap index will apply, which include considerable repex.

PEG has performed an econometric study funded by the HECO companies to identify drivers of mainland VIEU productivity growth and quantify their impact. A T&D "repex requirement indicator" that we developed was found in the study to be a highly significant VIEU cost driver. This indicator is based on past capex patterns using data on gross plant additions back to 1948.

PEG developed from this research an econometric MFP growth projection for the next five years which is specific to the business conditions that HECO expects to face in managing the costs that its revenue cap index will address. These projections are, essentially, an estimate of the MFP growth that typical utility managers would achieve in managing these costs. The projections take account of the fact

[112] The repex surge in the islands is occasioned by the surge in capex in the years following Hawaiian statehood.

[113] These plans will feature revenue decoupling.

that HECO will experience sluggish electric customer growth and a growing need for repex but the costs subject to indexing will not include those for any AMI buildout, new emissions controls, gas customer growth, or generation plant additions which mainland VIEUs have experienced. The projections provide the basis for an X factor that is customized to HECO's business conditions but doesn't weaken its incentive for capex containment.

This productivity research was based on a methodology pioneered by Denny, Fuss, and Waverman.[114] PEG first used econometric MFP growth projections in work for the OEB in a gas IR proceeding.[115] An article on this research was published in the *Review of Network Economics.*[116]

This kind of research could in principle be used to establish an X factor for Hydro Ottawa or other Ontario distributors. Econometric research on power distributor cost could consider the impact of productivity growth drivers such as customer growth, AMI, and the need for repex. This research could provide the basis for an econometric MFP growth projection for Hydro Ottawa during the four indexing years that is specific to the business conditions the Company is expected to face during these years. This could be the company's base TFP growth trend. Alternatively, X could be based on the industry productivity trend and the MFP growth projection could provide the basis for a CPEF adjustment like the C factor.

The potential advantages of this approach are numerous. Compensation could be provided for special capex challenges without weakening Hydro Ottawa's performance incentives. The Company would have less opportunity to exaggerate its capex needs.

On the downside, the research required to establish the method would be somewhat costly and controversial. The contracted budget for our engagement by OEB staff in this proceeding, and the schedule for the proceeding, did not allow for such research in this project. The MFP projection would reflect the typical impact of system *age* on cost when the OEB has encouraged distributors to base repex

[114] Denny, Fuss, and Waverman, *op. cit*.

[115] Lowry, M.N., Hovde, D., Getachew, L., and Fenrick, S. (2007), *Rate Adjustment Indexes for Ontario's Natural Gas Utilities*, Report to the Ontario Energy Board filed in Ontario Energy Board Cases EB-2007-0606 and EB-2007-0615, November 20, pp. 41-49.

[116] See Lowry, M.N., and Getachew, L., *Review of Network Economics*, "Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry" Vol.8, Issue 4, December 2009.

on system *performance*. However, this is not different in spirit from basing the base TFP trend on an industry study and then adding a stretch factor which reflects the stronger performance incentives generated by IR.

The X factor would likely be based on research using U.S. data and would likely be negative. However, the stretch factor would ensure that customers receive the benefit of productivity growth that is superior to the projection.

Sensible Pairings

Several of the rate setting options detailed in this Section are complements more than substitutes. Here are some provisions that could be sensibly combined.

- A California or Alberta-style ARM, which reflects a utility's recent past capex, reduces concerns about the utility's exaggerations of its capex requirements. This can increase the attractiveness of incentivizing or eliminating the capital variance account.
- A California or Alberta-style ARM could also be combined with a limit on the frequency of Custom IR plans.
- An MFP growth projection that considers the need for repex can be combined with a tracker to fund lumpy growth-related projects like the South Nepean MTS, the need for which is more difficult to identify econometrically due to data limitations.
- If the C factor approach is adopted without major modification, it could be combined with other mechanisms that strengthen incentives (e.g., capital variance account incentivization), reduce overcompensation (e.g., continued tracking), and reduce regulatory cost (e.g., Custom IR limits).
- Using Custom IR more frequently than three out of every five plans could be tied to a requirement that any surplus capital revenue be offset by future X factor reductions if the use of ARMs based on industry cost trends continues.

Appendix

A.1 U.S. vs. Canadian Data for Power Distributor Cost Benchmarking

Accurate statistical benchmarking is facilitated by abundant, high quality data on utility operations. In this section we discuss the relative advantages of U.S. and Ontario data for statistical benchmarking of Ontario power distributors.

Pros and Cons of Ontario Data

About seventy utilities provide power distribution services in Ontario today. These utilities also provide a wide range of customer services that include conservation and demand management ("CDM"). The distribution systems of some companies include subtransmission lines and substations that receive power at subtransmission or higher voltages. The largest provincial distributor, Hydro One Networks, also provides most power transmission services in Ontario.

Advantages of using data for other Ontario utilities to appraise the cost performance of Hydro Ottawa include the following.

- Standardized, high quality data are publicly and electronically available on operations of numerous Ontario distributors for more than a decade. Thus, a large sample is available for econometric estimation of cost model parameters. Large samples of good data improve the accuracy of econometric model parameter estimates.
- Data are available for all distributors on peak loads and the total length of distribution lines (in circuit km).
- There is no need for currency conversions in an Ontario benchmarking study, and adjustments are fairly straightforward if desired for differences between input prices in various parts of the province.

Disadvantages of Ontario data include the following.

- Many of the distributors serve small towns outside the larger metropolitan areas and hence face business conditions quite different than those of Hydro Ottawa.

- Many distributors recently transitioned to Modified International Financial Reporting Standards ("MIFRS"). These new standards reduced capitalization of OM&A expenses for many companies and thereby raised reported OM&A expenses.

- Itemized data on pension and benefit expenses of most Ontario distributors, including Hydro Ottawa, are unavailable for lengthy sample periods. These costs are difficult to benchmark accurately, and the Company proposes to address pension expenses with a variance account rather than indexing. Canadian labor price indexes are available only for salaries and wages and not for comprehensive employment costs

- Data needed to calculate capital costs and quantities for most distributors using monetary methods are available only since 1989.[117] In addition, data on *gross* plant additions, which we normally use to calculate capital costs, are only available starting in 2013. It is necessary to impute gross plant additions in earlier years using data on changes in the gross (undepreciated) value of plant. Another problem in measuring Ontario capital costs is that itemized data on distribution and general plant are not readily available. Statistics Canada suspended calculation of its electric utility construction price indexes several years ago. These circumstances tend to reduce the accuracy of statistical research on the capital cost and total cost performance of Ontario utilities.

- Itemization of OM&A salary and wage and material and service expenses is not readily available for a lengthy sample period.

Pros and Cons of U.S. Data

Power distributor services in the United States are provided to most customers by investor-owned utilities ("IOUs") but are provided in some areas by cooperative or municipal utilities.[118] U.S. distributors typically provide several customer services (e.g., metering, meter reading, billing, and

[117] We believe that it is straightforward to interpolate plant additions over the few years for which gross plant value data are available before the year 2000.

[118] Cities that are served by municipal utilities include Austin, Los Angeles, Memphis, Nashville, Sacramento, and Seattle.

collection) but varied levels of CDM services.[119] Most IOUs also provide power transmission services in their service territory and many provide generation and/or gas utility services.[120] The distribution systems of some companies include subtransmission lines and substations that receive power at transmission voltages.

American IOU operating data have several advantages in a Hydro Ottawa total cost benchmarking study.

- The U.S. government has gathered detailed, standardized data for decades on the operations of dozens of IOUs.
- Distributors provide an array of services that is similar to Hydro Ottawa's.
- Several IOUs serve medium-sized metropolitan areas.
- U.S. cost data are credibly itemized, permitting calculations of the cost of power distributor services even for vertically integrated utilities ("VIEUs").
- Data on the net value of plant and the corresponding gross plant additions have been itemized for power distribution and general assets since 1964. Custom price indexes are available on the construction cost trends of power distributors. These advantages make U.S. data the best in the world for accurate calculation, using monetary methods, of the consistent capital cost, price, and quantity indexes that are needed to appraise the capital cost and total cost performances of power distributors.
- Urbanization, operating scale, and other business conditions vary widely amongst IOUs and this facilitates their identification and quantification of their impact.

There are, however, some downsides to using U.S. IOU operating data in distributor cost research.

[119] CDM services in some states are provided by independent agencies.

[120] Examples of vertically integrated electric utilities ("VIEUs") include Duke Energy Carolinas, Florida Power and Light, Georgia Power, and Northern States Power.

- Good data on distribution line length, a potentially useful scale variable, are not publicly available for most major IOUs.[121]

- Peak load is another potentially relevant scale variable in a power distribution cost study. Available U.S. peak load data include sales for resale, and these sales are material for some VIEUs. In order to use these data in a distribution cost study it is necessary to adjust them and these adjustments will typically not be exact.

- Itemized data are available on administrative and general expenses and the value of general plant but these are driven by the entirety of each IOU's operations and not just by the provision of distributor services. If these costs are to be considered in the research, it is necessary to assign a portion of them to distributor services by some arbitrary means.

Mixing Ontario and U.S. Data

The appropriate mix of Ontario and U.S. data to use in a study to benchmark the costs of an Ontario distributor is difficult to ascertain. Since Hydro Ottawa did not provide us with all of the data we need in order to remove pension and other benefit expenses from its costs, we have decided to include the data from all seven Ontario distributors that are included in the Clearspring sample for the econometric research.

A.2 Measuring Capital Cost

Monetary Approaches to Capital Cost Measurement

Monetary approaches to the measurement of capital costs and prices have been widely used in statistical cost research. These approaches decompose capital cost into consistent capital price and quantity indexes such that

$$Cost^{Capital} = Price^{Capital} \cdot Quantity^{Capital}. \qquad [A1]$$

In utility cost studies, the capital prices are usually calculated using data on utility construction costs and the rate of return on capital. The capital price index is sometimes a "rental" or "service" price index, so

[121] Some data on *overhead* pole (aka structure or route) miles are available for a considerably larger group of companies from surveys of an American data vendor.

called since, in a competitive rental market, the price of rentals would tend to reflect the cost incurred to supply a unit of capital services (e.g., the use of an automobile for one week).

Several monetary methods to measuring capital cost are well established. A key issue in the choice between these methods is whether utility plant is valued in historic or replacement dollars. Another issue is the pattern of decay in the quantity of capital resulting from each year's gross plant additions. Decay can result from many factors including wear and tear, casualty losses (e.g., ice storms), increased maintenance requirements, reduced reliability, and obsolescence.

Three monetary methods have been used in statistical research on utility costs.

- The geometric decay ("GD") specification features a replacement (i.e., *current* dollar) valuation of plant and a constant rate of decay in the quantity of capital resulting from each year's gross plant additions. A utility's cost is therefore fairly sensitive to the age of its assets and TFP growth is comparatively sensitive to high levels of repex. Assets are valued in replacement dollars. The GD specification involves formulae for capital price and quantity indexes that are mathematically simple and easy to code and review.

  Academic research has supported use of the GD method to characterize depreciation in many industries. [122] GD has been the most widely-used method by far in North American X factor studies. PEG has used the GD method in most of its productivity and benchmarking work for the Board.

  The U.S. Bureau of Economic Analysis ("BEA") and Statistics Canada both use geometric decay as the default approach to the measurement of capital stocks in the national income and product accounts.[123] However, the U.S. Bureau of Labor Statistics uses the alternative

[122] See, for example, C. Hulten, and F. Wykoff (1981), "The Measurement of Economic Depreciation," in *Depreciation, Inflation, and the Taxation of Income From Capital*, C. Hulten ed., Washington D.C. Urban Institute and C. Hulton, "Getting Depreciation (Almost) Right," University of Maryland working paper, 2008.

[123] The BEA states on p. 2 its November 2018 "Updated Summary of NIPA Methodologies" that "The perpetual-inventory method is used to derive estimates of fixed capital stock, which are used to estimate consumption of fixed capital—the economic depreciation of private and government fixed capital. This method is based on investment flows and a geometric depreciation formula."

hyperbolic decay specification in its studies of the productivity trends of the US economy and its major sectors.

- The one hoss shay ("OHS") capital cost specification assumes that the quantity of capital from each year's gross plant additions does not decay gradually but, rather, all at once as the assets reach the end of their service lives and are replaced. Plant is once again valued at replacement cost and a capital service price is used. With this specification, a utility's capital cost is comparatively insensitive to the age of its system and TFP growth is comparatively insensitive to high levels of repex. The one hoss shay method has been used occasionally in X factor and benchmarking research.
- The cost of service ("COS") specification is designed to approximate the way that capital cost is calculated in utility regulation. This approach is based on the assumptions of straight-line depreciation and historical valuation of plant. A utility's capital cost is unusually sensitive to the age of its system and TFP growth is unusually sensitive to high levels of repex. The capital price and quantity formulas are complicated, making them more difficult to code and review. PEG has used this approach in several X factor studies, including two for the OEB.[124]
- Hyperbolic Decay ("HD"). HD is an alternative monetary capital cost specification that merits consideration in utility cost trend and cost performance studies. The service flow from groups of assets considered is assumed to decline at a rate that may increase as assets age. Like OHS and GD, an HD specification typically assumes a replacement valuation of plant. Cost is net of capital gains. The capital price is a service price which reflects these assumptions.

Benchmark Year Adjustments

Utilities have diverse methods for calculating depreciation expenses that they report to regulators. It is therefore desirable when calculating capital quantities using a monetary method to rely

[124] See Lowry, et. al., *Rate Adjustment Indexes for Ontario's Natural Gas Utilities, op. cit.;* Kaufmann, L., Hovde, D., Getachew, L., Fenrick, S., Haemig, K., and Moren, A., *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario*, in EB-2007-0673, (2008); and Lowry, M., Hovde, D., and Rebane, K., *X Factor Research for Fortis PBR Plans,* in BCUC Project 3698719, for Commercial Energy Consumers of British Columbia (2013).

on the reporting companies chiefly for the value of *gross* plant additions and then use a standardized depreciation treatment for all companies. Since some of the plant a utility owns may be 40-60 years old, it is desirable to have gross plant addition data for many years in the past.

For earlier years, the desired gross plant addition data are frequently unavailable. It is then customary to consider the value of all plant at the end of the limited-data period and to estimate the quantity of capital it reflects using construction cost indexes from earlier years and assumptions about the historical capex pattern. The year for which this estimate is undertaken is commonly called the "benchmark year" of the capital quantity index. Since the estimate of the capital cost in the benchmark year is inexact, it is preferable to base capital and total cost research on a sample period that begins many years after the benchmark year. Research on capital and total cost will be less accurate to the extent that this is impossible.

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New X Factor Research for HECO

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1. Introduction

Hawaii's Public Utilities Commission ("the Commission") is considering in Docket No. 2018-0088 the design of new multiyear rate plans ("MRPs") for Hawaiian Electric Company ("HECO") and its neighbor-island subsidiary utilities (the "HECO Companies" or "Companies"). The Commission ruled in Decision and Order No. 36326 ("D&O 36326"),[1] filed May 23, 2019, that each plan will feature an annual revenue adjustment ("ARA") that is driven by the formula

$$ARA = Inflation - (X + Customer\ Dividend) + Z.$$

The cost of some of the Companies' capital expenditures ("capex") will be separately addressed by major project interim recovery ("MPIR") trackers.

The value of the "X factor" in this formula is a key issue in the proceeding. In its initial comprehensive proposal filed on 14 August 2019 and its updated proposal filed on January 15, 2020, HECO proposed a **-1.41%** value for X and a **0.22%** Customer Dividend. This proposal was supported by analysis and empirical work by Pacific Economics Group Research LLC ("PEG") on the cost trends of mainland vertically integrated electric utilities ("VIEUs"). This work was detailed in an August report entitled *Designing Revenue Adjustment Indexes for Hawaiian Electric Companies*.[2] HECO has indicated that it intends to update its proposed value of X to -**1.32%** based on corrections provided by PEG which were presented in a Revenue Working Group ("RWG") meeting on March 13, 2020.

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[1] In D&O 36326, the Commission established the regulatory principles, goals, and outcomes to guide Phase 2, and identified a portfolio of specific PBR mechanisms for prioritized examination and development. D&O 36326 pages 1-2.

[2] The updated comprehensive proposal states that: "The proposed value of X is -1.41%, pending further evaluation of the X-factor and financial analyses of the MRP proposals. In PEG's "featured" run, the indicated Kahn X-factor was **-1.04**% for the full 1997-2017 sample period. The X-factor was even more negative for more recent sample periods, falling to **-1.41**% for the last fifteen years (2003-2017) and to **-2.35**% for the last 10 years (2008-2017). In these calculations, PEG found that growth in the capital cost of VIEUs was much more rapid than growth in their non-fuel O&M expenses. Given the increasingly negative value of the X-factor, use of the value for the last 15 years, rather than the value for the last 10 years, is somewhat conservative." Updated Comprehensive Proposal page 24.

Debate over the appropriate X factor has ensued during the months since the August filings of the parties. Questions that parties have raised include the following.

- Is the experience of VIEUs like those in PEG's study germane to the establishment of an X factor for HECO?
- Is HECO's claimed need for replacement capital expenditures ("repex") in the next five years a consideration in setting X?
- Should the X factor be adjusted to reflect the operations of the MPIR trackers?

The document entitled "Commission Staff Guidance for PBR Phase 2 Working Group Meetings, February 2020" states that "Parties are encouraged to include in their [future revised] proposals further analyses of the conceptual definition and quantification of the ARA "X" factor included in the January proposal updates…It should be clear how the definition and determination of the ARA formula relates to and is appropriate for application of the MPIR provisions."

Pacific Economics Group ("PEG") has since August conducted some new research that complies with Staff's request and sheds light on the questions above and the appropriate X factors for the HECO Companies. Notable tasks included the following.

- We have used new econometric cost research to study the drivers of growth in the multifactor productivity[3] ("MFP") of vertically integrated electric utilities and to make custom output and MFP growth projections for the HECO Companies.
- We computed more detailed X factor results using index research.
- We gathered comparative statistics on the age of HECO's system.

This is a report on our new research. We begin by reprising pertinent results from our August report. There follows a discussion of our latest research and salient results. There are brief concluding remarks.

[3] Technical terms are underlined at their first mention throughout this report.

2. Key Results from Our August Report

This section reprises key findings from our August Report in order to provide context for the discussion of our new research for HECO.

2.1 Basic Principles

A theoretical result from a classic paper by Denny, Fuss, and Waverman should inform the design of ARA formulas:

$$\textit{growth Cost} = \textit{growth Input Prices} - \textit{growth MFP} + \textit{growth Outputs}.^{4} \qquad [1]$$

Here *Input Prices* is an input price index. *Outputs* is an index of output growth that, if multidimensional, has weights for subindexes which reflect their relative cost impacts.[5] Econometric estimates of the elasticities of cost with respect to output variables provide a sensible basis for these weights.[6] *MFP* is a multifactor productivity index that is calculated with a consistent cost-based output index. Since vertically integrated electric utilities like HECO provide various services (e.g., generation, transmission, and distribution), and the ARA will address transmission costs, multidimensional indexes are useful for measuring their output.

This result would provide the basis for the following ARA formula for HECO.

$$\textit{growth Revenue} = \textit{growth Input Prices} - (\overline{MFP} + \textit{Customer Dividend}) + \textit{growth Outputs}^{HECO}$$

where $\overline{MFP}$ is an appropriate MFP growth target. It suggests that ARA formulas should by some means reflect actual or expected growth in the output of each subject utility. This could take the form of an explicit scale escalator or an X factor adjustment. We noted in the August

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

[5] Output indexes with subindex weights that reflect the relative *revenue* impacts of *billing determinants* are used in the design of *price* cap indexes.

[6] The elasticity of cost with respect to an output variable Y is the percentage change in cost that results from a 1% change in Y.

report that a sizable majority of revenue cap indexes approved in North America include explicit scale escalators. Most of these indexes have applied to energy distributors, and allowed revenue has been escalated for customer growth. If the ARA does not compensate the utility for growth in its operating scale, the expected scale index growth of the utility is an implicit customer dividend in the formula.

Some readers may find an alternative demonstration of the relevance of output growth to the design of ARA formulas persuasive. A key result of index theory is that cost growth is the sum of the growth of an appropriate input price index and input quantity index ("*Input Quantities*").

$$\text{growth Cost} = \text{growth Input Prices} + \text{growth Input Quantities}. \qquad [2]$$

If a revenue cap index compensates a utility only for input price inflation less MFP growth, it will therefore generally not provide sufficient compensation for input *quantity* growth even if the MFP growth trend is zero.

2.2 Inflation Measure Issues

If an ARA formula uses the gross domestic product price index ("GDPPI") as the inflation measure, the X factor should reflect the tendency of the GDPPI to track utility input prices accurately, not just the industry productivity trend. This can be accomplished with the following X factor formula

$$X = \text{trend } MFP_{Industry} + (\text{trend } GDPPI - \text{trend Input Prices}_{Industry}) \qquad [3]$$

where the term in parentheses is the inflation differential and $\text{Input Prices}_{Industry}$ is a utility industry input price index. The inflation differential tends to be negative due to the sluggish growth that the GDPPI has displayed for many years, and this differential can be as much or more important than the productivity trend in determining X.

It can also be shown that

$$\text{trend } GDPPI = \text{trend Input Prices}_{Economy} - MFP_{Economy} \qquad [4]$$

where $\text{Input Prices}_{Economy}$ and $MFP_{Economy}$ are the input price and *MFP* indexes of the economy.

Relations [3] and [4] imply that

$$X = (trend\ MFP_{Industry} - trend\ MFP_{Economy}) - (trend\ Input\ Prices_{Economy} - Input\ Prices_{Industry}). \quad [5]$$

The X factor can thus be expressed equivalently as the sum of a productivity differential and an input price differential. Relation [5] implies that X is reduced by the MFP growth of the economy, and this has tended to be material in the United States for many years.

Our August report documented numerous cases where regulators based X factors on productivity differentials. For example, the Department of Public Utilities ("DPU") in Massachusetts has used this approach in two recent proceedings that approved MRPs for power distributors.[7] Both plans feature revenue cap indexes with the GDPPI as the inflation measure.

2.3 Kahn Method Research

For our August report, PEG sidestepped these relatively complicated X factor formulas and instead presented the results of simpler "Kahn method" cost trend research. The basic idea is to find the value of X that would cause the trends in hypothetical ARA indexes to track the cost trends of the utilities on average during the sample period. A familiar approach to calculating capital costs can be used since capital cost trends do not need to be decomposed into price and quantity trends. The study used publicly available data from 45 mainland VIEUs in the econometric and Kahn method calculations. The full sample period considered was the 21 years from 1997 to 2017.

A multidimensional scale index with econometric cost elasticity weights that are appropriate for VIEUs was employed in these calculations. This reduces the indicated value of X. Since the Commission's approved ARA formula does not include a scale index, the need for an adjustment to the X factor for output growth remains an issue in the choice of an X factor.

[7] Since our August report, the Department approved a new MRP for power distributor services of National Grid. See Massachusetts D.P.U. 18-150.

The indicated X factor from this research was materially negative for all sample periods that we considered. A negative inflation differential, not negative productivity growth, was the chief source of the negative X factor. The indicated X factors were more negative for more recent sample periods. The declining value of X was mainly due to accelerated capital cost growth since 2007 which occurred despite slowdowns in GDPPI and output growth. These results suggest that the sample period is a key consideration in the choice of X factors for the HECO companies. HECO proposed to base X on our Kahn method results for the 15-year 2003-2017 period. The Massachusetts DPU chose a fifteen-year sample period to set X in both of its recent Massachusetts PBR proceedings.

2.4 Corrections to Kahn Method Calculations

In March 2020, PEG provided corrections to its X factor calculations using the Kahn methodology. The corrections can be summarized as follows. A minor correction was needed due to a few missing transmission miles observations in 1995, which affected the 1996 midyear miles, which in turn affected the 1997 growth rate. The impact was 2 basis points on the X factor for the longest sample period. The other correction was to the 2016 and 2017 cost data. PEG corrected the depreciation and amortization data to reflect only electric operations. PEG had previously used values for *total* utility operations inadvertently. This error affected only the data of companies with gas distribution operations. Results for all three sample periods changed modestly.

The corrected Kahn method results are provided in Tables 1-3 below. For the fifteen-year 2003-2017 period, the indicated X factor was reduced from -1.41% to **-1.32%**. Over this same period, PEG estimates in Table 3 that the multifactor productivity ("MFP") trend that is implicit in these calculations was reduced from -0.54% to -0.45%. It remains the case that a negative inflation differential, not negative productivity growth, was the chief source of the negative X-factor.

Reasons advanced in our August report for the decline in MFP growth included the following:

- slowing growth in the demand for electric utility services;

Table 1

Corrected U.S. VIEU Kahn X Factor Calculations [1,2]

Year	Total Cost	Operating Scale: Retail Customers	Mid-Year Average Generation Capacity	Fossil Steam and Other Generation Volume	Mid-Year Average Transmission Line Miles	Ratcheted Maximum Peak Demand	Scale Index[3]	GDPPI Inflation	Indicated X Factor: Using Scale Index	Using Customers
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[G]+[H]-[A]	[B]+[H]-[A]
1997	3.82%	1.80%	0.62%	5.16%	0.34%	3.74%	2.02%	1.70%	-0.10%	-0.31%
1998	3.45%	1.92%	0.09%	5.60%	0.32%	3.09%	1.86%	1.08%	-0.51%	-0.45%
1999	1.06%	1.40%	-0.68%	4.25%	0.38%	2.75%	1.30%	1.42%	1.67%	1.77%
2000	6.21%	2.07%	-1.49%	2.99%	-0.68%	2.15%	1.07%	2.25%	-2.89%	-1.90%
2001	3.16%	1.51%	0.55%	1.39%	-1.14%	1.55%	1.03%	2.26%	0.14%	0.61%
2002	2.53%	1.40%	4.69%	-1.61%	0.08%	1.23%	1.77%	1.52%	0.76%	0.39%
2003	2.43%	1.33%	4.58%	-1.09%	0.19%	1.86%	1.88%	1.98%	1.44%	0.89%
2004	2.90%	1.45%	2.03%	-0.11%	-0.07%	0.36%	1.12%	2.71%	0.92%	1.26%
2005	3.79%	1.51%	2.52%	1.44%	-0.31%	2.83%	1.81%	3.17%	1.20%	0.89%
2006	4.06%	0.20%	4.26%	1.07%	-0.93%	1.82%	1.40%	3.02%	0.36%	-0.85%
2007	6.05%	1.39%	3.26%	2.33%	0.10%	1.86%	1.87%	2.63%	-1.55%	-2.02%
2008	4.54%	1.04%	2.58%	2.45%	1.21%	0.70%	1.46%	1.91%	-1.16%	-1.59%
2009	5.10%	0.60%	2.14%	-4.23%	0.98%	0.69%	0.63%	0.78%	-3.69%	-3.71%
2010	7.85%	0.52%	2.21%	-0.06%	1.03%	1.15%	1.03%	1.22%	-5.59%	-6.11%
2011	4.05%	0.44%	1.70%	3.11%	0.72%	1.06%	1.09%	2.04%	-0.92%	-1.56%
2012	2.36%	0.59%	1.39%	-2.13%	1.52%	0.40%	0.61%	1.82%	0.07%	0.05%
2013	4.30%	0.78%	1.13%	1.06%	1.05%	0.31%	0.82%	1.60%	-1.88%	-1.92%
2014	5.41%	0.81%	1.13%	2.33%	0.67%	1.13%	1.05%	1.78%	-2.57%	-2.82%
2015	4.26%	1.01%	1.59%	-1.14%	1.06%	0.73%	0.93%	1.06%	-2.27%	-2.18%
2016	3.97%	1.08%	-0.60%	-2.96%	1.08%	0.21%	0.21%	1.31%	-2.45%	-1.58%
2017	2.63%	0.85%	-0.96%	-1.69%	0.66%	0.16%	0.08%	0.89%	-1.66%	-0.89%
Average Annual Growth Rates										
1997-2017	4.00%	1.13%	1.56%	0.87%	0.39%	1.42%	1.19%	1.82%	**-0.99%**	**-1.05%**
2003-2017	4.25%	0.91%	1.93%	0.03%	0.60%	1.02%	1.07%	1.86%	**-1.32%**	**-1.47%**
2008-2017	4.45%	0.77%	1.23%	-0.33%	1.00%	0.65%	0.79%	1.44%	**-2.21%**	**-2.23%**

Notes:

[1]Costs and volumes that are inapplicable to the HECO Companies were excluded from this analysis. These include the costs, capacities, and volumes of conventional hydraulic, pumped storage hydraulic, and nuclear generation.

[2]All values shown are an average of annual (logarithmic) growth rates of variables in a nationally-representative sample of 45 vertically intergrated electric utilities.

[3]Growth in the scale index is a cost-elasticity-weighted average of growth in customers, ratcheted peak demand, transmission line miles, generation capacity, and generation volume. Elasticity weights were those displayed in Table 7 of our August report. The formula is growth Scale [G] = 40.9% x [B] + 23.2% x [C] + 7.9% x [D] + 9.4% x [E] + 18.6% x [F].

Table 2

Impact of Various Cost Components on Kahn X Factor Results (Corrected)[1,2]

	GDPPI[3]	Operating Scale		Cost							Kahn X Factors by Cost Category					
				Capital					O&M	Total[8]						
Year		Retail Customers	Scale Index[4]	Rate of Return[5]	Rate Base[6]	Return on Rate Base	Depreciation and Amortization	Total[7]			Rate Base	Return on Rate Base	Depreciation and Amortization	Capital Cost	O&M Cost	Total Cost
	[A]		[B]	[C]	[D]	[E]=[C]+[D]	[F]	[G]	[H]	[I]	[A]+[B]-[D]	[A]+[B]-[E]	[A]+[B]-[F]	[A]+[B]-[G]	[A]+[B]-[H]	[A]+[B]-[I]
1997	1.71%	1.80%	2.02%	0.20%	2.75%	2.95%	5.21%	3.89%	3.77%	3.82%	0.98%	0.78%	-1.48%	-0.16%	-0.04%	-0.10%
1998	1.08%	1.92%	1.86%	1.46%	1.50%	2.96%	2.21%	2.73%	4.32%	3.45%	1.43%	-0.03%	0.73%	0.21%	-1.38%	-0.51%
1999	1.42%	1.40%	1.30%	-5.68%	1.72%	-3.96%	3.55%	-1.16%	4.56%	1.06%	1.00%	6.68%	-0.82%	3.88%	-1.83%	1.67%
2000	2.25%	2.07%	1.07%	5.04%	2.44%	7.48%	4.51%	6.38%	5.73%	6.21%	0.88%	-4.16%	-1.19%	-3.06%	-2.41%	-2.89%
2001	2.26%	1.51%	1.03%	-2.96%	3.37%	0.40%	4.05%	1.86%	4.99%	3.16%	-0.08%	2.89%	-0.76%	1.43%	-1.70%	0.14%
2002	1.52%	1.40%	1.77%	-2.50%	4.42%	1.92%	3.04%	2.34%	2.65%	2.53%	-1.13%	1.36%	0.25%	0.94%	0.63%	0.76%
2003	1.98%	1.33%	1.88%	-2.59%	4.89%	2.29%	3.43%	2.73%	1.79%	2.43%	-1.02%	1.57%	0.43%	1.13%	2.08%	1.44%
2004	2.71%	1.45%	1.12%	-2.22%	4.71%	2.48%	1.96%	2.17%	3.83%	2.90%	-0.88%	1.34%	1.86%	1.66%	-0.01%	0.92%
2005	3.17%	1.51%	1.81%	-2.41%	4.57%	2.16%	4.68%	3.18%	4.60%	3.79%	0.41%	2.82%	0.30%	1.80%	0.38%	1.20%
2006	3.02%	0.20%	1.40%	-2.23%	4.88%	2.65%	4.08%	3.26%	4.91%	4.06%	-0.45%	1.77%	0.34%	1.16%	-0.49%	0.36%
2007	2.63%	1.40%	1.87%	-1.71%	6.14%	4.43%	6.29%	5.35%	6.63%	6.05%	-1.64%	0.07%	-1.79%	-0.85%	-2.13%	-1.55%
2008	1.91%	1.04%	1.46%	0.58%	8.07%	8.65%	2.41%	5.92%	3.27%	4.54%	-4.70%	-5.28%	0.97%	-2.55%	0.11%	-1.16%
2009	0.78%	0.60%	0.63%	-0.39%	9.65%	9.26%	7.45%	8.59%	0.66%	5.10%	-8.25%	-7.86%	-6.04%	-7.19%	0.75%	-3.69%
2010	1.22%	0.52%	1.03%	-0.35%	10.19%	9.84%	7.46%	8.84%	6.06%	7.85%	-7.94%	-7.58%	-5.20%	-6.59%	-3.81%	-5.59%
2011	2.04%	0.44%	1.09%	-1.48%	8.06%	6.58%	7.79%	7.17%	-0.26%	4.05%	-4.93%	-3.45%	-4.66%	-4.04%	3.39%	-0.92%
2012	1.82%	0.59%	0.61%	-2.22%	7.12%	4.90%	2.18%	3.72%	0.28%	2.36%	-4.69%	-2.47%	0.26%	-1.29%	2.16%	0.07%
2013	1.60%	0.78%	0.82%	-1.03%	6.54%	5.51%	4.58%	5.06%	2.96%	4.30%	-4.12%	-3.09%	-2.16%	-2.63%	-0.53%	-1.88%
2014	1.78%	0.81%	1.05%	-1.89%	6.86%	4.97%	5.13%	5.03%	6.13%	5.41%	-4.03%	-2.14%	-2.30%	-2.19%	-3.30%	-2.57%
2015	1.06%	1.02%	0.93%	1.10%	8.76%	9.86%	6.40%	8.51%	-2.61%	4.26%	-6.77%	-7.87%	-4.41%	-6.53%	4.60%	-2.27%
2016	1.31%	1.08%	0.21%	-3.54%	7.60%	4.06%	7.02%	5.24%	1.70%	3.97%	-6.08%	-2.54%	-5.50%	-3.73%	-0.18%	-2.45%
2017	0.89%	0.85%	0.08%	-0.69%	5.17%	4.48%	4.30%	4.40%	-0.82%	2.63%	-4.19%	-3.51%	-3.32%	-3.42%	1.79%	-1.66%
Average Annual Growth Rates																
1997-2017	1.82%	1.13%	1.19%	-1.21%	5.69%	4.47%	4.65%	4.53%	3.10%	4.00%	**-2.68%**	**-1.46%**	**-1.64%**	**-1.52%**	**-0.09%**	**-0.99%**
2003-2017	1.86%	0.91%	1.07%	-1.40%	6.88%	5.48%	5.01%	5.28%	2.61%	4.25%	**-3.95%**	**-2.55%**	**-2.08%**	**-2.35%**	**0.32%**	**-1.32%**
2008-2017	1.44%	0.77%	0.79%	-0.99%	7.80%	6.81%	5.47%	6.25%	1.74%	4.45%	**-5.57%**	**-4.58%**	**-3.24%**	**-4.02%**	**0.50%**	**-2.21%**

Notes:

[1]Costs and volumes that are inapplicable to HECO were excluded from this analysis. These include those for conventional hydraulic, pumped storage hydraulic, and nuclear generation capacity.

[2]All values shown are an average of annual (logarithmic) growth rates of variables on a nationally-representative sample of 45 vertically intergrated electric utilities.

[3]The annual growth rate of the U.S. Gross Domestic Product Price Index ("GDPPI").

[4] Growth in the scale index is a cost-elasticity-weighted average of growth in customers, ratcheted peak demand, transmission line miles, generation capacity, and generation volume. The weights were obtained from econometric cost research for HECO presented in Table 7 in our August 2019 report. The formula becomes *growth* Scale [B] = 40.9% x [*growth* Retail Customers] + 23.2% x [*growth* Generation Capacity] + 7.9% x [*growth* Generation Volume] + 9.4% x [*growth* Transmission Line Miles] + 18.6% x [*growth* Ratcheted Peak Demand].

[5]The annual growth rate of an average of the Edison Electric Institute's "Rate Case Summary" ROE and the embedded cost of debt from FERC Form 1 data of a nationally representative sample of electric utilities.

[6]The growth rate of the average value of rate base at the start and end of the year.

[7]The annual growth rate in total capital cost does not equal the sum of the annual growth rates of return on rate base [E] and depreciation and amortization [F].

[8]The annual growth rate in total cost does not equal the sum of the annual growth rates of capital cost [G] and O&M cost [H].

Table 3

Decomposing the Kahn X Factor (Corrected)

Year	Kahn X Factor (with scale index)	GDPPI	Industry Input Price Growth	Inflation Differential	Residual X Resulting from Productivity and Other Factors
	[A]	[B]	[C]	[D] = [B] - [C]	[E] = [A] - [D]
1997	-0.10%	1.70%	3.72%	-2.01%	1.92%
1998	-0.51%	1.08%	3.98%	-2.90%	2.39%
1999	1.67%	1.42%	0.61%	0.81%	0.85%
2000	-2.89%	2.25%	5.71%	-3.46%	0.57%
2001	0.14%	2.26%	2.04%	0.22%	-0.08%
2002	0.76%	1.52%	1.98%	-0.47%	1.22%
2003	1.44%	1.98%	2.10%	-0.12%	1.55%
2004	0.92%	2.71%	2.33%	0.37%	0.55%
2005	1.20%	3.17%	2.30%	0.87%	0.32%
2006	0.36%	3.02%	2.89%	0.13%	0.23%
2007	-1.55%	2.63%	3.08%	-0.45%	-1.10%
2008	-1.16%	1.91%	4.00%	-2.09%	0.93%
2009	-3.69%	0.78%	2.99%	-2.20%	-1.48%
2010	-5.59%	1.22%	3.01%	-1.79%	-3.81%
2011	-0.92%	2.04%	2.70%	-0.65%	-0.26%
2012	0.07%	1.82%	2.41%	-0.59%	0.67%
2013	-1.88%	1.60%	2.42%	-0.81%	-1.06%
2014	-2.57%	1.78%	2.46%	-0.68%	-1.89%
2015	-2.27%	1.06%	3.41%	-2.35%	0.09%
2016	-2.45%	1.31%	1.21%	0.10%	-2.54%
2017	-1.66%	0.89%	3.58%	-2.69%	1.03%

Average Annual Growth Rates

1997-2017	-0.99%	1.82%	2.81%	**-0.99%**	**0.00%**
2003-2017	-1.32%	1.86%	2.73%	**-0.86%**	**-0.45%**
2008-2017	-2.21%	1.44%	2.82%	**-1.38%**	**-0.83%**

- capital spending to reduce generation emissions and increase access to and reliance on renewable resources;
- increased need for replacement capital expenditures (aka "repex");
- increased use of advanced metering infrastructure and other "smart grid" equipment; and
- higher reliability and resiliency expectations.

2.5 Recent X Factor Precedents

Our MFP and X factor results are broadly in line with recent U.S. X factor precedents.

- The average itemized MFP growth target in U.S. MRPs with rate or revenue cap indexes is about -0.30%.
- The average X factor in the three current U.S. MRPs with rate or revenue cap indexes is about -1.50%.
- Several recent PBR plans in Ontario have featured a 0% MFP growth target.

2.6 Productivity Drivers

The Denny, Fuss, and Waverman paper also provides a method for identifying drivers of productivity growth which is based on cost theory. They found that MFP growth reflects technological change and reductions in inefficiency --- two important sources of improved cost efficiency --- but also has other drivers that include changes in output and various other external business conditions. Productivity indexes are therefore not pure measures of operating efficiency.

To better understand this result, consider that a productivity index is the ratio of an output index to an input index. The quantity of inputs that a utility uses depends on various external business conditions as well as its efficiency. Thus, productivity growth is sensitive to changes in business conditions as well as to changes in efficiency.

While the ratio of outputs to inputs intuitively seems like a pure efficiency measure, outputs are not the only external business conditions that drive cost. Suppose for example that utility cost is also a function of the number of trees in the service territory. We could then measure efficiency by taking the ratio of trees to the quantity of inputs. More efficient utilities would have higher scores. However, this metric would not control for the large differences that exist in the output of utilities in the sample.

3. New Econometric Research

3.1 Pertinent Results of Cost Theory

Economic theory reveals that the cost of an enterprise is a function of input prices, operating scale ("*Outputs*", which may be multidimensional), and miscellaneous other external business condition variables ("*Other Variables*"). This relationship may be expressed in general terms as

$$Cost = f(Input\ Prices,\ Outputs,\ Other\ Variables,\ Time). \qquad [6]$$

We can measure the impacts of business conditions on utility cost by positing a specific form for the cost function and then estimating model parameters using econometric methods and historical data on utility operations. Here is a simple example of an econometric cost model.

$$\ln Cost^{Real} = \hat{\beta}_0 + \hat{\beta}_1 \times \ln Output_1 + \hat{\beta}_2 \times \ln Output_2$$

$$+ \hat{\beta}_3 \times \ln Other_1 + \hat{\beta}_4 \times \ln Other_2 + \hat{\beta}_T \times Trend \qquad [7]$$

Here, $Cost^{Real}$ is real cost, the ratio of cost to an input price index. The $\hat{\beta}$ terms are econometric estimates of model parameters. This model has a double log functional form in which cost and the values of business condition variables are logged. With this form, parameters $\hat{\beta}_1$ to $\hat{\beta}_4$ are also estimates of the elasticities of cost with respect to the four business condition variables. The term $\hat{\beta}_T$ is an estimate of the parameter for the trend variable in the model. This parameter would capture the typical net effect on utility cost trends of technological progress and changes in cost driver variables that are excluded from the model.

Econometric cost research has several uses in the determination of X factors for the HECO companies. In the case of our illustrative model, econometric estimates of output variable parameters can be used to construct an output quantity index with the following formula:

$$growth\ Outputs^C = [\hat{\beta}_1 / (\hat{\beta}_1 + \hat{\beta}_2)] \times growth\ Output_1 +$$

$$[\hat{\beta}_2 / (\hat{\beta}_1 + \hat{\beta}_2)] \times growth\ Output_2. \quad [8]$$

This formula states that output index growth is an elasticity-weighted average of the growth in the two output variables. An index of this kind can be used in MFP and Kahn method research. It can also serve as the scale escalator of an ARA formula. If the formula lacks such an escalator, the expected growth in the output index during the term of the MRP can provide the basis for an X factor adjustment.

Denny, Fuss, and Waverman provided the additional useful result that, for a cost model like [7], growth in a company's MFP can be decomposed as follows.

$$growth\ MFP = [1 - (\hat{\beta}_1 + \hat{\beta}_2)] \times growth\ Outputs$$

$$- (\hat{\beta}_3 \times growth\ Other_1 + \hat{\beta}_3 \times growth\ Other_2) - \hat{\beta}_T. \quad [9]$$

The first term in [9] is the economies of scale that are realized due to output growth. These economies are greater the smaller is the sum of the cost elasticities with respect to output ($\hat{\beta}_1$ + $\hat{\beta}_2$) and the greater is output index growth. Relation [9] also shows that a change in the value of a business condition variable like *Other*$_1$ raises cost it also slows MFP growth. If the trend variable parameter estimate has a negative (positive) value it would to that extent raise (lower) MFP growth. Formulas like [8] and [9] can be generalized to models with additional outputs and other business condition variables.

Econometric cost research and an equation like [9] can be used to identify MFP growth drivers and estimate their impact. Given forecasts of the change in output and other business conditions, an equation like [9] can also provide the basis for MFP growth projections that are specific to the business conditions of a utility that will be operating under PBR. For example, we can make projections that are specific to HECO during the four likely indexing years (2021-2024) of its PBR plan. These are effectively projections of the MFP growth of typical utility managers if faced with HECO's business conditions.

For the simple model detailed in equation [9] the MFP growth projection formula would be

$$\widehat{MFP^{C}_{HECO}} = [1 - (\hat{\beta}_1 + \hat{\beta}_2)] \times \overline{trend\ Outputs_{HECO}}$$

$$- (\hat{\beta}_3 \times \overline{trend\ Other_{1,HECO}} + \hat{\beta}_4 \times \overline{trend\ Other_{2,HECO}}) - \hat{\beta}_T. \quad [10]$$

[8]

Here $\widehat{MFP_{HECO}}$ is the projected annual MFP growth trend (average annual growth rate) for HECO during the final four years of its new plan. The variable $\overline{trend\ Outputs_{HECO}}$ is the expected growth trend in HECO's output index. $\overline{trend\ Other_{l,HECO}}$ is the expected growth trend for HECO in each external business condition l that is included in the model.

In an application to Canadian telecommunications Denny, Fuss, and Waverman, *op. cit.*, were the first to use econometric research and a formula like [9] to decompose MFP growth. The method was also used several times in California proceedings.[9] In work for the Ontario Energy Board, PEG used this method in an Ontario gas PBR proceeding to project the MFP trends of two large gas utilities and published a paper on the work in the *Review of Network Economics.*[10] These projections were useful because the productivity drivers facing these utilities (e.g., rapid growth in Toronto and Ottawa) were very different from those facing gas utilities in adjacent American states.

MFP growth projections have several advantages in the design of an X factor for HECO. They are useful for ascertaining the reasonableness of an X factor which is based on more

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[8] Here is a more general formula.

$$\Delta\widehat{MFP^{s}_{HECO}} = \left(1 - \Sigma_i \hat{\beta}_i\right) \cdot E\left(growth\ \overline{Outputs^{C}_{HECO}}\right) - \Sigma_l \hat{\beta}_l \cdot \mathrm{E}\left(growth\ \overline{Others_{l,HECO}}\right) - \hat{\beta}_T$$

Here $\hat{\beta}_i$ is the econometric parameter estimate for each output variable i while $\hat{\beta}_l$ is the parameter estimate for each other business condition l that is included in the model.

[9] See, for example, California Public Utilities Commission A.98-01-014.

[10] See Lowry, M.N., and Getachew, L., *Review of Network Economics*, "Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry" Vol.8, Issue 4, December 2009.

conventional industry cost trend research. Moreover, the projection can pertain to the specific costs that the ARA index will address. This sheds light on the need for an MPIR adjustment to the X factor. Despite being customized to HECO's business conditions, the use of these projections would not weaken the Company's cost containment incentives since they reflect only the cost impact of external business conditions.

3.2 VIEU Productivity Drivers

The usefulness of MFP growth projections depends on the sophistication with which the drivers of MFP growth are modelled. In the case of VIEUs the relevant drivers of MFP growth have in recent years included the following:

output growth

changes in various other business conditions

- need for replacement capex (aka "repex")
- need to reduce environmental costs (e.g., due to a renewable performance standard) by
    - adding pollution controls for fossil-fueled generators
    - extending the transmission system to remote renewable resources (e.g., wind and solar)
    - increasing generation from renewable resources
    - making other system improvements to accommodate renewables
- need for smart grid capabilities [e.g., automated metering infrastructure ("AMI")]
- reliability and resiliency standards
- need for better bulk power markets (e.g., fewer load pockets that are vulnerable to price spikes)
- changes in the technologies for providing utility products
- number of gas customers

Some of these conditions affect the MFP growth of utilities more than others. For example, MFP growth is especially sensitive to repex for several reasons.

- Utility technology is capital-intensive.
- Highly depreciated assets valued in *historical* dollars are replaced with assets which are valued in *current* dollars, are designed to last for decades, and must conform to the latest performance standards (e.g., National Electric Safety Code 2017). These standards typically exceed any that were previously applicable and may incorporate new technologies.
- Under the cost of service accounting traditionally used in ratemaking, the cost impact of repex is magnified by the fact that assets are valued in historical dollars.
- There is typically no counterbalancing growth in measured output.

Other kinds of capex (e.g., for better metering and pollution controls) may also improve system capabilities in ways that are not captured by the output index.

3.3 New Econometric Cost Model

Guided by the above analysis, PEG developed a new econometric model of VIEU cost. This model differed from that used in our research for the August report chiefly in including additional business condition variables that could sharpen analysis of recent MFP trends and provide the basis for good MFP growth projections. We added variables to capture the cost impact of recent generation capacity additions and system age challenges.[11]

Age Variable

An important focus of our new research has been the development of an appropriate age variable for the econometric work. To the extent that assets near and then exceed their average service lives ("ASLs"), cost tends to rise due to a greater need for repex. If the need for repex increases, intuition suggests that MFP growth will slow.

Standardized data on the age of assets are, unfortunately, not readily available for a large sample of U.S. electric utilities. However, extensive data are available on the value of gross additions to various kinds of electric utility plant in numerous prior years. We have used

[11] We excluded one variable from the previous model: the share of generation capacity fueled by coal or heavy oil.

these data to develop a repex requirement indicator ("RRI") for transmission and distribution ("T&D") assets.[12] This variable indicates how the need for T&D repex varies between utilities and changes over time.

The need for repex is modeled as a 13-year moving sum of the quantity of gross plant additions made ASL years ago, six years further into the past, and five years forward into the future.[13] For each asset j in year t-s let $VKA_{j,t-s}$ be the *value* of gross plant additions, $XKA_{j,t-s}$ be the *quantity* of plant additions, and $WKA_{j,t-s}$ be the value of the corresponding regional Handy-Whitman indexes ("HWIs") of electric utility construction costs. The repex requirements index for asset class j in year t ("$RRI_{j,t}$") then has the formula

$$RRI_{j,t} = \sum_{s=ASL-6}^{ASL+6} XKA_{j,t-s}$$

$$= \sum_{s=ASL-6}^{ASL+6} VKA_{j,t-s} / WKA_{j,t-s}$$

We calculated RRIs for transmission and distribution and then calculated the summary RRI for T&D by summing the separate T&D RRIs.

$$RRI_{TD,t} = RRI_{T,t} + RRI_{D,t}.$$

The assumed T&D ASLs were 54 years for HECO and 51 years for the mainland VIEUs.[14][15] Good data are available for HECO's T&D plant additions back to 1959, and the earliest year for which

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[12] Such an indicator is more problematic to construct for generation because aging generating plants may not be replaced, and replacements that are made may have a markedly different character (e.g., coal-fired capacity might be replaced with a mix of gas-fired and wind-powered capacity).

[13] This particular formulation had the strongest statistical support.

[14] For both the U.S. and HECO, the ASL was calculated as a weighted average of the lives of different types of T&D plant and equipment. In both cases the service lives from Hawaii PUC order number 35606 were used. The shares of gross plant by FERC account in total T&D gross plant were used as weights. The calculations for HECO and the mainland utilities differed in that sample average weights were used to calculate an ASL of 51 years. When the analogous HECO weights were used an ASL of 54 years was obtained.

[15] We use consolidated ASLs for T&D because if we used separate ASLs we would have to further limit the sample period for the econometric work because the ASL for transmission is higher than that for distribution.

we need a value for RRI in our MFP growth projections is 2020. We could therefore only consider plant additions 6 years before the average service life since 2020 - 54 - 1 - 6 = 1959. We expect that cost will be higher the higher is the value of the RRI.

Capacity Addition Variable

We also calculated a variable, MWadd, that was a moving sum of the megawatts ("MW") of generation capacity additions in the last ten years.

$$MWadd_t = \sum_{s=10} MW_{t-s}.$$

We expect that cost will be higher the higher is the value of MWadd.

Model Estimation

To estimate the parameters of the new VIEU cost model we used data from the same 45 utilities which we considered in our research for the August report. The 2006-17 sample period used to estimate this model was shorter than that for the August model due to limitations on the available age data. Data on T&D gross plant additions are only available back to 1948 for the 45 mainland utilities. The year 2006 is therefore the first for which the age variable in the model can be calculated because 1948 + 6 + 1+ 51 = 2006. This research required us to process plant addition data for the sampled utilities and predecessor companies from 1948 to 1964. [16]

Details of the new cost model are reported in Table 4. Please note the following key results.

[16] We had previously gathered these data only back to 1964.

Table 4

New Econometric Model of Total Base Rate Input Cost

Explanatory Variable	Parameter Estimate	T-Statistic	P-Value
Number of Customers	0.307	11.744 ***	0.000
Fossil Steam and Other Generation Volume	0.120	8.623 ***	0.000
Mid-Year Generation Capacity	0.194	8.156 ***	0.000
Mid-Year Transmission Line Miles	0.076	8.833 ***	0.000
Ratcheted Maximum Peak Demand	0.098	3.144 **	0.000
Percentage of Capacity Scrubbed	0.155	12.696 ***	0.000
Transmission and Distribution Plant Additions between 7 Years Younger and 6 Years Older than Average Service Life	0.104	6.378 ***	0.000
Percentage of Customers without AMI	-0.035	-1.777 *	0.076
Number of Gas Customers	-0.041	-3.837 ***	0.000
MW of Generation Capacity Added in Previous 10 Years	0.046	3.885 ***	0.000
Constant	20.273	1014.085 ***	0.000
Trend	0.002	2.185 **	0.029
Adjusted R-squared	0.962		
Sample Period	2006-2017		
Number of Observations	540		

*Estimate is significant at the 75% confidence level
**Estimate is significant at the 95% confidence level
***Estimate is significant at the 99.9% confidence level

- All five of the scale variables from the model in our August report still have statistically significant elasticity estimates. However, their relative magnitudes changed. Most notably, the generation volume has a higher estimate while customers and generation capacity have lower estimates.
- The share of generation capacity which was scrubbed had a positive and statistically significant cost impact. Our research found that a 1 % increase in the scrubbing share typically raised cost by about 0.16%. This means that an increase in the share of generation scrubbed tended to slow MFP growth.
- The number of gas customers served had a negative and statistically significant (though small) impact on cost. A 1% increase in gas customers typically reduced cost by about 0.04%. This means that gas customer growth accelerated electric MFP growth.
- T&D system age had a positive and highly significant impact on cost. A 1% increase in the RRI typically increased cost by about 0.10%. This means that an increase in RRI_{TD} tended to slow MFP growth.
- Recent generation capacity additions also had a statistically significant positive cost impact. A 1% increase in recent capacity additions typically raised cost by about 0.05%. This means that growth in recent capacity additions tended to slow MFP growth.
- The share of customers who do not have AMI had a statistically significant negative cost impact. A 1% decline in this share typically raised total cost by about 0.04%. This means that growth in AMI tended to slow MFP growth.
- The parameter estimate for the trend variable was also positive and statistically significant. It indicates that the cost of sampled utilities tended to *rise* by 0.25% annually for reasons that are not explained by the business conditions included in the model.

We also tried to consider the cost impact of transmission line growth. The variable we developed for this business condition did not have statistically significant parameter estimate and was excluded from the model.

3.4 HECO Output Growth

We explained in Section 2.1 above that, since the ARA indexes for the HECO Companies will not have explicit scale escalators, the expected growth in their scale is a valid concern in the choice of their X factors. Table 5 presents the latest forecasts of growth in the five outputs for each HECO Company.[17] These forecasts are tailored to the costs that will likely be addressed by the ARA index. Accordingly, we hold growth in generation capacity and transmission line miles at zero because the cost impact of any growth in these two scale variables would likely be addressed by cost trackers.

Forecasts of the other three output variables were obtained from the Company. We combined these with the econometric cost elasticity estimates for these variables which we reported in August to create forecasts of scale index growth for each company. Results are reported in Table 5. It can be seen that the forecasted annual growth trends in these “restricted” scale indexes are 0.27% for HECO, 0.40% for HELCO, and 0.24% for MECO.

[17] The impact of Covid-19 on output growth was not considered.

Table 5

Forecasted Growth in HECO Company Outputs

Output Variables	Ratcheted Maximum Peak Demand [a]	Generation Capacity [b]	Generation Volume [c]	Customers [d]	Transmission Line Miles [e]	**Elasticity-weighted Scale Index (all variables)**	**Elasticity-weighted Scale Index (a, c and d only)**
Estimated Cost Elasticities[1]	0.17	0.21	0.07	0.37	0.09		
Elasticity Shares[2]	0.19	0.23	0.08	0.41	0.09		
Years			**HECO**				
2020	1,327.00	1,288.70	6,774,948.64	307,962.00	778.25**	1.000	1.000
2021	1,327.00	1,288.70	6,756,161.00	309,587.00	778.25	1.001	1.002
2022	1,327.00	1,288.70	6,810,143.46	311,210.00	778.25	1.004	1.005
2023	1,327.00	1,288.70	6,884,144.00	312,833.00	778.25	1.007	1.008
2024	1,327.00	1,288.70	6,963,418.12	314,460.00	778.25	1.010	1.011
AAGR[3]	**0.00%**	**0.00%**	**0.69%**	**0.52%**	**0.00%**	**0.26%**	**0.27%**
			HELCO				
2020	191.00	182.00	1,117,849.02	86,987.00	603.48*	1.000	1.000
2021	190.60	182.00	1,108,572.21	87,650.00	603.48	1.058	1.002
2022	192.20	182.00	1,113,842.95	88,353.00	603.48	1.064	1.007
2023	192.50	182.00	1,118,378.14	89,064.00	603.48	1.068	1.011
2024	193.70	182.00	1,123,887.73	89,764.00	603.48	1.073	1.016
AAGR[3]	**0.35%**	**0.00%**	**0.13%**	**0.79%**	**0.00%**	**1.77%**	**0.40%**
			MECO				
2020	217.30	268.50	1,132,358.22	73,131.00	258.35*	1.000	1.000
2021	217.30	256.53	1,114,367.97	73,771.00	258.35	0.992	1.002
2022	217.30	256.53	1,099,919.18	74,258.00	258.35	0.993	1.004
2023	217.30	256.53	1,098,178.85	74,770.00	258.35	0.996	1.007
2024	217.30	232.60	1,102,900.01	75,286.00	258.35	0.977	1.010
AAGR[3]	**0.00%**	**0.00%**	**-0.66%**	**0.73%**	**0.00%**	**-0.59%**	**0.24%**

**2019 is the last value available

[1] Elasticity shares drawn from Table 7 of PEG's August report.

[2] Elasticity estimates drawn from Table 6 of PEG's August report.

[3] AAGR =average annual (logarithmic) growth rate

3.5 HECO MFP Projections

Econometric MFP growth projections for HECO for the four indexing years of the MRP can be found in Table 6. These projections are also based on the econometric parameter estimates from our new cost model as well as on Company forecasts of changes in outputs and other cost model business conditions. Analogous projections cannot be calculated for HELCO or MECO because we lack analogous data on the age of their T&D systems. These projections are specific to the costs that we expect to be addressed by the ARA.

Table 6

Econometric MFP Projections for HECO

	Incremental Scale Economies				Impact of Other External Business Conditions															Trend Variable Parameter Estimate	Projected MFP Growth Rate
	Sum of Estimated Output Elasticities		Forecasted Scale Index Growth	Incremental Scale Economies	Share of Generation Capacity Scrubbed			Share of Customers without AMI			Percentage Growth in Generation Capacity in Last 10 Years (unweighted)			Transmission and Distribution Plant Additions 7 Years Younger to 6 Years Older than ASL[3]			Number of Gas Customers				
					Estimated Cost Elasticity[1]	Growth Rate[2]	$Product_1$	Estimated Cost Elasticity[1]	Growth Rate[2]	$Product_2$	Estimated Cost Elasticity[1]	Growth Rate	$Product_3$	Estimated Cost Elasticity[1]	Growth Rate[2]	$Product_4$	Estimated Cost Elasticity[1]	Growth Rate[2]	$Product_5$		
	[A]	[B=1-A]	[C]	[D=B*C]	ε_1	GR_1	$\varepsilon_1 * GR_1$	ε_2	GR_2	$\varepsilon_2 * GR_2$	ε_3	GR_3	$\varepsilon_3 * GR_3$	ε_4	GR_4	$\varepsilon_4 * GR_4$	ε_5	GR_5	$\varepsilon_5 * GR_5$	J	D - ∑ε*GR - J
Years											**HECO**										
2021	0.794	0.21	0.13%	0.03%	15.53%	0.00%	0.00%	-3.54%	0.00%	0.00%	4.55%	0.00%	0.00%	10.37%	4.44%	0.46%	-4.09%	0.00%	0.00%	0.25%	-0.68%
2022	0.794	0.21	0.26%	0.05%	15.53%	0.00%	0.00%	-3.54%	0.00%	0.00%	4.55%	0.00%	0.00%	10.37%	7.67%	0.80%	-4.09%	0.00%	0.00%	0.25%	-0.99%
2023	0.794	0.21	0.29%	0.06%	15.53%	0.00%	0.00%	-3.54%	0.00%	0.00%	4.55%	0.00%	0.00%	10.37%	3.84%	0.40%	-4.09%	0.00%	0.00%	0.25%	-0.59%
2024	0.794	0.21	0.30%	0.06%	15.53%	0.00%	0.00%	-3.54%	0.00%	0.00%	4.55%	0.00%	0.00%	10.37%	0.73%	0.08%	-4.09%	0.00%	0.00%	0.25%	-0.26%
Averages			**0.24%**	**0.05%**	**15.53%**	**0.00%**	**0.00%**	**-3.54%**	**0.00%**	**0.00%**	**4.55%**	**0.00%**	**0.00%**	**10.37%**	**4.17%**	**0.43%**	**-4.09%**	**0.00%**	**0.00%**	**0.25%**	**-0.63%**

[1] Elasticities drawn from PEG econometric model.

[2] Growth rates are calculated logarthmically.

[3] ASL = Average service life of utility assets

- HECO doesn't anticipate increasing its scrubbing generation capacity in the next five years and if it did the costs would likely be addressed by the MPIR tracker.
- HECO has no gas customers and so the cost of its electric services will not be lowered by growth in the number of these customers.
- Costs of the AMI buildout will be addressed by the MPIR.
- The cost of any growth in transmission line miles and generation capacity would likely be addressed by the MPIR.
- The Company must, however, contend with a rising value for the T&D repex requirement indicator.

Table 6 indicates that, when these business conditions are taken into account, the MFP growth of HECO is predicted to average a 0.63% annual decline in the 2021-24 period. This compares to the -0.45% MFP trend of the sampled VIEUs which we have calculated over the fifteen year 2003-2017 sample period using the Kahn method.

4. New Index Research

We have also calculated X using the input price and productivity differentials that are traditionally used in other jurisdictions such as Massachusetts. These calculations used the cost of service ("COS") approach to measuring capital cost which we discussed on page 19 of our August report. The COS approach is mathematically complicated but designed to resemble the way that capital cost is calculated under cost of service regulation while still preserving the ability to decompose capital cost into a price and a quantity index. Historical plant valuations and straight-line depreciation are assumed. This approach greatly reduces the volatility of the capital price. With alternative capital cost specifications (e.g., one hoss shay), capital price volatility has led to controversy over input price differentials in several proceedings, including the recent National Grid proceeding in Massachusetts.

Results of this exercise can be found in Table 7. These results use the output index from our August report because HECO has chosen to base its X factor proposal on this research.[18] Over the 15-year 2003-2017 sample period, it can be seen that the indicated X factor is the same -1.32% that was produced by the corrected Kahn method calculations. This was the sum of a -1.16% productivity differential and a -0.17% input price differential. The substantially negative productivity differential reflects the fact that GDPPI inflation was slowed during the sample period by the 0.70% annual growth trend of the economy.[19] The MFP growth of the sampled VIEUs averaged -0.46%. The consistency of these results with our Kahn method calculations is notable.

[18] The cost model featured in the August report was also estimated with data for a longer sample period.

[19] The -0.17% input price differential is far below those approved in the two recent Massachusetts PBR proceedings. This reflects our use of the COS capital cost specification.

Table 7

X Factor Calculations Using Input Price and Productivity Differentials

Year	GDPPI	Input Price Index - Economy	Industry Input Price Growth	Input Price Differential	MFP Industry	MFP Economy	Productivity Differential	X-Factor
	A	B = A + F	C	D = B - C	E	F	G = E - F	H = D + G
1997	1.70%	2.52%	3.72%	-1.20%	2.52%	0.82%	1.71%	0.51%
1998	1.08%	2.56%	3.98%	-1.42%	2.38%	1.48%	0.90%	-0.53%
1999	1.42%	3.47%	0.61%	2.87%	0.99%	2.05%	-1.06%	1.81%
2000	2.25%	3.77%	5.71%	-1.94%	0.73%	1.52%	-0.79%	-2.73%
2001	2.26%	2.85%	2.04%	0.81%	0.04%	0.59%	-0.55%	0.26%
2002	1.52%	3.55%	1.98%	1.57%	0.93%	2.03%	-1.10%	0.46%
2003	1.98%	4.35%	2.10%	2.26%	0.86%	2.37%	-1.52%	0.74%
2004	2.71%	4.90%	2.33%	2.57%	0.05%	2.19%	-2.15%	0.42%
2005	3.17%	4.69%	2.30%	2.39%	1.66%	1.52%	0.15%	2.54%
2006	3.02%	3.50%	2.89%	0.61%	-0.23%	0.48%	-0.71%	-0.10%
2007	2.63%	3.18%	3.08%	0.10%	-0.58%	0.55%	-1.12%	-1.03%
2008	1.91%	0.73%	4.00%	-3.28%	-0.59%	-1.19%	0.60%	-2.68%
2009	0.78%	1.03%	2.99%	-1.95%	-2.09%	0.25%	-2.34%	-4.30%
2010	1.22%	3.81%	3.01%	0.80%	-2.29%	2.59%	-4.88%	-4.08%
2011	2.04%	1.87%	2.70%	-0.83%	0.44%	-0.18%	0.61%	-0.22%
2012	1.82%	2.51%	2.41%	0.10%	-0.32%	0.69%	-1.01%	-0.92%
2013	1.60%	1.64%	2.42%	-0.77%	-0.07%	0.04%	-0.11%	-0.88%
2014	1.78%	2.27%	2.46%	-0.19%	-2.11%	0.49%	-2.60%	-2.79%
2015	1.06%	1.92%	3.41%	-1.50%	-0.63%	0.86%	-1.49%	-2.99%
2016	1.31%	0.70%	1.21%	-0.51%	-1.34%	-0.61%	-0.73%	-1.24%
2017	0.89%	1.29%	3.58%	-2.29%	0.34%	0.40%	-0.05%	-2.35%

Average Annual Growth Rates

1997-2017	**1.82%**	**2.72%**	**2.81%**	**-0.09%**	**0.03%**	**0.90%**	**-0.87%**	**-0.96%**
2003-2017	**1.86%**	**2.56%**	**2.73%**	**-0.17%**	**-0.46%**	**0.70%**	**-1.16%**	**-1.32%**
2008-2017	**1.44%**	**1.78%**	**2.82%**	**-1.04%**	**-0.87%**	**0.33%**	**-1.20%**	**-2.24%**

5. Comparative Age Data

Our new econometric work suggests that the age of T&D assets is an important consideration in choosing X factors for the HECO companies. This raises the question of how old are HECO's T&D assets. Our recent research has included some statistical age comparisons.

We first calculated the accumulated depreciation ratios ("ADRs") for HECO and the sampled VIEUs. An ADR is the ratio of accumulated depreciation expenses to gross plant value. This is a measure of the *typical* age of utility assets. A high value for the ADR indicates higher typical age.

Table 8 compares the 2019 ADR for HECO to the 2017 ADRs for the VIEUs in our sample. It can be seen that HECO had the highest T&D ADR of all of VIEUs in our sample. Its distribution ADR ranked 1st and its transmission ADR ranked 6th. Distribution generally gets greater weight in a consolidated T&D ADR computation because Dx assets are more valuable.

One disadvantage of ADRs as measures of repex requirements is that they don't focus on the importance of assets that may imminently need replacement. We accordingly calculated, for the year 2017, the (inflation-adjusted) quantities of T&D assets that HECO added in the last 58 years and then considered what share of these quantities were added from 46 to 58 years ago. Results of this exercise are presented in Table 9. It can be seen that HECO had the fourteenth highest share out of 46 VIEUs considered.

Table 8

Accumulated Depreciation Ratios of HECO and Sampled VIEUs (2017)

	End of Year Gross Value of Plant			**Accumulated Depreciation**			**Accumulated Depreciation to Gross Plant Value Ratios**		
	Distribution [A]	**Transmission [B]**	**Transmission & Distribution [C=A+B]**	**Distribution [D]**	**Transmission [E]**	**Transmission & Distribution [F=D+E]**	**Distribution [D/A]**	**Transmission [E/B]**	**Transmission & Distribution [F/C]**
Hawaiian Electric*	**1,997,726,421**	**1,140,149,811**	**3,137,876,232**	**1,006,153,763**	**418,944,910**	**1,425,098,673**	**50.36%**	**36.74%**	**45.42%**
Union Electric Company	5,765,762,048	1,201,003,904	6,966,765,952	2,706,232,064	347,318,336	3,053,550,400	46.94%	28.92%	43.83%
Duke Energy Progress, Inc. (Carolina Power & Light)	6,236,201,472	2,619,581,696	8,855,783,168	3,005,977,600	798,253,120	3,804,230,720	48.20%	30.47%	42.96%
Tucson Electric Power Company	1,632,402,816	1,001,445,568	2,633,848,384	619,790,272	430,419,296	1,050,209,568	37.97%	42.98%	39.87%
Duke Energy Carolinas, LLC	11,345,729,536	3,874,750,720	15,220,480,256	4,657,540,096	1,403,966,080	6,061,506,176	41.05%	36.23%	39.82%
Mississippi Power Company	945,156,544	673,983,552	1,619,140,096	398,758,944	242,824,864	641,583,808	42.19%	36.03%	39.62%
Empire District Electric Company	949,112,320	359,691,936	1,308,804,256	419,838,560	94,678,048	514,516,608	44.23%	26.32%	39.31%
Duke Energy Indiana, Inc. (Public Service Company of Indiana)	3,052,046,592	1,589,453,312	4,641,499,904	1,237,162,752	508,933,504	1,746,096,256	40.54%	32.02%	37.62%
ALLETE (Minnesota Power)	586,984,640	775,409,920	1,362,394,560	270,588,768	238,204,912	508,793,680	46.10%	30.72%	37.35%
Kentucky Utilities Company	1,803,849,216	924,691,648	2,728,540,864	670,817,408	337,138,272	1,007,955,680	37.19%	36.46%	36.94%
Louisville Gas and Electric Company	1,370,549,888	432,829,792	1,803,379,680	506,337,760	158,104,576	664,442,336	36.94%	36.53%	36.84%
Southwestern Electric Power Company	694,909,824	487,736,736	1,182,646,560	295,418,048	133,802,064	429,220,112	42.51%	27.43%	36.29%
Kansas City Power & Light Company	2,388,798,208	496,676,000	2,885,474,208	826,347,200	204,671,392	1,031,018,592	34.59%	41.21%	35.73%
MDU Resources Group, Inc. (Montana-Dakota Utilities)	415,542,624	296,941,440	712,484,064	148,903,504	105,443,352	254,346,856	35.83%	35.51%	35.70%
Puget Sound Energy, Inc.	3,817,603,840	1,536,971,648	5,354,575,488	1,420,269,824	489,194,240	1,909,464,064	37.20%	31.83%	35.66%
Tampa Electric Company	2,437,444,096	859,088,576	3,296,532,672	983,985,664	191,193,024	1,175,178,688	40.37%	22.26%	35.65%
El Paso Electric Company	1,170,990,336	491,438,336	1,662,428,672	361,185,760	224,289,712	585,475,472	30.84%	45.64%	35.22%
MidAmerican Energy Company	2,856,761,088	1,833,480,576	4,690,241,664	1,141,918,336	496,162,144	1,638,080,480	39.97%	27.06%	34.93%
Florida Power & Light Company	15,796,473,856	5,395,656,704	21,192,130,560	5,499,323,904	1,870,325,760	7,369,649,664	34.81%	34.66%	34.78%
Monongahela Power Company	1,791,305,088	460,648,032	2,251,953,120	591,899,968	186,834,672	778,734,640	33.04%	40.56%	34.58%
Idaho Power Co.	1,710,126,208	1,163,240,448	2,873,366,656	628,829,056	364,308,768	993,137,824	36.77%	31.32%	34.56%
Alabama Power Company	7,032,719,360	4,119,101,184	11,151,820,544	2,548,985,600	1,291,912,576	3,840,898,176	36.24%	31.36%	34.44%
PacifiCorp	6,781,903,360	6,222,285,824	13,004,189,184	2,783,524,608	1,679,410,048	4,462,934,656	41.04%	26.99%	34.32%
Otter Tail Power Company	482,845,888	500,284,992	983,130,880	210,361,952	120,734,336	331,096,288	43.57%	24.13%	33.68%
Cleco Power LLC	1,455,913,600	722,335,680	2,178,249,280	492,741,280	233,670,608	726,411,888	33.84%	32.35%	33.35%
Entergy New Orleans, Inc. (New Orleans Public Service)	674,195,712	153,025,920	827,221,632	205,169,056	68,878,768	274,047,824	30.43%	45.01%	33.13%
Southwestern Public Service Company	2,096,724,608	1,679,310,720	3,776,035,328	717,641,344	501,945,376	1,219,586,720	34.23%	29.89%	32.30%
Northern States Power Company - MN	4,001,157,888	3,592,396,544	7,593,554,432	1,585,108,352	854,348,608	2,439,456,960	39.62%	23.78%	32.13%
Nevada Power Company	3,310,183,424	1,409,618,176	4,719,801,600	1,123,066,496	388,412,480	1,511,478,976	33.93%	27.55%	32.02%
Black Hills Power, Inc.	376,277,440	184,727,232	561,004,672	133,804,896	43,694,320	177,499,216	35.56%	23.65%	31.64%
Indiana Michigan Power Company	2,069,063,808	1,503,669,760	3,572,733,568	608,012,864	515,733,696	1,123,746,560	29.39%	34.30%	31.45%
Gulf Power Company	1,282,276,608	719,683,072	2,001,959,680	485,904,320	141,359,984	627,264,304	37.89%	19.64%	31.33%
Avista Corporation (Washington Water Power)	1,643,539,200	722,397,568	2,365,936,768	527,773,760	211,556,288	739,330,048	32.11%	29.29%	31.25%
Duke Energy Florida, Inc. (Florida Power)	5,479,825,408	3,105,263,104	8,585,088,512	1,969,014,656	683,543,872	2,652,558,528	35.93%	22.01%	30.90%
Virginia Electric and Power Company	11,097,772,032	8,301,881,856	19,399,653,888	4,391,818,240	1,446,902,912	5,838,721,152	39.57%	17.43%	30.10%
Appalachian Power Company	3,761,628,928	3,018,312,192	6,779,941,120	1,273,050,880	716,358,528	1,989,409,408	33.84%	23.73%	29.34%
Oklahoma Gas and Electric Company	4,050,774,016	2,621,320,704	6,672,094,720	1,359,161,856	580,920,256	1,940,082,112	33.55%	22.16%	29.08%
Entergy Arkansas, Inc. (Arkansas Power & Light)	3,354,571,264	2,196,105,472	5,550,676,736	1,099,171,840	495,532,448	1,594,704,288	32.77%	22.56%	28.73%
South Carolina Electric & Gas Co.	3,286,827,776	1,603,540,352	4,890,368,128	1,029,790,144	362,089,760	1,391,879,904	31.33%	22.58%	28.46%
Arizona Public Service Company	6,024,269,312	2,831,375,104	8,855,644,416	1,681,837,312	801,763,456	2,483,600,768	27.92%	28.32%	28.05%
Kansas Gas and Electric Company	1,135,290,624	991,892,032	2,127,182,656	313,376,512	269,193,088	582,569,600	27.60%	27.14%	27.39%
Entergy Mississippi, Inc. (Mississippi Power & Light)	1,885,919,360	1,257,741,952	3,143,661,312	473,904,960	358,392,800	832,297,760	25.13%	28.49%	26.48%
Public Service Company of Colorado	4,809,704,960	2,133,315,200	6,943,020,160	1,377,868,288	459,624,608	1,837,492,896	28.65%	21.55%	26.47%
Westar Energy (Western Resources or Kansas Power & Light)	1,366,391,808	1,299,441,152	2,665,832,960	357,783,392	316,321,696	674,105,088	26.18%	24.34%	25.29%
Public Service Company of Oklahoma	2,444,828,672	858,822,464	3,303,651,136	587,879,872	204,435,440	792,315,312	24.05%	23.80%	23.98%
Southwestern Public Service Company	1,297,259,392	2,678,015,232	3,975,274,624	356,124,224	404,067,552	760,191,776	27.45%	15.09%	19.12%
Averages	**3,260,159,589**	**1,783,494,214**	**5,043,653,803**	**1,197,612,086**	**486,865,534**	**1,684,477,620**	**36.08%**	**29.52%**	**33.42%**

46 Companies considered

*Values for Hawaiian Electric are preliminary 2019 data for the Company's Annual PUC Report.

Table 9

Estimated Prevalence of Old T&D Plant (2017)

(Sorted Oldest to Youngest)

	Ratio of 46-58 Year-Old Plant Additions to Total Plant Additions (adjusted for inflation)	Rank
Entergy New Orleans	44.4%	1
Union Electric	36.6%	2
Indiana Michigan Power	35.2%	3
Kansas City Power & Light	32.3%	4
MDU Resources Group	31.6%	5
Otter Tail	30.5%	6
Kentucky Utilities	27.6%	7
Mississippi Power	27.5%	8
Entergy Arkansas	25.4%	9
Monongahela Power	25.2%	10
Louisville Gas and Electric	25.0%	11
Southwestern Public Service	24.4%	12
Northern States Power - MN	24.4%	13
HECO	24.3%	14
Kansas Gas and Electric	24.2%	15
Puget Sound Energy	23.8%	16
Public Service Company of Oklahoma	23.8%	17
MidAmerican Energy	23.7%	18
ALLETE (Minnesota Power)	23.7%	19
Appalachian Power	23.6%	20
Duke Energy Indiana	23.6%	21
Duke Energy Carolinas	22.8%	22
Tampa Electric	22.2%	23
Idaho Power	22.0%	24
Entergy Mississippi	21.9%	25
Southern Indiana Gas and Electric	21.7%	26
Westar Energy (KPL)	21.5%	27
Oklahoma Gas and Electric	21.0%	28
Southwestern Electric Power	20.4%	29
Cleco Power	20.3%	30
Public Service Company of Colorado	19.6%	31
Gulf Power	19.5%	32
Florida Power	19.0%	33
Virginia Electric and Power	18.9%	34
PacifiCorp	17.0%	35
Avista	16.7%	36
South Carolina Electric & Gas	16.7%	37
Carolina Power & Light	16.5%	38
Empire District Electric	16.2%	39
Florida Power & Light	16.2%	40
Black Hills Power	16.2%	41
Arizona Public Service	16.1%	42
El Paso Electric	15.5%	43
Alabama Power	15.5%	44
Tucson Electric Power	14.8%	45
Nevada Power	7.6%	46
Average	**22.5%**	
Median	**22.1%**	

The importance of T&D system age is amplified for HECO because T&D assets loom especially large in the Company's cost structure. This reflects in large measure the sizable share of the Company's power supplies that are purchased rather than generated. Table 10 compares HECO's 2019 shares of T&D in both its gross and net plant value to 2017 full sample norms. It can be seen HECO's shares are unusually large.

Table 10

How the Composition of HECO's Plant Compares to 2017 Sample Norms

	Percent of Plant by Type of Plant		
	HECO*	**Sample**	**HECO vs Sample**
Percent of Plant by Type of Plant			
Gross Plant			
Total Plant			
Generation	26.3%	45.8%	-19.5%
Transmission	23.7%	17.8%	5.9%
Distribution	41.6%	31.0%	10.5%
Other	8.4%	5.4%	3.1%
Net Plant			
Total Plant			
Generation	29.7%	45.6%	-15.9%
Transmission	26.0%	19.6%	6.4%
Distribution	35.7%	28.8%	7.0%
Other	5.0%	4.0%	0.9%

*HECO values are preliminary for 2019.

6. MPIR Adjustment

6.1 Combining an ARA Index with Capex Trackers is Warranted for HECO

Productivity growth drivers vary between utilities and, over time, for the same utility. An X factor based on industry cost (e.g., input price and productivity) trends is therefore not always compensatory for the subject utility during the term of an MRP. MRPs that have ARAs based on cost trends therefore often have some provision for supplemental capital revenue (e.g., Alberta, British Columbia, Ontario) if the need for such revenue can be substantiated. Cost trackers are commonly used for this purpose and also have other justifications.

The fairness of supplemental revenue provisions is magnified if the subject utility has either not previously operated under MRPs or has operated under such plans but the prior ARA index was under compensatory. On a net present value basis, *under* compensation in the early years of operation under MRPs will tend to outweigh any possible *over*compensation in future years. Hence, initial MRPs with under compensatory ARA formulas would, under these circumstances, tend to be unfair to the utility.

There are several reasons to believe that combining capex trackers for renewables-related and major plant additions with an ARA formula based on industry cost trends is justifiable for HECO. Some of these reasons are revisited below.

- HECO has been compelled to operate for several years with a *growth GDPPI – 0* “RAM Cap” formula and has underearned despite its capital cost trackers. This suggests that *growth GDPPI – 0* has been an under compensatory ARA formula for the costs that it addresses.
- Growing numbers of the Company’s T&D assets are reaching replacement age so that high repex will be needed during the plan. This repex will materially slow MFP growth and will likely not be eligible for tracker treatment.
- Due chiefly to the large share of its power supplies which HECO purchases rather than self-generates, T&D cost looms unusually large in the total cost that will be addressed by HECO’s ARA index.

- The ARA index will contain no scale escalator.
- With its unusually high and growing reliance on intermittent renewable resources, the Companies may face other special cost pressures that are beyond its control.
- The Commission and/or some intervenors may wish to weigh in on HECO's renewables-related and major plant additions in advance. Capex trackers provide that opportunity.

6.2 Any Need to Adjust the MRP for Potential Overcompensation due to the MPIR is Limited

Despite the need for a capex tracker, it is possible for the combination of such a tracker and an RCI based on industry cost trend research to overcompensate HECO for its cost challenges. The following considerations suggest that the need to adjust HECO's MRP for overcompensation is limited, however.

- The share of HECO's capex that is tracked will likely be limited by eligibility restrictions. In addition to general eligibility restrictions (e.g., capex must be major or renewables-related), overruns may be ineligible for tracking and a portion of otherwise-eligible capex may occasionally be marked down, as happened with the Schofield Barracks project. The great bulk of HECO's capex, including all or nearly all repex, has not been tracked in most years since the MPIR was established.
- The approved ARA formula has no explicit scale escalator.
- Even if no output growth was expected, the extent of any overcompensation is not near the -1.32% proposed value of the X factor that our Kahn method calculations suggest are warranted. We showed in Table 3 that the X factor is negative chiefly due to the inflation differential. This differential was -0.99% for the full 21-year 1997-2017 sample period that PEG considered. For the fifteen-year 2003-2017 period the inflation differential was -0.86%.
- We developed an MFP growth projection that was specific to the costs that will be addressed by the ARA formula. No growth was assumed in generation capacity,

scrubbing capacity, transmission line miles, or AMI. The 0.45% decline in MFP growth that is implicit in the Company's proposal is quite reasonable compared to our -0.63% MFP growth projection.

- Many approved MRPs that combine ARA indexes based on cost trend research with capital cost trackers have no provisions intended to reduce possible overcompensation that may result. Examples include the current MRPs for power distributors in Alberta, British Columbia, and Massachusetts.

7. Conclusions

Our new research for HECO has shed additional light on the appropriate X factors for its ARA formulas. Using established cost theory and econometric methods, we identified drivers of VIEU productivity growth and estimated their productivity impacts. The need for T&D repex was found to be an important driver of MFP growth of sampled VIEUs in recent years. Ancillary statistics that we computed show that HECO has an unusually old T&D system.

We developed an MFP growth projection for HECO during the four indexing years of the Company's prospective PBR plan (2021-2024). This is the typical MFP growth that might be expected given the Company's business conditions. Considerable effort was devoted to customizing this projection to the costs that will be addressed by the ARA. This in principle eliminates the need for an MPIR adjustment to the X factor. MFP growth is projected to average a 0.63% annual decline on average during these years. The Company has proposed an X factor that reflects a -0.45% MFP trend that is more favorable to customers. X should be substantially more negative than the MFP growth target because GDPPI will be used as the inflation measure in the ARA formula and the formula will not include a scale escalator.

The -0.45% MFP growth target that is implicit in HECO's X factor proposal understates the growth in the true cost efficiency of sampled utilities for reasons that include the following.

- Costs of environmental damage that result from VIEU operations were excluded from the calculations because these costs are difficult to estimate accurately and are irrelevant for ratemaking. During the sample period, capex for pollution controls, gas- and renewable-powered generation, and for T&D capacity needed to increase reliance on renewables slowed calculated MFP growth but reduced environmental costs.
- Costs of generation fuel were excluded from the calculations because these costs would be tracked in HECO's new MRPs. Investments in renewable-powered generation and T&D facilities needed to handle the resultant intermittent power flows slowed calculated MFP growth but also reduced use of generation fuels.

- Some distribution capex improved system reliability and resilience, and the output index does not reflect this either.

Thus, in accepting an X factor of -1.32% that reflects a -0.45% MFP growth trend, the Commission would not acquiesce in a poor MFP growth standard.

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Incentive Regulation for Hydro One Transmission

5 September 2019

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1. Introduction and Summary

1.1. Introduction

Hydro One Networks ("Hydro One" or "the Company") proposed Custom Incentive Rate-Setting ("IR") for the bulk of its power transmission services in a March 2019 application.[1] The Ontario Energy Board (the "Board" or "OEB") has already approved an IR plan for a smaller affiliated transmission utility, Hydro One Sault Ste. Marie ("Hydro One SSM").[2] The proposed plan is similar to that which the Board recently approved for Hydro One's distributor services.[3] Escalation of a revenue cap index ("RCI") would be slowed by a Productivity (aka "X") Factor.

The proposed X factor is supported by transmission productivity and cost benchmarking research[4] by Power System Engineering, Inc. ("PSE"), a Madison, Wisconsin consulting firm. Steven Fenrick and Eric Sonju authored PSE's report.[5] PSE's report details an update to the productivity and benchmarking study PSE prepared for the Hydro One SSM IR proceeding. The revised study corrects for several errors identified in that proceeding and considers new cost projections that reflect Hydro One's latest Transmission Business Plan.

Hydro One's Custom IR evidence merits careful examination in this proceeding for reasons that include the following:

- The Company's transmission business accounts for a not immaterial portion of the rate-regulated charges of Ontario electric utilities, especially to industrial ratepayers.
- The OEB has long expressed an interest in extending IR to power transmission.

[1] EB-2019-0082.

[2] Ontario Energy Board, EB-2018-0218, Decision and Order, Hydro One Sault Ste. Marie LP, June 20, 2019. Hydro One SSM provides transmission services in a region east of Lake Superior. The company was created after the acquisition of Great Lakes Power Transmission Inc. in 2016 by Hydro One, Inc. It is now being integrated into the larger transmission operations of Hydro One Networks Inc., but its revenue requirement is still separately regulated.

[3] Ontario Energy Board, EB-2017-0049, Decision and Order, Hydro One Networks Inc., March 7, 2019.

[4] Exhibit A/Tab 4/Schedule 1/Attachment 1.

[5] Mr. Sonju is the President of PSE. Mr. Fenrick, a former employee of PEG, recently left PSE and is now a Principal Consultant and Partner of Clearspring Energy Advisors in Madison.

- No "top down" statistical benchmarking study of Hydro One's transmission cost has yet been fully vetted (i.e., including expert testimony in an oral hearing) in an OEB proceeding. Neither has a study been fully vetted on the transmission productivity trends of Hydro One or peer utilities.

Pacific Economics Group Research LLC ("PEG") is North America's leading energy utility productivity and statistical benchmarking consultancy. We have done several power transmission productivity and benchmarking studies, and recently played a key role in the development of IR for transmission services of Hydro-Québec. OEB staff retained PEG in Hydro One SSM's IR proceeding to critique PSE's evidence and prepare an alternative study and evidence. We have been asked to consider PSE's new evidence and the Company's IR proposal in this proceeding and to revise our study and evidence.

This is our report on this work. It is, in essence, an update of the evidence[6] we filed in the Hydro One SSM proceeding which takes into account PSE's new evidence, the OEB's recent IR decisions on Hydro One distribution[7] and Hydro One SSM, as well as evidence PEG filed in the current Toronto Hydro IR proceeding.[8] The following are the key areas where we update and upgrade our evidence from the Hydro One SSM case:

- We have revised our research methods in a few ways that include a better econometric cost model estimation procedure and Canadian asset price index. Further discussion of changes in our research methods since the Hydro One SSM proceeding can be found in Appendix Section B.3.
- We propose a supplemental stretch factor for determining the C factor and calibrate it to produce a markdown similar to that in the materiality threshold for incremental and advanced capital modules ("ICMs/ACMs") in the fourth generation incentive regulation mechanism ("4GIRM").
- Commentary on several topics has been expanded or refined.

[6] EB-2018-0218, Exhibit M1.

[7] EB-2017-0049, Decision and Order, March 7, 2019.

[8] EB-2018-0165, Exhibit M1 (Updated), May 22, 2019 and Undertaking J10.5 filed July 26, 2019.

Following a brief summary of our findings, Section 2 provides pertinent background information. Section 3 provides our critique of PSE's new research and testimony. Section 4 discusses new productivity and benchmarking results by PEG using better methods and new data. We provide in Section 5 our stretch factor and X factor recommendations for Hydro One's transmission services. Appendix A of the report discusses at a high level the use of index research in the design of a revenue cap index. Appendix B discusses various methodological topics in the report in more detail, while Appendix C discusses U.S. regulation of power transmission. A brief discussion of PEG's credentials is provided in Appendix D.

1.2. Summary

Empirical Issues

PSE developed an econometric model of total power transmission cost using operating data for Hydro One and 56 U.S. utilities over the 2004-2016 period. This model was used to benchmark Hydro One's transmission cost over the same historical period, as well as the Company's forecasted/proposed cost for the 2020-2022 period, during which it would operate under its proposed plan of rebasing in 2020 and a revenue cap for 2021 and 2022. PSE also calculated the multifactor productivity ("MFP") growth of 47 U.S. utilities and Hydro One in the provision of transmission services from 2005 to 2016. Hydro One's transmission productivity growth was calculated from 2005 to 2022.

U.S. Transmission Productivity

The sampled U.S. transmitters averaged a 1.45% annual MFP decline over PSE's full 2005-2016 sample period. Productivity in the use of operation, maintenance, and administration ("OM&A") inputs averaged a 1.11% annual decline while capital productivity averaged a 1.48% decline. PSE nevertheless recommends a 0.00% base productivity trend for the revenue cap index, and Hydro One embraced this proposal. The 1.45% difference between zero and the calculated transmitter MFP trend is portrayed as an implicit stretch factor.

Our review of PSE's research raised concerns about its calculations of U.S. transmission productivity. Here are our main concerns.

- The 2005-2016 sample period was one during which U.S. power transmission productivity was adversely influenced by special circumstances that included the Energy Policy Act of 2005. The Federal Energy Regulatory Commission ("FERC") was authorized to oversee reliability standards. Incentives to contain cost were weakened by special investment incentives and by formula rate plans administered by the FERC under which a growing number of transmitters operated. Some transmitters made investments to access remote renewable resources and improve the functioning of bulk power markets. Absent information that Hydro One will somehow face comparable cost pressures in the next few years, we believe that a longer sample period is desirable in a study intended to inform selection of its base productivity growth trend.

- PSE's treatment of OM&A expenses doesn't handle structural change in the U.S. transmission industry well. Many sampled utilities have joined independent transmission system operators ("ISOs") or regional transmission organizations ("RTOs"), and this materially affected the reported OM&A expenses of some companies. Exclusion from our calculations of costs that were especially sensitive to this restructuring is appropriate for benchmarking and X factor calibration research.
- The calculation of capital costs of the sampled U.S. transmitters was unnecessarily inaccurate. For example, the initial or benchmark year for the calculations was 1989 for U.S. utilities whereas a benchmark year of 1964 is possible, and is preferable in our view.

These and other concerns prompted us to develop our own power transmission productivity study using better methods and data for Hydro One and the same group of U.S. utilities over the longer 1996-2016 sample period. We found that the transmission MFP of sampled utilities averaged a 1.47% annual decline over the 2005-2016 sample period chosen by PSE but only a 0.25% decline over the full sample period. OM&A productivity growth averaged -1.64% over the shorter sample period but -0.69% over the full period. Capital productivity growth averaged -1.45% over the shorter period but -0.19% over the full period. Our estimates of transmitter output do not reflect any possible improvements in U.S. transmission reliability or bulk power market performance which may have occurred during this period.

Hydro One's Transmission Cost and Productivity Performance

PSE reports that the total transmission cost of Hydro One was a substantial 21.8% below its econometric cost model's prediction over the three most recent historical years for which data were available (2014-2016). The Company's forecasted/proposed total cost is 27.1% below the model's predictions during the years of the proposed IRM (2021-2022).

PSE reports that the transmission productivity growth trend of Hydro One was considerably better than that of its U.S. peers during the 2005-2016 historical period. The Company's annual MFP growth averaged a 0.18% annual decline. During the 2021-2022 period of the proposed IR plan, however, PSE reports that the forecasted/proposed total transmission cost of Hydro One would reflect a 1.70% average annual MFP decline that is more in line with its estimate of the recent U.S. trend.

Our chief concerns about PSE's assessment of Hydro One's transmission performance include the following:

- Capital cost data are available for Hydro One only since 2002, and this reduces the accuracy of capital cost and MFP calculations (whether made by PSE or PEG) which are based on these data.
- PSE's calculation of capital costs of the sampled U.S. transmitters was unnecessarily inaccurate because they don't rely on older but available U.S. data.
- The short sample period used in model estimation unnecessarily reduced the accuracy of cost model parameter estimates. The econometric estimate for the trend variable parameter was very sensitive to the sample period chosen and indicated that cost rose by 1.2% annually for reasons other than the values of the model's business condition variables.
- Transmission OM&A data for some U.S. utilities were non-comparable to Hydro One's due to their participation in ISOs or RTOs.
- U.S. input price indexes were used for Hydro One even though better Canadian indexes are available.

These and other concerns prompted us to undertake our own studies of Hydro One's transmission productivity and cost performance. The longer sample period that we used produces more accurate estimates of cost model parameters and long run transmission productivity trends. Our research is also based on better capital cost data and produces materially different and less favorable benchmarking results for Hydro One.

The Company's transmission cost performance has deteriorated markedly since 2008. Cost was found to be about 2.1% below the model's prediction on average from 2014-2016. The Company's forecasted/proposed total cost is 9.0% above our model's prediction on average during the 2020-2022 period.

Over the 2005-2016 historical sample period over which data are available for Hydro One transmission, we calculated the Company's transmission MFP to average a 1.17% annual decline while its OM&A productivity growth averaged 0.83% growth and its capital productivity averaged a 1.67% decline. The accuracy of our capital and multifactor productivity trend calculations is, like those of PSE, compromised by the unavailability of capital cost data for Hydro One before 2002. Over the two out years of the proposed IR plan, the Company's cost proposal/forecast is consistent with a 2.53% average annual MFP decline, 0.11% OM&A productivity growth, and a 2.94% annual capital productivity decline. Forecasted/proposed costs thus reflect capital and multifactor productivity growth that is well below longer-run U.S. norms.

Stretch Factor

We disagree with PSE's 0% stretch factor recommendation. One reason we disagree is that we do not get such favorable benchmarking results for Hydro One. Another is that we do not believe that the Company's base productivity trend proposal contains a large implicit stretch factor. We recommend a 0.30% stretch factor.

X Factor Recommendation

Our research supports a **-0.25%** base productivity trend drawn from our U.S. transmission MFP research for the full sample period with a **0.30%** stretch factor. The resultant X factor would be 0.05%.

Other Plan Design Issues

Hydro One's proposed IR plan is in many respects similar to that which the Board approved for Hydro One's distributor services in EB-2017-0049. We are nonetheless concerned about some features of Hydro One's proposal. The proposed ratemaking treatment of capital cost is our chief concern.

- Incentives to contain capex would be weakened by the proposed C factor, Capital In-Service Variance Account ("CISVA"), other capital cost variance accounts, and the Z factor provisions of the revenue cap index. The Company is perversely incented to spend excessive amounts on capital in order to trim OM&A expenses. The weak incentives to contain capex violate the spirit of the Board's Custom IR guidelines and are all the more worrisome given the capital-intensive nature of power transmission technology.
- Notwithstanding the CISVA, Hydro One is still incentivized to exaggerate its need for supplemental capital revenue. The regulatory cost for the OEB and stakeholders is

substantially raised and, ultimately, it is ratepayers who bear the burden of the capital cost increases.

- While customers must fully compensate Hydro One for expected capital revenue *shortfalls* when capex is high for reasons beyond its control, the Company need not return any *surplus* capital revenue in future plans if capital cost growth is unusually slow for reasons beyond its control. Over multiple plans, the revenue escalation between rate cases would not guarantee customers the full benefit of the industry's multifactor productivity trend, even when it is achievable.
- The kinds of capex accorded C-factor and variance account treatment are, for the most part, conventional transmission capex like that incurred by transmitters in studies used to calibrate base productivity trends. The Company can then be compensated twice for the same capex: once via the C factor and then again by low X factors in past, present, and future IRMs.
- The RCI would effectively apply chiefly to the (modest) revenue for OM&A expenses and provide only a floor for revenue growth, even though it is not designed to play either of these roles.

We discuss several possible upgrades to the ratemaking treatment of capital cost in Section 6 of the report. Having considered the pros and cons of these options, we recommend an extra stretch factor term for setting the C-factor. The OEB first approved this kind of provision in its recent Hydro One Distribution decision.[9] The specific 0.42% supplemental stretch factor that we recommend would produce a markdown on eligible capex that is similar to that produced by the ACMs available to provincial power distributors in fourth-generation IRMs. The resultant C factor would average 3.50%.

We endorse the Company's proposal to be able to keep a small percentage of accumulated capex underspends because this provision strengthens capex containment incentives. We recommend that the Company's share of the value of underspends be 5%.

[9] EB-2017-0049. Decision and Order issued March 7, 2019.

2. Background

2.1 Hydro One's Previous Regulatory Systems

Hydro One's initial transmission revenue requirement was established in 1999 and updated to reflect a change in the Company's allowed rate of return on equity ("ROE") in 2000. After that, the Company's revenue requirement was unchanged until 2007. Hydro One subsequently filed rate cases in 2008, 2010, 2012, 2014, and 2016. Each rate case filing featured two forward test years. Concerns about capex underspending led to the adoption of an In-Service Capital Additions Variance Account which requires the Company to return the revenue impact of underspends to customers.

The OEB recently issued a decision that detailed an IRM for Hydro One SSM. This decision includes the following noteworthy provisions.

- An RCI allows revenue requirement escalation based on the formula Inflation less an X factor +/- Z factors. No scale escalator was approved for the RCI formula, and the Board commented that parties had presented insufficient evidence to justify the inclusion of such a term.
- Hydro One SSM's proposed inflation measure was accepted. The Board found that this measure was consistent with the inflation measures approved for Ontario power distributors in 4GIRM and Ontario Power Generation. Weights for the two inflation subindexes are 14% for labor and 86% for non-labor.
- The base productivity trend was set at zero, reflecting in part the OEB's prior decisions and their desire to keep base productivity trends non-negative. No party had supported a negative base productivity trend, even though both productivity studies presented in evidence reported negative MFP trends for U.S. transmitters. Transmission productivity results were very sensitive to the choice of sample periods, with PEG advocating for a longer sample period and PSE advocating for a shorter period. The Board found both the PSE and

PEG productivity studies "informative of the transmission sector, yet [found] both reports have inherent issues, dependent upon the sample periods selected."[10]

- The stretch factor was set at 0.3%. The Board chose this value in part because they believed that "a stretch factor of 0.3% provides incentives to find further efficiency improvement beyond those proposed by the acquisition."[11] The Board rejected Hydro One's proposed 0% stretch factor partly on the grounds that the benchmarking evidence presented in the proceeding pertained to Hydro One Transmission rather than to Hydro One SSM. Savings resulting from the integration of Hydro One SSM into Hydro One and the lengthy deferred rebasing period were not considered in the stretch factor selection. The Board also noted that PSE's "construction standards index" variable had not been fully vetted and questioned the relevance of this variable to Hydro One SSM.
- Hydro One SSM can request supplemental funding for capex through Incremental Capital Module filings.

The Board more recently approved the Company's request to escalate its revenue requirement by an RCI for a single year. The RCI had an I-X formula, where the I factor was set at 1.4% based on the record of Hydro One SSM and the X factor was set at 0%. The OEB explained its decision to not set a positive value for the X factor:

> The OEB normally applies a productivity factor and a stretch factor to incentive ratesetting indices to incent expected productivity improvements. The OEB is not imposing an explicit productivity factor for 2019 in this case given the short duration of the term. The OEB is specifically not making a finding on the appropriateness of a productivity factor or stretch factor of zero for the 2020 to 2022 period.[12]

2.2 Hydro One's Instant IR Proposal

Hydro One has in this proceeding filed a Custom IR application for its power transmission services. Under the proposal, a multiyear rate plan would set rates for the three-year 2020-2022 period. The revenue requirement for 2020 would be established by a conventional rebasing which uses a

[10] EB-2018-0218, p. 19.

[11] EB-2018-0218, p. 21.

[12] Ontario Energy Board (2019), Decision and Order EB-2018-0130 Hydro One Networks Application for 2019 Electricity Transmission Revenue Requirement, April 25, p. 7.

forward test year. Allowed revenue for 2021 and 2022 would then be set using an RCI with a formula that features an Inflation Factor ("I"), Productivity Factor ("X"), Custom Capital Factor ("C"), and Z factor.

$$\textit{growth RCI} = I - X + C +/- Z.$$

The Company proposes an electricity transmission industry-specific inflation measure like that which the OEB adopted for Hydro One SSM. The growth rate of this measure would be a weighted average of the growth in two Statistics Canada inflation indexes: Canada's gross domestic product implicit price index for final domestic demand ("$\text{GDPIPIFDD}^{\text{Canada}}$") and the Average Weekly Earnings for Workers in Ontario ("$\text{AWE}^{\text{Ontario}}$"). The respective 86% and 14% weights on these two indexes would be based on the average shares of labor and other inputs in the total included transmission cost of the utilities in PSE's benchmarking sample. The inflation measure would be updated annually as calculated and issued by the OEB.

The proposed X factor would be fixed during the plan as the sum of a Custom Industry Total Factor Productivity ("TFP") (aka base productivity) trend and a Custom Productivity Stretch Factor. A 0% base productivity trend is proposed which is consistent with the OEB's 4^{th} generation IRM decision.[13] The proposed 0.00% stretch factor is supported by PSE's total cost benchmarking report. PSE claims that a 0% X factor also includes a sizable *implicit* stretch factor since PSE found the transmission MFP trend of sampled electric utilities to be materiality negative in recent years.

The C Factor is the percentage change in the total revenue requirement which is needed to eliminate any positive difference between the growth in the Company's approved capital revenue requirement and the growth in its capital revenue that is otherwise produced by the RCI. The capital revenue requirement thus defined would include depreciation, return on rate base, and taxes. The Company's forecasted/proposed capital cost is supported by a Transmission System Plan.

Based on Hydro One's forecasted/proposed revenue requirement, proposed X factor, and forecasted annual inflation of 1.4% during the two indexing years, the Company estimates that the C-factor would average about 3.84% annually during the two indexing years of plan. RCI growth would

[13] OEB, EB-2010-0379, *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, November 21, 2013 and as corrected on December 4, 2013.

average 5.24% annually. Thus, the C factor would accelerate allowed revenue growth substantially in 2021 and 2022.

Several of the Company's costs would be addressed by variance accounts. These would include the costs of pensions and other post-employment benefits, development of the Waasigan Transmission Line and East-West Tie line, and construction associated with the Supply to Essex County Transmission Reinforcement project. An asymmetrical CISVA would track the impact on the revenue requirement of 98% of any cumulative amount by which the value of in-service plant additions falls short of the OEB approved amount.

Hydro One could request Z factor treatment if a qualifying event occurred, based on the OEB's existing Z factor policy. A qualifying event would need to result in a change in the revenue requirement of $3 million or more.[14] Events that could trigger a Z factor claim include severe storms and investments that are government-mandated or outside of management's control for other reasons. Z-factor claims in Ontario may address OM&A and/or capital costs of qualifying events. While there is a materiality threshold, that threshold is not used as a dead zone, as is the case with the OEB's 4GIRM capital modules.

An asymmetrical earnings-sharing mechanism ("ESM") would share 50% of earnings which exceed the target rate of return on equity by more than 100 basis points. Earnings would be calculated in such a way that only those from OM&A would be addressed by this sharing mechanism. Hydro One has also proposed to apply the OEB's existing off-ramp policy. An off-ramp would be triggered if the actual achieved ROE on a regulated basis varied from the OEB-approved ROE by more than 300 basis points (i.e., ± 300 b.p.) in a single year. If an off-ramp is triggered, a regulatory review may be initiated. This review would be prospective in nature and could result in modifications to the plan, the plan continuing without change, or the termination of the plan.

2.3 Custom IR Guidelines

The *Handbook for Utility Rate Applications* ("Rate Handbook") provides guidelines for energy utilities requesting Custom IR plans.[15] The OEB stated that

[14] Exhibit I, Tab 5, Schedule 7.

[15] OEB, *Handbook for Utility Rate Applications*, October 2016, pp. 18-19 and 24-28.

> The annual rate adjustment must be based on a custom index supported by empirical evidence (using third party and/or internal resources) that can be tested. Custom IR is not a multi-year cost of service; explicit financial incentives for continuous improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast).
>
> The index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes. **If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service.** An application containing a proposed custom index which lacks the required supporting empirical information may be considered to be incomplete and not processed until that information is provided.
>
> **It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications**. **Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.**[16] [Emphasis added]

2.4 First Toronto Hydro Custom IR Proceeding

In its order approving Toronto Hydro's current (and expiring) Custom IR plan,[17] the OEB approved many of the basic features of subsequent Custom IR plans, including the adoption and calculation of the C factor, inclusion of an ESM, and the refund of capital underspends at the end of the plan term. The approved plan has a nearly 5-year term and escalates rates using the formula I – X + C, where I is the inflation factor, X is the sum of a 0% productivity trend and a 0.6% stretch factor, and C is a custom capital factor. A symmetrical ESM addresses non-capital related earnings variances outside of a 100-basis point dead band, while a variance account refunds all capex underspends to customers.

Despite approving much of Toronto Hydro's proposed Custom IR plan, the OEB expressed the following reservations about the quality of Toronto Hydro's filing.

> The OEB has determined that it cannot fully rely on Toronto Hydro's approach to establishing its spending proposals in determining if the outcome of that spending is desirable for ratepayers. It is not clear that Toronto Hydro's proposals are necessarily aligned with the interests of its customers, as they are largely supported by an asset condition analysis rather than the impact of the proposed work on the reliability of the system. The approach used by Toronto Hydro

[16] *Ibid*., pp. 25-26.

[17] EB-2014-0116

does not give a clear indication of how the overall spending is related to customer experience such as reliability.

The Application lacks evidence of corporate policy guiding Toronto Hydro staff to focus on impacts on customers when developing spending proposals. The focus overall is on the need for work based on asset condition assessment without a clear understanding of the results expected to be achieved through the work. Continuous improvement measurements are lacking

…

There does not appear to be any measurement of units of activity and their costs that would allow for year over year assessment of improvement in Toronto Hydro's proposed metrics. The OEB agrees with the parties which suggested that reporting measures such as specific performance improvements sought and achieved per asset class, tie-ins of capital program spending to the dollar value of OM&A savings achieved and how program spending specifically impacts the reliability and quality of service are desirable under the RRFE. However, as the RRFE is relatively new, the OEB does not expect all such measures to be implemented at once….

In the absence of these parameters, Toronto Hydro's rates have been set based on the OEB's assessment of Toronto Hydro's historic expenditures, and the OEB's expectations with respect to improved productivity informed by the external benchmarking evidence of the expert witnesses for OEB staff and Toronto Hydro.[18]

The OEB cut Toronto Hydro's proposed capex budget by 10% annually for the Custom IR term, without specifying which proposed components were disallowed. Toronto Hydro was urged to find efficiencies during the term of the Custom IR plan. The OEB also expected Toronto Hydro to show improvements in reliability metrics due to increased capex and to provide evidence on the relationship between capital investments and reliability performance at its next rebasing.

The Toronto Hydro Custom IR decision also provided general commentary on what the Board expected Custom IR plans to entail:

The Custom IR is described in the [Renewed Regulatory Framework for Electricity (RRFE)] as a suitable choice for distributors with large or highly variable capital requirements. However, this is an example, not a condition precedent, and the OEB will not make a decision as to whether it is the best option for any particular distributor. **The custom option in the policy allows for proposals that are tailored to a distributor's needs as well as for innovative proposals intended to align customer and distributor interests**.[19] [Emphasis added]

[18] EB-2014-0116, OEB Decision and Order, Toronto Hydro-Electric System Limited, December 29, 2015, p. 6-7.

[19] *Ibid*., p. 4.

Presumably then, the OEB is open to further innovations in the design of Custom IRs intended to align customer and utility interests. The OEB further stated that:

> [a] Custom IR, unlike other rate setting options in the RRFE, does not include a predetermined formulaic approach to annual rate adjustments, it does not automatically trigger a financial incentive for distributors to strive for continuous improvement. The OEB expects that Custom IR applications will include features that create these incentives in the context of the distributor's particular business environment.[20]

2.5 Hydro One Distribution's Recent IR Proceeding

Several aspects of the OEB's recent decision on Hydro One Distribution's Custom IR plan also suggest a wariness on the part of the Board with respect to multiyear capex forecasts and the related C factor. The Board disallowed $300 million (about 8.4%) of Hydro One Distribution's capex forecast.

In addition, the OEB ordered Hydro One Distribution to provide reports on various issues to show that the forecasts and expected efficiency gains it approved in this proceeding had been realized. For example, Hydro One Distribution was asked to report at the next rebasing on the actual performance of the capital program relative to the approved plan and improvements in performance in benchmarked areas (e.g., pole replacement) which resulted from discussing best practices with better performing peers. Hydro One Distribution was also ordered to report on the achievement of forecasted productivity savings.

The OEB also adopted an additional 0.15% stretch factor to apply solely to Hydro One Distribution's C-factor beyond the 0.45% stretch factor applied to the entire revenue requirement. This decision was made in part due to the OEB's concern that forecasted capex was causing rate base to grow more rapidly than inflation and in part to "incent further productivity improvements throughout the term, and to provide customers the benefit from these additional improvements upfront."[21] The OEB was also influenced by Hydro One Distribution's prior capital overspending and comments by OEB Staff's expert witness that the C Factor led to perverse incentives for companies to spend excessive amounts on capital to contain OM&A expenses.

[20] *Ibid*., p. 5.

[21] *Ibid*., p. 32.

3. Critique of PSE's Research and Testimony

3.1 U.S. Power Transmission Productivity

PSE Study

PSE calculated the transmission productivity trends of Hydro One and 47 U.S. electric utilities over the twelve-year 2005-2016 period. A **-1.45**% average annual multifactor productivity growth trend was reported for the sampled transmitters over this period. Annual growth in OM&A productivity growth averaged -1.11% while capital productivity growth averaged -1.48%.

Growth in output was calculated using a multidimensional index with two scale variables: line length and ratcheted maximum peak demand.[22] The weights for these variables were obtained from an econometric model of total power transmission cost which PSE developed with data for 57 utilities for the 2004-2016 period. The weight for line length was 37% whereas the weight for peak demand was 63%.

Capital cost was measured using a variant of the geometric decay method in which capital gains were not considered.[23] The benchmark year in the capital cost computation was 2002 for Hydro One and 1989 for the sampled U.S. transmitters.

PEG Critique

Our examination of PSE's productivity research raised several concerns. To facilitate the Board's review of the numerous and often complicated issues that arise in productivity studies, we first highlight our chief concerns with PSE's methodology. There follows a brief discussion of some of our other concerns.

Chief Concerns

Sample Period A twelve-year sample period is fairly short for an X factor calibration study, and it is good practice to report results for a longer period when the practitioner favors a short period. Our

[22] The term ratcheted peak demand means that the value of the variable equals the highest monthly peak demand that has yet been attained during the sample period. This variable is a reasonable proxy for the expected maximum possible peak demand for grid services.

[23] Geometric decay and other monetary methods for calculating capital costs, prices, and quantities are discussed in Appendix Section A.2.

major concern with the 2005-2016 sample period, however, is that U.S. transmission productivity growth was strongly influenced during these years by special circumstances that included policy initiatives of the U.S. government. These initiatives included ROE premia for some kinds of transmission assets and FERC oversight over reliability standards that caused transmitters to incur Critical Infrastructure Protection ("CIP") costs. A related concern is that a large and growing number of the sampled transmitters operated under formula rate plans administered by the FERC during PSE's sample period. These plans feature comprehensive cost trackers that weakened transmitter cost containment incentives.

Transmission capex was also boosted during this period by the need to improve the functioning of bulk power markets and to access remote renewable resources whose development was encouraged by federal tax policy and state renewable portfolio standards. In addition to the fact that the slowdown in productivity growth due to CIP standards may be temporary, Hydro One may seek to Z factor any qualifying incremental CIP costs it incurs during the proposed plan term, or request incremental capital revenue by other means.

PSE makes no claim in its evidence that productivity results for its chosen sample period are particularly suitable for Hydro One during the term of the proposed plan. The reasons for negative MFP growth in the U.S. during its chosen sample period may be very different from the challenges that the Company faces. In response to OEB staff interrogatory 68 in the Hydro One SSM proceeding, PSE stated that it is uncertain about the drivers of negative productivity growth during this period, and that formula rate plans are widely used by U.S. transmitters and weaken their incentives.

The 2004 start date of PSE's sample period was ostensibly chosen due to the fact that this is the first year that data are available for a peak demand variable that PSE used in its econometric model and output index. PSE relied on the Monthly Transmission System Peak Load data reported on page 400 of the FERC Form 1. These data were first reported for 2004. We believe that it is reasonable to instead rely on the monthly peak load data, reported on page 401b of FERC Form 1, to construct the ratcheted peak demand variable. These alternative data are available for a longer sample period. Another concern we have about the data PSE used is that some companies misreported their peak load.[24]

Structural Change PSE's treatment of OM&A expenses does not handle structural change in the U.S. transmission industry well. As discussed further in Appendix C, many U.S. electric utilities joined independent system operators or regional transmission organizations in the last twenty years. These agencies performed some of the functions that the utilities had previously undertaken. Many utilities in the sample began purchasing a wide range of transmission services from these agencies, and this materially affected the reported costs of some companies.

Capital Cost Specification Our biggest concern about PSE's capital cost specification is that only capital cost data back to 1989 were employed for the sampled U.S. utilities even though the requisite data are available back to 1964 or earlier. Capital cost data for Hydro One are available only since 2002.[25] A failure to use older capital cost data can materially reduce the accuracy of capital cost and quantity estimates, as we discuss further in Appendix Section A.2.

3.2. Hydro One's Transmission Cost Performance

PSE Research

PSE also presented evidence on the transmission cost performance of Hydro One. It calculated the transmission MFP trend of Hydro One over the 2005-2016 period and the MFP trend that is implicit in the Company's forecasted/proposed costs from 2017 to 2022. Over the full historical sample period, the Company's -0.18% average annual multifactor productivity growth was considerably more positive than that which PSE reported for the full sample. OM&A productivity averaged 1.21% growth, while capital productivity averaged -0.45% annual growth. Over the 2021-2022 period during which the RCI would be operative under its proposed plan, the Company's forecasted/proposed costs would produce -1.70% annual MFP growth. OM&A productivity would average 0.11% annual growth while capital productivity would average -1.93% growth.

[24] For example, the Southern Company operating utilities reported the peak demand for the entire transmission system peak of these companies rather than at the individual operating company level. PSE has estimated the values for these companies.

[25]Hydro One apparently does not have plant value data that would permit an earlier benchmark year. We understand that this is due in part to historical circumstances beyond the Company's control.

PSE used its econometric transmission cost model to benchmark the total transmission cost of Hydro One, producing favorable results. The Company's cost was a substantial 21.8% below its econometric cost model's prediction on average over the three most recent years for which historical data were available (2014-2016). The Company's forecasted/proposed total cost is an even more favorable 27.1% below the model's predictions during the three years of the proposed plan.

PEG Critique

Our review of PSE's research on Hydro One's transmission services prompted several concerns. Here are the most important ones:

- The relatively short sample period of the econometric work unnecessarily reduces the precision of the econometric model parameter estimates.
- The particular sample period chosen is also likely to produce an inappropriately negative value for the trend variable parameter. The estimated value of this parameter is 0.012. This effectively permits benchmarked cost to grow by a substantial 1.2% annually for reasons other than changes in the values of the model's business condition variables.
- Parameter estimates are also degraded by the failure to use available older data in the U.S. capital cost calculations.
- Due to data limitations beyond the control of PSE, capital cost data are available for Hydro One only since 2002. This reduces the accuracy of total cost benchmarking and multifactor productivity results for the Company, especially in the early years of the sample period.
- We do not object in principle to the use of a weather-related construction standards index but note that it is an example of developing a variable to address a special cost disadvantage of the Company when special cost advantages could be ignored. Moreover, the accuracy of the calculation of the value for Hydro One is critically important, and we believe that PSE has misstated Hydro One's value. PSE conceded in its response to Staff IR 59 in the Hydro One SSM proceeding that

> Complete mapping of transmission lines in Canada and the United States is not publicly available. Therefore, for constructing this variable, PSE used the Hydro One Networks' retail service territory as a proxy for its transmission service territory.[26]

This assumption is problematic for Hydro One given that the Company claims a retail service territory that is the land area of Ontario that is unserved by other electric power distributors. This has the effect of including the northern reaches of Ontario, where Hydro One provides neither transmission nor distribution services.[27] These areas include much of the zones CSA Medium A and CSA Heavy located in Northern Ontario.

Review of the data for this variable is complicated by the limited transparency provided by PSE in the construction of this variable. For example, while PSE provided the values for each transmitter in its working papers, PSE did not provide the mapping data and underlying calculations to substantiate these values.

- The calculations do not use Ontario inflation indexes. Instead, PSE used U.S. inflation indexes adjusted for changes in the purchasing power parity ("PPP") between the U.S. and Canada. For example, the Handy Whitman Index of power transmission construction costs in the North Atlantic region of the United States was used to deflate the plant values of Hydro One. We believe that Canadian input price trend indexes such as the implicit capital stock deflator for the Canadian utility sector are more appropriate for Hydro One. PSE also used a U.S. employment cost index when the AWE of Ontario workers is readily available. The US gross domestic product price index was used as a proxy for trends in material and service ("M&S") prices when numerous macroeconomic Canadian price indexes are available.
- PSE forecasts that Hydro One's OM&A expenses will grow by forecasted OM&A price inflation. Since the Company's output growth is expected to be near zero, this implies 0% OM&A productivity growth. However, PSE calculated a 1.11% average annual decline in the OM&A productivity of sampled transmitters. This rosy scenario improves Hydro One's total cost

[26] EB-2019-0218, Exhibit I, Tab 1, Schedule 59, p. 4.

[27] This may somewhat offset the exclusion of areas in Ontario that are served by other power distributors in the CSA Heavy zone that borders much of the Great Lakes in southern Ontario.

performance score and reduces its potential stretch factor without involving any real commitment on the Company's part or benefits to customers.

Here are some less important but nonetheless notable concerns that we have with PSE's cost performance research for this proceeding.

- Only Toronto values were used to levelize the Company's construction cost index even though much of the transmission system is located far from Toronto.
- The levelization of the capital price is applied to the wrong year, as Mr. Fenrick conceded in the Hydro One technical conference.
- The 1.65 value for the declining balance parameter which PSE used to calculate the rate of decay for the capital quantity index formula was appropriate for transmission *equipment* but not for transmission *structures*.
- Only Handy Whitman indexes for *transmission* plant were used to calculate capital price and quantity trends even though a material portion of the assets in the calculations are *general* plant.

4. Alternative Empirical Research by PEG

4.1 Benefits of U.S. Data

Most power transmission in the United States is provided by investor-owned electric utilities ("IOUs").[28] These utilities usually also provide distribution services and some also provide generation services. The division between the transmission and distribution systems varies somewhat across the industry.

U.S. data have several advantages in transmission cost and productivity research.

- The federal government has gathered detailed, standardized data for decades on the operations of dozens of IOUs that provide transmission services. These services are broadly similar to those provided by Hydro One.
- IOU cost data are credibly itemized, permitting calculations of the cost of transmission services even for vertically integrated utilities.
- PEG has gathered data on the net value of plant in 1964 and the corresponding gross plant additions since that year. Custom indexes are available on trends in the costs of transmission and general plant construction. These advantages make U.S. data the best in the world for accurate calculation of the consistent capital cost, price, and quantity indexes that are needed to appraise the capital cost and total cost performances of power transmitters.

In contrast, data on the transmission operations of utilities in the various provinces of Canada are not standardized. Consistent data on transmission capital costs are available for numerous years in only a few provinces, and even in these provinces are generally not available before 2000. PSE invited nine Canadian transmission utilities to participate in its study for Hydro One but none complied.

4.2 Data Sources

The source of data on the transmission cost, transmission system scale, and peak demand of U.S. electric utilities which we used in our empirical research was FERC Form 1. Data reported on Form

[28] Some federal and municipal utilities and rural electric cooperatives also provide power transmission services.

1 must conform to the FERC's Uniform System of Accounts. Selected Form 1 data were for many years published by the U.S. Energy Information Administration ("EIA").[29] More recently, these data have been available electronically in raw form from the FERC, and in more processed forms from commercial vendors such as SNL Financial.[30]

Data on U.S. salary and wage prices were obtained from the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor. The gross domestic product price index ("GDPPI") that we used to deflate M&S expenses of U.S. transmitters was calculated by the Bureau of Economic Analysis of the U.S. Department of Commerce. Data on the *levels* of heavy construction costs in various U.S. and Ontario locations were obtained from RSMeans. Data on U.S. electric utility construction cost *trends* were drawn from the *Handy Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates. Some of the business condition variables we used in our econometric cost model were obtained from PSE working papers.

4.3 Sample

Data for Hydro One and 43 U.S. transmitters were used in our productivity research. Data for Hydro One and 52 U.S. transmitters were used in our econometric research.[31] A larger sample is possible for the econometric work because a balanced panel (i.e., one with the same number of observations for each company) is not required. Table 1 provides a list of the sampled utilities.

The sample period for our econometric cost research was 1995-2016. The full sample period for our productivity research was 1996-2016. The additional years of data increase the precision of the econometric parameter estimates and produce results that are less sensitive to the unusual operating environment that transmitters in the States encountered after 2005.

[29] This publication series had several titles over the years. The most recent title is *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*.

[30] PSE evidently used SNL Financial data in its research.

[31] PEG excluded several companies from the sample that PSE used due to data problems. Reasons for these exclusions are provided in Appendix B.4.

Table 1
Sample of Utilities Used in PEG's Alternative Cost Research

Alabama Power
ALLETE (Minnesota Power)
Arizona Public Service
*Atlantic City Electric
Avista
*Baltimore Gas & Electric
Central Hudson Gas & Electric
*Central Maine Power
Cleco Power
Commonwealth Edison
Connecticut Light & Power
Consolidated Edison of New York
*Delmarva Power & Light
Duke Energy Carolinas
*Duke Energy Florida
Duke Energy Indiana
Duke Energy Ohio
Duke Energy Progress
Duquesne Light
El Paso Electric
Empire District Electric
Florida Power & Light
Gulf Power
Hydro One Transmission
Idaho Power
Indianapolis Power & Light
*Jersey Central Power & Light
Kansas City Power & Light
Kansas Gas & Electric
Kentucky Utilities
Louisville Gas & Electric
Mississippi Power
Monongahela Power
New York State Electric & Gas
*Niagara Mohawk Power
Northern States Power - Minnesota
Oklahoma Gas & Electric
*Orange & Rockland Utilities
Pacificorp
PECO Energy
Potomac Electric Power
Public Service Company of Colorado
*Public Service Electric & Gas
Rochester Gas & Electric
San Diego Gas & Electric
South Carolina Electric & Gas
Southern California Edison
Southern Indiana Gas & Electric
Southwestern Public Service
Tampa Electric Company
Tucson Electric Power
Union Electric
West Penn Power

*This company is in the econometric sample but not the TFP Sample.

4.4 Variables Used in the Research

Costs

The main task of a power transmitter is the long distance transmission of power. This is done at high voltage to reduce line losses. Transmitters typically own and operate substations that reduce the voltage of the power they carry before it is delivered to distribution systems. Many transmitters also own substations that increase the voltage of power received from generators. The principal assets used in transmission are high-voltage power lines, the towers and underground facilities that carry them, and substations. Other notable transmission assets include circuit breakers and land.

The cost of power transmission considered in our study was the sum of applicable capital costs and OM&A expenses. The capital costs we included were those for transmission plant and a sensible share of the cost of general plant. We employed a monetary approach to capital cost, price, and quantity measurement which featured a geometric decay specification. Capital cost was the sum of depreciation expenses and a return on net plant value.[32]

The OM&A expenses we used in the study included most of those reported for power transmission, along with a sensible share of many reported administrative and general expenses. We excluded some categories of transmission OM&A expenses out of concern that those of many sample utilities have been affected by independent system operators and regional transmission organizations as to compromise their comparability and exogenous character. The categories excluded on this basis are: transmission by others (account 565), load dispatching (accounts 561-561.8), maintenance of miscellaneous regional transmission plant (569.4) and miscellaneous transmission expenses (566).

Pension and other benefit expenses were also excluded from this study. One reason is that these expenses are sensitive to volatile external business conditions such as stock prices. In Canada, an additional problem with including pension and benefit expenses is the lack of federal labor price indexes that encompass them along with salaries and wages. The health insurance obligations of U.S. and Canadian utilities can differ considerably. Hydro One proposes to Y factor pensions and other post-employment benefits. Pension and benefit expenses are often excluded from statistical cost performance studies. We also excluded from this study all reported taxes and the OM&A expenses incurred by the utilities for power generation, procurement, regional market activities, distribution, customer accounts, customer service and information, sales, franchise fees, and gas services.

[32] General issues in the measurement of capital cost are discussed in Appendix section A.2. Details of our capital cost calculations are provided in Appendix section B.1.

Input Prices

OM&A

Summary OM&A input price indexes were used in our research which featured subindexes for labor and materials and services.[33] We used PSE's Ontario and U.S. price levels for salaries and wages. Values of each U.S. company's labor price index for other years were calculated by adjusting these levels for changes in regionalized indexes of employment cost trends for the utilities sector of the economy. These indexes were constructed from BLS Employment Cost Indexes. For Hydro One, we escalated the salary and wage price level using the $AWE^{Ontario}$ industry time series reported by Statistics Canada.

For M&S price inflation in the United States we used the U.S. GDPPI. This is the U.S. government's featured index of inflation in prices of the economy's final goods and services. Final goods and services include business equipment and exports as well as consumer products. For the M&S price inflation of Hydro One we used Statistics Canada's $GDPIPIFDD^{Canada}$.

In our econometric work the summary OM&A input price indexes used fixed 38% labor/62% M&S weights that were calculated by PSE using data from its benchmarking sample. For our U.S. productivity research, we instead used company-specific, time-varying cost share weights that we calculated from FERC Form 1 OM&A expense data.

Capital

Asset price indexes and rates of return on capital are required in the capital cost research. For the U.S. utilities we calculated 50/50 averages of rates of return for debt and equity.[34] For debt we used the embedded average interest rate on long-term debt of a large group of electric utilities as calculated from FERC Form 1 data. For equity we used the average allowed ROE approved in electric utility rate cases as reported by the Edison Electric Institute.[35] For Hydro One Networks, we employed the weighted average cost of capital that PSE used in its study.

[33] The formulas for our input price indexes are discussed further in Appendix B.1.

[34] This calculation was made solely for the purpose of measuring productivity *trends* and benchmarking cost performance and does not prescribe appropriate rate of return *levels* for utilities.

[35] The Edison Electric Institute is the principal trade association of U.S. electric utilities. The ROE data we used in the study were drawn from the backup data to the *EEI Rate Case Summary* quarterly reports.

As transmission asset price trend indexes for U.S. utilities we used the regional Handy Whitman Indexes of Public Utility Construction Costs for Total Transmission Plant. As general plant asset price indexes we used the Handy Whitman Indexes of Public Utility Construction Costs for reinforced concrete building construction. As an asset price trend index for Hydro One we used Statistics Canada's implicit capital stock deflator for the utility sector of Canada. Statistics Canada includes in the utility sector power generation and transmission, gas distribution, and water and sewer utilities as well as power distribution.

Multifactor

The summary multifactor input price indexes that we used in the econometric research were constructed for each transmitter by combining the capital and summary OM&A price indexes using company-specific, time-varying cost share weights.

U.S./Canada Price Patch

Since U.S. and Canadian cost data were used in the study, it was necessary to make some adjustments for differences in currencies in the two countries. M&S prices were patched using US/Canadian purchasing power parities computed by the Organization for Economic Cooperation and Development ("OECD"). Construction and labor price indexes did not require a special patch.

Output Variables

Two output (aka scale) variables were used in our econometric cost model: length of transmission line and ratcheted maximum peak demand. The line length data were drawn from Transmission Line Statistics on page 422 of FERC Form 1. To construct the ratcheted peak demand variable we used the monthly peak load data found on page 401b of the FERC Form 1 rather than the peak transmission demand data on which PSE relied.[36] Our econometric research revealed that a ratcheted peak demand variable constructed using these data had better explanatory power than the variable used by PSE.

[36] An idiosyncrasy of these alternative demand data is that they do not include non-requirements sales for resale. The requirement sales for resale that are included are contractually firm enough that the party receiving the power is able to count on it for system capacity resource planning. Non-requirements sales for resale do not meet this standard and include economy energy. The load associated with non-requirements sales for resale can be shed in times of capacity constraints.

We followed PSE's practice of according the two scale variables in our model a translog treatment by adding quadratic and interaction (aka "second-order") terms for these variables to the econometric cost model. No second-order terms were included in this model for the other variables in the model. Functional form issues are discussed further in Appendix Section B.2.

Other Business Condition Variables

Five other business condition variables were included in our econometric cost model. Three of these variables address characteristics of the transmission system. These are substation capacity per substation, the average voltage of transmission lines, and the share of assets overhead.[37] We expect the parameters of the first two to have positive signs, while the parameter for the last variable should have a negative sign. The model also includes the construction standards index for transmission tower construction which PSE developed and the share of transmission plant in the utility's non-general gross plant value. The latter variable should indicate the extent to which the utility was unable to realize economies of scope from the joint provision of transmission and distribution (and in some cases generation) services. We expect both of these variables to have positive parameter estimates.

Our model also contains a trend variable. This permits predicted cost to shift over time for reasons other than changes in the specified business conditions. Trend variables thereby capture the net effect on cost of diverse conditions, such as technical change, which are otherwise excluded from the model. Parameters for such variables often have a negative sign in econometric research on utility cost. However, the expected value of the trend variable parameter in a cost model is *a priori* indeterminate.

4.5 Econometric Results

We used the assembled data to develop an econometric model of the total cost of power transmission. The dependent variable in this research was *real* total cost: the ratio of total cost to the multifactor input price index. This specification enforces a key result of cost theory.[38]

[37] The extent of transmission plant overheading was measured as the share of overhead plant in the gross value of transmission conductor, device, and structure (pole, tower, and conduit) plant. System overheading typically involves lower capital costs. Since transmission is a capital-intensive business, high overheading should lower total cost.

[38] Theory predicts that 1% growth in a multifactor input price index should produce 1% growth in cost.

Results of our econometric work are reported in Table 2. This table includes parameter estimates and their associated asymptotic t-statistics and p-values. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. These significance tests were used in model development.

Examining the results in the table, it can be seen that the parameters of the business condition variables have sensible signs and parameter values.[39] Our research indicates that transmission costs tended to be higher to the extent that sampled utilities had:

- higher ratcheted maximum peak demand
- longer and higher voltage transmission lines
- more substation capacity per substation
- more transmission facilities underground
- transmission plant that constituted a larger share of total non-general plant
- higher construction standards.

The parameter estimates for the scale variables suggest that ratcheted peak demand had an estimated long-run cost elasticity of 0.571% whereas the estimated cost elasticity of transmission line length was 0.492%. The parameter estimate for the trend variable suggests that transmission cost tended to *fall* over the full sample period by about 0.6% annually for reasons that aren't explained by the business condition variables in the model. The adjusted R-squared for the model is 0.948.

4.6 Productivity Research

Methodology

We calculated indexes of the OM&A, capital, and multifactor transmission productivity of Hydro One and each U.S. utility in our sample. The annual productivity growth rate of each transmitter was calculated as the difference between the growth of its output and input quantity indexes. Cost-

[39] This remark pertains to the “first” order terms in the model, and not to the parameters of the second-order (quadratic and interaction) terms.

Table 2

PEG's Alternative Econometric Model of Transmission Total Cost

VARIABLE KEY

YL =	Kilometers of transmission line
D =	Ratched maximum peak demand
MVA =	Substation capacity per substation
VOLT =	Average voltage of transmission line
CS =	Construction standards index
PCTPOH=	Percent of transmission plant that is overhead
PCTPTX =	Percent of transmission plant in total plant
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YL	0.492	26.154	0.000
YL * YL	0.402	14.499	0.000
YL * D	-0.207	-8.447	0.000
D	0.571	30.634	0.000
D * D	0.243	7.307	0.000
MVA	0.044	2.350	0.019
VOLT	0.063	2.076	0.038
CS	0.238	5.239	0.000
PCTPOH	-0.395	-8.340	0.000
PCTPTX	0.140	10.538	0.000
Trend	-0.006	-7.270	0.000
Constant	12.173	695.103	0.000

Adjusted R^2	0.948
Sample Period	1995-2016
Number of Observations	1,127

weighted averages of these growth rates were then calculated. Cost weighting makes particular sense when calibrating the X factor of a large utility like Hydro One.

The growth rates of our output indexes were weighted averages of the growth in line kilometers and ratcheted maximum peak demand. The estimated cost elasticities for these two variables from our econometric research were used to establish weights. The weights were about 54% for ratcheted maximum peak demand and 46% for line length.

In calculating input quantity indexes for the U.S. utilities we broke down their applicable cost into those for transmission capital, general capital, labor, and M&S inputs. Each of these input groups had its own quantity subindex. The trend in each company's multifactor input quantity index was a weighted average of the trends in the four subindexes. The weights on these indexes were company-specific and time-varying. We also calculated summary OM&A and capital quantity indexes. The calculation of the input quantity trend for Hydro One instead used a single, consolidated capital quantity index for transmission and general plant.

Industry Trends

Table 3 reports results of our productivity calculations for the full sample. We found that the growth in the transmission MFP of sampled U.S. utilities averaged **-1.47**% over PSE's chosen 2005-2016 sample period but a more positive **-0.25**% over our full 1996-2016 sample period, during which the effects of formula rates and other recent changes in the U.S. transmission business were less pronounced. OM&A productivity growth averaged -1.64% over PSE's sample period but -0.69% over our full period. Capital productivity growth averaged -1.45% over PSE's sample period but -0.19% over our full period.

Our estimates of transmission output do not reflect any possible improvements in U.S. transmission reliability or bulk power market performance. Reliability is treated as an output variable in transmission productivity research commissioned by the Australian Energy Regulator. PSE acknowledged in response to OEB staff interrogatory #63 that reliability can be an output in a productivity study. [40]

[40] EB-2018-0218, Exhibit I/Tab 1/Schedule 63. The OEB adopted the evidentiary record from EB-2018-0218 into the current proceeding, by way of its letters of June 28 and July 4, 2019.

Table 3

U.S. Transmission Productivity Results Using PEG's Methods: Cost-Weighted Averages

(Growth Rates)[1]

Year	Output Quantity Index	Input Quantity Index: OM&A	Input Quantity Index: Capital: Transmission	Input Quantity Index: Capital: General	Input Quantity Index: Capital: Capital Summary	Input Quantity Index: Multifactor	Productivity: OM&A	Productivity: Capital: Transmission	Productivity: Capital: General	Productivity: Capital: Capital Summary	Productivity: Multifactor
1996	1.13%	-0.27%	-0.43%	0.60%	-0.39%	-0.30%	1.39%	1.56%	0.53%	1.52%	1.43%
1997	0.81%	0.63%	-0.51%	-4.34%	-0.58%	-0.71%	0.18%	1.32%	5.15%	1.39%	1.53%
1998	1.39%	0.72%	-1.21%	2.68%	-1.12%	-0.72%	0.67%	2.61%	-1.29%	2.51%	2.11%
1999	1.33%	-5.87%	-1.23%	-2.59%	-1.28%	-1.48%	7.20%	2.56%	3.92%	2.61%	2.81%
2000	0.58%	6.36%	-0.68%	7.64%	-0.50%	0.10%	-5.78%	1.26%	-7.06%	1.08%	0.48%
2001	1.63%	0.39%	-0.27%	14.22%	0.02%	0.04%	1.25%	1.90%	-12.59%	1.61%	1.60%
2002	0.54%	-4.40%	-0.06%	-6.67%	-0.09%	-0.60%	4.93%	0.60%	7.20%	0.63%	1.14%
2003	1.50%	3.46%	-0.36%	1.32%	-0.31%	0.04%	-1.96%	1.86%	0.18%	1.82%	1.46%
2004	0.45%	3.15%	0.18%	1.93%	0.19%	0.65%	-2.70%	0.27%	-1.49%	0.25%	-0.20%
2005	2.34%	6.81%	0.41%	2.35%	0.43%	1.20%	-4.47%	1.93%	-0.01%	1.91%	1.14%
2006	1.63%	1.74%	0.46%	-2.27%	0.43%	0.69%	-0.11%	1.17%	3.91%	1.21%	0.94%
2007	1.02%	5.27%	1.16%	-2.43%	1.07%	1.59%	-4.25%	-0.14%	3.45%	-0.05%	-0.57%
2008	0.45%	3.73%	1.15%	3.15%	1.18%	1.36%	-3.28%	-0.70%	-2.69%	-0.73%	-0.91%
2009	-0.20%	3.18%	2.27%	1.08%	2.24%	2.45%	-3.38%	-2.47%	-1.28%	-2.44%	-2.64%
2010	0.64%	5.83%	1.69%	-0.73%	1.60%	2.31%	-5.19%	-1.06%	1.36%	-0.96%	-1.67%
2011	0.33%	-0.07%	2.31%	0.92%	2.24%	1.86%	0.41%	-1.98%	-0.58%	-1.90%	-1.52%
2012	0.60%	0.30%	1.68%	5.11%	1.68%	1.26%	0.29%	-1.09%	-4.52%	-1.08%	-0.66%
2013	0.25%	2.59%	4.02%	7.73%	4.03%	3.86%	-2.34%	-3.77%	-7.48%	-3.78%	-3.61%
2014	0.79%	-2.39%	3.75%	-0.37%	3.69%	3.10%	3.18%	-2.96%	1.17%	-2.90%	-2.30%
2015	0.62%	-2.80%	4.01%	2.49%	4.01%	3.08%	3.42%	-3.39%	-1.87%	-3.39%	-2.46%
2016	-0.14%	3.88%	3.17%	7.04%	3.21%	3.28%	-4.02%	-3.31%	-7.18%	-3.35%	-3.42%
Average Annual Growth Rates											
1996-2016	**0.84%**	**1.54%**	**1.02%**	**1.85%**	**1.03%**	**1.10%**	**-0.69%**	**-0.18%**	**-1.01%**	**-0.19%**	**-0.25%**
2005-2016	**0.70%**	**2.34%**	**2.17%**	**2.01%**	**2.15%**	**2.17%**	**-1.64%**	**-1.48%**	**-1.31%**	**-1.45%**	**-1.47%**

[1]All growth rates are calculated logarithmically.

Hydro One Networks' Trends

Table 4 reports results of our transmission productivity calculations for Hydro One. Over the full 2005-2016 sample period for which Hydro One's historical data are available, the Company's annual multifactor productivity growth averaged -1.17% while its OM&A productivity growth averaged 0.83% and its capital productivity growth averaged -1.67%. The accuracy of the capital and multifactor productivity results for Hydro One is reduced by the unavailability of older capital cost data.

Over the two out years of the proposed plan (2021-2022), the Company's forecasted/proposed costs are consistent with -2.53% average multifactor productivity growth, 0.11% OM&A productivity growth, and -2.94% capital productivity growth. The Company's forecasted/proposed costs thus reflect

Table 4

Hydro One's Transmission Productivity Growth

(Growth Rates)[1]

Year	Output Quantity Index	Input Quantities OM&A	Input Quantities Capital	Input Quantities Multifactor	Productivity OM&A	Productivity Capital	Productivity Multifactor
2005	1.43%	-9.42%	0.32%	-1.80%	10.85%	1.11%	3.23%
2006	1.88%	10.14%	-0.22%	2.06%	-8.26%	2.10%	-0.18%
2007	0.00%	10.51%	1.46%	3.62%	-10.51%	-1.46%	-3.62%
2008	0.08%	-15.01%	0.32%	-3.24%	15.09%	-0.24%	3.32%
2009	-0.01%	11.84%	2.49%	4.56%	-11.85%	-2.50%	-4.57%
2010	0.04%	-1.38%	3.87%	2.69%	1.42%	-3.83%	-2.65%
2011	0.04%	-4.07%	3.01%	1.48%	4.11%	-2.97%	-1.44%
2012	0.44%	0.19%	5.68%	4.54%	0.24%	-5.24%	-4.10%
2013	0.03%	2.30%	1.52%	1.68%	-2.27%	-1.50%	-1.65%
2014	-0.05%	-11.22%	2.77%	0.09%	11.17%	-2.82%	-0.14%
2015	0.15%	9.92%	0.71%	2.43%	-9.78%	-0.57%	-2.28%
2016	0.00%	-9.69%	2.14%	-0.03%	9.69%	-2.14%	0.03%
2017	-0.58%	-5.26%	1.77%	0.57%	4.68%	-2.35%	-1.15%
2018	0.61%	-1.97%	3.25%	2.40%	2.58%	-2.64%	-1.78%
2019	0.00%	-16.81%	1.78%	-0.99%	16.82%	-1.77%	1.00%
2020	0.00%	4.06%	2.03%	2.31%	-4.06%	-2.03%	-2.31%
2021	0.01%	-0.10%	3.13%	2.69%	0.10%	-3.12%	-2.68%
2022	0.01%	-0.10%	2.77%	2.38%	0.11%	-2.76%	-2.37%
Average Annual Growth Rates							
2005-2016	**0.34%**	**-0.49%**	**2.01%**	**1.51%**	**0.83%**	**-1.67%**	**-1.17%**
2012-2016	**0.11%**	**-1.70%**	**2.57%**	**1.74%**	**1.81%**	**-2.45%**	**-1.63%**
2021-2022	**0.01%**	**-0.10%**	**2.95%**	**2.53%**	**0.11%**	**-2.94%**	**-2.53%**

[1]All growth rates are calculated logarithmically.

OM&A productivity growth that is well above industry norms but capital productivity growth that is well below industry norms.

4.7 Cost Benchmarking Results

We used our econometric transmission cost model to benchmark the total transmission cost of Hydro One. In this exercise we used PSE's forecasts for growth in input prices. Due to unavailability of older capital cost data, results will tend to be more accurate in the later years.

Results of our benchmarking work are presented in Table 5. It can be seen that the Company's transmission cost performance began a steady decline after 2008. Its cost was about 2.1% below the model's prediction on average from 2014 to 2016, the three most recent historical years for which data for all required variables were available. The Company's forecasted/proposed total costs are about 9.0% above the model's prediction on average during the three years of its proposed IR plan (2020-2022).

Table 5

Transmission Total Cost Performance of Hydro One Using PEG's Econometric Model

[Actual - Predicted Cost (%)][1]

Year	Cost Benchmark Score
2004	-20.5%
2005	-23.3%
2006	-22.5%
2007	-19.5%
2008	-21.4%
2009	-18.0%
2010	-15.7%
2011	-12.9%
2012	-10.4%
2013	-4.8%
2014	-4.9%
2015	-0.4%
2016	-0.9%
2017	1.5%
2018	2.5%
2019	3.5%
2020	6.2%
2021	8.7%
2022	12.0%
Average 2004-2016	**-13.5%**
Average 2014-2016	**-2.1%**
Average 2020-2022	**9.0%**

1 Formula for benchmark comparisons is $\ln(Cost^{HON}/Cost^{Bench})$.

5. X Factor Recommendations

5.1 Base Productivity Trend

We believe that the **-0.25**% trend in the MFP of the U.S. power transmission industry which we calculated for our full 1996-2016 sample period is a reasonable base productivity trend for Hydro One.

5.2 Stretch Factor

We disagree with PSE's 0.0% stretch factor recommendation, which is based on the contentions that an explicit stretch factor is not warranted given Hydro One's superior cost performance and that there is a large implicit stretch factor in the 0.0% base productivity trend. Here are the considerations we feel are pertinent for choosing a stretch factor.

- The Company's cost performance does not score as well in our study as in PSE's study. We found that the Company's forecasted/proposed total cost during the three years of the proposed plan would be 9.0% above our model's prediction on average. In 4GIRM this kind of cost benchmarking score is commensurate with a 0.3% stretch factor.
- Stretch factors should also reflect the difference between the incentive power of the proposed plan and the incentive power of the regulatory systems of companies in the productivity studies used to calibrate the stretch factor. The incentive power of the proposed plan is not strong due to the comparatively short three-year term, the ESM, and the capital cost trackers. On the other hand, the incentive power of U.S. transmission regulation was significantly weakened by the FERC's use of ROE premia and formula rate plans, particularly during PSE's shorter and more recent sample period.
- The MFP growth trend of the transmission industry is considerably more rapid (though still negative) using our alternative sample period and methods. PSE has not made a persuasive case as to why the unusually negative MFP growth of U.S. transmitters in recent years is applicable to Hydro One despite large differences in operating conditions.
- The RCI formula does not include a scale escalator to help fund output growth. On the other hand, the plan includes variance accounts for costs of major line extensions, and supplemental revenue for growth-related capex may also be obtained via the C factor.

Growth in the Company's output has been slow in recent years and this is expected to continue.

- Stretch factors linked to cost performance have the additional benefit of serving as efficiency carryover mechanisms that reward utilities for long-term cost savings and penalize them for their absence.

Balancing these considerations, we believe that a 0.30% stretch factor is reasonable for Hydro One.

5.3 X Factor

A -0.25% base productivity trend and a 0.30% stretch factor would produce a 0.05% X factor. This is the X factor that we recommend.

6. Other Plan Design Issues

The other provisions of Hydro One's proposed transmission Custom IR are in some respects uncontroversial. We have noted that the plan is similar to Custom IRs that the Board has approved for other utilities. We are nonetheless concerned about some features of Hydro One's proposal.

The proposed ratemaking treatment of capital is our chief concern. The C factor would ensure that the Company would recover almost all of its projected/proposed capital cost if it incurred this cost. Almost all of any cumulative capex underspend would be returned to the ratepayer. Several additional variance accounts and the Z factor would also address capex. Hence, capital revenue would chiefly be established on a cost of service basis.

Despite the proposed clawback of capex underspends, Hydro One would still have some incentive to exaggerate its capex needs, since exaggerations strengthen the case for a C Factor and reduce the pressure on the Company to contain capex. Exaggeration of capex needs may reduce the credibility of Hydro One's forecasts in future proceedings. However, the Company can always claim that it "discovered" ways to economize. British distributors operating under several generations of IR plans with revenue requirements based on cost forecasts have repeatedly spent less on capex than they forecasted. Hydro One would also be incentivized to "bunch" its deferrable capex in ways that increase supplemental revenue. If, for example, the Company could somehow manage to time its capex so that the $I – X$ escalation was compensatory, it would obtain no supplemental revenue.

The clawback of almost all capex underspends and the variance account and Z factor treatments of some kinds of capex would greatly weaken the Company's incentive to contain capex. Incentives to contain capex and OM&A costs would be imbalanced, creating a perverse incentive to incur excessive capex in order to reduce OM&A costs. The Company actually stated in its application that it needs to keep 2% of capex underspends

> to ensure alignment between the behaviours that are incented by the account and the outcomes that rate payers value. … Absent the 2% dead band, Hydro One is incented to fully spend 100% of its planned capital amounts and focus on identifying any additional productivity initiatives on OM&A programs where part of the savings can be kept by the utility.[41]

[41] Exhibit A, Tab 4, Schedule 1, p. 11.

The weak incentives to contain capex are inconsistent with the Board's Custom IR guidelines which, as we noted in Section 2.3, proscribe a multiyear cost of service approach, require "explicit financial incentives for continuous improvements and cost control targets," and beyond the stretch factors used in 4GIRM. This reality is all the more sobering when it is remembered that power transmission is an unusually capital-intensive business.

Another problem with the proposal is that while customers must fully compensate Hydro One for expected capital revenue *shortfalls* when capex is high for reasons beyond its control, the Company need not return any *surplus* capital revenue in future plans if capital cost growth is unusually slow for reasons beyond its control. Slow capital cost growth may very well occur in the future for reasons other than good cost management. For example, depreciation of recent and prospective surge capex will tend to slow future capital cost growth and accelerate productivity growth. Over multiple plans, the revenue escalation between rate cases would not guarantee customers the full benefit of the industry's multifactor productivity trend, even when it is achievable.

A related problem is that most of the capex addressed by the C factors, capital variance accounts, and Z factors would be similar in kind to that incurred by transmitters sampled in past and future productivity studies that are used to calibrate Hydro One's X factors.[42] The Company can then be compensated twice for the same capex: once via the C factor and then again by low X factors in past, present, and future IRMs.

Given the inherent unfairness to customers of asymmetrically funding capital revenue shortfalls, Hydro One's weak incentive to contain capex, and the Company's incentive to exaggerate capex requirements and bunch capex, stakeholders and the Board must be especially vigilant about the Company's capex proposal.[43] This raises regulatory cost. The need for the OEB to sign off on multiyear total capex proposals greatly complicates Custom IR proceedings and is one of the reasons why the Board now requires and reviews transmission business plans - a major expansion of its workload and that of stakeholders. Despite the extra regulatory cost, OEB staff and stakeholders will inevitably struggle to effectively challenge the Company's capex proposal. In essence, the OEB's Custom IR rules

[42] Hydro One would not, however, be compensated during the plan for capex overruns.

[43] Proposed programs that raise capex and reduce OM&A expenses merit especially close examination.

have sanctioned British (forecast-based) approaches to determining multiyear capital revenue requirements, without necessarily making the same investment that British (and Australian) regulators have made in the capability for appraising and ruling on multiyear capex proposals.[44]

Another concern is that the substantial compensation for capex funding shortfalls which has been permitted by the OEB under Custom IR may be more remunerative than that available under the ACMs and ICMs featured in 4GIRM. These modules feature materiality thresholds that include a markdown on capex eligible for supplemental revenue. If the markdowns under Custom IR and 4GIRM are imbalanced, utilities may choose Custom IR, with its weaker performance incentives and higher regulatory cost, even though compensatory operation under 4GIRM is feasible.

In pondering this quandary, the following remarks of the OEB in its decision approving Toronto Hydro's expiring Custom IR plan resonate.

> The record in this case is one of the largest that the OEB has ever seen. It is important to strike a balance between the amount of evidence necessary to evaluate the Application and the goal of striving for regulatory efficiency. It is important to note that it is not the OEB's role, nor the intervenors, to manage the utility or substitute their judgment in place of the applicant's management. That is the job of the utility. The OEB has established a renewed regulatory framework for electricity (RRFE) which places a greater emphasis on outcomes and less of an emphasis on a review of individual line items in an application.[45]

In light of these remarks, it seems desirable to consider how to make Custom IR more mechanistic, incentivizing, and fair to customers while still ensuring that it is reasonably compensatory over time for efficient utilities.

The Alberta Utilities Commission ("AUC") faced a similar challenge following an unhappy experience with capital cost trackers in their first-generation IR plans for provincial gas and electric power distributors. A number of possible reforms to the ratemaking treatment of capital were discussed in the AUC's generic proceeding on second-generation plans. The AUC eventually chose a means for providing supplemental capital revenue which was much less dependent on distributor capex forecasts. Regulatory cost was reduced thereby, and capex containment incentives were strengthened.

[44] Consider, for example, that Ofgem's own view of a power transmitter's required cost growth is assigned a 75% weight in contested IR proceedings. This view is supported by independent engineering and benchmarking.

[45] OEB, *Decision and Order*, EB-2014-0116, December 29, 2015, p. 2.

A "K-bar" value was established for each distributor for the first year of the plan based on the extent to its recent *historical* capex levels, adjusted for growth in inflation, X, and billing determinant growth, were not funded by base rates. K-bar values in subsequent years have been escalated by the growth in rate or revenue cap index. Capital cost trackers may be requested to provide supplemental funding for eligible capex of a type that is required by a third party and extraordinary and not previously included in the distributor's rate base.[46]

Informed by our research and testimony for a party to that Alberta proceeding, and by our familiarity with Custom IR, we believe that the following alternatives to Hydro One's proposed ratemaking treatment of capital merit consideration.

- An obvious candidate for a different approach is that chosen by the OEB in their recent decision on IR for Hydro One's distributor services.[47] A supplemental stretch factor would apply to the calculation of the C factor.
- Eligibility of capex for supplemental C factor revenue could be scaled back by other means. For example, capex in the last year of the plan term could be declared ineligible for supplemental revenue because this involves only one year of underfunding.
- The X factor could be raised, mechanistically in the Company's future IRMs, to reduce expected double dipping and give customers a better chance of receiving the benefits of industry productivity growth in the long run. This would be tantamount to having the Company borrow revenue escalation privileges from future plans. Knowledge that there is a price to be paid in the long run for asking for extra revenue now would strengthen Hydro One's capex containment incentives.
- Capital costs that occasion supplemental revenue could be subject to continued tracking in later plans. Customers would then receive the benefit of depreciation of the surge capex between plans. Once again, knowledge that there is a price to be paid in the long run for

[46] In the first generation of PBR plans in Alberta, capital cost trackers were the sole means by which a distributor could obtain supplemental funding for eligible capex.

[47] OEB, *Decision and Order*, EB-2017-0049, March 7, 2019.

asking for extra revenue now would strengthen Hydro One's capex containment incentives. The IR plans for the Fortis companies in British Columbia track the cost of *all* older capital.

- The proposed capex budget could be reduced by a material amount, as in the OEB's decisions in the last Toronto Hydro proceeding and the Hydro One distribution IR proceeding.

After considering the pros and cons of these options, we recommend that the OEB add a supplemental stretch factor to Hydro One's C factor calculation and calibrate this factor so that it produces a markdown on plant additions that is similar to that which would be produced by an ACM. We calculate that the analogous stretch factor would average about 0.42%. Details of our calculations can be found in Appendix Section B.4.

Several arguments can be advanced for making the supplemental capital cost stretch factor even higher.

- The Board rationalized the 10% markdown factor for ACMs and ICMs chiefly on the grounds that it may reduce regulatory cost. We have ventured a much wider range of arguments in favor of a markdown.
- As further discussed in Appendix B.4, the 10% markdown factor actually marks down otherwise-eligible capex by considerably less than 10%.

Hydro One should, in our view, be permitted to keep a share of the value of any capex underspends. This would strengthen the Company's incentive to contain capex (but also its incentive to exaggerate its capex needs). We believe that the Company should be permitted to keep 5% of the value of capex underspends.

Appendix A: Index Research for X Factor Calibration

In this section of the report we discuss pertinent principles and methods for the design of revenue cap indexes. We begin by discussing basic indexing concepts. There follow discussions of the use of indexing research in revenue cap index design and other important methodological issues.

A.1 Principles and Methods for Revenue Cap Index Design

Basic Indexing Concepts

Input Price and Quantity Indexes

The growth rate of a company's cost can be shown to be the sum of the growth in a cost-weighted input price index ("*Input Prices*") and input quantity index ("*Inputs*").

$$\textit{growth Cost} = \textit{growth Input Prices} + \textit{growth Inputs}. \qquad [A1]$$

These indexes summarize growth in the prices and quantities of the various inputs that a company uses. Capital, labor, and miscellaneous materials and services are the major classes of base rate (non-energy) inputs used by gas and electric utilities. These are capital-intensive businesses, so the heaviest weights are placed on the capital subindexes.

Productivity Indexes

The Basic Idea A productivity index is the ratio of an output quantity (aka scale) index ("*Outputs*") to an input quantity index.

$$\textit{Productivity} = \frac{\textit{Outputs}}{\textit{Inputs}}. \qquad [A2]$$

It is used to measure the efficiency with which firms convert production inputs into the goods and services that they provide. Some productivity indexes measure productivity *trends*. The growth of a productivity trend index is the difference between the growth of the output and input quantity indexes.[48]

$$\textit{growth Productivity} = \textit{growth Outputs} - \textit{growth Inputs}. \qquad [A3]$$

[48] This result holds true for particular kinds of growth rates.

Productivity grows when the output index rises more rapidly (or falls less rapidly) than the input index. Productivity can be volatile for various reasons that include fluctuations in output and/or the uneven timing of certain expenditures. The volatility of productivity growth tends to be greater for individual companies than the average for a group of companies.

The scope of a productivity index depends on the array of inputs that are addressed by the input quantity index. A *multifactor* productivity index measures productivity in the use of multiple inputs. These are sometimes call *total* factor productivity indexes even though they rarely encompass all inputs. Some indexes measure productivity in the use of a single input class such as labor. These indexes are sometimes called *partial* factor productivity ("PFP") indexes.

Output Indexes The output (quantity) index of a firm summarizes growth in its outputs or operating scale. If the index is multidimensional, growth in each output dimension that is itemized is measured by a sub-index, and growth in the summary index is a weighted average of the growth in the sub-indices.

In designing an output index, choices concerning sub-indices and weights should depend on the way the index is to be used. One possible objective of output research is to study the impact of output growth on *cost.*[49] In that event, the index should be constructed from one or more output (aka scale) variables that measure dimensions of the "workload" that drive cost. If there is more than one output variable, the weights for these variables should reflect their relative cost impacts.

The sensitivity of cost to a small change in the value of an output or any other business condition variable is commonly measured by its cost "elasticity." Cost elasticities can be estimated econometrically using data on the costs of utilities and on outputs and other business conditions that drive these costs. Such estimates provide the basis for elasticity-weighted output indexes.[50] An MFP index calculated using a cost-based output index ("$Outputs^C$") will be denoted as MFP^C.

[49] Another possible objective is to measure the impact of output growth on *revenue*. In that event, the sub-indices should measure trends in *billing determinants* and the weight for each itemized determinant should reflect its share of *revenue*.

[50] An early discussion of elasticity-weighted output indexes is found in Denny, Michael, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

$$\textit{growth } MFP^{C} = \textit{growth Outputs}^{C} - \textit{growth Inputs}. \qquad \text{[A4]}$$

This may fairly be described as a "cost efficiency index."

Sources of Productivity Growth

Economists have studied the drivers of productivity growth using mathematical theory and empirical methods.[51] This research has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

A second important source of productivity growth is output growth. In the short run, output growth can spur a company's productivity growth to the extent that it has excess capacity. In the longer run, economies of scale can be realized even if capacity additions are required if cost nonetheless tends to grow less rapidly than output. Increased capacity utilization and incremental scale economies will typically be lower the slower is output growth.[52]

A third important productivity growth driver is changes in the miscellaneous external business conditions, other than input price inflation and output growth, which affect cost. An example for a power transmitter is system undergrounding. To the extent that growth of a service territory's urban core(s) produce more undergrounding of transmission facilities, cost surges and MFP growth slows.

System age can drive productivity growth in the short and medium term. Productivity growth tends to be greater to the extent that the capital stock is large relative to the need to replace plant that is nearing retirement age. If a utility requires unusually high replacement capital expenditures ("capex"), capital productivity growth can be unusually slow. The utility is, effectively, replacing depreciated older facilities with newer facilities that will last for many years and may be sized to accommodate future demand growth but are for these reasons more expensive.

Productivity growth is also driven by changes in X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum possible efficiency. Productivity growth will increase

[51] The seminal paper on this topic is Denny, Fuss and Waverman, *op. cit.*

[52] Incremental scale economies may also depend on the current scale of an enterprise. For example, larger utilities may be able to achieve smaller incremental scale economies.

to the extent that X inefficiency diminishes. A company's potential for future productivity growth from this source is greater the higher is its current inefficiency.

Our analysis suggests that productivity growth can be different between utilities, and over time for the same utility, for reasons that are beyond their control. For example, a utility with unusually slow output growth and an unusually high number of assets needing replacement can have unusually slow productivity growth.

Use of Index Research in Regulation

Revenue Cap Indexes

Cost theory and index logic support the design of revenue cap indexes. The following basic result of cost theory is useful.

$$growth\ Cost = growth\ Input\ Prices - growth\ MFP^{C} + growth\ Outputs^{C}.\text{[53]} \qquad [A5]$$

The growth in the cost of a utility is the difference between the growth in its input price and cost efficiency indexes plus the trend in a consistent cost-based output index.

Assuming that growth in the RCI should track growth in the cost of the typical utility, this result provides the basis for a revenue cap index of general form:

$$growth\ Revenue^{Allowed} = growth\ Input\ Prices - X + growth\ Scale^{C}_{Utility} \qquad [A6a]$$

where

$$X = \overline{MFP}^{C}_{Industry} + Stretch. \qquad [A6b]$$

Here $Scale^{C}_{Utility}$ is an index of growth in the operating scale of the subject utility. X, the "X factor," reflects the base MFP^{C} growth trend ("$\overline{MFP}^{C}$") of the industry and a stretch factor. The base MFP^{C} growth trend is typically the trend in the MFP^{C} of the regional or national utility industry. Notably, a consistent cost-based scale index should be used in the supportive MFP research. Since the X factor

[53] An alternative basis for a revenue adjustment index can be found in index logic. Recall from relation [A1] that the growth in the cost of an enterprise is the sum of the growth in an appropriately designed input price index and input quantity index. Then,

$$\begin{aligned} growth\ Cost &= growth\ Input\ Prices + growth\ Scale^{C} - (growth\ Scale^{C} - growth\ Input\ Quantities) \\ &= growth\ Input\ Prices - growth\ MFP^{C} + growth\ Scale^{C} \end{aligned}$$

often includes a stretch factor in approved MRPs, it is sometimes said that the productivity research has the goal of "calibrating" (rather than solely determining) X.

For gas and electric power distributors, the number of customers served is a sensible scale escalator for a revenue adjustment index. The customers variable typically has the highest estimated cost elasticity amongst the scale variables considered in econometric research on the cost of energy distributors. A scale escalator that includes volumes and/or peak demand as scale variables diminishes a utility's incentive to promote DSM. This is an argument for excluding these variables from a revenue adjustment index scale escalator for a distributor.

The number of customers can replace $Scale^{C}_{Utility}$ in relation [A6a], with the following result:

$$growth\ Revenue^{Allowed} = growth\ Input\ Prices_{Industry} - X + growth\ Customers_{Utility} \qquad [A7a]$$

$$X = \overline{MFP}^{N}_{Industry} + Stretch.^{54} \qquad [A7b]$$

where $\overline{MFP}^{N}$ is the trend in an MFP index that uses the number of customers to measure output.

In power transmission no single scale variable is dominant. A multidimensional scale index with weights based on econometric research on transmission cost is therefore more appropriate.

Scale Escalators

Revenue adjustment indexes do not always include explicit scale escalators. A revenue adjustment index of general form

$$growth\ Revenue^{Allowed} = growth\ GDP\ IPI - X \qquad [A8a]$$

where

$$X = \overline{MFP}^{C}_{Industry} + Stretch.$$

is equivalent to the following:

$$growth\ Revenue^{Allowed} = growth\ GDP\ IPI - X + growth\ Scale_{Utility} \qquad [A8b]$$

[54] An equivalent formula is:
$growth\ Revenue^{Allowed} - growth\ Customers = growth\ (Revenue^{Allowed}/Customer) = growth\ Input\ Prices - X.$
This is sometimes called a "revenue per customer" index.

where

$$X = \overline{MFP}^{C}_{Industry} + Expected(growth\ Scale_{Utility}) + Stretch. \quad [A8c]$$

It can be seen that if the MRP does not otherwise compensate the utility for growth in its operating scale, the expected scale index growth of the utility is an implicit stretch factor. The value of this implicit stretch factor will be larger the more rapid is the utility's expected scale index growth.

A.2 Capital Specification

Monetary Approaches to Capital Cost and Quantity Measurement

The capital cost ("CK") specification is critical in research on the transmission input price and productivity trends of utilities because the technology of transmission is capital intensive. The annual cost of capital includes depreciation expenses, a return on investment, and some taxes. If the price (unit value) of the asset changes over time this cost may also be net of any capital gains or losses.

Monetary approaches to the measurement of capital prices and quantities are conventionally used in research on the costs and input price and productivity trends of utilities. These approaches permit the decomposition of capital cost into a consistent capital quantity index ("*XK*") and capital price index ("*WK*") such that

$$CK = WK \cdot XK. \quad [A9]$$[55]

The growth rate of capital cost then equals the sum of the growth rates of the capital price and quantity indexes.

In U.S. electric utility research, capital quantity indexes are typically constructed by deflating the value of gross plant additions using a Handy Whitman electric utility construction cost index and

[55] In rigorous statistical cost research, it is often assumed that a capital good provides a stream of services over some period of time (the "service life" of the asset). The capital *quantity* index measures this flow, while the capital *price* index measures the trend in the simulated price of renting a unit of capital service. The design of the capital service price index is consistent with the assumption about the decay in the service flow. The product of the capital service price index and the capital quantity index is interpreted as the annual cost of using the flow of services.

subjecting the resultant quantity estimates to a mechanistic decay specification. Capital prices are calculated from these same construction cost indexes and from data on the rate of return on capital.[56]

Alternative Monetary Approaches

Several monetary methods for measuring capital cost have been established. A key issue in the choice between these methods is the pattern of decay in the quantity of capital from the plant additions that are made each year.[57] Another issue is whether plant is valued in historic or replacement dollars. Here are brief descriptions of the three monetary methods that have been most commonly used in the design of rate and revenue adjustment indexes.

1. Geometric Decay ("GD"). Under the GD method, the capital quantity is treated as the flow of services from plant additions in a given year. The flow is assumed to decline at a constant rate over time. Plant is typically valued in replacement dollars. Cost is usually computed net of capital gains.

   A GD capital quantity index is typically combined with a consistent GD capital price that simulates the price for capital services in a competitive rental market in which the capital stocks of suppliers experience GD. This price is driven by trends in construction costs and the rate of return on capital.

2. One-Hoss-Shay ("OHS"). Under the OHS method, the flow of services from a capital asset is assumed to be constant until the end of its service life, when it abruptly falls to zero. This is the pattern that is typical of an incandescent light bulb. However, in energy utility research this constant flow assumption has, due to data limitations, been applied to the total plant additions for groups of assets that have varied service lives. Plant is once again valued at replacement cost and cost is computed net of capital gains. As with GD, it is common to use a capital service price that is consistent with the OHS assumption.

[56] If taxes are included in the study, capital prices are also a function of tax rates.

[57] Decay can result from many factors including wear and tear, casualty loss, increased maintenance requirements, and technological obsolescence. The pattern of decay in assets over time is sometimes called the age-efficiency profile.

3. Cost of Service ("COS"). The GD and OHS approaches for calculating capital cost use assumptions that are quite different from those used to calculate capital cost under traditional COS ratemaking.[58] Replacement valuation of plant, capital gains, and use of capital service prices can all give rise to volatile GD and OHS capital costs and prices. The derivation of a revenue adjustment index using index logic does not require a service price treatment of the capital price.

   An alternative COS approach to measuring capital cost has been developed by PEG that is so-called because it is based on the straight-line depreciation and historical plant valuations, techniques used in utility capital cost accounting. Capital cost can still be decomposed into a price and a quantity index, but the capital price cannot be represented as a capital service price. The price and quantity index formulae are complicated, making them more difficult to code and review. However, capital prices are less volatile.

Benchmark Year Adjustments

Utilities have diverse methods for calculating depreciation expenses that they report to regulators. When calculating capital quantities using a monetary method, it is therefore customary to rely on the reporting companies chiefly for the value of *gross* plant additions and then use a standardized decay specification for all companies. Since some of the plant a utility owns may be 40-60 years old, it is desirable to have gross plant addition data for many years in the past.

For the earlier years that are pertinent in these calculations the desired gross plant addition data are frequently unavailable. It is then customary to take the total value of plant, with its diverse vintages, at the end of this limited-data period and to estimate the quantity of capital that it reflects using construction cost indexes from earlier years and assumptions about the historical plant addition pattern. The year for which this estimate is undertaken is commonly called the "benchmark year" of the capital quantity index. Since the estimate of the capital quantity in the benchmark year is inexact, it is preferable to base capital and total cost research on a sample period that begins many years after the benchmark year. Research on capital and total cost will be less accurate to the extent that this is impossible.

[58] The OHS assumptions are more markedly different.

Appendix B: Additional Information on Research Methods

B.1 Technical Details of PEG's Empirical Research

This section of Appendix B contains more technical details of our empirical research. We first discuss our input quantity and productivity indexes, respectively. We then address our methods for calculating input price inflation and capital cost.

Input Quantity Indexes

The growth rate of a summary (multidimensional) input quantity index is defined by a formula that involves subindexes measuring growth in the quantities of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and quantity subindexes.

Index Form

We have constructed summary OM&A, capital, and multifactor input quantity indexes. Each summary input quantity index is of chain-weighted Törnqvist form.[59] This means that its annual growth rate is determined by the following general formula:

$$\ln\left(Inputs_t \big/ Inputs_{t-1} \right) = \sum_j \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1} \right) \cdot \ln\left(X_{j,t} \big/ X_{j,t-1} \right). \qquad [B1]$$

Here in each year *t*,

$Inputs_t$ = Summary input quantity index

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

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

It can be seen that the growth rate of the index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the natural logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable cost of each utility in the current and prior years served as weights.

[59] For seminal discussions of this index form see Törnqvist (1936) and Theil (1965).

Productivity Growth Rates and Trends

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

$$\ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right) = \ln\left(\frac{Outputs_t}{Outputs_{t-1}}\right) - \ln\left(\frac{Inputs_t}{Inputs_{t-1}}\right). \qquad [B2]$$

The long-run trend in each productivity index was calculated as its average annual growth rate over the full sample period.

Input Price Indexes

The growth rate of an input price index is defined by a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and price subindexes.

The multifactor input price index used in the econometric total cost model was of Törnqvist form. This means that the annual growth rate of each index was determined by the following general formula. For any asset category *j*,

$$\ln\left({Input\ Prices_t}/{Input\ Prices_{t-1}}\right) = \sum_j \frac{1}{2}\cdot\left(sc_{j,t} + sc_{j,t-1}\right)\cdot\ln\left({W_{j,t}}/{W_{j,t-1}}\right). \qquad [B3]$$

Here in each year *t*,

$Input\ Prices_t$ = Input price index

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

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

The growth rate of the index is a weighted average of the growth rates of input price subindexes. Each growth rate is calculated as the logarithm of the ratio of the subindex values in successive years. The average shares of each input group in the applicable cost of each utility during the two years are the weights.

Capital Cost and Quantity Specification

A monetary approach was used to measure the capital cost of each utility. Recall from Appendix section A.2 that under this approach capital cost is the product of a capital quantity index and a capital price index.

$$CK = WKS \cdot XK.$$

Geometric decay was assumed in the construction of both of these indexes.

Data previously processed by PEG permitted us to use 1964 as the benchmark year for the U.S. capital cost and quantity calculations. The value of each capital quantity index for each U.S. utility in 1964 depends on the net ("book") value of its transmission and general plant as reported in FERC Form 1. We estimated the benchmark year quantities of capital by dividing these values, respectively, by triangularized weighted averages of 52 consecutive values of a regional Handy Whitman Index of power transmission construction cost and 18 values of a regional Handy Whitman Index of reinforced concrete building construction cost for periods ending in the benchmark year. A triangularized weighted average places a greater weight on more recent values of the construction cost index. This makes sense intuitively since more recent plant additions are less depreciated and to that extent tend to have a bigger impact on net plant value.

The following GD formula was used to compute values of each capital quantity index in subsequent years. For any asset category *j*,

$$XK_{j,t}=(1-d)\cdot XK_{j,t-1} + \frac{VI_{j,t}}{WKA_{j,t}}. \quad [B4]$$

Here, the parameter *d* is the economic depreciation rate and VI_t is the value of gross additions to utility plant. The assumed 52-year average service life for transmission plant, 18-year average service life for general plant, 1.65 declining balance rate for equipment, and 0.91 declining balance rate for structures were used to set *d*.

The formula for the corresponding GD capital service price indexes used in the research was

$$WKS_{j,t}= d\cdot WKA_{j,t} + r_t\cdot WKA_{j,t-1}. \quad [B5]$$

The first term corresponds to the cost of depreciation. The second term corresponds to the real rate of return on capital. We decided not to include a capital gains term in the service price formula because this simplifies the analysis and has been a common practice in past OEB IR proceedings. The need for a capital gains term is reduced by the fact that the study does not include taxes. Were taxes included, the removal of capital gains would place undue weight on capital cost in total cost benchmarking appraisals.

B.2 Econometric Research Methods

This section of Appendix B provides additional and more technical details of our econometric research. We begin by discussing the choice of a form for the econometric benchmarking models. There follow discussions of econometric methods.

Form of the Econometric Cost Model

Specific forms must be chosen for cost functions used in econometric research. Forms commonly employed by scholars include the linear, double log, and translog. Here is a simple example of a *linear* cost model:

$$C_{h,t} = a_0 + a_1 \cdot L_{h,t} + a_2 \cdot D_{h,t}. \qquad [B6]$$

Here is an analogous cost model of *double log* form:

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln L_{h,t} + a_2 \cdot \ln D_{h,t}. \qquad [B7]$$

Here, for each company h, $C_{h,t}$ is cost, L is the length of transmission lines and D is ratcheted peak demand.

The double log model is so-called because the right- and left-hand side variables in the equation are all logged.[60] This specification makes the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, parameter a_1 indicates the percentage change in cost resulting from 1% growth in the length of transmission lines. Elasticity estimates are useful and make it easier to assess the reasonableness of model results. It is also noteworthy that, in a double log model, elasticities are *constant* in the sense that they are the same for every value that the cost and business condition variables might assume. This model specification is restrictive and may be inconsistent with the true form of the cost relationship we are trying to model.

Here is an analogous model of *translog* form:

$$\ln C_{h,t} = a_o + a_1 \cdot \ln L_{h,t} + a_2 \cdot \ln D_{h,t} + a_3 \cdot \ln L_{h,t} \cdot \ln L_{h,t} + a_4 \cdot \ln D_{h,t} \cdot \ln D_{h,t} + a_5 \cdot \ln L_{h,t} \cdot \ln D_{h,t} \qquad [B8]$$

This form differs from the double log form in the addition of quadratic and interaction terms. These are sometimes called second-order terms. Quadratic terms like $\ln D_{h,t} \cdot \ln D_{h,t}$ permit the elasticity of cost with respect to each business condition variable to vary with the value of the variable. The elasticity of

[60] i.e., the variable is used in the equation in natural logarithmic form, as ln(X) instead of X.

cost with respect to a scale variable may, for example, be lower for a small utility than for a large utility. Interaction terms like ln $L_{h,t} \cdot$ ln $D_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable. For example, the elasticity of cost with respect to growth in peak load may depend on the length of a transmitter's transmission lines.

The translog form is an example of a "flexible" functional form. Flexible forms can accommodate a greater variety of possible functional relationships between cost and the business condition variables. A disadvantage of the translog form is that it involves many more variables than simpler forms like the double log. As the number of variables accorded translog treatment increases, the precision of a model's parameter estimates and cost predictions falls. It is therefore common in econometric cost research to limit the number of variables accorded translog treatment.

In our econometric work for this proceeding, we have chosen a functional form that has second-order terms only for the two scale variables. This preserves degrees of freedom but permits the model to recognize some nonlinearities. All of the second-order terms in our model had statistically significant parameter estimates.

Econometric Model Estimation

A variety of parameter estimation procedures are used by econometricians. The appropriateness of each procedure depends on the distribution of the error terms. The estimation procedure that is most widely known, ordinary least squares ("OLS"), is readily available in econometric software. Another class of procedures, called generalized least squares ("GLS"), is appropriate under assumptions of more complicated and realistic error specifications. For example, GLS estimation procedures can permit the variance of the error terms of cost models to be heteroskedastic, meaning that they vary across companies. Variances can, for example, be larger for companies with large operating scale. In this study we used GLS escalators that corrected for autocorrelation and groupwise heteroskedasticity.

Note, finally, that the model specification was determined using data for all sampled companies. However, estimation of parameters and appropriate standard errors for the cost model actually used for benchmarking required that the utility of interest be dropped from the sample. The parameter estimates used in developing the cost model and reported in Table 2 above therefore vary slightly from those in the models used for benchmarking.

B.3 Summarizing Methodological Changes

The following changes have been made in our research methodology since the Hydro One SSM report.

- Certain errors that were made in the study supporting our Hydro One SSM evidence have been corrected as discussed in our Hydro One SSM interrogatory response found in Exhibit L1 Tab 1 Schedule 6.
- We excluded capital gains from the calculation of capital costs and prices. This increased the importance of capital cost performance in the productivity and benchmarking results.
- Our econometric model estimation procedure now corrects for autocorrelation as well as groupwise heteroscedasticity.
- We used Statistics Canada's implicit price deflator for the assets of the Canadian utility sector rather than the Ontario utilities sector. This grew more rapidly than the IPD for Ontario utility assets.
- We upgraded our estimates of depreciation rates. We made small improvements to the depreciation rate calculations by employing separate depreciation treatment of structures vs. equipment not previously done by either PSE or PEG. We also used service lives more consistent with the HON study used by PSE than we had earlier.[61]
- We removed several companies from the sample. Three were removed because the transmission line mile data had large changes due to reclassifications between transmission

[61] The first issue is that the declining balance parameter used by PSE is for equipment and not structures. The second is that the service life used by PSE was drawn from a Hydro One depreciation study for all plant and not just for transmission plant. The first problem was addressed by classifying each account as either structures or equipment and calculating a depreciation rate by asset type with the appropriate declining balance parameter. The overall depreciation rate was calculated as a plant-weighted average of the individual depreciation rates. This was done for transmission and general plant separately. The second issue stems from PEG previously applying the overall service life to transmission calculations. This was corrected by the foregoing calculation and by using the separate Hydro One average service lives for transmission and general in the triangularized-weighted average calculations in the benchmark year.

and distribution. One company was removed due to the cost of a large joint venture being assigned to rents.[62]

- We used data provided by Hydro One in response to an interrogatory to reduce the company's OM&A cost to be consistent with the PEG definition of cost for U.S. transmitters.

B.4 Calculation of the Supplemental Stretch Factor

Introduction and Summary

Supplemental capital funding has become an increasingly important issue in Ontario as the OEB tries to balance a desire for strong performance incentives, fair outcomes for customers, and low regulatory cost against the occasional need for high but prudent capital expenditures that cannot be funded by price and revenue cap indexes alone. For the 4GIRM, the Board sanctioned incremental and advanced capital modules with materiality thresholds and dead zones that effectively mark down the plant additions eligible for extra revenue. Markdowns like these can strengthen utility performance incentives, trim regulatory cost, and share IR benefits with customers more fairly.

Custom IR plans approved by the OEB to date typically supplement revenue by adding a C factor to the rate or revenue cap index formula. In EB-2017-0049 the Board approved a supplemental stretch factor for Hydro One (which we will call an S-factor) which lowered Hydro One Distribution's proposed C-factor. However, the approved S-factor of 0.15% may not provide the same markdown as the materiality thresholds in an ICM or ACM.

We have endeavored to calculate the ACM-equivalent S-factor in 3 steps.

Step 1: Calculate the percentage of proposed gross plant additions that would not be funded by an ACM were it to apply to Hydro One Transmission.

Step 2: Calculate the percentage of new (additions-related) capital cost that is not funded in Custom-IR according to the I – X and S factors.

[62] The three companies excluded for reclassifications of assets are Black Hills, PPL Electric Utilities, and Public Service of New Hampshire. Each showed large transfers of transmission plant that were associated with large changed in reported transmission line miles. The company excluded for rents was Nevada Power. Accounting for the 25% jointly owned One Nevada line cost was corrupting OM&A cost by the inclusion of large amounts of capital cost inconsistent with the rest of the study. The exclusion of this company allowed us to include rents in the cost calculations and make the work more consistent with the PSE study.

Step 3: Equate the two and solve for S. Plug S into the C-factor formula to obtain the adjusted C-factor.

The impact of our calculations on Hydro One's proposed C-factor is shown in Table B1. The calculations of the C-factor follow the familiar formula, $C = C_n - S_{cap} \cdot (I + S)$.

Table B1

Resultant C-factor under different S-factors

C Factor Component (%)	Variable	2021	2022	Average
Percentage of Total RR in previous year	C_n	5.18	4.68	4.93
Capital Cost Share	S_{cap}	78.42%	79.16%	78.79%
I	I	1.40	1.40	1.40
S (HON-Tx Proposed)	S_1	0.00	0.00	0.00
S (HON Dx IRM)	S_2	0.15	0.15	0.15
S (ACM Equivalent)	S_3	0.31	0.53	0.42
C Factor: HON-Tx Proposed	$C_1=C_n-S_{cap}*(I+S_1)$	4.09	3.59	3.84
C Factor: S=0.15	$C_2=C_n-S_{cap}*(I+S_2)$	3.96	3.46	3.71
C Factor: ACM Equivalent	$C_3=C_n-S_{cap}*(I+S_3)$	3.84	3.16	3.50

As can be seen, the ACM-equivalent S-factor for Hydro One Transmission averages 0.42%, which is higher than that which the OEB approved in the recent Hydro One Dx Custom IR decision (EB-2017-0049). The average resultant C-factor is 3.50%, compared to Hydro One's proposed 3.84%.

In the balance of this Appendix section, we first present a glossary of terms and then discuss our calculations step by step.

Glossary of Terms and Key Identities

C = C factor

CK = capital cost

CK^{new} = capital cost of new additions

CKD = depreciation expenses

CKR = return on rate base

g = actual billing determinant growth (assumed to equal G for simplicity)

R = total revenue

RK = capital revenue

RK^+ = supplemental capital revenue

RKR = return on rate base revenue requirement

ROM = OM&A revenue

VK^{net} = net plant value (aka rate base)

r = rate of return on rate base

VKA = value of proposed gross plant additions

$VKA^{eligibile}$ = value of proposed gross plant additions eligible for extra revenue

VKA^{funded} = value of gross plant additions funded by both price cap mechanism and any supplemental capital revenue

$VKA^{ineligible}$ = value of proposed gross plant additions ineligible for supplemental revenue

$VKA^{price\ cap}$ = value of gross plant additions funded by the price cap mechanism

M = markdown factor used in the 4GIRM Threshold Value formula

S = extra stretch factor in the C factor formula, like that approved in EB-2017-0049

Sc_K = capital cost share

$Sc_{OM\&A}$ = OM&A cost share

TC = total cost

I = annual price inflation

X = X factor term of the rate or revenue cap index = base productivity trend + stretch factor

Several simplifying assumptions are made throughout the analysis for ease of review and presentation. Costs are assumed equal to revenues in the base year and retirements are ignored.

Here are a few identities to keep in mind for the analysis:

$$VKA = VKA^{eligible} + VKA^{ineligible}$$

$$VKA^{funded} = VKA^{price\ cap} + VKA^{eligible}$$

Step 1: Calculate 4GIRM and the Supplemental Capital Threshold Value

When a utility is operating under 4GIRM, the revenue for costs addressed by the price cap index in the first indexing year is determined by the following formula:

$$R_1 = ROM_1 + RK_1 = R_0 \cdot (1 + I - X) \cdot (1 + g) + RK_1^+. \quad [B9]$$

Revenue in year 1 grows with billing determinants and the approved I-X price cap index and there may also be some supplemental capital revenue ("RK_1^+"). The total capital revenue requirement can be decomposed into revenue required for depreciation, the return on rate base, and taxes. However, the rationale for the ACM/ICM materiality threshold is based only on the return on rate base component of capital cost (“*CKR*”), so we consider only this and the corresponding revenue (“*RKR*”) in the following discussion.

Consider now the difference between *CKR* and *RKR* in the first year of an IRM. The former is the proforma return on rate base capital cost incurred by the company and the latter is the return on rate base capital revenue provided by the price cap mechanism and any supplemental capital revenue. The formulas are

$$CKR_1 = r \cdot VK_1^{net} = r \cdot (VK_0^{net} + VKA_1 - CKD_1) \quad [B10]$$

and, in the absence of supplemental revenue,

$$RKR_1 = r \cdot VK_0^{net} \cdot (1 + I - X) \cdot (1 + g). \quad [B11]$$

Here $VK_1^{net} = VK_0^{net} + VKA_1 - CKD_0$ because the rate base in year 0 equals the prior year’s rate base plus the value of additions made in the current year minus annual depreciation.

In the absence of RK^+, all VKA_1 above the threshold value would be underfunded and cost would exceed revenue, i.e.,

$$CKR_1 > RKR_1. \quad [B12]$$

Substituting [B10] and [B11] into [B12] yields the following relation:

$$r \cdot (VK_0^{net} + VKA_1 - CKD_1) > r \cdot \left(VK_0^{net} \cdot (1 + I - X) \cdot (1 + g)\right). \quad [B13]$$

Rearranging, distributing, and collecting terms then gives

$$VKA_1 > CKD_1 + VK_0^{net} \cdot \left(g + (I - X)\right) \cdot (1 + g). \quad [B14]$$

Inspecting the results, it can be seen that part of the funding for plant additions comes from the depreciation of old plant.

The "Threshold Value" formula in the ACM/ICM materiality threshold for the first indexing year is obtained by dividing both sides of [B14] by depreciation and appending a "markdown factor", $M > 0$, to the right-hand-side.

Threshold Value Formula

$$\frac{VKA_1}{CKD_0} > 1 + \frac{VK_0^{net}}{CKD_0} \cdot \{[g + (I - X)] \cdot (1 + g)\} + M \qquad \text{[B15]}$$

This formula was adopted by the OEB in EB-2014-0219. Note that depreciation is in the base year (CKD_0) in the OEB's approved formula.

The markdown factor allows the OEB to set the minimum amount by which capital expenditures must exceed the funded amount before any additions become eligible for extra capital revenue. The OEB initially set *M* at 20% and later lowered it to 10%. The value of additions that are ineligible for supplemental revenue are then given by the following formula. Since Hydro One is under a revenue cap index, assume *g* = 0.

$$VKA_1^{ineligible} = CKD_0 + VK_0^{net} \cdot (I - X) + M \cdot CKD_0 \,. \qquad \text{[B16]}$$

Since $VKA = VKA^{eligible} + VKA^{ineligible}$, it follows that

$$VKA^{eligible} = VKA - VKA^{ineligible} \,. \qquad \text{[B17]}$$

Plugging [B16] into [B17], the portion of gross plant additions eligible for supplemental capital revenue is then

$$VKA_1^{eligible} = VKA_1 - [CKD_0 + VK_0^{net} \cdot (I - X) + CKD_0 \cdot \mathrm{M}] \qquad \text{[B18]}$$

$$= VKA_1 - [(1 + M) \cdot CKD_0 + VK_0^{net} \cdot (I - X)]. \qquad \text{[B19]}$$

Note here that the markdown factor *M* only applies to base year depreciation and not to the other source of funding as a result of the OEB's chosen Threshold Value formula. *M* could reasonably be applied to the second source of funding as well. If the utility's plant additions are close to qualifying for extra revenue, it will be incentivized to bolster its proposed additions so as to obtain supplemental revenue. Bunching of plant additions can help with this.

The full funding for gross plant additions in indexing year *1* is then the sum of gross plant additions provided by the price cap and those eligible for supplemental revenue.

$$VKA_1^{funded} = CKD_0 + VK_0^{net} \cdot [(1 + I - X) - 1] + VKA_1^{eligible}\,. \qquad [B20]$$

By substituting [B19] into [B20] and carrying out simple algebra, it can be shown that

$$VKA_1^{funded} = VKA_1 - M \cdot CKD_0. \qquad [B21]$$

The share of VKA_1 that is *not* funded under 4GIRM in year *1* is then

$$\frac{VKA_1 - VKA_1^{funded}}{VKA_1} = \frac{VKA_1 - (VKA_1 - \mathrm{M} \cdot \mathrm{CKD}_0)}{VKA_1} \qquad [B22]$$

$$= \frac{M \cdot CKD_0}{VKA_1}. \qquad [B23]$$

As can be seen from [B23], the percentage of gross plant additions that would not be funded in the first year of an ACM plan is the ratio of *M* times base year depreciation to gross plant additions in year 1. The percentage markdown will be less to the extent that *VKA* exceeds the materiality threshold. It can be shown with more algebra that the markdown formula in the second year is the same as the first year but with VKA_2 instead of VKA_1.

We calculate this percentage for Hydro One in each year of its proposed IR plan in Table B2. Were this mechanism used to determine Hydro One's extra capital revenue instead of the proposed C factor, it can be seen that the underfunding would be roughly 3.63% of proposed plant additions in the first indexing year and 3.65% of proposed plant additions in the second year.

Table B2

Calculating the ACM Markdown

Variable Name	Plant Additions Markdown	Base Year 2020	Year 1 2021	Year 2 2022
M	M Factor		10%	10%
CKD_0	Base Year Depreciation ($M)	474.60	--	--
VKA	Gross Plant Additions ($M)		1,297.70	1,293.00
	Markdown = $M \cdot CKD_0/VKA_t$		3.66%	3.67%

Step 2: Calculate the Markdown in the C Factor in Custom-IR

Under a C factor mechanism like that approved for Hydro One's distributor services, growth in revenue for inputs that are addressed by indexing conforms to the following formula.[63] In these calculations, we assume that base year revenue equals base year costs ($RK_0 = CK_0$). From growth rate math, it can be shown that

$$growth\ R = Sc_K \cdot growth\ RK + Sc_{OM\&A} \cdot growth\ ROM \qquad [B24]$$

$$= Sc_K \cdot [(I - X) + (growth\ CK - I - S)] + Sc_{OM\&A} \cdot (I - X) \qquad [B25]$$

$$= Sc_K \cdot [growth\ CK - (X + S)] + Sc_{OM\&A} \cdot (I - X). \qquad [B26]$$

Since the X factor is the sum of the base productivity trend and a stretch factor, capital revenue growth is reduced by the base productivity trend, but this is currently 0 in Ontario regulation. Hence the two stretch factor terms are the only basis for a capital revenue growth markdown. The stretch factor component of *X* ranges from 0 to 0.6% in Ontario and reflects statistical total cost benchmarking results.

Now, capital revenue in year 1 is defined by

$$RK_1 = RK_0 \cdot (1 + growth\ RK) \qquad [B27]$$

$$= RK_0 + RK_0 \cdot growth\ RK \qquad [B28]$$

$$= RK_0 + RK_0 \cdot [growth\ CK - (X + S)] \qquad [B29]$$

$$= RK_0 + RK_0 \cdot \left[\frac{\mathrm{CK}_1 - \mathrm{CK}_0}{\mathrm{CK}_0} - (X + S)\right] \qquad [B30]$$

$$= RK_0 + RK_0 \cdot \left[\frac{CK_1 - RK_0}{RK_0} - (X + S)\right] \qquad [B31]$$

$$= CK_1 - RK_0 \cdot (X + S). \qquad [B32]$$

[63] We are, effectively, abstracting from variance accounts and Z factors.

NB: We can derive the C-factor using [B25] but it is not necessary for this step. From [B25], since the sum of sc_K and $sc_{OM\&A}$ equals 1 by definition, we have

$$\begin{aligned} growth\ R &= I - X + sc_K \cdot [growth\ CK - (I+S)] \\ &= I - X + \frac{CK_0}{TC_0} \cdot \left[\frac{CK_1 - CK_0}{CK_0} - (I+S)\right] \\ &= I - X + \left[\frac{CK_1 - CK_0}{TC_0} - \frac{CK_0}{TC_0} \cdot (I+S)\right] \\ &= I - X + C \end{aligned}$$

The share of capital cost from new plant additions ("CK_1^{New}") that is ineligible for supplemental revenue is then (invoking $RK_0 = CK_0$)

$$\frac{CK_1 - RK_1}{CK_1^{New}} = \frac{RK_0 \cdot (X+S)}{CK_1^{New}} \qquad [B33]$$

$$= \frac{CK_0 \cdot (X+S)}{CK_1^{New}}. \qquad [B34]$$

Capital revenue in year 2 is defined by

$$RK_2 = RK_1 \cdot (1 + growth\ RK) \qquad [B35]$$

$$= RK_1 + RK_1 \cdot growth\ RK \qquad [B36]$$

which, letting $RK_1 = CK_1 - RK_0 \cdot (X+S)$ from [B32] above,

$$= CK_1 - RK_0 \cdot (X+S) + (CK_1 - RK_0 \cdot (X+S)) \cdot [\text{growth } \mathrm{CK}_2 - (X+S)] \qquad [B37]$$

$$= CK_1 - RK_0 \cdot (X+S) + (CK_1 - RK_0 \cdot (X+S)) \cdot \left[\frac{\mathrm{CK}_2 - \mathrm{CK}_1}{\mathrm{CK}_1} - (X+S)\right] \qquad [B38]$$

$$= CK_1 - CK_0 \cdot (X+S) + [CK_1 - CK_0 \cdot (X+S)] \cdot \left[\frac{\mathrm{CK}_2 - \mathrm{CK}_1}{\mathrm{CK}_1} - (X+S)\right] \qquad [B39]$$

$$= CK_2 - CK_1 \cdot (X+S) - \big(CK_0 \cdot (X+S)\big) \cdot \left(\frac{CK_2}{CK_1} - (X+S)\right). \qquad [B40]$$

The percentage of CK_2^{New} that is not eligible for supplemental revenue is then

$$\frac{CK_2 - RK_2}{CK_2^{New}}$$

which can be shown to equal

$$\frac{CK_1 * (X+S) + CK_0 * (X+S) * \left(\frac{CK_2}{CK_1}\right) - CK_0 * (X+S)^2}{CK_2^{New}}.$$

Table B3 presents the capital cost markdown results as a share of new capital cost.

Table B3

Capital Cost Markdown

Variable Name	Capital Cost Markdown	Base Year 2020	Year 1 2021	Year 2 2022
CK	Capital Cost ($M)	1,298.00	1,384.70	1,467.40
CK^{NEW}	Capital Cost of New Additions ($M)	--	111.42	230.89
	Markdown (Depends on X and S)		11.65·(X+S)	6.93·(X+S)-5.62·$(X+S)^2$

Step 3: Solve for *S* and Calculate the ACM-Equivalent C Factor

It is reasonable for the C factor to produce underfunding of new capital cost which is no less than the underfunding of the value of gross plant additions in 4GIRM. In Step 3, we calibrate *C* to produce such a markdown for Hydro One. To accomplish this, we solve for the value of *S* which equates [B23] and [B33]. In other words, solve for *S* such that the following result holds each year.

$$\frac{VKA_t - VKA_t^{funded}}{VKA_t} = \frac{CK_t - RK_t}{CK_t}.$$

We showed in Step 1 the percentage markdown on 4GIRM gross plant additions under a 4GIRM formula (the left-hand side) and we showed in Step 2 the percentage markdown on capital cost multiplied by (*X+S*) (the right-hand side). Table B4 shows the resultant S factors from equating the two. The S factor would be 0.31% in 2021 and 0.53% in 2022, averaging 0.42% over the two years. Thus, the S-factor that achieves parity with an ACM-style capital markdown is higher than the 0.15% S factor approved in the Hydro One Distribution IRM.

Table B4

Calculating the ACM-Equivalent S Factor for Capital Cost

Variable Name		Base Year 2020	Year 1 2021	Year 2 2022
	Step 1: Plant Additions Markdown			
M	M Factor		10%	10%
CKD_0	Base Year Depreciation ($M)	474.60	--	--
VKA	Gross Plant Additions ($M)		1,297.70	1,293.00
[A]	Markdown = $M \cdot CKD_0/VKA_t$		3.66%	3.67%
	Step 2: Capital Cost Markdown			
CK	Capital Cost ($M)	1,298.00	1,384.70	1,467.40
CK^{NEW}	Capital Cost of New Additions ($M)	--	111.42	230.89
[B]	Markdown (Depends on X and S)		$11.65 \cdot (X+S)$	$6.93 \cdot (X+S) - 5.62 \cdot (X+S)^2$
	Step 3: Solve for S			
	Set [A]=[B] and solve for S			
	S-factor (assume X=0)		0.31%	0.53%

Appendix C: Federal Regulation of U.S. Power Transmission

To appraise the relevance of statistical cost research using U.S. transmission data for the situation of Hydro One, it is important to understand some key factors of the U.S. transmitter operating environment. Regulation of U.S. power transmission rates is undertaken today chiefly by the FERC. Transmitter productivity has been greatly affected by FERC regulation and by state and federal policies.

C.1 Unbundling Transmission Service

Transmission regulation prior to the mid-1990s reflected the vertically-integrated structure of most investor-owned electric utilities in that era. These utilities typically owned both the transmission and distribution systems in the areas they served and obtained most of their power supplies from their own generation facilities. There were fewer bulk power purchases and independent power producers using transmission services than there are today.

Wholesale customers (e.g., municipal utilities) could obtain bundled generation and transmission services from adjacent utilities by negotiating contracts with them. Power was sometimes purchased from a third party. If the contract path for such a purchase passed over multiple transmission systems the customer might have to pay multiple transmitters for service, a phenomenon called "pancaked rates". Disputes over wholesale contracts for the purchase and transmission of power could be brought to the FERC. Utilities sometimes had the ability to discriminate between their customers regarding the terms of transmission service.

Starting in the 1970s, federal policy has increasingly encouraged 3rd party generators and the development of more robust bulk power markets. This increased the demand for public, non-discriminatory tariffs for wholesale transmission service. In 1996, FERC Order 888 required transmitters to provide service under open access transmission tariffs ("OATTs"). To ensure that service was provided on a non-discriminatory basis, the FERC also ordered transmitters to establish an information network to provide network information to transmission customers and to obtain their native load transmission service solely using the OATT and the publicly available information network. Third parties were provided the option to procure the same types of service at the same quality levels as the transmitter's native load. Many details of the resultant functional unbundling and the information service for transmission customers were addressed in FERC Order 889.

Bulk power markets were also expanded by restructuring retail markets in many American states. Retail customers in these states had a greater choice of power suppliers. Many large industrial customers became bulk power market participants.

C.2 Formula Rates

Rates for jurisdictional transmission services can be set by the FERC in periodic rate cases. Transmitters also have the option to request formula rate mechanisms, wherein rates are reset annually to reflect the changing cost of their service. Formula rates may rely on a transmitter's historical cost and revenue data or on forward-looking cost and revenue data with a subsequent true up of forecasts to actual values.

Formula rates have been used at the FERC and its predecessor, the Federal Power Commission, to regulate interstate services of gas and electric utilities since at least 1950. Early FERC rationales for using formula rates included the following.[64]

- Establishment of rates for a new utility;
- Establishment of rates for the transaction of one utility with an affiliated utility; and
- Economies in regulatory cost.

Regulatory cost economies are a major consideration for a commission with jurisdiction over the transmission services of more than 100 electric utilities and dozens of interstate oil and gas pipelines.

Use of formula rates by the FERC was encouraged in the 1970s and early 1980s by rapid input price inflation. Despite slower inflation in more recent years, the FERC's use of formula rates has grown in the power transmission industry. Growing use of OATTs greatly increased the need to set rates for transmission services by some means. Formula rates were also encouraged by national energy policies such as the Energy Policy Act of 2005 which promoted transmission investment and increased attention to reliability. Early adopters of formula rates included midwestern and New England utilities and the Southern Company. Many of the formula rate mechanisms approved by the FERC have been the product of settlements.

[64] A useful discussion of early precedents for formula rates at the FERC can be found in a March 1976 administrative law judge decision in Docket No. RP75-97 for Hampshire Gas.

At the 2004 start date of PSE's sample period about 15 of the 56 sampled U.S. transmitters in PSE's econometric sample operated under formula rates. By the 2016 end point of PSE's sample period fewer than 15 sampled transmitters *did not* operate under formula rates. PEG is not aware of any transmitters that abandoned formula rate plans during PSE's sample period. Thus, about half of the U.S. transmitters in the PSE sample received approval of formula rate plans during the PSE sample period.

C.3 ISOs and RTOs

As another means to promote development of bulk power markets and non-discriminatory transmission service, in 1996 the FERC encouraged electric utilities to transfer operation of their transmission systems to an independent system operator. In this arrangement, the transfer of control was voluntary and utilities retained ownership of their portions of the grid. ISOs have scheduled services, managed transmission facility maintenance, provided transmission system information to potential customers, ensured short-term grid reliability, and considered remedies for network constraints. ISO services must be provided under an OATT that is not discriminatory to any market participant. These tariffs recover the ISO's cost, which sometimes including the sizable charges of transmission owners for the use of their systems.

In a 1999 order, the FERC pushed for further structural change in the markets for transmission services by encouraging formation of RTOs. The FERC has higher requirements for RTO approval than for ISOs. For example, RTO tariffs must include the transmission owners' cost. RTOs also typically have a larger footprint, serving multiple states while some ISOs serves a single state or Canadian province.

Several ISOs were formed between 1996 and 2000. The FERC has approved applications for RTOs that serve much of the Northeast, East Central, and Great Plains regions of the U.S. The Midwest ISO (dba today as Midcontinent ISO) and PJM Interconnection were approved for RTO status in 2001, while the Southwest Power Pool and ISO New England became RTOs in 2004. ISOs that are not RTOs currently operate in some Canadian provinces, New York, Texas, and California.[65] Relatively few utilities in the southeastern and intermountain states are members of an ISO or RTO.[66] The charges of

[65] Texas transmitters in the Electricity Reliability Council of Texas are generally not subject to FERC regulation.

[66] In recent years, several South Central U.S. transmitters joined MISO.

transmission owners who are members of ISOs and RTOs may still be reset in periodic rate cases or formula rate plans.

C.4 Energy Policy Act of 2005

Beginning in the late 1970s, U.S. transmission capex trended downward in real terms. Part of this decline was due to low generation plant additions, particularly in the late 1990s. Other reasons for the decline in capex were difficulties in siting transmission lines. The grid did not always handle the demands placed on it by growing bulk power market transactions, and congestion costs occurred in some areas. The decline in capex eventually led to concerns by the FERC and other policymakers that transmitters were not sufficiently investing in their networks, thus jeopardizing the success of bulk power markets.

This is the context in which the Energy Policy Act of 2005 was passed. It affected transmission investment and many other aspects of transmitter operations. The Act gave the FERC authority to oversee transmission reliability. The FERC could sanction mandatory reliability standards and penalties. Development of these standards, now called Critical Infrastructure Protection standards, was largely delegated to the North American Electric Reliability Corporation ("NERC"). Numerous NERC Reliability Standards were approved by the FERC in 2007. These standards are intended to prevent reliability issues resulting from numerous sources including operation and maintenance of the system, resource adequacy, cybersecurity, and cooperation between operators.

Concerns about siting of transmission lines were somewhat mitigated by a provision allowing the federal government to designate "national interest electric transmission corridors" to mitigate areas of significant transmission congestion. This provision has proven to be somewhat controversial, as it is viewed as a federal intrusion into an issue that states have traditionally addressed. Nevertheless, it is likely that potential federal oversight of transmission siting encouraged state regulators to expedite transmission siting proceedings.

Concerns about transmission owner incentives were addressed by the addition of a mandate for the FERC to incentivize both transmission investments and participation in an RTO or ISO. The Energy Policy Act of 2005 required FERC to adopt a rule that would accomplish the following:

> ''(1) promote reliable and economically efficient transmission and generation of electricity **by promoting capital investment in the enlargement, improvement, maintenance, and operation**

of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities;

''(2) **provide a return on equity that attracts new investment in transmission facilities** (including related transmission technologies);

''(3) **encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities**; and

''(4) allow recovery of—

> ''(A) all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to section 215; and
>
> ''(B) all prudently incurred costs related to transmission infrastructure development pursuant to section 216.[67]

In FERC Orders 679 and 679-A, released in 2006, the FERC adopted a wide range of incentives to encourage transmission investment. These incentives included the ability for a transmitter to include 100% of CWIP in rate base, ROE premiums for plant additions resulting from some projects, accelerated depreciation, full cost recovery for abandoned facilities and pre-operation costs, and cost tracking for individual projects. In addition, ROE premiums were permitted for transmitters who joined or remained in an RTO or ISO.

In this framework, a transmission operator would need to file an application and show that the requested incentives were appropriate. These applications could also be tied to a request by a transmitter to switch from a fixed rate adjusted only in a rate proceeding to a formula rate that is updated annually. Between 2006 and 2012, the FERC reviewed more than 80 applications for transmission incentives related to proposed projects.

[67] Energy Policy Act of 2005, Title XII, Sec. 1241 (b).

Appendix D: PEG Credentials

PEG is an economic consulting firm with headquarters in Madison, Wisconsin USA. We are a leading consultancy on incentive regulation and statistical research on the performance of electric and natural gas utilities. Our personnel have over sixty years of experience in these fields, which share a common foundation in economic statistics. Work for a mix of utilities, regulators, government agencies, and consumer and environmental organizations has given us a reputation for objectivity and dedication to good research methods. Our practice is international in scope and has included dozens of projects in Canada.

Mark Newton Lowry, the senior author and principal investigator for this project, is the President of PEG. He has over thirty years of experience as an industry economist, most of which have been spent addressing utility issues. He has prepared productivity research and testimony in more than 30 separate proceedings. Author of dozens of professional publications, Dr. Lowry has chaired numerous conferences on performance measurement and utility regulation. He recently coauthored two influential white papers on IR for Lawrence Berkeley National Laboratory. In the last five years, he has played a prominent role in IR proceedings in Alberta, British Columbia, Colorado, Hawaii, Minnesota, and Quebec as well as Ontario. He holds a PhD in applied economics from the University of Wisconsin.

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COMMONWEALTH OF MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES

MASSACHUSETTS ELECTRIC COMPANY
NANTUCKET ELECTRIC COMPANY
D/B/A NATIONAL GRID

D.P.U 18-150

INVESTIGATION AS TO
THE PROPRIETY OF
PROPOSED TARIFF CHANGES

DIRECT TESTIMONY OF
DR. MARK NEWTON LOWRY

On behalf of

THE OFFICE OF THE ATTORNEY GENERAL

MARCH 22, 2019

DIRECT TESTIMONY OF
MARK NEWTON LOWRY
on behalf of the
THE OFFICE OF THE ATTORNEY GENERAL

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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Mark Newton Lowry. My business address is 44 East Mifflin St., Suite 601, Madison, WI 53703.

Q. What is your present occupation?

A. I am the President of Pacific Economics Group Research LLC ("PEG"), an economic consulting firm with headquarters in Madison, Wisconsin. Our primary focus is economics of energy utility regulation. Performance-based ratemaking ("PBR") and statistical research on the cost performance of energy utilities are areas of expertise. Our personnel have over sixty years of experience in these fields, which share a common foundation in economic statistics. Our work on behalf of utilities, regulators, government agencies, and consumer and environmental groups has given us a reputation for objectivity and dedication to sound research methods. Our practice is international in scope and includes numerous projects in Canada. The Ontario Energy Board ("OEB") is a longstanding client that we have helped to become a world PBR leader.

Q. Please summarize your professional experience.

A: I have over thirty years of experience as an industry economist, most of which have been spent addressing energy utility issues. I have presented in testimony results of research I supervised on PBR and the productivity of energy utilities in more than 30 proceedings. My most recent study of the productivity trends of power distributors was published by Lawrence

Berkeley National Laboratory in 2017.[1] I have authored dozens of professional publications on my work and have spoken at many conferences on PBR and performance measurement.

Before joining PEG, I was a vice president at Laurits R. Christensen Associates ("LRCA"), where I prepared research and testimony on energy utility input price and productivity trends. I also spent several years as an assistant professor in an applied economics department at the main campus of the Pennsylvania State University. A copy of my resume is attached as Schedule MNL-1.

Q. Where have you previously testified?

A: I have testified on PBR and/or cost performance before regulatory commissions in Alberta, British Columbia, California, Colorado, Delaware, the District of Columbia, Georgia, Hawaii, Illinois, Kentucky, Maine, Maryland, Massachusetts, Minnesota, Missouri, Oklahoma, New Jersey, New York, Ontario, Pennsylvania, Québec, Rhode Island, Texas, Vermont, and Washington state.

Q. What is your prior experience as a witness in Massachusetts?

A: I was the witness for Boston Gas Company on productivity and PBR plan design in the first case to establish a PBR plan with an indexed attrition relief mechanism for a Massachusetts energy utility.[2] I have also testified before the Department of Public Utilities ("Department")

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1 Lowry, M., Deason, J., Makos, M. and Schwartz, L., *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric* Utilities, for Lawrence Berkeley National Laboratory, July 2017.

2 D.P.U. 96-50, *Investigation by the Department of Public Utilities on its own motion as to the propriety of the rates and charges set forth in the following tariffs: M.D.P.U. Nos. 944 through 970, filed with the Department on May*

on PBR and productivity issues for Unitil.[3] I filed comments on PBR on behalf of Commonwealth Energy and worked for a coalition of Massachusetts utilities on service quality regulation. Finally, I prepared electric power distributor productivity research for NSTAR Electric that provided the basis for the Company's X factor in an early PBR plan established in settlement.[4]

Q. Please describe your educational background.

A. I attended Princeton University before earning a bachelor's degree in Ibero-American Studies and a PhD in Applied Economics from the University of Wisconsin-Madison.

II. PURPOSE OF TESTIMONY

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Office of the Attorney General ("AGO").

Q. What is the purpose of your testimony?

17, 1996 to become effective June 1, 1996 by Boston Gas Company; and investigation of the proposal of Boston Gas Company to implement performance-based ratemaking, and a plan to exit the merchant function.

[3] D.P.U. 13-90, *Petition of Fitchburg Gas and Electric Light Company (Electric Division) d/b/a Unitil to the Department of Public Utilities for approval of the rates and charges set forth in Tariffs M.D.P.U. Nos. 229 through 238, and approval of an increase in base distribution rates for electric service pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., filed with the Department on July 15, 2013, to be effective August 1, 2013.*

[4] D.P.U. 05-85, *Petition of Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company and NSTAR Gas Company (collectively, the "Companies") for approval by the Department of Telecommunications and Energy of (1) a Joint Motion for Approval of Settlement Agreement and (2) the Settlement Agreement entered into by the Companies with the Attorney General of Massachusetts, the Low-Income Energy Affordability Network and Associated Industries of Massachusetts.*

A. Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("NGrid" or "the Company") have filed a petition with the Department for an increase in the Company's base rates. The petition includes a proposal for a five-year PBR plan. The Company's proposed plan is similar to the plan the Department recently approved for NStar Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy ("Eversource").[5] Under its proposed plan, NGrid's allowed base revenue would be escalated by a revenue cap index ("RCI") with a formula that includes an inflation measure and an X factor.[6]

NGrid's X factor proposal is based on index research and testimony by Dr. Mark Meitzen of LRCA. Here, LRCA used a research methodology similar to the methodology they used in D.P.U. 17-05.[7] My testimony will address the X factor issue. I evaluate the work of LRCA and discuss some general problems with the capital cost specification LRCA used. In addition, I briefly discuss problems with the National Economic Research Associates ("NERA") research which was the foundation for LRCA's study. Next, I propose an alternative X factor that is based on my company's research. An extensive report on PEG's research and X factor issues is attached as Schedule MNL-2. This report is intended to provide the Department with information on RCI design that the Department can use in this and future PBR proceedings.

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[5] D.P.U. 17-05, *Order Establishing Eversource's Revenue Requirement* (November 30, 2017).

[6] Exh. NG-LRK-1, at 5. The Company's PBR Proposal includes seven components: (1) an inflation factor; (2) a "productivity offset" or X-factor formula; (3) a consumer dividend; (4) a Z factor; (5) an earnings sharing mechanism; (6) a plan term; and (7) performance incentive mechanisms and scorecard metrics.

[7] Exh. NG-MEM-1; *see also*, D.P.U. 17-05, *Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for Approval of General Increases in Base Distribution Rates for Electric Service and Approval of a Performance Based Ratemaking Mechanism*, Exh. ES-PBRM-1.

III. X FACTOR ISSUES

A. CRITIQUE OF THE LRCA EVIDENCE

Q. Please summarize LRCA's testimony in this proceeding.

A: LRCA's study for NGrid has its origins in power distribution productivity research by NERA. The study employs a monetary approach to the measurement of capital cost called the one-hoss-shay ("OHS") method, which specifies that the quantity of capital resulting from the total value of plant additions in a given year is constant until the plant is retired at the end of its estimated average service life. LRCA's study assumes a 33-year average service life. I have criticized the NERA/LRCA approach to measuring capital cost in several Canadian proceedings.[8]

Using data for the fifteen-year 2002-2016 period, LRCA reported a -0.13% total factor productivity ("TFP") trend for the U.S. power distribution industry and a remarkably brisk 3.50% input price trend. These results were used to calculate input price and productivity differentials, a common practice in Massachusetts regulation. The sum of the resultant -0.95% productivity differential and -0.77% input price differential is **-1.72%**, which LRCA and NGrid have proposed as the base X factor. To this, NGrid proposes to add a 0.40% consumer dividend in years when inflation exceeds 2%. The 0.40% value is based on statistical benchmarking work by Dr. Lawrence Kaufmann of Kaufmann Consulting.

Q. Why did LRCA use the productivity research methods of another consultant?

[8] *See, e.g.*, Alberta Utilities Commission Proceedings 566 and 20414, and Ontario Energy Board Cases EB-2016-0152 and EB-2017-0307.

A. In 2010, the Alberta Utilities Commission ("AUC") retained NERA to prepare a productivity study for use in the calibration of X factors in a new PBR regime for provincial gas and electric power distributors. NERA's study of the productivity trends of U.S. power distributors featured a long sample period starting in 1973, and NERA advocated for an X factor based on results for the *full* sample period. Costs of several customer services were excluded from NERA's study since these services are not provided by Alberta distributors. Another unusual feature of NERA's study was the negative total factor productivity ("TFP") trend of distributors after 2000. This finding runs counter to the results that PEG obtains with methods that we have used in past studies for Massachusetts utilities.

Rather than undertake original productivity research, some utility witnesses in this proceeding embraced the results of NERA's study, but only for the period after 2000. The AUC rejected the recommendations of utility witnesses for negative X factors. Instead, AUC chose a base productivity trend of 0.96% based on NERA's results for the full sample period.

In the AUC's second generic PBR proceeding NERA did not testify.[9] The Brattle Group and LRCA separately testified on behalf of utilities and each updated NERA's study, with some modifications, rather than undertaking original studies.[10] Both consultancies based their X factor recommendations on results since 2000. LRCA argued that index research for X factor calibration should be "forward looking" and based on results for a national sample. The witness for LRCA, Dr. Meitzen, had extensive experience in the field of telecommunications productivity measurement but had never testified on energy utility productivity. The AUC

[9] Alberta Utilities Commission, Proceeding 20414.

[10] Alberta Utilities Commission, Proceeding 20414.

once again rejected the recommendations of the utility witnesses and instead approved an X factor of 0.30%. This decision was informed by PEG evidence of a TFP trend of 0.43% for the full sample of U.S. electric power distributors using an alternative capital cost specification.

Q. Has the productivity trend of U.S. power distributors been considered in subsequent PBR proceedings?

A. Yes. NERA subsequently presented an updated version of its power distribution productivity study in Ontario testimony to establish a PBR plan for two merging gas utilities. NERA and the OEB's consultant (PEG) both recommended a 0% base TFP trend for these utilities, which was ultimately approved by the Board.

Even though LRCA did not prevail on the X factor issue in Alberta, Eversource retained them to prepare index research for Eversource's PBR application in D.P.U. 17-05. In its study for Eversource, LRCA's methods remained quite similar to that of NERA. One notable change was LRCA's use of the number of customers as the output index. However, LRCA, like NERA, excluded costs of customer services and administrative and general tasks even though these costs are incurred by Eversource and were included by NERA in earlier research and testimony for Central Maine Power.[11] LRCA also retained NERA's capital cost methods. In addition to a substantially negative productivity differential, LRCA computed a substantially negative input price differential. The Department utilized LRCA's research in D.P.U. 17-05 and sanctioned LRCA's use of OHS but approved a lower X factor than LRCA

[11] Maine Public Utilities Commission, Docket 1999-00666.

recommended.

Recently, in a Québec proceeding to design an RCI for Hydro-Québec Distribution, the Régie de l'énergie considered the X factor issue.[12] PEG was a witness in this proceeding for industrial intervenors. With full knowledge of the Department's decision in D.P.U. 17-05 and of PEG's critique of the NERA/LRCA methodology, the Régie chose a 0.30% base productivity trend.

Q. What is your assessment of LRCA's X factor evidence for NGrid?

A. I have serious concerns about some of the methods used in LRCA's research for NGrid. Most importantly, I believe that LRCA, like NERA, used the OHS approach to measuring capital cost incorrectly. The benchmark year adjustment is wrong, and the assumed average service life of distribution assets is too low. Results are very sensitive to the assumed average service life. The average service lives of distribution assets have been rising for years and a 36-year assumption is more realistic. LRCA's input price research is even more problematic than its productivity research. Taken together, LRCA's errors materially suppress the indicated X factor in the Company's favor.

Q. Please explain your reservations about LRCA's input price research.

A. The capital price index that LRCA uses includes capital gains because plant is valued in replacement dollars. This matters because an unusual run-up in electric power distribution

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[12] Québec Régie de l'énergie, R-4011-2017.

construction costs, due in part to rising copper prices, occurred during these years that is unlikely to be repeated in the next five years. LRCA's input price index captured this run-up but not the offsetting capital gains. The problem was compounded by LRCA's relatively short sample period. LRCA's treatment of the input price differential runs counter to their stated goal of conducting a forward-looking study. In their recent Ontario testimony, NERA calculated an input price differential using data from the 1973-2016 period. NERA witness Dr. Jeff Makholm stated that "For input price growth, I find no statistically significant input price differential (which is the result I have always found for the US distribution data set)."[13]

Q. Have you tested the sensitivity of LRCA's results to the problems you discuss?

A. Yes. PEG used LRCA's data but then incorporated an improved OHS specification using a 36 year average service life and a more appropriate input price index. We found that the TFP trends of U.S. power distributors averaged 0.30% from 2003 to 2016 and that the input price trend was only 2.17%. The resulting -0.52% productivity differential and 0.56% input price differential sum to a 0.04% base X factor. The analogous results for Northeastern distributors are a -0.33% TFP trend, a -1.15% productivity differential, and a 0.51% input price differential. These sum to a -0.64% base X factor.

Q. Are you comfortable with LRCA's use of the number of customers as the output index

[13] OEB proceeding EB-2017-0307, Exh. B, Tab 2, at 32 (November 23, 2017).

in its productivity work?

A. Not entirely. I acknowledge that the number of customers is commonly used to measure output in energy distributor productivity studies, including several studies that I have directed. The number of customers has also been used as the scale escalator in some RCI formulas. However, I explain at some length in Section 3.1 of my report (Schedule MNL-2) that, contrary to the unpersuasive representations of LRCA, the number of customers need not be used as the sole output measure in an RCI calibration study. Multidimensional scale indexes can instead be used, with weights based on econometric research on the cost impact of various candidate scale variables. Such indexes would likely assign a large weight to customer growth but might include other scale variables such as peak demand. Peak demand rose more rapidly than the number of customers served for many U.S. power distributors during the last fifteen years.

Q. Do you have other concerns with LRCA's work?

A. Yes, although these problems do not significantly influence LRCA's results. Here are some examples.

- LRCA includes pensions and benefits in its study even though these are slated for tracker treatment in the NGrid plan.
- LRCA treated pension and benefit expenses as material and service costs rather than labor costs;
- Some mergers were not correctly handled; and
- The sample size is unnecessarily small. This apparently is due to LRCA's reliance on the

NERA data. The capital quantity calculations require many years of plant value data. As NGrid states in response to information request DPU-NG-13-8:

> Dr. Meitzen originally obtained the dataset from the NERA study that was submitted in Alberta. FERC only posts Form 1 data on its website back to 1994. Thus, the required capital data back to 1964 for companies not in the original NERA sample would require extensive effort to compile.[14]

B. GENERAL CONCERNS ABOUT ONE HOSS SHAY

Q. Please discuss some of the general disadvantages of OHS.

A. In my view, the geometric decay ("GD") approach to calculating utility capital cost is a more appropriate approach than OHS for X factor calibration research. Under GD, the quantity of capital from plant additions is assumed to decline gradually over time. Capital cost trends using GD reflect depreciation in a manner similar to that resulting from the capital cost methods used in Massachusetts to calculate utility revenue requirements. This matters since the RCI is designed to adjust allowed revenue between rate cases.

The LRCA/NERA approach to OHS, in contrast, abstracts from depreciation. Even though NGrid acknowledged in response to information request AG-23-8 that assets that exhibit a OHS service flow pattern depreciate in value, neither the capital quantity index nor the capital service price reflect it.[15]

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[14] Exh. DPU-NG-13-8.

[15] Exh. AG-23-8.

Here are some other general concerns I have with the OHS method:

- OHS formulas are more difficult to code, review, and understand. The sensitivity of results to the average service life assumption is one of many problems.
- Studies have found that prices in many used asset markets are inconsistent with the OHS assumption.[16]
- Many electric power distributor assets do not deliver a constant flow of services. Even if they did, the OHS specification of a constant service flow does not make sense for heterogeneous groups of assets with varied service lives like those typically used in LRCA's study. The following quote from a capital cost manual published by the Organization of Economic Cooperation and Development explains this point:

> In practice, cohorts of assets are considered for measurement, not single assets. Also, asset groups are never truly homogenous but combine similar types of assets. When dealing with cohorts, retirement distributions must be invoked because it is implausible that all capital goods of the same cohort retire at the same moment in time. Thus, it is not enough to reason in terms of a single asset but age efficiency and age-price profiles have to be combined with retirement patterns to measure productive and wealth stocks and depreciation for cohorts of asset classes. An important result from the literature, dealt with at some length in the Manual is that, for a cohort of assets, the combined age-efficiency and retirement profile or the combined age-price and retirement profile often resemble a geometric pattern, i.e. a decline at a constant rate. While this may appear to be a technical point, it has major practical advantages for capital measurement. *The Manual therefore recommends the use of geometric patterns for depreciation* because they tend to be empirically supported, conceptually correct and easy to implement.[17]

16 For a survey of these studies see Barbara M. Fraumeni, "The Measurement of Depreciation in the U.S. National Income and Product Accounts," *Survey of Current Business*, July 1997, pp. 7-23. A recent Canadian study is John Baldwin, Huju Liu, and Marc Tanguay, "An Update on Depreciation Rates for the Canadian Productivity Accounts," *The Canadian Productivity Review*, Catalogue No. 15-206-X, January 2015.

17 OECD, *Measuring Capital OECD Manual 2009,* Second Edition, at 12.

For these and other reasons, the OHS approach to measuring capital cost is less widely used than GD in productivity studies.

Q. Which approach to measuring capital cost is more widely used in X factor calibration studies?

A. To date, the GD approach has been most widely used in studies of this kind. For example, it is frequently used today in productivity and other statistical cost research by consultants to Ontario energy utilities. GD was also used in the great majority of LRCA's productivity studies before Dr. Meitzen started testifying for power distributors. Dr. Meitzen himself has used GD in numerous productivity studies that he prepared for telecommunications utilities and has enumerated several advantages of GD in reports that he authored. For example, this quote supporting GD, from a report Dr. Meitzen coauthored for the Peruvian telecom regulator OSIPTEL, reprises several of the points that I have already made:

> Productivity studies that are based on net stocks of capital generally employ this [geometric decay] assumption, since their net stocks are based on straight-line depreciation assumptions. The geometric pattern is based on the assumption that the productivity of an asset decreases at a constant percentage rate… Numerous productivity studies have employed this assumption, including our previous studies of the U.S. telephone industry. Hulten also notes that most empirical studies of depreciation support the use of the geometric function over the one-hoss shay or straight-line function.
>
> There are two sources for the decline in the efficiency of an asset as it ages. First, the asset may produce fewer services as it ages. Second, an asset may require more labor or materials (e.g., more maintenance) to provide the same level of services. For a cohort of assets (i.e., assets of the same asset class and the same vintage) there is a third source of efficiency decline, namely the retirement of assets. Retirement of a cohort of assets will generally occur over a number of years. As individual assets are removed from production, their contribution to the cohort will also be removed, and the overall productivity of the cohort will be reduced.[18]

[18] L. R. Christensen, M. Meitzen, P. E. Schoech, L. D. Kirsch, C. A. Herrera, and S. M. Schroeder *Price Cap Design and X Factor Estimation for Peruvian Telecommunications Regulation*, Report to OSIPTEL, May 1999, p. 68.

Q. If GD makes sense for telecommunications, how does Dr. Meitzen defend his use of the OHS method in his three power distribution productivity studies?

A. Dr. Meitzen claims in response to information request AG-23-3(c) that rapid technological change in telecommunications has caused some assets to be retired prematurely, even if they were previously yielding a constant service flow.[19]

Q. Does this make sense?

A. This is one argument for using GD in telecommunications productivity research. However, Dr. Meitzen enumerates several others. A substantial part of the business of local telecommunications exchange carriers consists of wires and poles. Moreover, technological obsolescence is sometimes observed in the business of a power distributor as well. For example, there has been rapid change in the last decade in technologies for metering, billing, pricing, and customer services. New smart grid technologies are frequently discussed in the trade press and considered for use in Massachusetts.

I should also note that many of the other arguments that Dr. Meitzen made in support of GD in the OSIPTEL report also apply to power distributors. For example, the service lives in a cohort of annual distribution plant additions are varied. Moreover, the cost of maintaining some distribution assets rises as they age. NGrid stated this in response to information request AG-15-3(f):

> The question asks whether keeping distribution plant in "good working order …" tends to require increasing *real* maintenance costs. It is not discernible whether the question intended to distinguish *real* from *nominal* expenditures. However, for assets that require regular maintenance, the costs associated with

[19] Exh. AG-23-3(c).

> keeping the plant in good working order tend to increase over the life of the asset, until it is retired. National Grid's experience, as shared with the sponsor, is that maintenance costs can increase as assets age for some specific assets. [20]

C. ORIGINAL PEG RESEARCH

Q. Have you undertaken an independent indexing study for the AGO using PEG's preferred methods and data?

A. Yes. To provide the Department with better information, PEG used a larger sample of distributors than LRCA and a longer sample period, which included 2017, the most recent year for which data are currently available. PEG calculated candidate base X factors using two alternative methods: GD and the Kahn Method. Using the GD approach to capital cost, the TFP growth of all utilities in our sample averaged 0.33%, the productivity differential was -0.65%, and the input price differential was -0.06%. The analogous results for Northeastern distributors are a 0.36% TFP trend, a -0.62% productivity differential, and a -0.12% input price differential.

Q. Please explain the Kahn Method.

A. This method for setting X factors was developed by noted regulatory economist Alfred Kahn, who was a professor at Cornell University. The Kahn method has been used several times by the FERC to set the X factors in PBR plans for interstate oil pipelines. It is easy to use and employs a traditional approach to calculating capital cost. The X factor resulting from such a calculation reflects the input price and productivity differentials of utilities without having to calculate them.

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[20] Exh. AG-15-3(f).

Applying the Kahn method to NGrid, PEG calculated trends in the cost of base rate inputs of a sample of power distributors using FERC Form 1 data and traditional cost accounting. We then solved for the value of X, which caused the trend in distributor cost to equal the trend in a particular kind of RCI on average. The generic RCI used the gross domestic product price index ("GDP-PI") as the inflation measure. The analysis excludes costs that are likely to be addressed by trackers and riders in NGrid's plan. As discussed further in our report (Schedule MNL-2), we calculated a base X factor for NGrid using the Kahn method using national data and arrived at a value of -0.41%. The analogous result using Northeast data was -0.45%.

D. X FACTOR RECOMMENDATIONS

Q. What conclusions do you draw concerning the base X factor?

A. Our review of the assembled productivity evidence reveals the following facts:

Using PEG's upgraded OHS capital cost methodology and LRCA's data, the productivity differential for the full U.S. sample is -0.52% and the inflation differential is 0.56%. These indicate a base X factor of **0.04%.** The indicated base X factor using corrected OHS and Northeast data is **-0.64%.**

Using the GD capital cost methodology, PEG's own data, and research results for a larger sample and a longer sample period produces a productivity differential of -0.65% and an input price differential of -0.06%. This indicates a base X factor of **-0.71%.** The indicated base X factor using Northeast data is **-0.74%.**

The indicated base X factor using the Kahn method is **-0.41%.**

Other plan provisions should also be considered when choosing the X factor:

- The stretch factor is an important part of customer benefits from any PBR plan. A 0.40% value has been recommended for a reason: NGrid has been spending large sums on capex in recent years and its cost of service is, at least temporarily, high. The proposed 0.40% stretch factor is contingent on 2% inflation. This provision is rare in PBR plans. Productivity growth does not vary with inflation. Inflation has been sluggish in recent years and this may continue.

- NGrid is requesting tracker treatment for certain grid modernization and electric vehicle capital expenditures ("capex") that are now and will in the future be incurred by the utilities sampled in productivity studies. These kinds of capex will be incurred by the utilities used in future X factor calibration studies. If PBR continues, there is then a danger that customers will pay twice for the same capital expenditures.

- NGrid has also asked for higher vegetation management expenses to be tracked. This is also unusual in PBR plans but may be defensible if an increase in service quality is expected.

- NGrid is not requesting a scale escalator for its RCI growth formula. However, our analysis has shown that expected customer growth is not an implicit stretch factor. Trends in other dimensions of scale are also pertinent. Peak demand growth is widely recognized to be a major driver of power distribution cost, and this has been slowed by an aggressive DSM program.

Based on the assembled evidence, and assuming that the RCI does not include an explicit scale escalator as proposed, PEG recommends a base X factor of **-0.60%** for NGrid.

Further, we believe that the Department should recognize that there are a range of methodologies that warrant consideration when choosing X factors. The 0.40% additional stretch factor should not be contingent on inflation. Therefore, NGrid's total X factor should then be -0.20%.

Q. Does this conclude your direct testimony?

A. Yes.

PBR Plan Design for National Grid in Massachusetts

March 22, 2019

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1. Introduction and Summary

1.1. Introduction

On November 15, 2018, National Grid USA filed an application with the Massachusetts Department of Public Utilities ("Department") concerning rates for the power distributor services of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("NGrid" or the "Company"). The Company's petition proposes a five-year Performance-Based Ratemaking ("PBR") plan which includes a change in base distribution rates, followed by a PBR mechanism ("PBRM") to adjust rates annually for four years.[1] The proposed plan is similar to that which the Department recently approved for power distributor services of NStar Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy ("Eversource").[2] If approved by the Department, NGrid's plan would allow the Company's base revenue to escalate by a revenue cap index ("RCI") with a formula that includes an inflation measure and an X factor.

The X factor is a key issue in PBR plans of this type. NGrid's X factor proposal is based on input price and productivity research and testimony by Dr. Mark Meitzen of the consulting firm Laurits R. Christensen Associates ("LRCA"). Dr. Meitzen used a research methodology like the one he employed in testimony for Eversource.[3]

NGrid is one of the largest power distributors in the Commonwealth. LRCA's research supporting the X factor approved for Eversource was controversial and vigorously contested.[4] These considerations increase the importance of a careful appraisal of NGrid's PBR proposal and supportive index research. Controversial technical work and PBR provisions should be highlighted and, where warranted, challenged to avoid undesirable precedents for the NGrid and other Massachusetts utilities in the future.

Pacific Economics Group Research ("PEG") is the leading North American consultancy in the field of energy utility input price and productivity research. PEG has consulted with regulators, utilities,

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[1] Exh. NG-PBRP-1, at 50.

[2] D.P.U. 17-05, *Order Establishing Eversource's Revenue Requirement* (November 30, 2017).

[3] *See generally*, D.P.U. 17-05, Exhs. ES-PBRM-1; ES-PBRM-Rebuttal-1.

[4] *See, e.g.*, D.P.U. 17-05, Exhs. AG/DED-1; ES-AG/DED-Surrebuttal-1.

consumer groups and government agencies; giving PEG a reputation for objectivity and advocacy for sound regulations. Our personnel have testified several times for utilities in Massachusetts and other New England states. The Attorney General of Massachusetts ("AGO") has retained PEG to prepare analysis and commentary on LRCA's research and testimony and certain aspects of NGrid's PBR proposal.

Following a summary of PEG's findings, Section 2 of this report reviews pertinent background information regarding NGrid's proposed PBR plan. In Section 3, the nature of productivity research and its role in RCI design are discussed. In Section 4, PEG critiques LRCA's methodologies and findings using alternative methods. Section 5 presents results of original X factor calibration research that PEG prepared for the AGO. Finally, Section 6 discusses the stretch factor and PEG's X factor recommendations. Appendices address some of the more technical issues raised in the report in more detail.

1.2. Summary

X Factor

PEG has serious concerns about some of the methods used in LRCA's research for NGrid. Most importantly, we believe that LRCA has used the one-hoss-shay ("OHS") approach to measuring capital cost incorrectly and that their errors materially suppress the indicated X factor in the Company's favor. With an improved OHS approach and LRCA's data, PEG finds using national data that the total factor productivity ("TFP") trends of U.S. power distributors averaged 0.30% from 2003 to 2016. The productivity differential was -0.52% and the input price differential was 0.56%. The indicated base X factor would be **0.04%** and not the **-1.72%** that LRCA reports. Further, the OHS method has general disadvantages in X factor calibration, which are discussed below.

PEG also calculated a base X factor using two alternative methods: geometric decay ("GD") and the Kahn Method. Our research used a larger sample of distributors than LRCA did and a longer sample period that included 2017. Using GD, the TFP growth of all utilities in the national sample averaged 0.33%. The productivity differential was -0.65% and the input price differential was -0.06%. These findings indicate a base X factor of **-0.71%.** The indicated base X factor using Northeast data is **-0.74%.** The base X factor using the Kahn method and national data was **-0.41%.** The base X factor using the Kahn method and Northeast data was **-0.45**%. The stretch factor would be operative only if inflation exceeds 2%.

Other plan provisions also merit consideration in the choice of an X factor. The stretch factor is contingent on inflation exceeding 2%. An uptick in vegetation management expenses would be tracked. A tracker treatment is proposed for certain grid modernization and electric vehicle capital expenditures ("capex"). These kinds of capex will raise the cost of U.S. distributors in productivity studies used to set X factors.

Based on the assembled evidence and assuming that the RCI as proposed does not have an explicit scale escalator, PEG recommends a **-0.60%** base X factor for NGrid. To this would be added the 0.40% stretch factor. The stretch factor would apply whether or not inflation exceeded 2%.

2. Background

NGrid's proposed PBR plan is essentially a multi-year rate plan ("MRP") that includes an RCI for allowed revenue escalation and a performance metric system. The term of the plan would be five years. Initial rates would be established in a general rate case. Allowed base revenue would then be escalated for four years by an RCI with an inflation minus a productivity offset (i.e., I – X) formula. A decoupling mechanism would ensure that actual revenue would track allowed revenue closely.

The RCI formula would feature the gross domestic product price index ("GDP-PI") as the inflation measure. The proposed -1.32% X factor would be the sum of a -1.72% base productivity offset and a 0.40% consumer dividend would be added if inflation exceeds 2%. The base productivity offset would be the sum of a productivity differential and an inflation differential. Thus, the input price and productivity trends of power distributors are both issues in this proceeding.

Some costs would be scheduled for tracker treatment. These would include pension and benefit and demand-side management ("DSM") expenses. Supplemental revenue would be available for an electric vehicle infrastructure program and grid modernization. A Z factor provision would adjust revenue for unforeseeable, exogenous cost changes.[5]

The grid modernization tracker, as proposed, addresses the cost of investments pre-approved by the DPU in grid modernization plan proceedings and the Company's proposed storage program. A grid modernization program was approved in 2018 to allow NGrid to invest in various technologies including Volt/Var Optimization, advanced distribution automation, and feeder monitors over a 3-year term. The Company is required to file a new grid modernization plan during the MRP term. It is unclear how much grid modernization capex will be approved for tracking during the latter years of the term. The storage program has been proposed in this proceeding. If approved, the Company would build several storage projects.

NGrid has another cost tracker that addresses the capital and operation and maintenance ("O&M") costs associated with EV deployment. The Company received approval of Phase 1 of the deployment in 2018 and has proposed Phase 2 of deployment in this proceeding. For Phase 2, the

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[5] Exh. NG-LRK-1, at 7.

Company proposes to deploy charging infrastructure, provide rebates and discounts to customers, provide fleet advisory services, market and evaluation the plan, and undertake research and development.

The Company also proposes to continue to rely on an existing vegetation management tracker to fund the incremental O&M costs of its enhanced vegetation management pilot. The current program was approved in D.P.U. 17-92 for a 4-year period beginning April 1, 2019.[6] The existing program allows the Company to perform targeted vegetation management of worst performing circuits with enhanced clearances including condition assessment and outreach with affected individuals. In the current proceeding, the Company has proposed to expand the vegetation management provision to address the incremental O&M costs of switching to a four-year pruning cycle, as well as to expand the removal of ash trees damaged by the emerald ash borer and oak trees damaged by gypsy moths.

The Company has also proposed to continue its storm fund replenishment tracker to address incremental O&M costs of major storms. This fund allows NGrid to receive funding, net of a deductible per storm, to address major storm costs. To help stabilize the fund, costs of extreme storms would continue to be addressed separately.

The Company has also proposed to include a Z factor, referred to as an exogenous cost adjustment. In order to qualify as an exogenous cost, an event must be beyond the Company's control; arise from a change in accounting requirements, regulatory, judicial, or legislative directives or enactments; be unique to the electric distribution industry rather than the general economy; and exceed a materiality threshold. The materiality threshold would be $3 million per event for 2020, and the Company has proposed to escalate the threshold for each year of the plan by the growth in GDP-PI. Two specific types of events would be explicitly eligible for exogenous cost treatment: severe storms and any excise tax on high-cost employer medical insurance plans under the Patient Protection and Affordable Care Act.

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[6] D.P.U. 17-92, *Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for approval for an Enhanced Vegetation Management Pilot Program and the recovery of associated costs through an Enhanced Vegetation Management Pilot Program Provision, M.D.P.U. No. 1343* (August 13, 2018).

A tiered earnings sharing mechanism ("ESM") would share surplus earnings above a 200 basis point deadband above the allowed return of equity.[7] An efficiency carryover mechanism was considered by NGrid but not proposed.

The performance metric system would include performance incentive mechanisms ("PIMs") for peak load reduction, transportation electrification, EV program cost containment, and "customer ease" as well as the PIMs that are already operational for service quality and DSM. Three new "scorecard metrics" without PIMs are also proposed.[8] The proposal also encompasses a Climate Mitigation and Adaptation Plan.[9]

[7] Exh. NG-LRK-1, at 7.

[8] Exh. NG-LRK-1, at 8-10.

[9] Exh. NG-NG-PBRP-1, at 104-105.

3. Principles for X Factor Calibration

3.1. Productivity Research and its Use in Regulation

This section of the report considers some technical and theoretical issues that arise in input price and productivity research to support X factor choices in PBR plans. Issues are emphasized which arise in our appraisal of NGrid's PBR proposal and the input price and productivity research presented by LRCA.

Productivity Indexes

A productivity index measures the efficiency with which firms use production inputs to achieve certain outputs. The growth in a productivity index is the difference between the growth in an output index ("Outputs") and the growth in an input quantity index ("Inputs").

growth Productivity = growth Outputs – growth Inputs. [1]

That is, productivity grows when the output index rises more rapidly than the input index.

Productivity can be volatile but usually has a rising trend in the longer run. The volatility is typically due to fluctuations in outputs and/or the uneven timing of expenditures. The productivity growth of individual companies tends to be more volatile than the average productivity growth of a group of companies.

The scope of a productivity index depends on the array of inputs addressed by the input quantity index. Partial factor productivity indexes measure productivity in the use of certain inputs such as capital or labor. A *multifactor* productivity index measures productivity in the use of multiple inputs. In Massachusetts, these are usually called *total factor* productivity indexes even though such indexes rarely address the productivity of all inputs.

The output (quantity) index of a firm summarizes growth in its outputs. If the index is multidimensional, then the growth in each output dimension which is itemized is measured by a subindex, and growth in the summary index is a weighted average of the growth in the subindices.

In designing an output index, choices concerning subindices and weights should depend on the way the index is to be used. One possible objective is to measure the impact of output growth on *revenue*. In that event, the subindices should measure trends in *billing determinants* and the weight for each itemized determinant should reflect its share of revenue.[10] A productivity index calculated using a revenue-weighted output index ("$Outputs^R$") will be denoted as $Productivity^R$.

$$growth\ Productivity^R = growth\ Outputs^R - growth\ Inputs. \quad [2a]$$

Another possible objective of output research is to measure the impact of output growth on *cost.* In that event, the index should be constructed from one or more output variables that measure dimensions of "workload" that drive cost. If there is more than one output variable, the weights for these variables should reflect their relative cost impacts. The sensitivity of cost to a small change in the value of a business condition variable is commonly measured by its cost "elasticity." Cost elasticities can be estimated econometrically using data on the operations of utilities. Such estimates provide the basis for elasticity-weighted output indexes.[11] A productivity index calculated using a cost-based output index ("$Outputs^C$") will be denoted as $Productivity^C$.

$$growth\ Productivity^C = growth\ Outputs^C - growth\ Inputs. \quad [2b]$$

This may fairly be described as a "cost efficiency index."

Sources of Productivity Growth

Economists have considered the drivers of productivity growth using mathematical theory and empirical methods.[12] This research has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

A second important productivity growth driver is economies of scale. These economies are realized in the longer run if cost tends to grow less rapidly than operating scale. Incremental scale

[10] This approach to output quantity indexation is due to the French engineer and economist Francois Divisia (1889-1964).

[11] An early discussion of elasticity-weighted output indexes is found in Denny, Michael, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

[12] *See, e.g.*, Denny, Fuss and Waverman, *op. cit.*

economies (and thus productivity growth) will typically be lower the slower is output growth.[13]

A third driver of productivity growth is X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum possible efficiency. Productivity growth will increase to the extent that X inefficiency diminishes. A company's potential for future productivity growth from this source is greater the higher its current inefficiency level is.

Productivity growth is also affected by changes in the miscellaneous business conditions, other than input price inflation and output growth, which affect cost. A good example for a power distributor is forestation. In a suburb or rural area where forestation is increasing, rising vegetation management expenses due to maturing trees will cause operation and maintenance ("O&M") and total factor productivity growth to slow.

System age can drive productivity growth in the short and medium term. Productivity growth tends to be greater to the extent that the initial capital stock is large relative to the need to refurbish or replace aging plant. If a utility requires unusually high replacement capex, capital productivity growth can be unusually slow. On the other hand, productivity growth tends to accelerate in the aftermath of unusually high capex as the surge capital depreciates, thereby reducing the rate of return component of capital cost.

A TFP index with a *revenue*-weighted output index ("TFP^R") has an important driver that doesn't affect a cost efficiency index. This is true since:

$$\begin{aligned} growth\ TFP^R &= growth\ Outputs^R - growth\ Inputs + (growth\ Outputs^C - growth\ Outputs^C) \\ &= (growth\ Outputs^C - growth\ Inputs) + (growth\ Outputs^R - growth\ Outputs^C) \\ &= growth\ MFP^C + (growth\ Outputs^R - growth\ Outputs^C). \end{aligned} \quad [3]$$

Relation [3] shows that the growth in TFP^R can be decomposed into the trend in a cost efficiency index and an "output differential" that measures the difference between the impact that trends in outputs have on revenue and cost.

[13] Incremental scale economies may also depend on the current scale of an enterprise. For example, there may be diminishing incremental returns to scale as enterprises grow.

The output differential is sensitive to changes in external business conditions such as those that drive system use. For example, the revenue of a power distributor may depend chiefly on system use, while cost depends chiefly on system capacity. In that event, mild weather can depress revenue more than cost, reducing the output differential and slowing growth in TFP^R and earnings.

Use of Index Research in Regulation

Revenue Cap Indexes

Cost theory and index logic support the design of RCIs. Consider the following basic result of cost theory:

$$\textit{growth Cost} = \textit{growth Input Prices} - \textit{growth Productivity}^C + \textit{growth Scale}^C.\text{[14]} \qquad [4]$$

The growth in the cost of a company is the difference between the growth in its input price and cost efficiency indexes plus the trend in a consistent cost-based output index. This result provides the basis for a revenue cap escalator of general form:

$$\textit{growth Allowed Revenue}^{Utility} = \textit{growth Input Prices} - X + \textit{growth Scale}^{Utility} \qquad [5a]$$

where

$$X = \overline{TFP^C} + \textit{Stretch}. \qquad [5b]$$

Here X, the “X factor,” reflects a base productivity growth target (“$\overline{TFP^C}$”) that is typically the trend in the TFP^C of the regional or national utility industry or some other peer group. Notably, a cost-based output index should be used in the supportive productivity research. Further, a “stretch factor” is often added to the formula, which slows price cap index growth in a manner that shares the financial benefits of performance improvements which are expected under the PBR plan with customers. Since the X factor often includes *Stretch* it is sometimes said that the productivity research has the goal of “calibrating” (rather than solely determining) X.

An alternative basis for an RCI can be found in index logic. It can be shown that the growth in the cost of an enterprise is the sum of the growth in an appropriately designed input price index and input quantity index:

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[14] *See, e.g.*, Denny, Fuss and Waverman, *op. cit.*

growth Cost = growth Input Prices + growth Input Quantities [6]

Then,

growth Cost = growth Input Prices + growth Scale^C - (*growth Scale*^{C} – *growth Input Quantities*)

= *growth Input Prices – growth Productivity*^{C} + *growth Scale*^{C} [7]

For gas and electric power distributors, the number of customers served is a sensible scale escalator for an RCI. The customers variable typically has the highest estimated cost elasticity amongst the scale variables modelled in econometric research on distribution cost. A scale escalator that includes volumes and peak demand as output variables diminishes a utility's incentive to promote DSM. This is an argument for excluding these variables from an RCI scale escalator.

Relation [6] can then be expanded to obtain the following result:

growth Cost = growth Input Prices + growth Input Quantities + (*growth Customers - growth Customers*)

= *growth Input Prices* – (*growth Customers - growth Inputs*) + *growth Customers*

= *growth Input Prices* – *growth TFP*^{N} + *growth Customers*

where *TFP* ^{N} is a TFP index that uses the number of customers to measure output. This result provides the rationale for the following revenue cap index formula

growth Revenue = growth Input Prices – X + growth Customers [8a]

where

$X = \overline{TFP}^N + Stretch$. [8b]

An equivalent formula is:

growth Revenue – growth Customers

= *growth* (*Revenue/Customer*) = *growth Input Prices – X*. [8c]

This is sometimes called a "revenue per customer" index and, for convenience, this expression will be used to refer to RCIs which conform to either [8a] or [8c].

Inflation Issues

If a macroeconomic inflation index, such as GDP-PI, is used as the inflation measure in a RCI, then Relation [4] can be restated as:

$$\begin{aligned} \textit{growth Cost} &= \textit{growth Input Prices} - \textit{growth Productivity} + \textit{growth Scale} \\ &\quad + \textit{growth GDPPI} - \textit{growth GDPPI} \\ &= \textit{growth GDPPI} - [\textit{growth Productivity} + (\textit{growth GDPPI - growth Input Prices})] \\ &\quad + \textit{growth Scale}. \end{aligned} \qquad [9]$$

Relation [9] shows that cost growth depends on GDP-PI inflation, growth in operating scale and productivity, and on the difference between GDP-PI and utility input price inflation. The difference between GDP-PI and utility input price inflation may be termed the "inflation differential."

The GDP-PI is the U.S. government's featured index of inflation in the prices of the economy's final goods and services.[15] It can then be shown that the trend in the GDP-PI is well-approximated by the difference between the trends in the economy's input price and (multifactor) productivity indexes.

$$\textit{growth GDPPI} = \textit{growth Input Prices}^{Economy} - \textit{growth Productivity}^{Economy}. \qquad [10]$$

The formula for the X factor can then be restated as:

$$X = [(\overline{TFP}^{C} - \overline{TFP}^{Economy}) + (\overline{\textit{Input Prices}}^{Economy} - \overline{\textit{Input Prices}}^{Industry})]. \qquad [11]$$

Here, the first term in parentheses is called the "productivity differential." It is the difference between the TFP trends of the industry and the economy. The second term in parentheses is called the "input price differential." It is the difference between the input price trends of the economy and the industry.

Relation [11] is notable because it has been the basis for the design of several approved X factors in PBR. This approach has been especially popular in New England regulation.[16]

3.2. Capital Specification

Monetary Approaches to Capital Cost and Quantity Measurement

The capital cost specification is critical in research on the productivity trends of energy distributors because the technology of these companies is capital intensive. The cost of capital ("*CK*") includes depreciation expenses, a return on investment, and certain taxes. If the price (unit value) of the asset changes over time this cost may also be net of any capital gains or losses.

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[15] Final goods and services include consumer products, government services, and exports.

[16] This approach has been approved in Massachusetts on several occasions. *See, e.g.*, D.P.U. 96-50, D.T.E. 03-40, D.T.E. 05-27, and D.P.U. 17-05.

Monetary approaches to the measurement of capital prices and quantities are conventionally used in TFP research. Capital cost decomposes into a consistent capital quantity index ("*XK*") and capital price index ("*WK*") such that

$$CK = WK \cdot XK.^{17} \quad [12]$$

Capital quantity indexes are constructed by deflating the value of plant additions using an asset price index and subjecting the resultant quantity estimates to a mechanistic decay specification. In research on the productivity of U.S. energy utilities, Handy Whitman utility construction cost indexes have traditionally been used for this purpose.

In rigorous statistical cost research, it is commonly assumed that a capital good provides a stream of services over some period of time (i.e., service life of the asset). The capital quantity index measures this flow, while the capital price index measures the trend in the price of a unit of capital service. The design of the capital service price index is consistent with the assumption about the service flow. The product of the capital service price index and the capital quantity index is interpreted as the annual cost of using the flow of services.

Alternative Monetary Approaches

Several monetary methods have been established for measuring capital quantity trends. A key issue in the choice between some monetary methods is the pattern of decay in the service flow from capex in a given year. Decay can result from many factors including wear and tear, casualty loss, increased maintenance requirements, and technological obsolescence. The pattern of decay in assets over time is sometimes called the age-efficiency profile. Another issue in the choice between monetary methods is whether plant is valued in historic dollars or replacement dollars. Three monetary methods have been used in X factor calibration research:

1. Geometric Decay ("GD"). Under the GD method, the flow of services from investments in a given year declines at a constant rate ("*d*") over time. The quantity of capital at the end of each period

[17] The growth rate of capital cost equals the sum of the growth rates of the capital price and quantity indexes.

t ("XK_t") is related to the quantity at the end of *last* period and the quantity of gross plant *additions* ("XKA_t") by the following "perpetual inventory" equation:

$$XKt = XK_{t-1} \bullet (1-d) + XKA_t \ . \quad [13a]$$

$$= XK_{t-1} \bullet (1\text{-}d) + \frac{VKA_t}{WKA_t}. \quad [13b]$$

Here *d* is the (constant) rate of decay in the quantity of older capital. In Relation [13b], the quantity of capital added each year is measured by dividing the reported value of gross plant additions by the contemporaneous value of a suitable asset price index ("*WKA*"). In research on the productivity of U.S. energy utilities a Handy Whitman Construction Cost Index is conventionally used for this purpose.

The GD method assumes a replacement (i.e., current dollar) valuation of plant. Replacement valuation differs from the historical (a.k.a. "book") valuation used in North American utility accounting. Cost is computed net of capital gains and the capital service price reflects this.

2. One-Hoss-Shay ("OHS"). Under the OHS method, the flow of services from a capital asset is assumed to be constant until the end of its service life, when it abruptly falls to zero. This is the pattern that is typical of an incandescent light bulb. However, OHS in practice applies this constant flow assumption to plant additions for large groups of assets. The quantity of plant at the end of the year is the sum of the quantity at the end of the prior year plus the quantity of gross plant additions less the quantity of plant retirements ("XKR_t").

$$XK_t = XK_{t-1} + XKA_t - XKR_t. \quad [14a]$$

$$= XK_{t-1} + \frac{VKA_t}{WKA_t} - \frac{VKR_t}{WKA_{t-s}}. \quad [14b]$$

Since utility retirements are valued in historical dollars, the quantity of retirements in year *t* can be calculated by dividing the reported value of retirements by the value of the asset price index for the year when the assets retired were added.

Plant is once again valued at replacement cost. Cost is computed net of capital gains and the capital service price reflects this.

3. Cost of Service ("COS"). The GD and OHS approaches for calculating capital cost use assumptions that are different from those used to calculate capital cost under traditional COS

ratemaking.[18] With both approaches, the trend in capital cost is a simulation of the trend in cost incurred for capital services in a competitive rental market. It may be argued that the derivation of an RCI using index logic (*see supra* 10-11) does not require a service price treatment of the capital price.

An alternative COS approach to measuring capital cost has been developed that decomposes capital cost into a price and quantity index using a simplified version of COS accounting. Capital cost is not intended to simulate the cost of capital services in a competitive rental market. Capital price cannot be represented as a capital service price. This approach is based on the assumptions of straight-line depreciation and historic valuation of plant. The formulae are complicated, making them more difficult to code and review.[19]

Benchmark Year Adjustments

Utilities have various methods for calculating depreciation expenses that they report to regulators. It is, therefore, desirable when calculating capital quantities using a monetary method, to rely on the reporting companies chiefly for the value of gross plant additions but to use a standardized depreciation treatment for all companies. Since some of the plant a utility owns may be 40-60 years old, it is desirable to have gross plant addition data for many years in the past.

For earlier years, the desired gross plant addition data are frequently unavailable. Consequently, it is customary to consider the value of all plant at the end of the limited-data period and then estimate the quantity of capital that it reflects using construction cost indexes from earlier years and assumptions about the historical capex pattern. The year for which this estimate is undertaken is commonly called the "benchmark year" of the capital quantity index. Since the estimate of the capital quantity in the benchmark year is inexact, it is preferable to base capital and total cost research on a sample period that begins many years after the benchmark year. Research on capital and total cost will be less accurate to the extent that this is impossible.

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[18] The OHS assumptions are more markedly different.

[20] *See, e.g.*, Exh. M2, Tab 11.1, Schedule OPG-002, Att. A of the Ontario Energy Board's recent proceeding on Ontario Power Generation Payments Amounts (EB-2016-0152).

Choosing the Right Monetary Approach

The relative merits of alternative monetary approaches to measuring capital cost have been discussed at some length in PBR proceedings.[20] Based on PEG's experience in proceedings of this nature, we believe that the following considerations are particularly relevant:

1. The goal of productivity research in X factor calibration is to find a just and reasonable means to adjust rates between rate applications.

   Productivity studies have many uses but the best methodology for one application may not be best for another application. One use of productivity research is to measure the trend in a utility's operating efficiency. Another use is to calibrate the X factor in a price-cap or revenue-cap index.

   Rate and revenue cap indexes used in MRPs of utilities, including NGrid's proposal, are intended to adjust utility revenue between general rate cases that employ a cost of service approach to capital cost measurement. In North America, the calculation of capital cost for ratemaking typically involves an historical valuation of plant and straight-line depreciation. Absent a rise in the target rate of return, the cost of each asset shrinks over time as depreciation reduces net plant value and the return on rate base.

2. OHS is not preferable to GD as the foundation for a monetary approach to capital quantity measurement.

   The OHS specification is sometimes argued to better fit the service flows of individual utility assets. OHS has been used in some productivity studies filed in proceedings to determine X factors.

   Other considerations suggest that the OHS specification is disadvantageous. Here are some notable problems:

- *OHS is More Difficult to Implement Accurately than GD.* A comparison of equations [13b] and [14b] shows that implementation of GD and OHS both require a deflation of gross plant *additions*. This is straightforward since the years of the additions are known exactly. The

[20] *See, e.g.*, Exh. M2, Tab 11.1, Schedule OPG-002, Att. A of the Ontario Energy Board's recent proceeding on Ontario Power Generation Payments Amounts (EB-2016-0152).

challenge with OHS is that it also requires the deflation of plant *retirements.* The vintages of reported retirements are generally unknown to persons outside the company. OHS practitioners commonly deflate the value of retirements by the value of the construction cost index for a year in the past that reflects the assumed average service life of the assets.

Examining equation [14b], the quantity of capital in a given year will be smaller when the quantity of retirements is larger. The estimated quantity of retirements will be larger when the average service life of the assets is higher. Thus, TFP growth tends to be more rapid under the OHS approach when the average service life that is used in calculations is higher.

PEG's empirical research suggests that productivity results using OHS are quite sensitive to the average service life assumption. Seemingly reasonable service life estimates can produce negative capital quantities for some utilities. In power distribution productivity research in other proceedings, PEG found results using the OHS capital cost specification to be much more sensitive to the assumed average service life of assets than those using GD.[21,22] The sensitivity of OHS results to service life assumptions can be reduced by using plant addition and retirement data that are itemized with respect to asset type. Unfortunately, itemizations of FERC Form 1 plant addition and retirement data are not publicly available before 1994.

It should also be noted that the mathematical coding for GD is particularly intuitive and easy to implement and review. The OHS specification involves a complicated capital service price that lacks intuition. See, by way of illustration, the OHS capital input price formula stated in Exh. NG-MEM-1, at 58. The derivation of an OHS capital service price is discussed in the Appendix.

- *Prices in Many Used Asset Markets are Inconsistent with an OHS Assumption.* Alternative patterns of physical asset decay involve different patterns of asset value depreciation. Accordingly, trends in used asset prices can shed light on asset decay patterns. Several statistical studies of trends in used asset prices have revealed that they are generally not

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[21] *See, e.g.*, Lowry, M.N. and Hovde, D., *PEG Reply Evidence*, Exhibit 20414-X0468, AUC Proceeding 20414, revised June 22, 2016, pp. 15-18.

[22] *See also*, Exh. M2, Tab 11.1, Sch. OPG-002, Att. A of the OEB's EB-2016-0152 proceeding for PEG's attempt to implement an established form of OHS for hydroelectric power generation.

consistent with the OHS assumption.[23] Instead, depreciation patterns, like that commensurate with GD, appear to be the norm for machinery and are generally the norm for buildings as well.[24]

- *An OHS Assumption Does Not Make Sense for Heterogeneous Groups of Assets.* In real-world productivity studies, capital quantity trends are rarely, if ever, calculated for individual assets. Instead, capital quantity trends are calculated from data on the value of plant additions (and, in the case of OHS, retirements) which encompass multiple assets of various kinds. Even if each individual asset had an OHS age/efficiency profile, the age/efficiency profile of the aggregate plant additions could be poorly approximated by OHS for several reasons:

    1. Assets of the same kind could end up having different service lives. Identical light bulbs installed by homeowners on June 1 in a given year, for instance, will burn out at different times;
    2. Different kinds of assets can have markedly different service lives; and
    3. Individual assets, in any event, frequently have components with different service lives. The tires in a motor vehicle, for example, typically need replacement several times before the wheels need to be replaced.

    Alternative capital cost specifications such as GD can provide a better approximation of the service flow of a group of assets that individually have OHS patterns or which are composites of assets with OHS patterns.

    Consistent with these remarks, the authors of a capital research manual for the Organization of Economic Cooperation and Development ("OECD") stated in the Executive Summary that:

    > In practice, cohorts of assets are considered for measurement, not single assets. Also, asset groups are never truly homogenous but combine similar types of assets. When dealing with cohorts, retirement distributions must be invoked because it is implausible that all capital goods of the same cohort retire at the same moment in time. Thus, it is not enough to reason in terms of a single asset but age efficiency and age-price profiles have to be combined with retirement

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[23] For a survey of these studies see Barbara M. Fraumeni, "The Measurement of Depreciation in the U.S. National Income and Product Accounts*," Survey of Current Business*, July 1997, pp. 7-23. A recent Canadian study is John Baldwin, Huju Liu, and Marc Tanguay, "An Update on Depreciation Rates for the Canadian Productivity Accounts," *The Canadian Productivity Review*, Catalogue No. 15-206-X, January 2015.

[24] OECD, *Measuring Capital OECD Manual 2009*, Second Edition, p. 101.

> patterns to measure productive and wealth stocks and depreciation for cohorts of asset classes. An important result from the literature, dealt with at some length in the Manual is that, for a cohort of assets, the combined age-efficiency and retirement profile or the combined age-price and retirement profile often resemble a geometric pattern, i.e. a decline at a constant rate. While this may appear to be a technical point, it has major practical advantages for capital measurement. *The Manual therefore recommends the use of geometric patterns for depreciation* because they tend to be empirically supported, conceptually correct and easy to implement.[25] [italics in original]

- *Power Distributor Assets Do Not Exhibit a Constant Flow of Services.* A common sign of decline in the flow of services from an asset is a rise in the expenses to operate and maintain it. Another sign of a diminishing flow of services is a continual stream of "refurbishment" capital expenditures that do not boost volume or capacity. Utilities tend to experience rising OM&A expenses and refurbishment capex as many of their assets age.

- *The OHS Approach is Less Widely Used.* The disadvantages of the OHS method help to explain why alternative specifications are favored in productivity and capital quantity research. For example, GD is used to calculate capital quantities in the National Income and Product Accounts of the U.S. and Canada. Statistics Canada also uses GD in its MFP studies for sectors of the economy.[26] The U.S. Bureau of Labor Statistics, the Australian Bureau of Statistics, and Statistics New Zealand use hyperbolic decay, not OHS, in their sectoral MFP studies.

  GD has also been the capital cost specification most widely used in productivity studies intended for X factor calibration in the North American energy and telecommunications industries. GD is routinely used today in productivity and other statistical cost research by consultants serving Ontario electric utilities. PEG personnel have used the GD approach in most of its more than 30 productivity studies in work for diverse clients that have included Boston Gas.[27] PEG's 2017 study of power distributor productivity for Lawrence Berkeley National Laboratory also used

[25] OECD, *op. cit.*, at 12.

[26] For evidence on this see John R. Baldwin, Wulong Gu, and Beiling Yan (2007), "User Guide to Statistics Canada's Annual Multifactor Productivity Program," *Canadian Productivity Review*, Catalogue no. 15-206-XIE – No. 14., p. 41 and Statistics Canada, *The Statistics Canada Productivity Program: Concepts and Methods*, Catalogue no. 15-204, January 2001.

[27] D.P.U. 96-50.

GD.[28] Laurits R Christensen, major professor in the PhD committee of Dr. Makholm, and his colleague Dr. Mark Meitzen of LRCA used GD in virtually all of their numerous studies of telecommunications utility productivity. LRCA has to our knowledge also used GD in most of their studies over the years of *energy* utility productivity, including ones for the staff of Maine Public Utilities Commission and for Union Gas.[29] Concentric Energy Advisors used GD in their gas utility productivity study for Enbridge Gas Distribution in Ontario.[30]

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[28] Lowry, M.N., Deason, J., and Makos, M. (2017), "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities,", Lawrence Berkeley National Laboratory, July, pp. B.19-20.

[29] *See, e.g.*, Maine PUC proceeding 2007-00215 and Hemphill, R., and Schoech, P. (1999), "An Evaluation of the Union Gas Limited Performance-Based Regulation Proposal", at 25. Dr. Schoech was listed in response to information request AG-23-3b as a member of the LRCA team for the NGrid project.

[30] James Coyne, James Simpson, and Melissa Bartos, Concentric Energy Advisors, Inc., Incentive Ratemaking Report*, Prepared for Enbridge Gas Distribution*, OEB Proceeding EB-2012-0459, Exh. A2, Tab 9, Sch. 1, p. B-11 (June 28, 2013).

4. Critique of LRCA's Productivity Research and Testimony

4.1. Background

LRCA's study for NGrid has its origins in power distribution productivity research by National Economic Research Associates ("NERA"). An early version of this study was prepared for a Central Maine Power proceeding in the late 1990s.[31] In 2010, the Alberta Utilities Commission ("AUC") retained NERA to prepare an analogous study for use in the calibration of X factors in a new PBR regime for provincial gas and electric power distributors. Since many customer services are no longer provided by distributors in Alberta, NERA removed the cost of these services from its study for the AUC as well as administrative and general ("A&G") expenses.

NERA's study featured an unusually long sample period and advocated an X factor based on results for the full sample period. An unusual feature of the study was a negative MFP trend after 2000. Power distribution studies by PEG have not shown such a trend. Rather than undertake original productivity research, some utility witnesses in this proceeding embraced results of the NERA study for the period after 2000. The AUC rejected their recommendations and instead based its 0.96% base productivity trend on NERA's results for the full sample period.

In the AUC's second generic PBR proceeding NERA did not testify. The Brattle Group and LRCA separately testified on behalf of utilities and each updated NERA's study with some modifications rather than undertaking original studies. Each consultancy based their X factor recommendations on results since 2000. LRCA argued that X factor calibration research should be "forward looking". The witness for LRCA, Dr. Mark Meitzen, had extensive experience in the field of telecommunications productivity measurement but had never testified on energy utility productivity. The AUC's 0.30% X factor recommendation was informed by utility studies using OHS but also by a study by PEG that used GD and found that the average TFP trend of U.S. power distributors was 0.43%.

NERA subsequently presented an updated version of its power distribution productivity study in testimony that supported a PBR proposal by two Ontario gas utilities. NERA and OEB's consultant

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[31] Maine PUC Case 1999-00666.

recommended a 0% base productivity trend for these utilities, which was ultimately approved by the Board.

PEG was a participant in these proceedings and opposed the NERA/LRCA methodology. We argued that the marked slowdown in productivity growth around 2000 was chiefly due to NERA's use of a volumetric output index. Volumetric output indexes are sensitive to the decline in residential and commercial use per customer, as discussed in Section 3.1 above. The decline in average use growth has been real but is not very relevant to the design of RCIs for power distributors.

PEG has also been critical of NERA/LRCA's capital cost treatment. We have argued that the OHS approach to measuring capital cost has notable disadvantages and that the NERA/LRCA treatment of OHS is flawed. When the OHS treatment is upgraded, power distributor productivity growth is not negative. We argued that NERA obtained a reasonable TFP trend over their lengthy full sample period in their Alberta study because brisk growth in average use in the early years offset productivity declines in later years. In recent years, NERA-style TFP indexes have been declining due to a combination of declining average use and an inappropriate capital cost specification.

In its study for Eversource, LRCA's methodology remained quite similar to that of NERA.[32] One notable change was to use the number of customers as the output index. LRCA did not include the costs of customer services or A&G tasks even though these were costs incurred by Eversource. In addition to a substantially negative productivity differential, LRCA also computed a substantially negative input price differential. Although the Department embraced LRCA's research, including its use of OHS, the Department adopted a lower X factor than LRCA recommended.[33]

Following the Eversource decision, the X factor issue was revisited by the Régie de l'énergie in a recent Québec proceeding to design an RCI for power distribution services of Hydro-Québec.[34] PEG was a witness in this proceeding for industrial intervenors. With knowledge of both the Department's decision in D.P.U. 17-05 and PEG's critique of the NERA/LRCA methodology, the Régie acknowledged a 0.3% distribution industry productivity trend.

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[32] *Compare* Exh. NG-MEM-1 *with* D.P.U. 17-05, Exh. ES-PBRM-1.

[33] D.P.U. 17-05, at 392.

[34] Québec Régie de l'énergie, R-4011-2017.

4.2. LRCA's Study for NGrid

For this proceeding, LRCA calculated the input price and productivity trends of a sample of U.S. utilities in the provision of power distributor services over the fourteen-year period 2003-2016.[35] The number of customers was used to measure output growth.

Unlike the Eversource study, expenses for A&G tasks and certain customer services were added to LRCA's NGrid study. Dr. Meitzen stated that A&G expenses were allocated on a "non-economic conceptual basis." Exh. NG-MEM-1, at 32. He stated further that his "plant-apportioned" results that allocate A&G "provides a balance between the economic measure of [TFP] and non-economic considerations of a traditional approach to the ratemaking process." Exh. NG-MEM-1, at 48.

Dr. Meitzen stressed that the X factor should be "forward looking", stating that:

> Although [the X factor] is typically determined by a productivity study that is based on historical information, [the X factor] is forward looking as it is based on those differentials that are expected to prevail over the course of the PBR term. That is, the historic TFP (and input price) study is used as a predictor of expected performance over this period.
>
> Exh. NG-MEM-1, at 29.

Dr. Meitzen further stated that:

> The 15 year period strikes a balance between using the most recent, relevant information for determining forward-looking changes in productivity and using a period long enough to account for short term variation in results.
>
> Exh. NG-MEM-1, at 33.

For the full national sample and "plant apportioned" cost, LRCA reported a -0.13% TFP trend and a remarkably brisk 3.50% input price trend. These results were used to calculate input price and productivity differentials. The sum of the resultant -0.95% productivity differential and -0.77% input price differential was a base X factor of **-1.72%.**[36] LRCA also produced results for a Northeast sample of utilities in the New England and mid-Atlantic states. LRCA reported a -0.69% Northeast MFP trend and a brisk 3.48% input price trend. The sum of the resultant -1.51% productivity differential and -0.75% input

[35] Exhibit NG-MEM-1 at 35.

[36] Exhibit NG-MEM-1, Figure 9, at 44.

price differential was a base X factor of **-2.27%**. LRCA recommends that the base X factor be based on the national plant-apportioned results.

4.3. Major Concerns

LRCA's methodology for measuring power distribution productivity and its discussion of RCI design are controversial. To facilitate the Department's review of the numerous and sometimes complicated issues that arise in productivity studies, below are PEG's most important concerns regarding LRCA's methodology.

Capital Specification

PEG has concerns about the OHS approach that LRCA used to measure capital cost. PEG discussed several general disadvantages of the OHS approach in Section 3.2 above. Here, we argue that LRCA's particular approach to executing OHS is flawed. Since LRCA does not itemize quantities of different kinds of distributor assets, their OHS approach is particularly sensitive to the choice of the average service life used in the conversion of the total value of distribution plant retirements each year to a quantity.

LRCA assumes a 33-year average service life.[37] The basis for this specification is presented in response to information request AG-15-4 and AG-23-4. They sought to estimate average service life by calculating a weighted average of the service lives for various distribution asset classes which utilities report periodically on FERC Form 1. The weights are the shares of each asset class in plant value.

The requisite data were readily available for this calculation only from 1994 to 2016. LRCA reports that the median average service life thus calculated rose over this period from 37.29 years in 1994 to 46.35 years in 2016.

LRCA claims that, since capital data for the 1964 to 2016 period are used in its capital quantity calculations, the average service life should be set at the value for the midpoint of this interval, which is 1990. The value of this is unavailable for 1990 but LRCA maintains that an appropriate value is the 33 years that NERA also used.

PEG has several reservations about LRCA's average service life calculations.

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[37] Exhibit NG-MEM-1, pages 56 and 59.

- The average service life for 1990 is unknown. Different estimates for its value can be reasonably entertained.

  LRCA noted that there existed an upward trend in service lives to 2016 which we calculated as 0.87% per year. Using the LRCA 1994 mean value of 38.96 years and the 0.87% trend results in a value of 37.635 years in 1990. A similar calculation using the median as opposed to mean values results in a 1990 estimate of 35.84 years. A few years difference in the estimated service life may not seem material, but we have found that the OHS method is highly sensitive to the assumed service life.

- LRCA's analysis relies on utility *estimates* of average service lives which were reported to the FERC. These estimates were not always freshly calculated and rise substantially over time. It is therefore likely that they were *downward biased* as estimates of the true service lives of assets at the time that they were reported.

- The average service life at the *midpoint* of the 1972-2016 period is unlikely to be representative of retirements that occurred between 2002 and 2016.

- Average service lives going forward are clearly much higher than they were in 1990. Freezing the average service life at its estimated 1990 value seems inconsistent with LRCA's goal of calculating a forward-looking X factor.

PEG notes that the controversy over average service life when OHS is used to calculate capital cost is unfortunate and a good reason to consider results using different capital cost methods. Since the Department is nonetheless interested in results using OHS, we believe that the evidence points to an OHS value of 36 years.

The benchmark year adjustment that NERA used is another problem. We noted in Section 3 above that the computation of a capital quantity index starts with a benchmark year adjustment. PEG believes that LRCA's calculations of capital quantity indexes in its benchmark year are incorrect. OHS is sometimes characterized as a method for calculating the quantity associated with *gross* plant value. Yet LRCA deflated *net* plant values by an average of past values of a construction cost index. Consequently, PEG believes that the initial quantities of capital for each utility in LRCA's sample are understated. LRCA's method effectively removed accumulated depreciation associated with older capital twice. It was first removed when calculating net plant value and then removed again when the original value of plant is retired. When an alternative and higher average service life is used to calculate capital quantities, this understated initial capital stock can result in negative capital quantities for some utilities. Utility witnesses in Alberta used these negative capital quantities as an argument against a higher average service life.[38] A related concern is that LRCA, like NERA, did not assume a consistent 33-year average service life in making its benchmark year calculation.

Input Price Differential Calculations

NERA's input price differential calculations are also a cause for concern. As discussed in Section 3.2 above, input price differentials using implicit service price indexes are inherently awkward in X factor calibrations because assets are valued in current dollars and capital gains are considered. The 2003-2016 sample period used by LRCA was especially problematic since power distribution construction costs rose rapidly, due in part to a run-up in copper prices that was never fully reversed. This runup is illustrated in Figure 1 below, which compares GDP-PI inflation to the inflation in the producer price index for copper wire and Handy Whitman electric power distribution construction cost index.

LRCA has compounded this problem in two ways:

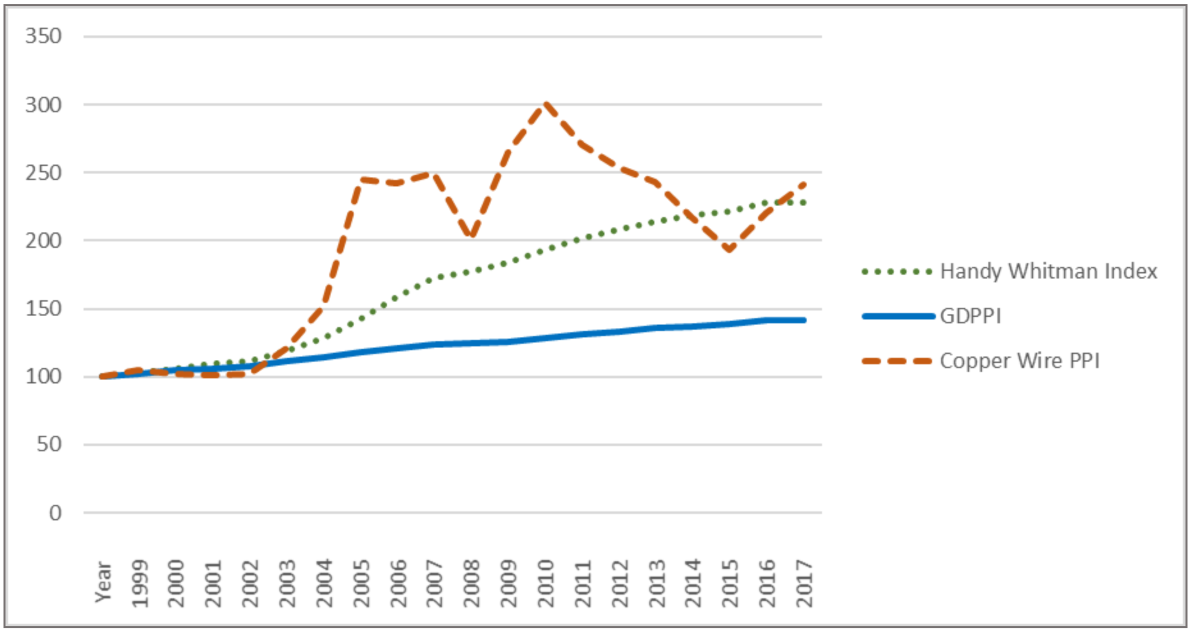
1. The sample period LRCA used is, in our opinion, too short to accurately calculate a long-term input price differential. In its recent Ontario testimony, NERA calculated an input price differential using power distribution data from the 1973-2016 period. NERA witness Dr. Jeff Makholm stated that "For input price growth, I find no statistically significant input price differential (which is the result I have always found for the US distribution data set)."[39]
2. LRCA froze the expected real rate of return in its input price index, stating that it assumed that "investor's forward looking real rate of return (cost of capital less the inflation rate) is constant through time."[40] However, LRCA allowed the construction cost index to accelerate briskly. In so doing, LRCA permitted the input price index to grow rapidly, thereby imparted a substantial negative bias to its input price differential calculations.

[38] Brattle Undertaking #4 as filed in Alberta Utilities Commission Proceeding 20414 as Exhibit 20414-X0564 and Transcript Volume 8, pp. 2808-2809 from Alberta Utilities Commission Proceeding 20414.

[39] OEB proceeding EB-2017-0307, Exhibit B, Tab 2, filed November 23, 2017, p. 32.

[40] Exh. NG-MEM-1, at 59.

Figure 1
Trends in Power Distribution Construction Costs



Sampled Companies

LRCA excluded numerous companies from its sample even though the data were available, apparently because these companies were not part of the original NERA sample. Substantially larger samples are feasible.[41]

Revenue Cap Index Design

PEG's explanation in Section 3.1 of the principles for RCI design differs from LRCA's. Particularly, we show that the scale index used to calculate TFP growth need not be the number of customers served. An elasticity-weighted scale index can be used to measure output in such research. This implies that an RCI that lacks an explicit scale escalator does not necessarily offer customer growth as an "implicit stretch factor". Trends in other scale variables can be considered. Econometric research on electric distribution cost which PEG just presented in Toronto testimony found that the number of

[41] *See, e.g.*, Lowry, M., Deason, J., Makos, M. and Schwartz, L., *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, for Lawrence Berkeley National Laboratory, July 2017, p. B.13 where PEG undertook a power distributor productivity study with 86 power distributors.

customers served has an estimated cost elasticity of 0.601 but ratcheted peak demand has an estimated elasticity of 0.351.[42] The share of peak demand in the sum of the two elasticities is a sizable 37%.[43] We acknowledge, however, that the number of customers has been used in productivity studies, including studies by PEG, to calibrate the X factors of RCIs for gas and electric power distributors. These studies were sometimes done with the expectation that a revenue per customer cap would be approved.

Other Concerns

There are a number of smaller problems with LRCA's U.S. power distribution research. Taken together they have little effect on LRCA's research results but nonetheless merit mention.

- LRCA failed to correct for some mergers;
- Pension and benefit expenses are included in the study even though NGrid proposes to track the cost of these expenses;
- Pension and benefit expenses were inappropriately treated as material and service expenses. This led to more volatile and inaccurate TFP results;
- Even though pension and benefit expenses are included in the study, LRCA uses an employment cost index for salaries and wages to deflate labor cost rather than an ECI for total compensation.

Alternative Results

To illustrate some of the problems with LRCA's capital cost treatment, PEG has developed an alternative calibration exercise using LRCA's data. First, the benchmark year capital quantity calculation was revised to deflate *gross* plant value. Next, the average service life was raised from 33 to 36 years. In addition, the input price index was changed to unfreeze the expected real rate of return.

Results of this exercise are presented in Tables 1a, 1b, and 1c below. TFP growth for the full national sample averaged 0.30%. The productivity differential was -0.52% and the input price differential was 0.56%. The indicated base X factor from this research is therefore **0.04%**. The analogous result using Northeast US data is **-0.64%**. Thus, replacing the flawed NERA/LRCA approach to the OHS capital cost calculations with a more defensible treatment produces a substantially higher X factor that is less favorable to NGrid.

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[42] Lowry, M.N., *IRM Design for Toronto Hydro-Electric System*, OEB, EB-2018-0165, Exhibit M1, March 20, 2019.

[43] The ratcheted peak demand of a utility is the highest value that it has yet attained.

Table 1a

PEG Modifications to LRCA Analysis – Distribution Industry

Period	Output Quantity	Input Quantity	Revenue Per Customer MFP	Input Price
2002	-	-	-	-
2003	1.28%	3.33%	-2.05%	-2.07%
2004	1.14%	-2.49%	3.63%	2.18%
2005	1.42%	1.20%	0.21%	2.01%
2006	1.04%	6.95%	-5.90%	7.10%
2007	1.07%	-4.95%	6.02%	5.90%
2008	0.64%	-0.65%	1.28%	6.50%
2009	0.08%	0.41%	-0.33%	2.88%
2010	0.38%	2.28%	-1.90%	-0.68%
2011	0.36%	1.00%	-0.64%	0.78%
2012	0.52%	1.31%	-0.78%	-3.44%
2013	0.80%	-2.86%	3.66%	6.61%
2014	0.60%	-0.27%	0.87%	2.21%
2015	0.77%	-0.31%	1.08%	0.21%
2016	0.89%	1.86%	-0.97%	0.21%
Average	**0.78%**	**0.49%**	**0.30%**	**2.17%**
Original LRCA Results				
Average	**0.78%**	**0.91%**	**-0.13%**	**3.50%**
Difference	0.00%	-0.42%	0.43%	-1.33%

Table 1b

PEG Modifications to LRCA Analysis – U.S. Economy

Year	GDPPI	MFP	Input Price
	[A]	[B]	[A] + [B]
2002	-	-	-
2003	1.87%	2.29%	4.15%
2004	2.64%	2.61%	5.25%
2005	3.05%	1.53%	4.58%
2006	3.01%	0.35%	3.36%
2007	2.66%	0.39%	3.04%
2008	1.89%	-1.19%	0.70%
2009	0.78%	-0.26%	0.52%
2010	1.16%	3.25%	4.42%
2011	2.06%	0.07%	2.13%
2012	1.91%	0.69%	2.60%
2013	1.76%	0.41%	2.16%
2014	1.86%	0.87%	2.73%
2015	1.03%	0.93%	1.96%
2016	1.08%	-0.46%	0.62%
Average	**1.91%**	**0.82%**	**2.73%**
Original LRCA Results			
Average	**1.91%**	**0.82%**	**2.73%**
Difference	0.00%	0.00%	0.00%

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Table 1c

X Factor Calculations Using an Alternative OHS Capital Cost Specification

Period	MFP			Input Price			X Factor
	Industry	U.S.	Difference	U.S.	Industry	Difference	
	[A]	[B]	[C=A-B]	[D]	[E]	[F=D-E]	[G=C+F]
2002	-	-	-	-	-	-	-
2003	-2.05%	2.29%	-4.34%	4.15%	-2.07%	6.22%	1.89%
2004	3.63%	2.61%	1.02%	5.25%	2.18%	3.07%	4.09%
2005	0.21%	1.53%	-1.32%	4.58%	2.01%	2.57%	1.25%
2006	-5.90%	0.35%	-6.25%	3.36%	7.10%	-3.74%	-9.99%
2007	6.02%	0.39%	5.63%	3.04%	5.90%	-2.86%	2.78%
2008	1.28%	-1.19%	2.47%	0.70%	6.50%	-5.80%	-3.33%
2009	-0.33%	-0.26%	-0.07%	0.52%	2.88%	-2.36%	-2.43%
2010	-1.90%	3.25%	-5.15%	4.42%	-0.68%	5.10%	-0.06%
2011	-0.64%	0.07%	-0.71%	2.13%	0.78%	1.35%	0.64%
2012	-0.78%	0.69%	-1.47%	2.60%	-3.44%	6.04%	4.57%
2013	3.66%	0.41%	3.25%	2.16%	6.61%	-4.45%	-1.19%
2014	0.87%	0.87%	0.00%	2.73%	2.21%	0.52%	0.52%
2015	1.08%	0.93%	0.15%	1.96%	0.21%	1.75%	1.90%
2016	-0.97%	-0.46%	-0.51%	0.62%	0.21%	0.41%	-0.10%
Average	**0.30%**	**0.82%**	**-0.52%**	**2.73%**	**2.17%**	**0.56%**	**0.04%**
Original LRCA Results							
Average	**-0.13%**	**0.82%**	**-0.95%**	**2.73%**	**3.50%**	**-0.77%**	**-1.72%**
Difference	0.43%	0.00%	0.43%	0.00%	-1.33%	1.33%	1.76%

5. Productivity Research by PEG

5.1. Data

The primary source of the cost and quantity data for PEG's independent research on input price and productivity trends of U.S. power distributors is FERC Form 1. Selected FERC Form 1 data were for many years published by the U.S. Energy Information Administration (EIA).[44] More recently, the data have been available electronically from the FERC and in more processed forms from commercial vendors. The FERC Form 1 data used in PEG's study were obtained directly from government agencies and processed by PEG. Customer data were drawn from FERC Form 1 in the early years of the sample period and from Form EIA-861 (the *Annual Electric Power Industry Report)* in later years.

Data were eligible for inclusion in the sample from all major investor-owned electric utilities in the United States that filed the FERC Form 1 in 1964 (the benchmark year for our study, described further below) and that, together with any important predecessor companies, have reported the necessary data continuously. To be included in the PEG study, the data also were required to be of good quality and plausible. Data from 80 utilities met PEG's standards and were used in our indexing work. We believe that these data are the best available for rigorous work on the productivity trends of U.S. power distributors.

Table 2 below lists the companies from which PEG's data were drawn. It can be seen that most broad regions of the United States are well represented.[45]

[44] This publication series had several titles over the years. A recent title is Financial Statistics of Major U.S. Investor-Owned Electric Utilities.

[45] Unfortunately, the requisite customer data are not available for most Texas distributors.

Table 2

Sample of Utilities Used in Productivity Model Research

Alabama Power
ALLETE (Minnesota Power)
Appalachian Power
Arizona Public Service
Atlantic City Electric*
Avista
Baltimore Gas and Electric
Black Hills Power
Central Hudson Gas & Electric*
Central Maine Power*
Cleco Power
Cleveland Electric Illuminating
Commonwealth Edison
Connecticut Light and Power*
Consolidated Edison Company of New York*
Delmarva Power & Light
DTE Electric
Duke Energy Carolinas
Duke Energy Florida
Duke Energy Indiana
Duke Energy Kentucky
Duke Energy Ohio
Duke Energy Progress
Duquesne Light*
El Paso Electric
Empire District Electric
Entergy Arkansas
Entergy Mississippi
Entergy New Orleans
Florida Power & Light
Gulf Power
Idaho Power
Indiana Michigan Power
Indianapolis Power & Light
Jersey Central Power & Light*
Kansas City Power & Light
Kansas Gas and Electric
Kentucky Power
Kentucky Utilities
Louisville Gas and Electric
Madison Gas and Electric
MDU Resources Group
Metropolitan Edison*
Mississippi Power
Monongahela Power
Nevada Power
New York State Electric & Gas*
Niagara Mohawk Power*
Northern Indiana Public Service
Northern States Power - MN
Ohio Edison
Oklahoma Gas and Electric
Orange and Rockland Utilities*
Pacific Gas and Electric
Potomac Electric Power*
Pennsylvania Electric*
Pennsylvania Power*
Portland General Electric
PPL Electric Utilities*
Public Service Company of Colorado
Public Service Company of New Hampshire*
Public Service Company of Oklahoma
Public Service Electric and Gas*
Puget Sound Energy
San Diego Gas & Electric
South Carolina Electric & Gas
Southern California Edison
Southern Indiana Gas and Electric
Southwestern Public Service
Tampa Electric
Toledo Edison
Tucson Electric Power
Union Electric
United Illuminating*
Virginia Electric and Power
West Penn Power*
Western Massachusetts Electric*
Wisconsin Electric Power
Wisconsin Power and Light
Wisconsin Public Service

Total of 80 Companies

*** Indicates a member of the Northeast Sample**

5.2. Defining Costs

The major tasks in power distribution are the local delivery of power, the reduction of its voltage, and the metering of quantities delivered. Most power is delivered to customers at the voltage at which it is consumed. This requires distributors to step down the voltage of power from the voltage at which they receive it from the transmission sector.[46] Distributors use transformers near the point of delivery to reduce voltage to the level at which it is consumed. Some also own and operate substations that receive power at subtransmission or transmission voltage.

Distributors also typically provide various customer services. In the United States, these typically include metering, meter reading, customer account, and customer service and information ("CS&I") services. Expenses reported on FERC Form 1 for CS&I services include those for utility DSM programs. These expenses will be subject to tracker treatment in National Grid's proposed plan, vary widely between utilities, and are not itemized for easy removal. We accordingly excluded all CS&I expenses from the costs of the utilities in our study.

Pension and benefit expenses are often excluded from utility cost performance studies because they are sensitive to volatile external business conditions such as stock prices. NGrid has proposed to track these expenses in its PBR plan. Consequently, unlike LRCA, PEG has excluded these expenses in this study.

The O&M expenses that PEG used in the study for U.S. utilities included those for power distribution, customer accounts, metering, and meter reading. We also included a sensible share of A&G expenses.[47] PEG excluded all reported O&M expenses incurred by sampled U.S. utilities for generation, power procurement, transmission, customer service and information, franchise fees, and gas services. The capital costs were those for distribution plant.

The total cost of power distributor services considered in the PEG study was the sum of capital costs and applicable O&M expenses. In our input price and productivity research for the AGO we employed a monetary approach to capital cost, price, and quantity measurement which featured GD.

[46] Some large industrial customers take delivery of power directly from the transmission system.

[47] This procedure is theoretically arbitrary but has little impact on results.

Capital cost was the sum of depreciation expenses and a return on net plant value less capital gains.[48] Further details of PEG's capital cost calculations are provided in Appendix Section A.1.

5.3. Input Price Indexes

Operation & Maintenance

The labor prices for U.S. utilities were escalated by regionalized Bureau of Labor Statistics ("BLS") Employment Cost Indexes for salaries and wages. Material and service ("M&S") prices were escalated by the U.S. GDP-PI.

Capital

Construction cost indexes and rates of return on capital are required in the capital cost research. PEG calculated weighted averages of rates of return for debt and equity.[49] PEG calculated for each sample year a 50/50 average of the embedded average interest rate on long-term debt as calculated from FERC Form 1 data, and the average allowed rate of return on equity ("ROE") approved in electric utility rate cases as reported by the Edison Electric Institute.[50] PEG used construction cost indexes from Whitman, Requardt and Associates to deflate the value of plant additions of the sampled distributors.

Summary Input Price Index

Summary input price indexes were constructed by PEG which were weighted averages of price subindexes for various inputs. Calculation of these indexes used company-specific, time-varying cost share weights for the U.S. utilities. The cost shares were calculated from FERC Form 1 O&M expense data.

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[48] Capital gains are included due to the geometric decay capital cost treatment that we employ, as noted in Section 3.2 values capital at replacement cost.

[49] This calculation was made solely for the purpose of measuring productivity *trends* and does not prescribe appropriate rate of return *levels* for utilities.

[50] The Edison Electric Institute is the principal trade association of U.S. electric utilities. The ROE data we used in the study were drawn from the backup data to the *EEI Rate Case Summary* quarterly reports.

5.4. Scope of Research

PEG calculated indexes of growth in the O&M, capital, and total factor productivity of each sampled utility in the provision of power distributor services. Simple arithmetic averages of those growth rates were then calculated for all sampled companies.

5.5. Index Construction

Productivity growth was calculated for each sampled utility as the difference between the growth rates of output and input quantity trends. PEG used the growth in the total number of retail customers served as the scale metric.

In calculating input quantity trends, we broke down the applicable cost into three categories: (1) distribution plant; (2) labor; (3) M&S inputs. The cost of labor was defined for this purpose as O&M salaries and wages. The cost of M&S inputs was defined as applicable O&M expenses net of these labor costs. The growth of each total factor input quantity index was a weighted average of the growth in quantity subindexes for labor, materials and services, and power distribution plant.

5.6. Sample Period

The full sample period for which productivity results were calculated was 1997-2017.[51] The year 2017 is the latest for which the required data are currently available.

5.7. Index Results

Table 3 below summarizes our productivity research for the U.S. sample. Over the full 1997-2017 sample period, the average annual growth rate in the MFP of all sampled U.S. power distributors using GD was about +0.33%. The productivity differential was -0.65%.

Table 4 below presents PEG's input price results. The input price growth of the industry averaged 2.89% over the full sample period. The input price growth of the economy averaged 2.83%. The input price differential was -0.06%, close to zero. The sum of the input price and productivity differentials was **-0.71%.** This is the indicated base X factor from this research. The analogous base X factor using Northeast data was **-0.74%.**

[51] In other words, 1997 was the earliest year for growth rate calculations.

Table 3

Calculating the Productivity Differential – U.S.[1]

	U.S. Power Distributors: Output Quantity Index	Output Quantity Growth Rate	Input Quantity Index	Input Quantity Growth Rate	Productivity Index	Productivity Growth Rate [A]	U.S. Private Business MFP Index[2] Index	MFP Growth Rate [B]	Productivity Differential [A] - [B]
1996	100.00		100.00		100.00		100.00		
1997	101.39	1.38%	99.74	-0.26%	101.66	1.65%	101.13	1.12%	0.53%
1998	102.99	1.56%	102.08	2.33%	100.89	-0.76%	102.64	1.48%	-2.25%
1999	104.33	1.29%	104.06	1.92%	100.25	-0.63%	104.61	1.90%	-2.53%
2000	105.84	1.44%	104.61	0.52%	101.18	0.92%	106.11	1.43%	-0.51%
2001	107.94	1.97%	104.25	-0.34%	103.54	2.31%	106.59	0.45%	1.87%
2002	109.42	1.36%	104.94	0.66%	104.27	0.70%	108.76	2.02%	-1.32%
2003	110.33	0.83%	107.53	2.44%	102.60	-1.62%	111.27	2.29%	-3.90%
2004	111.66	1.20%	106.04	-1.40%	105.30	2.60%	114.21	2.61%	-0.01%
2005	113.18	1.36%	106.77	0.68%	106.01	0.67%	115.97	1.53%	-0.85%
2006	113.71	0.47%	107.64	0.81%	105.64	-0.34%	116.38	0.35%	-0.70%
2007	114.91	1.05%	110.19	2.35%	104.28	-1.30%	116.83	0.39%	-1.68%
2008	115.62	0.61%	109.74	-0.41%	105.35	1.02%	115.45	-1.19%	2.21%
2009	115.88	0.23%	108.38	-1.24%	106.92	1.47%	115.16	-0.26%	1.73%
2010	116.45	0.50%	109.48	1.01%	106.37	-0.52%	118.96	3.25%	-3.77%
2011	116.76	0.27%	109.85	0.33%	106.30	-0.07%	119.05	0.07%	-0.13%
2012	117.28	0.44%	109.92	0.07%	106.69	0.37%	119.87	0.69%	-0.32%
2013	117.92	0.55%	109.26	-0.61%	107.93	1.15%	120.36	0.41%	0.75%
2014	118.60	0.58%	110.20	0.86%	107.63	-0.28%	121.41	0.87%	-1.15%
2015	119.50	0.75%	110.30	0.09%	108.34	0.66%	122.55	0.93%	-0.27%
2016	120.61	0.92%	111.78	1.33%	107.90	-0.40%	121.98	-0.46%	0.06%
2017	121.57	0.79%	113.37	1.41%	107.23	-0.62%	122.90	0.76%	-1.38%
Average Annual Growth Rate									
1997-2017		**0.93%**		**0.60%**		**0.33%**		**0.98%**	**-0.65%**

[1]All growth rates calculated logarithmically.
[2]Source: U.S. Bureau of Labor Statistics

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Table 4
Calculating the Input Price Differential – U.S.[1]

	Input Price Indexes								Input Price Differential
	United States						U.S. Power Distributor Input Prices		
	GDP-PI[2]		MFP[3]		Implied IPI				
	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate	Growth Rate
		[A]		[B]		[C=A+B]		[D]	[E=C-D]
1996	100.00		100.000		100.00		100.00		
1997	101.73	1.72%	101.13	1.12%	102.88	2.84%	105.07	4.94%	-2.11%
1998	102.85	1.10%	102.64	1.48%	105.57	2.58%	108.59	3.29%	-0.71%
1999	104.33	1.42%	104.61	1.90%	109.14	3.32%	111.19	2.37%	0.95%
2000	106.68	2.23%	106.11	1.43%	113.20	3.66%	110.71	-0.44%	4.09%
2001	109.08	2.22%	106.59	0.45%	116.26	2.67%	111.30	0.53%	2.14%
2002	110.74	1.51%	108.76	2.02%	120.44	3.53%	108.76	-2.31%	5.84%
2003	112.83	1.87%	111.27	2.29%	125.55	4.15%	110.53	1.62%	2.54%
2004	115.85	2.64%	114.21	2.61%	132.32	5.25%	106.35	-3.85%	9.11%
2005	119.44	3.05%	115.97	1.53%	138.52	4.58%	99.75	-6.41%	10.99%
2006	123.09	3.01%	116.38	0.35%	143.25	3.36%	82.78	-18.65%	22.01%
2007	126.40	2.66%	116.83	0.39%	147.68	3.04%	73.68	-11.63%	14.67%
2008	128.81	1.89%	115.45	-1.19%	148.72	0.70%	71.58	-2.89%	3.60%
2009	129.82	0.78%	115.16	-0.26%	149.49	0.52%	101.57	34.99%	-34.47%
2010	131.34	1.16%	118.96	3.25%	156.24	4.42%	130.21	24.84%	-20.42%
2011	134.07	2.06%	119.05	0.07%	159.61	2.13%	151.25	14.98%	-12.85%
2012	136.65	1.91%	119.87	0.69%	163.81	2.60%	149.59	-1.10%	3.70%
2013	139.08	1.76%	120.36	0.41%	167.39	2.16%	152.80	2.12%	0.04%
2014	141.69	1.86%	121.41	0.87%	172.02	2.73%	161.88	5.77%	-3.04%
2015	143.15	1.03%	122.55	0.93%	175.43	1.96%	170.93	5.44%	-3.48%
2016	144.71	1.08%	121.98	-0.46%	176.52	0.62%	182.78	6.70%	-6.08%
2017	147.49	1.90%	122.90	0.76%	181.27	2.66%	183.50	0.39%	2.26%
Average Annual Growth Rate									
1997-2017		**1.85%**		**0.98%**		**2.83%**		**2.89%**	**-0.06%**

[1]All growth rates calculated logarithmically

[2]Gross Domestic Product Price Index calculated by the BEA.

[3]Multifactor productivity for the U.S. private business sector calculated by the BLS.

5.8. Kahn Method Research

A base X factor was also calculated for NGrid using a simpler “Kahn Method” exercise. This method was developed by noted regulatory economist Alfred Kahn, who was a professor at Cornell University. It has been used by the FERC to set the X factors in PBR plans for interstate oil pipelines. In an application to this proceeding, PEG would calculate trends in the cost of base rate inputs of a sample of power distributors using FERC Form 1 data and traditional cost accounting and then solve for the value of X which would have caused the trend in distributor cost to equal the trend in a generic RCI. The base X factor resulting from such a calculation reflects the input price and productivity differentials of utilities.

Calculating X Using the Kahn Method

PEG postulated a hypothetical generic revenue cap index like that in Relation [8a] with the following form:

$$\textit{growth Allowed Base Revenue}^{Utility} = \textit{growth GDPPI} - X + \textit{growth Customers}. \qquad [15]$$

We then calculated the trend in the cost of base rate inputs for each utility in the sample. In these calculations, capital cost was defined as the sum of depreciation and amortization expenses and return on rate base. We excluded costs that were unlikely to be addressed by trackers and riders in NGrid’s regulatory system. We calculated the value of X that would cause the trends in the costs of the sampled power distributors to equal the trends in the hypothetical RCIs with formulas like Relation [8] on average over the sample period. The full sample period considered by PEG was the twenty-one-year period, 1997-2017. PEG also considered results for shorter and more recent periods.

Results of this exercise can be seen in Table 5 below. For all sample periods considered, the average annual growth in cost was more rapid than the average annual growth in the GDP-PI. The average annual growth in the number of customers served was not large enough to close this gap. Thus, the X factor must be negative if the hypothetical RCIs are to track historical distributor costs on average. The Kahn X factor was **-0.41%** for the full 1997-2017 sample period. The analogous result for the Northeast sample was **-0.45%.**

Table 5

U.S. Power Distributor Kahn X Factor Calculations[1]

Year	GDP-PI[1]	Customers	Total Cost	Kahn X
	[A]	[B]	[C]	[D=A+B-C]
1997	1.72%	1.38%	2.66%	0.45%
1998	1.10%	1.56%	5.20%	-2.54%
1999	1.43%	1.29%	3.90%	-1.19%
2000	2.23%	1.44%	4.27%	-0.60%
2001	2.22%	1.97%	3.26%	0.93%
2002	1.52%	1.36%	0.17%	2.70%
2003	1.87%	0.83%	3.45%	-0.76%
2004	2.64%	1.20%	0.92%	2.92%
2005	3.06%	1.36%	3.09%	1.32%
2006	3.00%	0.47%	2.84%	0.63%
2007	2.66%	1.05%	5.41%	-1.70%
2008	1.89%	0.61%	3.50%	-1.00%
2009	0.78%	0.23%	2.03%	-1.02%
2010	1.16%	0.50%	3.74%	-2.08%
2011	2.06%	0.27%	3.12%	-0.80%
2012	1.91%	0.44%	2.45%	-0.11%
2013	1.76%	0.55%	1.89%	0.41%
2014	1.87%	0.58%	3.98%	-1.53%
2015	1.03%	0.76%	3.84%	-2.05%
2016	1.08%	0.92%	3.02%	-1.02%
2017	1.90%	0.79%	4.24%	-1.55%
Average Annual Growth Rates				
1997-2017	1.85%	0.93%	3.19%	**-0.41%**
2002-2017	1.89%	0.74%	2.98%	**-0.35%**
2007-2017	1.64%	0.61%	3.38%	**-1.13%**

Note: All values shown are an average of annual (logarithmic) growth rates of variables on a nationally-representative sample of 80 power distributors.

[1]Gross Domestic Product Price Index calculated by the BEA.

Pacific Economics Group Research, LLC

6. X Factor Recommendations

6.1. Stretch Factor

The Company proposes a consumer dividend of 0.40% contingent on GDP-PI growth exceeding 2%. The 0.4% recommendation is based on a statistical benchmarking study by Dr. Lawrence R. Kaufmann, President of Kaufmann Consulting. Dr. Kaufmann has done work for PEG as a Senior Advisor, but he is not an employee of PEG, and he worked separately for NGrid in this proceeding. He reported in his testimony that NGrid's productivity level was about 27% below that of NSTAR Electric's over the 2014-16 sample period.

PEG was not asked by the AGO to consider Dr. Kaufmann's study. Accordingly, we take 0.4% as a given in what follows. We note, however, that it is controversial to make a stretch factor contingent on the inflation rate. Inflation has been sluggish in recent years and this may continue. The potential for productivity growth does not vary with inflation and this provision is rare in approved PBR plans. We accordingly do not believe that there should be a stretch factor contingency.

6.2. X Factor

PEG's review of the assembled evidence on industry productivity trends has the following highlights.

- Using our upgraded OHS results and LRCA's national data, the productivity differential of -0.52% and the inflation differential of 0.56% sum to an indicated base X factor of **0.04%.** The indicated base X factor using Northeast data was -0.64%.
- Using our GD method and national data, the productivity differential of -0.65% and the inflation differential of -0.06% sum to base X factor of **-0.71%.** The indicated base X factor using Northeast data is **-0.74%.**
- The indicated base X factor using the Kahn method and national data is **-0.41%.** The analogous result using Northeast data is **-0.45%.**
- Other plan provisions also merit consideration in the choice of an X factor. The stretch factor would be effective only when inflation exceeded 2%. A tracker treatment is proposed for certain grid modernization and electric vehicle costs. Costs of an upgraded vegetation management program would also be tracked.
- The RCI has no scale escalator, but this does not produce an implicit stretch factor equal to expected customer growth. Growth in other scale variables also matters. We have shown that the trend in peak demand matters, and this has been slowed by an aggressive DSM program.

Based on the assembled evidence, PEG recommends a **-0.60%** base X factor for NGrid. To this would be added the 0.40% stretch factor. The total X factor would then be -0.20%.

Appendix

Details of the PEG Productivity Research

This Appendix contains more technical details of PEG's productivity research. We first discuss our input quantity and productivity indexes, respectively. We then address our method for calculating input price inflation and capital cost.

Input Quantity Indexes

The growth rate of a summary input quantity index is defined by a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and quantity subindexes.

Index Form

Each summary input quantity index used in the study was of chain-weighted Törnqvist form. This means that its annual growth rate was determined by the following general formula:

$$\ln\left(Inputs_{t} \big/ Inputs_{t-1} \right) = \sum_{j} \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1} \right) \cdot \ln\left(X_{j,t} \big/ X_{j,t-1} \right). \qquad [A1]$$

Here, in each year *t*,

$Inputs_t$ = Summary input quantity index

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

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

It is evident that growth rate of the index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable cost of each utility in the current and prior years served as weights.

Productivity Growth Rates and Trends

The annual growth rate in each productivity index is given by the formula:

$$\ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right)$$
$$= \ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}}\right) - \ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right). \qquad [A2]$$

The long-run trend in each productivity index was calculated as its average annual growth rate over the full sample period.

Input Price Indexes

The growth rate of a summary input price index is defined by a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and price subindexes.

Price Index Formulas

The summary input price indexes used in this study were of Törnqvist form. This means that the annual growth rate of each index was determined by the following general formula.

$$\ln\left(\frac{Input\ Prices_t}{Input\ Prices_{t-1}}\right) = \sum_j \frac{1}{2}\cdot\left(sc_{j,t} + sc_{j,t-1}\right)\cdot\ln\left(\frac{W_{j,t}}{W_{j,t-1}}\right). \qquad [A3]$$

Here, in each year *t*,

$Input\ Prices_t$ = Input price index

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

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

The growth rate of the index is a weighted average of the growth rates of input price subindexes. Each growth rate is calculated as the logarithm of the ratio of the subindex values in successive years. The average shares of each input group in the applicable cost of each utility during the two years are the weights.

Capital Cost and Quantity Specification

A monetary approach was chosen to measure the capital cost of each utility. As discussed in Section 3.2 above, under this approach capital cost is the product of a capital quantity index and a capital (service) price index.

$$CK = WK \cdot XK.$$

GD was assumed. PEG took 1964 as the benchmark year for the capital quantity index. The values for the capital quantity index in the benchmark year were based on the net value of plant as reported in the FERC Form 1. We estimated the benchmark year (inflation-adjusted) value of net plant by dividing this book value by an average of the values of an index of utility construction cost for a period ending in the benchmark year. The construction cost indexes (WKA_t) were the applicable regional Handy-Whitman Index of Cost Trends of Power Distribution Construction.[52]

The following formula was used to compute values of the capital quantity index in subsequent years:

$$XK_t = (1-d) \cdot XK_{t-1} + \frac{VI_t}{WKA_t}. \qquad \text{[A4]}$$

Here, the parameter d is the economic depreciation rate and VI_t is the value of gross additions to utility plant.

The formula for the corresponding GD capital service price indexes used in the research was

$$WKS_{j,t} = d \cdot WKA_{j,t} + WKA_{j,t-1}\left[r_t - \frac{(WKA_{j,t} - WKA_{j,t-1})}{WKA_{j,t-1}}\right]. \qquad \text{[A5]}$$

The first term in the expression corresponds to the cost of depreciation. The second term corresponds to the real rate of return on capital. This term was time-variant but smoothed to reduce capital cost volatility.

[52] These data are reported in the Handy-Whitman Index of Public Utility Construction Costs, a publication of Whitman, Requardt and Associates.

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IRM Design for Toronto Hydro-Electric System

May 22, 2019 (revised)

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1. Introduction and Summary

1.1. Introduction

Toronto Hydro-Electric System ("Toronto Hydro" or "the Company") proposed a Custom Incentive Rate-setting ("IR") mechanism for its power distributor services in an August 2018 application.[1] A multiyear rate plan is proposed which is similar to that which the Ontario Energy Board ("OEB") approved for the Company in 2015.[2] Escalation of a Custom Price Cap Index ("PCI") would be slowed by an X factor. The Company retained Power System Engineering Inc. ("PSE") to prepare cost and reliability benchmarking research and testimony in support the proposed X factor. A C factor would ensure recovery of projected/proposed capital cost.[3] A capital-related revenue requirement variance account ("CRRRVA") would asymmetrically compensate customers for cumulative capex underspends but not overspends. An Externally Driven Capital Variance Account would adjust revenue for variations in the externally-driven capital costs of projects such as mass transit extensions.

Toronto Hydro is one of Ontario's largest electricity distributors. Its approach to Custom IR has provided a template for other utilities in the province. These considerations increase the value of careful appraisal of the Company's new incentive ratemaking ("IR") proposal and the supportive statistical cost research. Controversial technical work and IR provisions should be identified and, where warranted, challenged to avoid undesirable precedents for the Company and other Ontario utilities in the future. The OEB has constructively commented on plan design and statistical cost research methods in its decisions in past IR proceedings.

OEB staff retained Pacific Economics Group Research LLC ("PEG") to appraise and comment on PSE's benchmarking research and testimony and, if needed, to prepare an alternative study. We were also asked to consider other aspects of the Company's IR proposal. This is the report on our work.

The plan for the report is as follows. We begin by providing pertinent background information. There follow critiques of PSE's evidence and the presentation of some results using our preferred

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[1] EB-2018-0165, Toronto Hydro-Electric System Limited Custom Incentive Rate-setting Application for 2020-2024 Electricity Distribution Rates and Charges, filed August 15, 2018.

[2] EB-2014-0116, OEB Decision and Order, Toronto Hydro-Electric System Limited, December 29, 2015.

[3] The capital cost in the C factor calculation is as much a proposal as it is a projection or forecast.

methods and data. We conclude by discussing other features of the Company's Custom IR proposal. An Appendix addresses some of the more technical issues in more detail.

1.2. Summary

X Factor

The X factor in Toronto Hydro's proposed PCI is the sum of a 0% base productivity trend and a 0.30% custom stretch factor. These proposals are supported by total cost benchmarking research and testimony by PSE. PSE found that the Company's costs were 18.6% below the model's benchmark prediction on average over the three most recent years for which historical data are available (2015-17). However, the Company's projected/proposed costs over the five years of the new plan (2020-2024) were 6.0% below the model's predictions on average. Cost performance deteriorated during the current plan and would continue to deteriorate under the proposed plan. Toronto Hydro maintained in its evidence that a 0% base productivity trend contains a material *implicit* stretch factor.

Mr. Fenrick, one of the PSE study leaders, is a former employee of PEG and his benchmarking methods are in some respects similar to ours. We nonetheless disagree with some of the methods PSE used in this study. Here are our biggest concerns.

- We acknowledge that the Company faces substantial urban challenges in the provision of distributor services but disagree with the model's treatment of these challenges. Moreover, the model doesn't capture rural challenges that some distributors face, unlike a previous total cost benchmarking model that PSE prepared for Hydro One Networks in another electricity distributor rate application.[4]
- In addition to numerous business condition variables, the model includes an unusually large number of quadratic and interaction terms for these variables which jeopardize the precision of all parameter estimates.[5]

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[4] Fenrick, S., Power Systems Engineering, *Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network*, EB-2017-0049, Exhibit A-3-2, Attachment 2, June 7, 2017.

[5] These terms are explained in Section 3.1 and Appendix A.2.

- Generally speaking, we have found that the results of the PSE study are not robust with respect to changes in their methodology. Small changes in methodology produced large changes in the Company's ranking.
- The calculation of capital costs for the utilities in the econometric study sample is inaccurate.

We applaud the Company's willingness to present reliability benchmarking results and suggest some upgrades to their models. These models show that Toronto Hydro has substandard outage frequency but superior outage duration. PEG developed an alternative total cost benchmarking model using a longer sample period that includes 2017, more accurate capital cost data, and a better model specification. Using this model we found that Toronto Hydro's total cost was about equal to the benchmark on average from 2015 to 2017. However, the Company's total cost performance has deteriorated steadily under the current Custom IRM and is forecasted to continue to deteriorate under the proposed new plan. The projected/proposed total cost is about 15.6% above our model's prediction on average in the five years from 2020 to 2024.

PEG also developed experimental models to evaluate Toronto Hydro's projected/ proposed operation, maintenance, and administrative ("OM&A") expenses, capital cost, and capital expenditures ("capex"). These models are sensible and generate results that should be informative to regulators and the Company alike. During the term of the proposed plan, the Company's projected/proposed OM&A expenses would be about 12.1% *below* the model's predictions whereas the Company's capital cost would be about 35.7% *above* the predictions and capex would be about 14.9% above predictions. The results of these studies are summarized in Figures 1 and 2.

We also wish to challenge the notion that a 0% base productivity target contains an implicit stretch factor. Ontario data have limitations for the accurate measurement of productivity trends. U.S. productivity trends are also germane to the consideration of the right X factors for Custom IR plans. Recent research on the cost of U.S. power distributors suggests that their multifactor productivity ("MFP") growth trend has been positive.

Figure 1

Benchmarking Results for Toronto Hydro's Proposed Reliability (2020-2024)

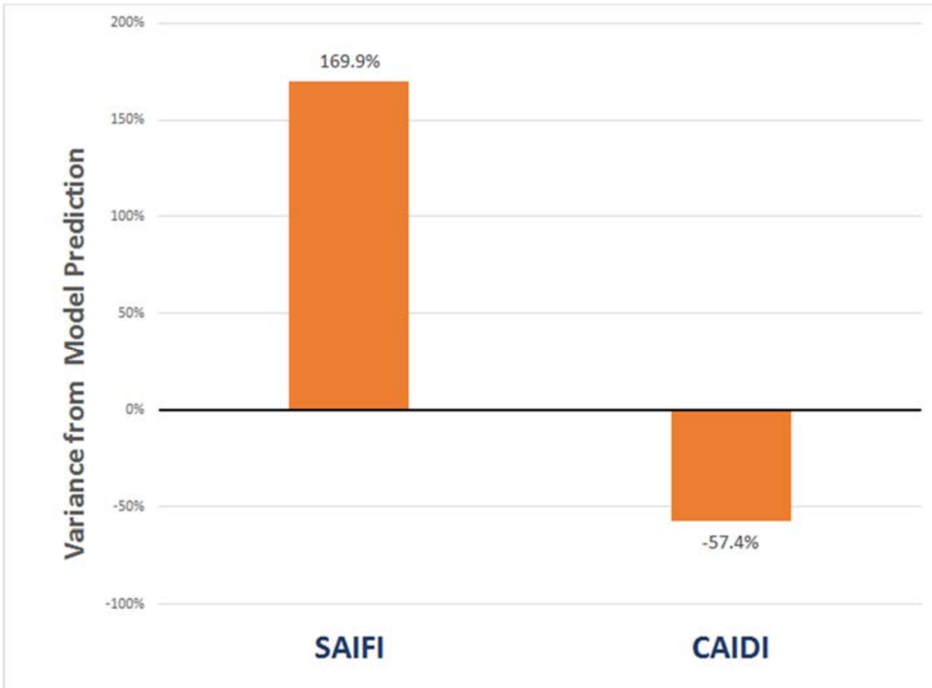
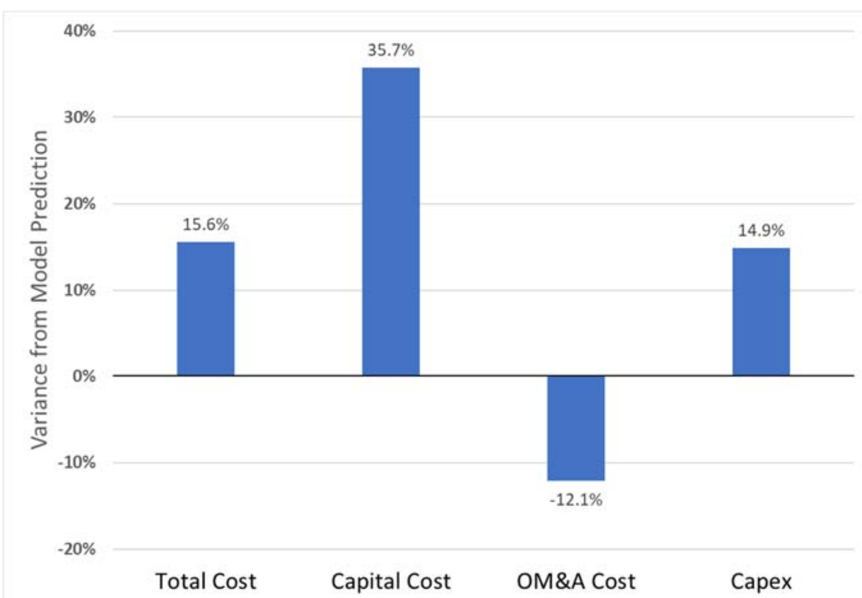


Figure 2

Benchmarking Results for Toronto Hydro's Proposed Costs (2020-2024)



On the basis of our research, we believe that a 0.45% stretch factor is indicated for Toronto Hydro provided that the Board is comfortable fixing the stretch factor for the full plan term. Combined with a 0% base productivity factor, this would yield an X factor of 0.45%. The PCI formula would then be Inflation - 0.45% exclusive of Z or growth factors.

In addition to the techniques used by PSE we have more general reservations about the use of benchmarking in this application.

- PSE's benchmarking suggests a continuation of the material decline in the cost performance of Toronto Hydro which occurred during its first Custom IR plan. It is possible that this is a rational response to special circumstances, such as the advanced age of some facilities and brisk load growth that strains capacity in some areas. However, no evidence has been provided that suggests that Toronto Hydro's cost performance has been and will be improving when these circumstances are accounted for. This violates the Board's Custom IR guidelines for cost efficiency evidence in our opinion. Taking better account of special circumstances should be a long-term goal in Custom IR benchmarking.
- Setting the stretch factor on the basis of a cost *forecast* rather than *actual achieved historical* cost reduces the incentive to cut costs during a plan since cutting cost cannot lower the stretch factor. Consideration should be paid to having the stretch factor reset annually during the years of its plan on the basis of whichever benchmarking model the Board prefers. The chosen model need not be updated.
- We believe that it desirable to go beyond total cost benchmarking in Custom IR proceedings by starting to consider performance in the management of the major cost subaggregates.

Other Plan Design Features

The IR plan proposed by Toronto Hydro is, in several respects, uncontroversial. We have noted that this plan is similar to that which the Board approved for the Company in EB-2014-0116. The proposed inflation factor and base productivity factor are in line with recent Board IR decisions. An earnings sharing mechanism would symmetrically share with customers earnings variances from non-capital causes outside a dead band.

We are nonetheless concerned about some features of Toronto Hydro's proposal. Here are our main concerns and suggested alternative plan provisions.

- The proposed ratemaking treatment of capital cost is problematic. Incentives to contain capex would be weakened by the CRRRVA and the Externally-Driven Capital Variance Account. The Company is perversely incented to spend excessive amounts on capital that slows growth of OM&A expenses. Notwithstanding the CRRRVA, the Company is still incentivized to exaggerate its need for supplemental revenue. The regulatory cost for the OEB and stakeholders is substantially raised and, ultimately, it is ratepayers who bear the burden of the capital cost increases.

- The kinds of capex accorded C factor and variance account treatment are, for the most part, conventional distribution capex that is similar to that incurred by distributors in studies used to calibrate the base productivity trend. The PCI would effectively apply chiefly to revenue for OM&A expenses and provide only a floor for price growth, even though it is designed to play neither of these roles. OM&A productivity growth in the United States has recently been positive.

We discuss several possible upgrades to the capital cost treatment. An extra stretch factor term for setting the C factor like that which the OEB recently approved for Hydro One Distribution is certainly one option.

1.3. PEG Credentials

PEG is an economic consulting firm with home offices on Capitol Square in Madison, Wisconsin USA. We are a leading consultancy on IR and the measurement of energy utility performance. Our personnel have over sixty years of experience in these fields, which share a common foundation in economic statistics. The University of Wisconsin has trained most of our staff and is renowned for its economic statistics program. Work for a mix of utilities, regulators, government agencies, and consumer and environmental organizations has given PEG a reputation for objectivity and dedication to good research methods. Our practice is international in scope and has included dozens of projects in Canada.

Mark Newton Lowry, the author of this report and principal investigator for the project, is the President of PEG. He has over thirty years of experience as an industry economist, most spent on energy utility issues. Author of numerous professional publications, Dr. Lowry has also chaired several conferences on performance measurement and utility regulation. He has provided productivity, benchmarking, and other statistical cost research and testimony in over 30 proceedings. His latest study on the productivity trends of U.S. power distributors was published in 2017 by Lawrence Berkeley

National Laboratory ("Berkeley Lab").[6] In Canada, Dr. Lowry has in recent years played a prominent role in IR proceedings in Alberta, British Columbia, and Québec as well as Ontario. He holds a PhD in applied economics from the University of Wisconsin.

[6] Mark Newton Lowry, Matt Makos, and Jeff Deason, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, Lawrence Berkeley National Laboratory, July 2017.

2. Background

2.1. The Company's Proposal

Toronto Hydro has filed a Custom IR application for its electricity distributor services.[7] Under the proposal, a multiyear rate plan would set rates for the five-year 2020-2024 period. Rates for 2020 would be established by a conventional rebasing process that uses a forecasted test year. A Custom PCI applicable to years 2021-2024 of the plan would have a growth rate formula featuring an inflation factor ("I"), an X factor, a Custom Capital ("C") Factor, and a growth ("g") factor.

$$CPCI = I - X + C - g.$$

The Company has proposed to use the inflation measure that the OEB adopted in its 4th generation IRM ("GIRM") decision. The growth in this inflation measure would be a weighted average of the growth in two inflation indexes: Canada's gross domestic product implicit price index for final domestic demand ("$GDPIPIFDD^{Canada}$") and the average weekly earnings for all employees in Ontario ("$AWE^{Ontario}$"). Both of these indexes are calculated by Statistics Canada. The inflation measure would be updated annually as calculated and issued by the OEB.

The proposed X factor would be fixed as the sum of a 0% productivity factor and a 0.30% custom stretch factor. The 0% productivity factor would be based on the OEB's 4th GIRM decision, its most recent industry productivity determination for Ontario's power distributors. The 0.30% stretch factor is supported by total cost benchmarking research by PSE. Toronto Hydro claims that this X factor also includes an *implicit* stretch factor because of the difference between the -0.33% multifactor productivity trend found in the PEG study[8] that informed the OEB's 4th GIRM decision and the OEB's determination of a 0% MFP trend.[9]

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[7] We use the term distributor services to encompass distribution and customer (e.g., billing and collection) services.

[8] PEG Research, *Productivity and Benchmarking Research in Support of Incentive Rate Setting In Ontario: Final Report To The Ontario Energy Board*, EB-2010-0379, November 21, 2013 and as corrected on December 19, 2013 and January 24, 2014.

[9] OEB EB-2010-0379, *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, November 21, 2013 and as corrected on December 4, 2013.

The C Factor would provide supplemental revenue for the difference between the growth in the Company's projected/proposed capital cost and the growth in its capital revenue that is otherwise yielded by the I Factor. The C Factor is calculated as $C_n - (S_{cap} * I)$, where

C_n = the percent change in forecast total revenue requirement attributable to changes in depreciation, return on equity, and payments in lieu of taxes/taxes; and

S_{cap} = the share of forecast capital-related revenue requirement in the forecast total revenue requirement.

The (S_{cap}*I) term reduces the possibility of double counting capital funding between C_n and the escalation provided by Inflation – X. By limiting the application of S_{cap} to the inflation measure rather than I - X, the C Factor would effectively be based on forecasted/proposed cost adjusted downward for the full 0.30% stretch factor. Based on Toronto Hydro's revenue requirement forecast, proposed X factor, and annual inflation of 1.2% for the CPCI term, the Company estimates that C_n will be a little higher than 3.5% for the CPCI term and S_{cap} will be about 73% on average. This results in an overall C factor averaging about 2.75% annually during the four indexing years of plan.

The g factor reduces growth in the PCI to reflect the Company's forecast of growth in its billing determinants during the four years that the CPCI would be operational. Toronto Hydro has proposed a g factor of 0.2% for each year of the plan which would not be trued up or reforecast.

Several costs would be addressed by variance accounts. These would include those for pension and other post-employment benefits, renewable enabling improvements not funded through provincial rate protection, and the gains or losses on asset derecognition (e.g., asset disposal). A lost revenue adjustment mechanism would compensate the Company for load losses due to conservation and demand management ("CDM") programs. Costs of CDM programs would continue to be funded by Ontario's Independent Electricity System Operator rather than through rates. An asymmetrical capital-related revenue requirement variance account ("CRRRVA") would reduce rates for cumulative plant addition underspends during the plan term. An Externally Driven Capital Variance Account would adjust rates for variation in the capital costs of external events such as facility relocations due to highway construction.

Toronto Hydro would continue to have the option to request Z factors if a qualifying event occurs, based on the OEB's existing Z factor policy. A qualifying event would need to result in a change in the revenue requirement of $1 million or more.

A symmetrical earnings-sharing mechanism ("ESM") would annually address variances between actual and allowed revenue requirements for OM&A expenses and revenue offsets that cause the Company's ROE to be outside of a dead band. Toronto Hydro has also proposed to apply the OEB's existing off-ramp policy. An off-ramp would be triggered if earnings variances exceed the OEB-approved rate of return on equity by more than 300 basis points in a single year. If an off-ramp is triggered, a regulatory review may be initiated. This review would be prospective in nature and could result in modifications to the plan, the plan continuing without changes, or the termination of the plan.

The Company has proposed to add 15 metrics to its existing performance scorecard and service quality reporting requirements. Each of these metrics would be associated with a goal, which may be to monitor, improve, or maintain performance. For each metric associated with the goal of maintaining or improving performance, Toronto Hydro's recent historical average performance was provided. The Company states that these targets are calibrated based on its proposed capital spending and that any change to this spending may affect the proposed targets.

2.2. Custom IR Guidelines

The *Handbook for Utility Rate Applications* ("Rate Handbook") provides guidelines for energy utilities requesting Custom IR plans.[10] The OEB stated that

> The annual rate adjustment must be based on a custom index supported by empirical evidence (using third party and/or internal resources) that can be tested. Custom IR is not a multi-year cost of service; explicit financial incentives for continuous improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast).
>
> The index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes. **If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service.** An application containing a proposed custom index which lacks the required supporting empirical information may be considered to be incomplete and not processed until that information is provided.
>
> **It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications**. **Given a utility's ability to customize the approach to rate-setting**

[10] OEB, *Handbook for Utility Rate Applications*, October 2016, pp. 18-19 and 24-28.

> **to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.**[11] [Emphasis added]

Benchmarking is a fundamental requirement of a Custom IR application, both 1) *external* benchmarking to analyze specific measures or programs by comparing year over year performance against key metrics and/or comparing unit costs (or other measures) against best practice benchmarks amongst a comparator group and 2) *internal* benchmarking to assess continuous improvement by the utility over time. Methodologies other than unit cost benchmarking are permitted in these studies. Utilities are expected to present objective, well researched benchmarking information supported by high quality and thorough analysis (using either third party or internal resources) which can be rigorously tested.

The OEB has also shown an interest in service quality benchmarking. The *2013 Report of the Board* outlining the final provisions of 4th GIRM stated that

> The Board will continue to build on its approach to benchmarking with further empirical work on the electricity distribution sector in relation to the distributor customer service and cost performance outcomes, including total cost benchmarking for the 2014 rate year. Future work will involve comprehensive benchmarking [i.e., model(s) that combine standards for customer service, including distribution system reliability, and cost performance].[12]

The OEB mentioned the eventual adoption of reliability benchmarking again in its 2015 *Report of the Board on Electricity Distribution System Reliability Measures and Expectations.* Reliability benchmarking considerations also led the System Reliability Working Group to suggest the use of the IEEE 1366 approach to determining major event exclusions in reliability reporting. The OEB subsequently adopted the IEEE 1366 approach as its preferred option for identifying major events.

2.3. First Toronto Hydro Custom IR Proceeding

In its order approving the first Custom IR plan for Toronto Hydro, the OEB approved many of the basic features of future Custom IR plans, including the adoption and calculation of the C factor, the inclusion of an earnings sharing mechanism, and the refund of capital underspends at the end of the plan term. More specifically, the OEB approved a plan that had a 5-year term and escalated rates using

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[11] *Ibid*., pp. 25-26.

[12] OEB *Report of the Board Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, EB-2010-0379, *op. cit*., p. 23.

the formula I – X + C, where I was the OEB's approved inflation measure, X was the sum of a 0% productivity trend and a 0.6% stretch factor, and C was a custom capital factor. A symmetric ESM addressed non-capital revenue requirement earnings variances outside of a 100-basis point deadband, while a variance account was developed to refund capex underspends to customers.

Despite approving much of Toronto Hydro's proposed Custom IR plan, the OEB appears to have expressed reservations about the quality of Toronto Hydro's filing.

> The OEB has determined that it cannot fully rely on Toronto Hydro's approach to establishing its spending proposals in determining if the outcome of that spending is desirable for ratepayers. It is not clear that Toronto Hydro's proposals are necessarily aligned with the interests of its customers, as they are largely supported by an asset condition analysis rather than the impact of the proposed work on the reliability of the system. The approach used by Toronto Hydro does not give a clear indication of how the overall spending is related to customer experience such as reliability.
>
> The Application lacks evidence of corporate policy guiding Toronto Hydro staff to focus on impacts on customers when developing spending proposals. The focus overall is on the need for work based on asset condition assessment without a clear understanding of the results expected to be achieved through the work. Continuous improvement measurements are lacking…
>
> There does not appear to be any measurement of units of activity and their costs that would allow for year over year assessment of improvement in Toronto Hydro's proposed metrics. The OEB agrees with the parties which suggested that reporting measures such as specific performance improvements sought and achieved per asset class, tie-ins of capital program spending to the dollar value of OM&A savings achieved and how program spending specifically impacts the reliability and quality of service are desirable under the RRFE. However, as the RRFE is relatively new, the OEB does not expect all such measures to be implemented at once….
>
> In the absence of these parameters, Toronto Hydro's rates have been set based on the OEB's assessment of Toronto Hydro's historic expenditures, and the OEB's expectations with respect to improved productivity informed by the external benchmarking evidence of the expert witnesses for OEB staff and Toronto Hydro. [13]

The OEB cut Toronto Hydro's proposed capex budget by 10% for the Custom IR term, without specifying which costs to cut. The Company was urged to find efficiencies during the term of the Custom IR plan. The OEB also expected Toronto Hydro to show improvements in reliability metrics due to increased capex and to be prepared to provide evidence on the relationship between capital investments and reliability performance at its next rebasing.

[13] OEB, Decision and Order EB-2014-0116, *op. cit*., p. 6-7.

The Toronto Hydro Custom IR decision also provided general commentary on what the Board expected Custom IR plans to entail.

> The Custom IR is described in the [Renewed Regulatory Framework for Electricity (RRFE)] as a suitable choice for distributors with large or highly variable capital requirements. However, this is an example, not a condition precedent, and the OEB will not make a decision as to whether it is the best option for any particular distributor. The custom option in the policy allows for proposals that are tailored to a distributor's needs as well as for innovative proposals intended to align customer and distributor interests….

Presumably, then the OEB was open to further innovation in the design of Custom IR plans. The OEB further stated that

> A Custom IR, unlike other rate setting options in the RRFE, does not include a predetermined formulaic approach to annual rate adjustments, it does not automatically trigger a financial incentive for distributors to strive for continuous improvement. The OEB expects that Custom IR applications will include features that create these incentives in the context of the distributor's particular business environment.[14]

2.4. Hydro One Distribution Proceeding

Several aspects of the OEB's recent decision on Hydro One Networks ("HON") Distribution's Custom IR plan also suggest a wariness on the part of the Board with respect to multiyear capex forecasts and the related C factor. The first was to disallow $300 million (or 8.4%) from HON's capex forecast. The OEB provided several reasons for its disallowance including:

- There were perceived gaps and deficiencies in Hydro One's customer consultation and investment planning processes.
- Hydro One's historical performance has shown significant gaps between the planned capital work program and the work that was actually executed.
- Benchmarking studies involving Hydro One's capital program have shown that Hydro One's performance has been worse than its peers.
- Proposed significant increases in the test period compared to the previous five years have not been fully justified.
- The impact of the new vegetation management strategy on the proposed capital program has not been taken into account.

[14] OEB, Decision and Order EB-2014-0116, *op. cit.*, pp. 4-5.

- The timing of the smart meter replacement program has not been properly supported.[15]

In addition, the OEB ordered HON to provide reports on a variety of issues to show that the forecasts and expected efficiency gains it approved in this proceeding had been realized. For example, the OEB directed HON to report at the next rebasing that detailed actual performance on the capital program relative to the approved plan and improvements in performance in benchmarked areas (e.g., pole replacement) that resulted from discussing best practices with better performing peers. HON was also ordered to report on the achievement of forecasted productivity savings.

The OEB also adopted an additional 0.15% stretch factor to apply solely to HON's C-factor beyond the 0.45% stretch factor applied to the entire revenue requirement. This decision was made in part due to the OEB's concern that forecasted capex was causing rate base to grow more rapidly than inflation and in part to "incent further productivity improvements throughout the term, and to provide customers the benefit from these additional improvements upfront."[16] The OEB was also influenced by HON's prior capital overspending and a proposal by its expert advisor that a materiality threshold and deadband be added to the C Factor.

[15] EB-2017-0049, OEB Decision and Order, Hydro One Networks, March 7, 2019, p. 70.

[16] *Ibid*., p. 32.

3. PSE's Benchmarking Research

3.1. Summary of PSE's Work

PSE benchmarked the total cost of the Company's base rate inputs which it incurs in the provision of power distributor services. This study appraised Toronto Hydro's historical costs over the 13-year 2005-2017 period and its projected/proposed costs for the 2018-2024 period. The Company's component OM&A expenses, capital costs (e.g., depreciation and return on plant value), and capex were not separately benchmarked.

An econometric model provided the total cost benchmarks. PSE developed this model using data on power distributor operations of 83 investor-owned utilities ("IOUs") in the United States and of Toronto Hydro and six other Ontario distributors that serve urban areas. The model contains two scale variables, the number of customers served and ratcheted maximum peak demand. Differences in the wage levels utilities faced were calculated using detailed U.S. and Canadian government data on wage rates, for labor categories that electric utilities use, in cities that the sampled utilities serve. PSE used these levels in the construction of summary input price indexes that had other features discussed below.

The challenge posed by urbanization is a major issue when benchmarking Toronto Hydro's cost. PSE estimated the percentage of the service territory served by each sampled distributor which was highly urbanized. There are, additionally, first-order terms for the following five business condition variables:

- percentage of distribution plant (by value) that is underground;
- percentage of customers with advanced metering infrastructure ("AMI");
- share of electric customers in the sum of electric and gas customers served;
- share of the service territory that is forested; and
- standard deviation of service territory elevation.

The model also contains a trend variable and a binary variable that indicates whether the data in a panel is for an Ontario distributor.

With respect to the form of PSE's cost model, a full complement of quadratic and interaction terms (e.g., Customers^2 and Customers x Ratcheted Peak Demand) for the two scale variables is added to their first order terms (Customers and Ratcheted Peak Demand). This is common in econometric cost models, but PSE also adds an unusually large number of quadratic and interaction terms for the other business condition variables (e.g., forestation^2).[17]

PSE reported that the Company's total costs were well below the benchmarks yielded by its model in the early historical years considered. However, Toronto Hydro's cost advantage began a notable decline after 2006. Cost was 22.8% below the model's prediction in 2014, the last year before the start of Toronto Hydro's current IRM, and is forecasted to be 11.6% below the model's prediction in 2019, the last year of the plan. Projected/proposed costs would be only 6.0% below the model's predictions on average during the years of the new plan. On this basis, and in conformance with the OEB 4th GIRM rules, PSE has advocated and the Company has proposed a fixed 0.30% stretch factor during the full term of the plan.

PSE also benchmarked the Company's reliability. Econometric models were developed for the System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI") using U.S. data. These models control for various business conditions, such as forestation and undergrounding, which can affect reliability. The models were developed using data from utility reports to state regulators as well as form EIA 861 data. Benchmarking work using these models suggests that the Company has long been an inferior SAIFI performer but a superior CAIDI performer and that these performances will not change much during the new plan.

The Company also submitted a unit cost benchmarking study prepared by UMS.[18] This study reviewed Toronto Hydro's cost performance for select capex and maintenance programs, including wood pole replacements, transformer replacements, breaker replacements, vegetation management, pole tests and treatments, overhead line patrols, and vault inspections. It is notable that this study uses an urban peer group and subjects the unit cost metrics to statistical adjustments to account for differences in cost reporting, input prices, and miscellaneous external business conditions. The study

[17] Functional forms are discussed further in the Appendix.

[18] Exhibit 1B/Tab 2/Schedule 1, Appendix B, and updated in Exhibit I/Tab 1B/Schedule 4 (response to OEB Staff 1B-4).

shows Toronto Hydro to be a 2nd quartile performer for most categories and programs studied relative to its peer group after normalization.

3.2. Critique

PSE Cost Benchmarking

Mr. Fenrick, one of the PSE study leaders, is a former employee of PEG and his benchmarking methods are in some respects similar to ours. For example, we both favor the econometric approach to benchmarking and believe that total cost benchmarking using a monetary approach to the measurement of capital cost is worthwhile. PSE has to its credit taken the time to develop a number of business condition variables that stand up to econometric scrutiny.

<u>Major Concerns</u>

We nonetheless disagree with some of the methods PSE used in its benchmarking study for Toronto Hydro. Our biggest concerns are addressed first to facilitate OEB review. We start by discussing our concerns about PSE's treatment of urban challenges. We agree that the provision of distribution services using facilities located under streets and buildings pose special cost challenges, especially in downtown areas where a high level of reliability is required. However, we do not believe that PSE has the urban challenge appropriately modelled.

PSE uses an urban congestion variable in its model. We prefer to call this an "urban challenge" variable because the cost of urban service is materially raised by high reliability requirements in office districts as well as by congestion problems. Our concerns about the variable that PSE developed include the following.

- It seems equally sensible to use the estimated urban area as the variable in a cost model since cost will clearly be higher the larger is the urban area served.
- Toronto Hydro and Consolidated Edison of New York ("Con Ed") have by far the highest values for PSE's urban challenge variable. If these two companies have unusually poor cost performances the variable's parameter estimate would reflect this. Con Ed is the worst cost performer in our replication of PSE's model. The parameter estimate for PSE's urban challenge variable is, in any event, very sensitive to the inclusion of Con Ed in the sample.

- PSE's model also has an interaction term between the share of assets that are undergrounded and its urban challenge variable. While undergrounding can increase the urban challenge, Toronto Hydro and many other utilities have assets that are undergrounded but are not located in congested areas or under streets and buildings. Some of these assets were directly buried. This practice is especially common in suburban areas, particularly those developed since the late 1970s, due in part to municipal requirements. The cost of direct-buried lines is considerably lower than the cost of underground vaulted lines.
- We are concerned about the sizable and unexplained value of the Ontario dummy variable.

Here are some other major concerns we have with PSE's benchmarking work in this proceeding.

- The model does not give balanced attention to the special challenges of serving rural areas, which Toronto Hydro does not face. PSE reports that it considered a rural challenge variable (total area/customer) but its parameter estimate was not quite statistically significant. PSE's total cost benchmarking model for Hydro One Distribution included this variable.[19]
- We are not convinced that an undergrounding variable is needed in a total cost model that includes an urban challenge variable. One reason is that the extent of system undergrounding is not fully exogenous, like the share of the service territory that is urban. Another is that the impact of undergrounding on capital cost varies with the type of undergrounding (e.g. vaulting vs. direct bury).
- The unusually large number of quadratic and interaction terms for the business condition variables in the model compromises the accuracy of all parameter estimates. There is even a quadratic version of the undergrounding/urban congestion interaction term. Quadratic interaction terms are rarely seen in econometric cost research.
- Power distributors use capital-intensive technologies, so the treatment of capital is a major issue when benchmarking their total cost or capital cost. PSE used a 1989 benchmark year to calculate the capital cost of *all* U.S. utilities in the econometric cost sample and a 2002 benchmark year for Toronto Hydro and the other Ontario distributors, even though a 1989

[19] Fenrick, S., EB-2017-0049, *op. cit*., p. 18.

benchmark year is feasible for all of the Ontario distributors in the sample, and a 1964 benchmark year is feasible for the U.S. distributors. The cost of gathering the requisite U.S. capital data for a 1964 benchmark year is non-negligible, but PSE has expended effort to develop several complicated business condition variables. Since capital cost typically accounts for more than half of the total cost of distributor base rate inputs in PSE's study, the recent benchmark year substantially reduces the accuracy of the benchmarking work.

- Research on the total cost of U.S. utilities usually uses a "monetary" approach to the calculation of capital cost.[20] This involves deflation of asset values that utilities report (e.g., their gross plant additions) using price indexes. PSE used an American Handy Whitman Electric Utility Construction Cost Index ("HWI") for power distribution in North Atlantic states to deflate the asset values of the included Ontario distributors. They attempted to make this index more relevant to Canada by adjusting each value for U.S./Canadian purchasing power parities ("PPPs") obtained from the Organization for Economic Cooperation and Development ("OECD").

  The appropriate asset price deflator to use in Ontario power distributor cost research is an issue of growing importance. One reason is that Statistics Canada stopped computing Electric Utility Construction Price Indexes ("EUCPIs") after 2014. These had been available for power distribution assets and substations. The trend in the EUCPIs in the decade prior to this was implausible.

  PEG spent considerable time and effort during the recent Hydro One distribution IR proceeding reviewing alternative asset price deflators.[21] We found that HWIs and EUCPIs both have drawbacks. Both indexes were designed many years ago and have some cost-share weights and inflation subindexes that are now quite dated. The labor price component of the distribution system EUCPI grew quite slowly in the later years of its calculation. However, trends in prices of labor and other construction inputs in the North Atlantic states may not be appropriate for Toronto Hydro and other Ontario utilities. For example, the HWI would be sensitive to a surge in power transmission capex that puts

[20] Monetary approaches to measuring capital cost are discussed further in Appendix Section A.1.

[21] EB-2017-0049, Exhibit L1, Tab 8, Schedule HONI-14 Attachment.

upward pressure on distribution construction costs. Purchasing power parities ("PPPs") calculated for the entire economy may not satisfactorily adjust for differences in Ontario and northeast U.S. construction cost trends.

Alternative asset price indexes are available. Based on our review, our professional opinion is that the most promising replacement for the EUCPI in Ontario distributor cost research is Statistics Canada's implicit price index for the capital stock of the Ontario utility sector.[22] This is readily computed from Statistics Canada's data on Flows and Stocks of Fixed Non-Residential Capital. This data collection program measures trends in the quantities of various capital assets using a monetary method. Statistics Canada generates this dataset by gathering investment data from various sources including the Capital Repair and Expenditures Survey. Our research showed that this index tracked the EUCPI in its good years better than the HWI with a PPP adjustment.

Smaller Concerns

Here are some smaller concerns we have with PSE's benchmarking study. We do not believe that these problems had a major impact on the benchmarking results. However, future benchmarking studies, by Toronto Hydro and other utilities, which steer clear of these problems will have more credibility.

- Fixed 70/30 weights were assigned to labor and material and service expenses in the OM&A price index for U.S. utilities, even though flexible weights are available for the American IOUs in the sample and the labor cost share is typically well below 70% for these companies. Thus, the OM&A input price indexes for American distributors were unnecessarily inaccurate.
- PSE used the U.S. gross domestic product price index, converted to Canadian dollars using PPPs, as the material and services ("M&S") price index for the Ontario utilities.

[22] Statistics Canada, 36-10-0096-01, Flows and Stocks of Fixed Non-Residential Capital, CANSIM. The implicit price index is calculated as the ratio of current value of net stock to the corresponding quantity index.

- PSE used the U.S. Employment Cost Index ("ECI") for *salaries and wages* as its labor price escalator even though an ECI for *total* compensation is available which would be more appropriate since its study includes pension and benefit expenses.

General Concerns

In addition to our comments above on specific techniques used by PSE, we have more general reservations about the use of benchmarking in this application.

- PSE's benchmarking suggests a continuation of the material decline in the cost performance of Toronto Hydro which occurred during its first Custom IR plan. It is possible that brisk cost growth is a rational response to special circumstances such as capacity constraints and advanced system age. However, no evidence has been provided that suggests that Toronto Hydro's cost performance is improving after taking account of such challenges. This arguably violates the Board's Custom IR guidelines that we discussed in Section 2.
- Setting the stretch factor on the basis of a cost forecast rather than the actual cost incurred during the plan removes a potential incentive benefit of stretch factors in that cost reductions cannot lower stretch factors. Consideration should be paid to having the stretch factor reset annually during the years of its plan on the basis of whichever benchmarking model the Board prefers.
- Total cost benchmarking does not shed light on the sources of high and low costs that utilities incur. Knowledge of strengths and weaknesses in more granular management of major cost categories such as OM&A expenses is useful to utilities and regulators alike.

Implicit Stretch Factor

We also wish to challenge the notion that a 0% base productivity target contains an *implicit* stretch factor. Ontario data have many limitations for the accurate measurement of multifactor productivity trends. These include the recent transition of many utilities to IFRS accounting.

PEG calculated the MFP trends of a large sample of U.S. power distributors in its recent study on multiyear rate plans for Berkeley Lab.[23] We reported MFP trends of 0.45% for the full 1980-2014 sample

[23] Lowry, Makos, and Deason, o*p. cit*., p. B.15.

period and of 0.39% for the more recent 1996-2014 sample period. In a fall 2017 presentation funded by LBNL which Dr. Lowry made to the New England Council of Public Utility commissions, Dr. Lowry reported that the MFP trend of sampled power distributors for the more recent 1996-2016 sample period was 0.43% per annum for the full U.S. sample and 0.31% for the Northeast U.S.

PSE Reliability Benchmarking

We believe that PSE has, with the Company's sponsorship, done a service to Ontario's regulatory community by making progress in the area of reliability benchmarking. Cost benchmarking should ideally be combined with reliability benchmarking, and reliability performance is germane when considering requests for supplemental capex funding. PSE has gathered a respectable sample of publicly available U.S. data that span the years 2010-2016. Major event days have been excluded, if not with fully consistent definitions. The models presented by PSE are a good starting point for further improvements. We present alternative models in Section 3.3. below.

3.3. Alternative Benchmarking Results Using PSE's Data

Alternative Cost Models

We tested the robustness of PSE's results by developing some alternative total cost benchmarking models using its dataset.

- Instead of using the estimated percentage of the total area served which was congested, we used the estimated area congested. We substituted this alternative in all of the variables that PSE constructed. Toronto Hydro's average score during the five years of its proposed plan declined from about 6% using PSE's model to about 52% over.
- We removed all of the translog terms for the non-scale business conditions from the model. The percentage urban variable had a highly significant and positive parameter estimate. However, PSE's average score for the 2020-24 period was about 39% over the model's prediction.
- Consolidated Edison of New York was removed from the sample. Toronto Hydro's average score during the five years of its proposed plan changed from about 6% under using PSE's model to 653% under.

These results provide strong evidence that PSE's total cost benchmarking results for Toronto Hydro are not robust.

Alternative Reliability Models

PEG developed alternative econometric reliability models using the data provided by PSE in its working papers. We modelled CAIDI and SAIFI using business condition variables obtained from PSE and an additional weather variable that are pertinent to power distributor reliability performance. The sampled companies were the same. We extended the sample period to include 2017.

Results of our reliability research can be found in Tables 1 and 2. Our SAIFI model indicates that SAIFI was higher the greater is the share of distribution assets overhead. The SAIFI impact of overheading was magnified by forestation. Our research also shows that SAIFI was greater

- the lower is the share of the service territory that was urban
- the greater were extreme temperatures in the service territory.
- the more extensive was forestation when more distribution plant is overhead
- the greater was precipitation
- the greater was the standard deviation of elevation
- when the IEEE major event day standard was used.

The parameter estimate for the trend variable suggests that the SAIFI of sampled utilities trended downward by 1.85% annually for reasons not explained by the model's business condition variables. The adjusted R-squared of the model was 0.30%. While this is much lower than in our cost models, it should be remembered that the SAIFI metric already controls for the number of customers served.

Our model for CAIDI indicates that CAIDI was higher

- the greater was the share of service territory area that was urban.
- the more extensive was forestation
- the greater was the area of the service territory per customer
- the greater was precipitation
- the greater was the standard deviation of elevation in the service territory.

Table 1

Econometric Model of SAIFI

VARIABLE KEY

PCTCU =	% service territory congested urban
PCTPOH =	% of distribution plant overhead
EXTREME =	Sum of cooling degree hours above 30°C and heating degree hours below -15°C
PCP =	Annual average precipitation
PCTFOREST =	% service territory forested
ELEVSTD =	Elevation standard deviation
IEEE =	Binary variable indicating the IEEE standard
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
PCTCU	-39.913	-6.32	0.00
PCTPOH	1.236	14.66	0.00
EXTREME	0.056	7.52	0.00
PCP	0.131	6.37	0.00
PCTPOH*PCTFOREST	0.204	1.76	0.08
ELEVSTD	0.035	3.45	0.00
IEEE	0.111	5.62	0.00
Trend	-0.019	-5.82	0.00
Constant	0.128	4.12	0.00

Adjusted R^2 0.305

Sample Period 2010-2017

Number of Observations 496

Table 2

Econometric Model of CAIDI

VARIABLE KEY

PCTCU =	% service territory congested urban
PCTFOREST =	% service territory forested
AREAYN16 =	Square km of service territory per customer in 2016
PCP =	Annual average precipitation
ELEVSTD =	Elevation standard deviation
PCTAMI =	% of customers with AMI meters
IEEE =	Binary variable indicating the IEEE standard

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
PCTCU	18.924	9.095	0.000
PCTFOREST	0.055	10.167	0.000
AREAYN16	0.066	7.686	0.000
PCP	0.063	5.151	0.000
ELEVSTD	0.081	12.758	0.000
PCTAMI	-0.049	-2.908	0.004
IEEE	-0.031	-2.651	0.008
Constant	4.824	446.464	0.000

Adjusted R^2 0.232

Sample Period 2010-2017

Number of Observations 496

- the lower was the level of AMI penetration
- when the IEEE major event day standard was not used.

The adjusted R-squared of the model was modest 0.23%. Thus, CAIDI is less well explained by our modelling than SAIFI.

Benchmarking results for Toronto Hydro can be found in Tables 3 and 4. It can be seen that the Company's SAIFI was far above our model's prediction throughout the sample period. The results are quite sensitive to the inclusion of the urban variable. The Company's CAIDI tended to be well below the model's predictions throughout the sample period and improved noticeably from 2013 to 2018.

Table 3

Year by Year SAIFI Benchmarking Results

Year	Percent Difference[1]
2005	131.2%
2006	158.1%
2007	161.6%
2008	160.9%
2009	147.2%
2010	155.0%
2011	158.9%
2012	149.6%
2013	159.7%
2014	152.6%
2015	161.2%
2016	161.3%
2017	160.2%
2018	*164.3%*
2019	*164.8%*
2020	*166.5%*
2021	*168.1%*
2022	*169.9%*
2023	*171.7%*
2024	*173.5%*
Annual Averages	
2010-2017	**157.3%**
2015-2017	**160.9%**
2020-2024	**169.9%**

[1] Formula for benchmark comparison is $\ln(SAIFI^{THESL}/SAIFI^{Bench})$.

Note: Italicized numbers are projections/proposals.

Table 4

Year by Year CAIDI Benchmarking Results

Year	Percent Difference[1]
2005	-45.4%
2006	-62.0%
2007	-52.1%
2008	-58.4%
2009	-34.8%
2010	-42.2%
2011	-39.9%
2012	-54.3%
2013	-52.5%
2014	-60.8%
2015	-59.7%
2016	-66.1%
2017	-65.3%
2018	*-64.9%*
2019	*-58.0%*
2020	*-57.8%*
2021	*-57.6%*
2022	*-57.4%*
2023	*-57.2%*
2024	*-57.0%*
Annual Averages	
2010-2017	**-55.1%**
2015-2017	**-63.7%**
2020-2024	**-57.4%**

[1] Formula for benchmark comparison is $\ln(CAIDI^{THESL}/CAIDI^{Bench})$.

Note: Italicized numbers are projections/proposals.

4. PEG's Original Cost Benchmarking Work

4.1. Sources of Data on Cost, Price, and Operating Scale

Accurate statistical benchmarking is facilitated by abundant, high quality data on utility operations. In this section we discuss sources of the data we used in our study to benchmark the cost of Toronto Hydro.

Ontario

About seventy utilities provide power distribution services in Ontario today. These utilities also provide a wide range of customer services that include conservation and demand management ("CDM"). The largest distributor, Hydro One Networks, also provides most power transmission services in Ontario.

<u>Pros and Cons of Ontario Data</u>

Advantages of using data for other Ontario utilities to appraise the cost performance of Toronto Hydro include the following.

- Standardized, high quality data are publicly and electronically available on operations of numerous Ontario distributors for more than a decade. Thus, a large sample is available for econometric estimation of cost model parameters. Large samples of good data improve the accuracy of econometric model parameter estimates.
- Data are available for all distributors on peak loads and the total length of distribution lines (in circuit miles).
- There is no need for currency conversions in an Ontario benchmarking study, and adjustments are fairly straightforward if desired for differences between input prices in various parts of the province.

Disadvantages of Ontario data include the following.

- Many of the distributors serve small towns outside the larger metropolitan areas and hence face business conditions quite different than those of Toronto Hydro.

- Many distributors recently transitioned to Modified International Financial Reporting Standards ("MIFRS"). These new standards reduced capitalization of OM&A expenses for many companies.
- Itemized data on pension and benefit expenses of most Ontario distributors, including Toronto Hydro, are unavailable for lengthy sample periods. These costs are difficult to benchmark accurately, and the Company proposes to address these costs with a variance account rather than indexing. Canadian labor price indexes are available only for salaries and wages and not for comprehensive employment costs
- Data needed to calculate capital costs and quantities for most distributors using a monetary method are available only since 1989.[24] In addition, data on *gross* plant additions, which we normally use to calculate capital costs, are only available starting in 2013. It is necessary to impute gross plant additions in earlier years using data on changes in the gross (undepreciated) value of plant. Another problem in measuring Ontario capital costs is that itemized data on distribution and general plant are not readily available. Statistics Canada suspended calculation of its electric utility construction price indexes several years ago. These circumstances tend to reduce the accuracy of statistical research on the capital cost and total cost performance of Ontario utilities.
- Itemization of OM&A salary and wage and material and service expenses is not readily available for a lengthy sample period.
- PSE has, in any event, made its business condition data available in this proceeding only for six additional Ontario distributors.

Based on these considerations, the only observations for Ontario utilities that we use in our study are those for Toronto Hydro.

Data Sources

The primary source of data on the cost and operating scale of Ontario power distributors is the Regulatory Recordkeeping Requirements ("RRR") reports. The OEB has required each jurisdictional

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[24] We believe that it is straightforward to interpolate plant additions over the few years for which gross plant value data are available before the year 2000.

power distributor to file this report since 2002. A uniform system of accounts called the *Accounting Procedures Handbook* has been established for the RRR reports. Most data on Canadian prices used in the study were obtained from Statistics Canada.

United States

Power distributor services in the United States are provided to most customers by investor-owned electric utilities ("IOUs") but are provided in some areas by cooperative or municipal utilities.[25] U.S. distributors typically provide several customer services (e.g., meter reading, billing, and collection) but varied levels of CDM services. Most IOUs also provide power transmission services in their service territory and many provide generation services.[26] The reported distribution costs of some companies include subtransmission lines and substations that receive power at subtransmission and higher voltages.

Pros and Cons of U.S. Data

U.S. data have numerous advantages in a Toronto Hydro total cost benchmarking study.

- The U.S. government has gathered detailed, standardized data for decades on the operations of dozens of IOUs.
- Most IOUs provide an array of distributor services that is similar to Toronto Hydro's.
- Many IOUs serve large urban areas.
- U.S. cost data are credibly itemized, permitting calculations of the cost of power distributor services even for vertically integrated utilities.
- Data on the net value of plant and the corresponding gross plant additions have been itemized for power distribution and general assets since 1964. Custom price indexes are available on the construction cost trends of power distributors. This makes U.S. data the best in the world for accurate calculation, using monetary methods, of the consistent capital

[25] Cities that are served by municipal utilities include Austin, Los Angeles, Memphis, Nashville, Sacramento, and Seattle.

[26] Examples of vertically integrated electric utilities ("VIEUs") include Duke Energy Carolinas, Florida Power and Light, Georgia Power, and Northern States Power.

cost, price, and quantity indexes that are needed to appraise the capital cost and total cost performances of power distributors.

There are, however, some downsides to using U.S. data in distributor cost research.

- Consistent data on *total* distribution line length, a potentially useful scale variable, are not publicly available for most major IOUs.[27]
- Peak load is another potentially relevant scale variable in a power distribution cost study. Available U.S. peak load data require adjustments to be comparable to the analogous Ontario data.
- Itemized data are available on administrative and general expenses and general plant but these are driven by the entirety of each IOU's operations and not just by the provision of distributor services. If these costs are to be considered in the research, it is necessary to assign a portion of them to distributor services by some arbitrary means.

U.S. Data Sources

The source of U.S. utility cost data used in our study is Federal Energy Regulatory Commission ("FERC") Form 1. Data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Selected Form 1 data were for many years published by the U.S. Energy Information Administration ("EIA").[28] More recently, these data have been available electronically in raw form from the FERC and in more processed forms from commercial vendors such as SNL Financial.

Data on the number of retail customers served by the utilities were drawn from Form EIA-861 (the *Annual Electric Power Industry Report*) for most years of the sample period and from FERC Form 1 for some early years. Customer data from these two sources are generally similar.

Data on U.S. labor prices were drawn from the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor. The gross domestic product price index ("GDPPI") that we used to deflate material and service expenses of U.S. distributors was obtained from the Bureau of Economic Analysis of

[27] Data on *overhead* pole (aka structure or route) miles are available for a considerably larger group of companies from surveys of an American data vendor.

[28] This publication series had several titles over the years. The most recent title is *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*.

the U.S. Department of Commerce. Data on levels of heavy construction costs in various U.S. and Canadian locations were purchased from R.S. Means. Data on U.S. electric utility construction cost *trends* were purchased from Whitman, Requardt and Associates.

U.S. data were eligible for inclusion in our sample from all major IOUs in the United States which filed Form 1 in 1964 (the benchmark year for our study, described further in the Appendix) and that, together with any important predecessor companies, have reported the data required for our calculations continuously since then. To be included in the study the data were also required to be of good quality and plausible.

To take advantage of some of the Z variable data that PSE have gathered, we have used data on the sizable number of American IOUs that PSE used in its studies. These utilities serve some of the largest urban areas in the United States, including Baltimore, Charlotte, Chicago, Cincinnati, Cleveland, Denver, Detroit, Indianapolis, Kansas City, Las Vegas, Miami, Minneapolis, New York, Philadelphia, Phoenix, Pittsburgh, Portland, San Diego, San Francisco, St. Louis, Tampa, and Washington.[29]

Sample Summary

Data from a total of 84 distributors were used in our econometric cost research. This is six companies fewer than in the PSE sample due to the exclusion of the other Ontario distributors. The sampled companies are listed in Table 5. We believe that these data form a good base for rigorous research on the cost performance of Toronto Hydro. The sample is large and varied enough to permit development of credible econometric cost models with several business condition variables. Most regions of the United States are well-represented.[30] The sample period for the econometric cost research was 1995 to 2017.[31]

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[29] All of the cities mentioned have metropolitan areas with a population exceeding two million.

[30] However, the requisite data are not available for most Texas distributors.

[31] The sample period for the capex model was 1996-2017.

Table 5

Sample of Utilities Used in Econometric Cost Model Development

*Alabama Power	MDU Resources Group
*ALLETE (Minnesota Power)	Metropolitan Edison
*Appalachian Power	*Mississippi Power
*Arizona Public Service	Monongahela Power
Atlantic City Electric	*Nevada Power
Avista	New York State Electric & Gas
*Baltimore Gas & Electric	*Niagara Mohawk Power
*Black Hills Power	Northern Indiana Public Service
*Central Hudson Gas & Electric	Northern States Power - MN
*Central Maine Power	Northern States Power - WI
*Cleco Power	*Ohio Edison
*Cleveland Electric Illuminating	*Oklahoma Gas & Electric
*Commonwealth Edison	Orange & Rockland Utilities
Connecticut Light & Power	*Pacific Gas & Electric
Consolidated Edison of New York	*PECO Energy
*Consumers Energy	Pennsylvania Electric
*Delmarva Power & Light	Pennsylvania Power
*DTE Electric	*Portland General Electric
*Duke Energy Carolinas	*Potomac Electric Power
*Duke Energy Florida	*PPL Electric Utilities
*Duke Energy Indiana	*Public Service Company of Colorado
*Duke Energy Kentucky	Public Service Company of New Hampshire
*Duke Energy Ohio	*Public Service Company of Oklahoma
Duke Energy Progress	*Public Service Electric & Gas
*Duquesne Light	*Puget Sound Energy
El Paso Electric	*San Diego Gas & Electric
Empire District Electric	*South Carolina Electric & Gas
*Entergy Arkansas	*Southern California Edison
*Entergy Mississippi	Southern Indiana Gas & Electric
*Entergy New Orleans.	*Southwestern Public Service
*Florida Power & Light	*Tampa Electric Company
*Gulf Power	***Toronto Hydro**
*Idaho Power	Toledo Edison
*Indiana Michigan Power	*Tucson Electric Power
*Indianapolis Power & Light	Union Electric
Jersey Central Power & Light	*United Illuminating
*Kansas City Power & Light	*Virginia Electric & Power
*Kansas Gas & Electric	*West Penn Power
*Kentucky Power	Western Massachusetts Electric
*Kentucky Utilities	*Wisconsin Electric Power
*Louisville Gas & Electric	*Wisconsin Power & Light
*Madison Gas & Electric	Wisconsin Public Service

* These companies experienced AMI penetration during the sample period and therefore have non-NA values for PCTAMIGROWTH. These companies were the only companies to be included in the capex model.

4.2. Definition of Variables

Costs

The major tasks in power distribution are the local delivery of power, the reduction of its voltage, and the metering of quantities delivered. Most power is delivered to customers at the voltage at which it is consumed. This requires distributors to step down the voltage of power from the voltage at which they receive it from the transmission sector.[32] All distributors use transformers near the point of delivery to reduce voltage to the level at which it is consumed. Some also own and operate substations.

Distributors also typically provide various customer services. In North America, these typically include metering, meter reading, customer account, and customer service and information ("CS&I") services. In the United States, reported expenses for CS&I services include those for CDM programs. These expenses vary widely between utilities and are not itemized for easy removal. We accordingly follow the path of PSE by excluding all CS&I expenses from the costs of US utilities in our study.

Pension and benefit expenses are often excluded from utility cost performance studies because they are sensitive to volatile external business conditions such as stock prices. In Canada, an additional problem with including pension and benefit expenses in econometric cost research is the lack of federal labor price indexes that encompass them. Pension and benefit expenses can be removed from the data for Toronto Hydro and American IOUs. We have therefore excluded these expenses from this study.

The O&M expenses we used in the study for U.S. utilities included those for power distribution, customer accounts, metering, and meter reading. We also included a sensible share of A&G expenses.[33] We excluded all reported O&M expenses incurred by sampled U.S. utilities for generation, power procurement, transmission, customer service and information, franchise fees, and gas services. The capital costs we included were those for distribution plant and a sensible share of the cost of general plant.

[32] Some large industrial customers take delivery of power directly from the transmission system.

[33] The particular method chosen for allocating general costs is theoretically arbitrary but has little impact on results.

Like PSE we excluded expenses for CDM from the costs of sampled Canadian distributors. All reported administrative and general expenses were included. The capital costs we considered were those for distribution plant and all reported general plant.

The total cost of power distributor services considered in our study was therefore the sum of capital costs and *applicable* O&M expenses. We employed a monetary approach to capital cost, price, and quantity measurement which featured geometric decay. Capital cost was the sum of depreciation expenses and a return on net plant value less capital gains.[34] Further details of our capital cost calculations are provided in Appendix Section A.1.

Input Price Indexes

OM&A

Summary OM&A input price indexes were constructed by PEG which were weighted averages of price subindexes for labor and material and service ("M&S") inputs. Calculation of these indexes used 70/30 labor/M&S weights for Toronto Hydro and company-specific, time-varying cost share weights for the U.S. utilities. The cost shares were calculated from FERC Form 1 OM&A expense data.

Methods for constructing the price subindexes used in these calculations differed somewhat for for Ontario and the United States.

Ontario We used the indexes that PSE calculated to compare the levels of U.S. and Canadian salaries and wages in particular years. Labor price index values for earlier and later years were then established by trending these levels using Statistics Canada's $AWE^{Ontario}$ in Ontario. The $GDPPIFDD^{Canada}$ was our proxy for a Canadian M&S price trend index.

United States The labor price levels for U.S. utilities that we obtained from PSE were escalated by regionalized BLS Employment Cost Indexes for salaries and wages. M&S prices were escalated by the U.S. gross domestic product price index. This is the U.S. government's featured index of inflation in prices of the economy's final goods and services. Final goods and services include business equipment and exports as well as consumer products.

[34] Capital gains are included due to the geometric decay capital cost treatment that we employ, which like other monetary methods values capital at replacement cost.

Capital

Construction cost indexes and rates of return on capital are required in the capital cost research. For each sampled company we calculated for each sample year a 50/50 average of the embedded average interest rate on long-term debt as calculated from FERC Form 1 data, and the average allowed rate of return on equity ("ROE") approved in electric utility rate cases as reported by the Edison Electric Institute.[35]

We used the Statistics Canada implicit price index for the capital stock of Ontario utilities to deflate the value of plant additions of Toronto Hydro. Statistics Canada includes in the utility sector power generation and transmission, gas distribution, and water and sewer utilities as well as power distribution. For the United States we used the applicable regional Handy Whitman Indexes of Public Utility Construction Costs for Total Electric Utility Distribution Plant.

Multifactor

The summary *multifactor* input price index for each U.S. and Ontario utility in our sample was constructed by combining the capital and summary O&M price indexes using company-specific, time-varying cost share weights for all companies. The ratio of cost to this index was the dependent variable in the econometric total cost research.[36]

U.S./Canada Price Patch

Since transnational data were used in the study, it was necessary to adjust for differences in currencies of distributors in different countries. M&S prices were patched using purchasing power parities ("PPPs") computed by the Organization for Economic Cooperation and Development ("OECD"). Labor prices did not require a patch because they were based on average salaries and wages stated in nominal U.S. or Canadian dollars. Construction cost indexes did not require a patch since data on heavy construction cost levels in the U.S. and Canada were drawn from the same source and are stated in nominal U.S. and Canadian dollars.

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[35] The Edison Electric Institute is the principal trade association of U.S. electric utilities. The ROE data we used in the study were drawn from the backup data to the *EEI Rate Case Summary* quarterly reports.

[36] The dependent variables in the econometric models for OM&A, capital, and capex costs were, similarly, cost divided by the corresponding input price index.

Scale Variables

Two measures of distributor operating scale were used in all four of our econometric cost models: ratcheted peak demand and the number of retail electric customers served. The ratcheted peak demand in a given year is the highest value of peak demand that has thus far been achieved by the utility during the sample period. This is a better measure of the *expected* maximum peak demand that typically drives distribution cost. The U.S. peak demand data were adjusted to remove the estimated amount that was due to required sales for resale since these are not distributor loads.

All four costs that we modelled should be higher the higher are the values of both of these scale variables. To provide some flexibility to the model's functional form we added quadratic and interaction terms to each model for these variables.[37] This is a common practice in econometric cost research. The expected signs for the parameters for these variables are indeterminate.

Other Business Condition Variables

Several other business condition variables were used in one or more of our econometric cost models. One of these variables was the estimated share of area served by the utility that was urban. This variable, developed by PSE, should have a positive parameter estimate in the total cost, capital cost, and capex models. Its sign is indeterminate in the OM&A cost model.

The OM&A model has a variable indicating the share of distribution assets that are overhead. This makes sense because undergrounding is an attribute of the capital quantity, which is a variable in an OM&A cost function.[38] We expect this variable to have a negative sign.

The challenge of low customer density is captured by the estimated area served that is non urban. We expect cost to be higher the higher is the value of this variable in the total and capital cost models.

The cost of serving non-urban areas is generally raised by forestation. We therefore included in our models PSE's variable for the percentage of area forested in the service territory. We expect the

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[37] Quadratic terms and other functional form issues are discussed in Appendix Section A.2.

[38] In a restricted or short-run cost function, cost depends on the prices of *included* inputs, output, miscellaneous other external business conditions, and the quantity of *other* inputs that a utility uses. In the context of an OM&A cost function the quantities and attributes of capital inputs are pertinent.

parameter for this variable to have a positive sign in the OM&A and total cost models. Its expected sign is indeterminate in a capital cost or capex model.

The models also contain a variable indicating the share of customers that have AMI. We expect this variable to have a positive sign in the total cost and capital cost models. Its expected sign is indeterminate in the OM&A model since AMI reduces meter reading expenses but raises costs of processing and analyzing the copious data that AMI gathers.

The models also have a variable indicating the standard deviation of elevation in the service territory. As the value of this variable increases, roads between destinations become less direct and work off the road tends to be more difficult. We therefore expect this variable's parameter estimate to have a positive sign in all four models.

The models also have a variable indicating the share of electric customers in the sum of electric and gas customers. We expect this variable's parameter estimate to have a positive sign in all four models in which it may appear since higher values mean less opportunities to realize economies of scope from the joint provision of gas and electric service.

The capex model also has variables indicating the *growth* in operating scale and AMI. We expect the parameter estimates for these variables to have positive signs.

The models also have trend variables. These variables permit predicted cost to shift over time for reasons other than changes in the specified business conditions. Trend variables thereby capture the net effect on cost of diverse conditions, such as technical change, which are otherwise excluded from the models. Parameters for such variables have often had negative signs in econometric research on utility cost. However, the expected signs of trend variable parameters in cost models are nonetheless indeterminate.

How Does PEG's Cost Benchmarking Differ?

- Fewer Ontario utilities in the sample, but longer sample period that includes 2017 data
- Alternative urban and rural challenge specifications
- Fewer interaction and quadratic terms
- Pension and benefit expenses excluded
- Better capital cost specification
- Better Ontario input price indexes
- Experimental benchmarking models for OM&A expenses, capital cost, and capital expenditures were also developed

We generally tried to use as many business condition variables with statistically significant and sensibly signed parameter estimates as we could in each cost model. If a variable appears in one model and not another, it is either because the variable does not belong in one of the models or because it did not have a correctly signed and statistically significant parameter estimate. It makes sense that some variables matter more for OM&A expenses than they do for capital cost and vice versa. We were more sparing in the use of extra quadratic and interaction terms than PSE was out of concern that too many variables reduce the precision of parameter estimates.

4.3. Econometric Research

Like PSE we developed an econometric model of the total cost of power distributor base rate inputs. We also developed experimental econometric models of three major components of total cost: OM&A expenses ("opex"), capital cost, and capital expenditures ("capex"). Estimation results for all four models are reported in Tables 6-11. These tables include parameter estimates and their associated asymptotic t values and p-statistics. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. These significance tests were used in model development. A t test requires selection of a critical value for the asymptotic t ratio. We employed a critical value that is appropriate for a 90% confidence level.[39] In all of these models, all of the parameter estimates for the first-order terms of the business condition variables are statistically significant and plausible as to sign and magnitude.

Total Cost

Results for the total cost model are presented in Table 6. Here are some salient results.

- The parameter estimates for the number of customers and ratcheted peak demand are highly significant and positive. The parameter estimates for the additional quadratic and interaction terms associated with these scale variables are also highly significant. This suggests that the relationship of cost to the scale variables is nonlinear.
- Total cost was higher the higher was the share of the service territory that was urban but also higher the greater was the area of the remainder of the service territory.
- Total cost was also raised by forestation, the greater was AMI penetration, the standard deviation of elevation, and the share of gas and electric customers that were electric.
- The estimate of the trend variable parameter suggests that cost was falling by about 0.4% annually over the sample period for reasons other than changes in the values of the included business condition variables.

The adjusted R^2 for the model was 0.970. This suggests that the model has a high level of explanatory power.

[39] A one-tailed test was appropriate for most first order terms in the model. Two-tailed tests were appropriate for the quadratic and interaction terms associated with the scale variables.

Table 6

Econometric Model of Total Cost

VARIABLE KEY

N = Number of customers
D = Ratcheted maximum peak demand
PCTCU = % service territory congested urban
AREA_OTHER = Service territory area multiplied by (1-PCTCU)
PCTFOREST = % service territory forested
PCTELEC = % electric customers
PCTAMI = % of customers with AMI meters
ELEVSTD = Elevation standard deviation
Trend = Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.606	29.053	0.000
N*N	0.501	6.414	0.000
D	0.346	16.273	0.000
D*D	0.564	6.828	0.000
D*N	-0.515	-6.593	0.000
PCTCU	14.484	7.659	0.000
AREA_OTHER	0.019	3.138	0.002
PCTFOREST	0.042	13.573	0.000
PCTELEC	0.088	4.885	0.000
PCTAMI	0.028	2.729	0.006
ELEVSTD	0.032	6.399	0.000
Trend	-0.004	-7.809	0.000
Constant	19.777	2074.058	0.000

Adjusted R^2 0.970
Sample Period 1995-2017
Number of Observations 1907

OM&A Expenses

Results for the opex cost model are presented in Table 7.

- The parameter estimates for the number of customers and ratcheted peak demand were both significant and positive.[40] Notice that the number of customers served has a greater cost impact than in the total cost model. This is as we might expect since OM&A expenses include many customer related expenses such as those for metering and billing.
- The parameter estimates for the additional quadratic and interaction terms associated with these scale variables are also highly significant. This suggests that the relationship of cost to the scale variables is nonlinear.
- Opex was higher the greater was the share of the service territory that was urban and the higher was the extent of system overheading. Overheading had a greater cost impact the larger was the non-urban area served.
- Cost was, somewhat surprisingly, higher when more customers had AMI.
- Opex was also higher the greater was forestation, the standard deviation of elevation, and the share of electric customers in the sum of gas and electric customers.

The estimate of the trend variable parameter indicates a 0.7% annual decline in opex for reasons other than changes in the values of included business condition variables. This decline is considerably more rapid than that in the total cost model. Table 7 also reports the adjusted R^2 statistic for the opex model. Its 0.927 value was considerably lower than that of the total cost model.

[40] Ratcheted peak demand was significant using a one-tailed test.

Table 7

Econometric Model of OM&A Expenses

VARIABLE KEY

N = Number of customers
D = Ratcheted maximum peak demand
PCTCU = % service territory congested urban
PCTPOH = % of plant overhead
AREA_OTHER = Service territory area multiplied by (1-PCTCU)
PCTFOREST = % service territory forested
PCTELEC = % electric customers
PCTAMI = % of customers with AMI meters
ELEVSTD = Elevation standard deviation
Trend = Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.903	25.120	0.000
N*N	1.239	10.398	0.000
D	0.061	1.631	0.103
D*D	0.921	6.705	0.000
D*N	-1.045	-8.359	0.000
PCTCU	9.542	2.260	0.024
PCTPOH	0.772	10.591	0.000
AREA_OTHER*PCTPOH	0.151	2.616	0.009
PCTFOREST	0.053	12.757	0.000
PCTELEC	0.106	3.735	0.000
PCTAMI	0.042	2.153	0.031
ELEVSTD	0.038	5.431	0.000
Trend	-0.007	-8.228	0.000
Constant	18.848	1275.331	0.000

Adjusted R^2	0.927
Sample Period	1995-2017
Number of Observations	1907

Capital Cost

Econometric results for the capital cost model are presented in Table 8.

- The parameter estimates for the number of customers and ratcheted peak demand are both highly significant and positive. Note that ratcheted peak demand is a bigger cost driver in this model than in the total cost model whereas the number of customers served is a smaller driver. Most of the parameter estimates for the extra quadratic and interaction terms for these variables are significant.
- Capital cost was higher the greater was the *share* of the area served that was urban but also higher the greater was the area served that was non-urban.
- Capital cost was also greater the greater was forestation, AMI penetration, the standard deviation of elevation, and the ratio of electric customers to the sum of gas and electric customers.

The estimate of the trend variable parameter indicates a 0.53% annual decline in capital cost for reasons other than changes in the values of the model's business condition variables.

Capex

Results for the capex model are presented in Table 9.

- The parameter estimates for the number of customers and ratcheted peak demand were both highly significant and positive. The parameter estimates for the extra quadratic and interaction terms were insignificant.
- Capex was higher the more rapid was growth in customers, ratcheted peak demand, and AMI penetration.
- Capex was also greater the higher was the share of service territory area that was urban and the standard deviation of service territory elevation.
- The estimate of the trend variable parameter suggests that capex was declining by about 0.33% annually during the sample period for reasons other than changes in the values of the included business condition variables.

Table 8

Econometric Model of Capital Cost

VARIABLE KEY

N = Number of customers
D = Ratcheted maximum peak demand
PCTCU = % service territory congested urban
AREA_OTHER = Service territory area multiplied by (1-PCTCU)
PCTFOREST = % service territory forested
PCTELEC = % electric customers
PCTAMI = % of customers with AMI meters
ELEVSTD = Elevation standard deviation
Trend = Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.531	40.125	0.000
N*N	-0.106	-1.891	0.059
D	0.421	30.529	0.000
D*D	0.127	2.161	0.031
D*N	0.006	0.111	0.911
PCTCU	23.833	15.025	0.000
AREA_OTHER	0.069	15.069	0.000
PCTFOREST	0.036	14.521	0.000
PCTELEC	0.046	5.224	0.000
PCTAMI	0.027	5.009	0.000
ELEVSTD	0.016	4.554	0.000
Trend	-0.005	-15.629	0.000
Constant	17.413	2753.493	0.000

Adjusted R^2	0.964
Sample Period	1995-2017
Number of Observations	1907

Pacific Economics Group Research, LLC

Table 9

Econometric Model of Capex

VARIABLE KEY

N = Number of customers
D = Ratcheted maximum peak demand
PCTCU = % service territory congested urban
ELEVSTD = Elevation standard deviation
NGROWTH = % change in number of customers over last ten y
PCTAMIGROWTH = % change in PCTAMI from 2002 to 2017
DGROWTH = % change in D over sample period
Trend = Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.494	9.195	0.000
N*N	0.279	1.121	0.263
D	0.569	9.738	0.000
D*D	0.384	1.405	0.160
D*N	-0.254	-0.996	0.319
PCTCU	44.993	8.364	0.000
ELEVSTD	0.055	4.373	0.000
NGROWTH	0.567	2.956	0.003
PCTAMIGROWTH	0.020	3.393	0.001
DGROWTH	0.317	2.441	0.015
Trend	-0.003	-1.751	0.080
Constant	14.492	503.923	0.000

Adjusted R^2	0.868
Sample Period	1996-2017
Number of Observations	1306

The 0.868 adjusted R^2 for the capex model is the lowest of the four models that we developed. The lack of a system age specification in the model is likely one reason why its explanatory power isn't higher.

4.4. Business Conditions of Toronto Hydro

The external business conditions faced by Toronto Hydro should be considered in fashioning benchmarks for the company. The Company is an electric utility based in Toronto. It distributes power in the City of Toronto and is owned by the city. The service territory includes one of North America's largest downtown office districts and high reliability is expected there. The Toronto metropolitan area is the ninth largest in the U.S. and Canada. Salaries and wages tend to be well above the U.S./Canadian norm.

The territory also includes several other areas of high density where office and residential high rises are concentrated. Many of these areas are located near mass transit stations. However, the sizable "horseshoe area" surrounding Toronto's central business district is for the most part suburban in character. Undergrounding of the distribution system is quite extensive in Toronto but many undergrounded facilities do not lie beneath streets and buildings.

The Company does not provide generation, power transmission, or natural gas services. This limits its opportunities to realize scope economies. All customers now have AMI. The service territory lies along the shore of Lake Ontario and has little variation in elevation.

4.5. Econometric Benchmarking Results

We benchmarked the opex, capital cost, total cost, and capex of Toronto Hydro in each year of the historical 2005-2017 period as well as in the 2018-2024 period for which the Company has provided proposals/projections. These benchmarks were based on our econometric model parameter estimates and the values for the business condition variables which are appropriate for the Company in each historical and future year.

Tables 10-13 and Figures 3-6 report results of this benchmarking work. For each cost considered, we provide results for each year as well as average results for the last three historical years of the sample period (2015-2017).[41] We also provide average benchmarking results for the five years of the proposed new Custom IR plan (2020-24).

[41] Recollecting the recent benchmark years for estimating capital cost in Ontario, the capital cost and total cost benchmarking results are likely to be more accurate in these three years.

Table 10 and Figure 3 show results of our econometric *total* cost benchmarking. It can be seen that the company's total cost was well below the model's predictions in the early years of the sample period but declined steadily. Cost efficiency will decline substantially under the current Custom IR plan and is projected to continue declining substantially during the next plan. On average, projected/proposed total cost during the new plan exceed the benchmarks by a substantial 15.6%.

Table 11 and Figure 4 show results of our econometric opex benchmarking. It can be seen that Toronto Hydro's expenses tended to be well below the model's predictions in the early years of the sample period. While opex performance has been worse since 2009, the Company's opex continues to be less than the model's predictions. Proposed/projected opex will be 12.1% below the model's predictions on average during the five years of the proposed plan.

Table 12 and Figure 5 show results of our econometric *capital* cost benchmarking. It can be seen that the Company's capital cost was well below the model's projections at the beginning of the sample period. However, capital cost performance has steadily declined. Over the five years of the new plan, proposed/projected capital cost will exceed the model's predictions by 35.7% on average.

Table 13 and Figure 6 show results of our econometric *capex* benchmarking. It can be seen that that the Company's capex was far *below* the model's predictions in most years from 2005 to 2009 and well *above* the model's predictions in most years since. Over the five years of the new plan, proposed/projected capex will exceed the model's predictions by 14.9% on average.

Table 10

Year by Year Total Cost Benchmarking Results

Year	Percent Difference[1]
2005	-38.5%
2006	-37.5%
2007	-30.9%
2008	-29.1%
2009	-27.5%
2010	-20.0%
2011	-12.2%
2012	-13.9%
2013	-8.7%
2014	-6.9%
2015	-4.6%
2016	0.8%
2017	3.7%
2018	*7.5%*
2019	*8.7%*
2020	*11.4%*
2021	*13.4%*
2022	*15.9%*
2023	*17.8%*
2024	*19.5%*
Annual Averages	
2005-2017	**-17.3%**
2015-2017	**0.0%**
2020-2024	**15.6%**

[1] Formula for benchmark comparison is $\ln(Cost^{THESL}/Cost^{Bench})$.

Note: Italicized numbers are projections/proposals.

Figure 3

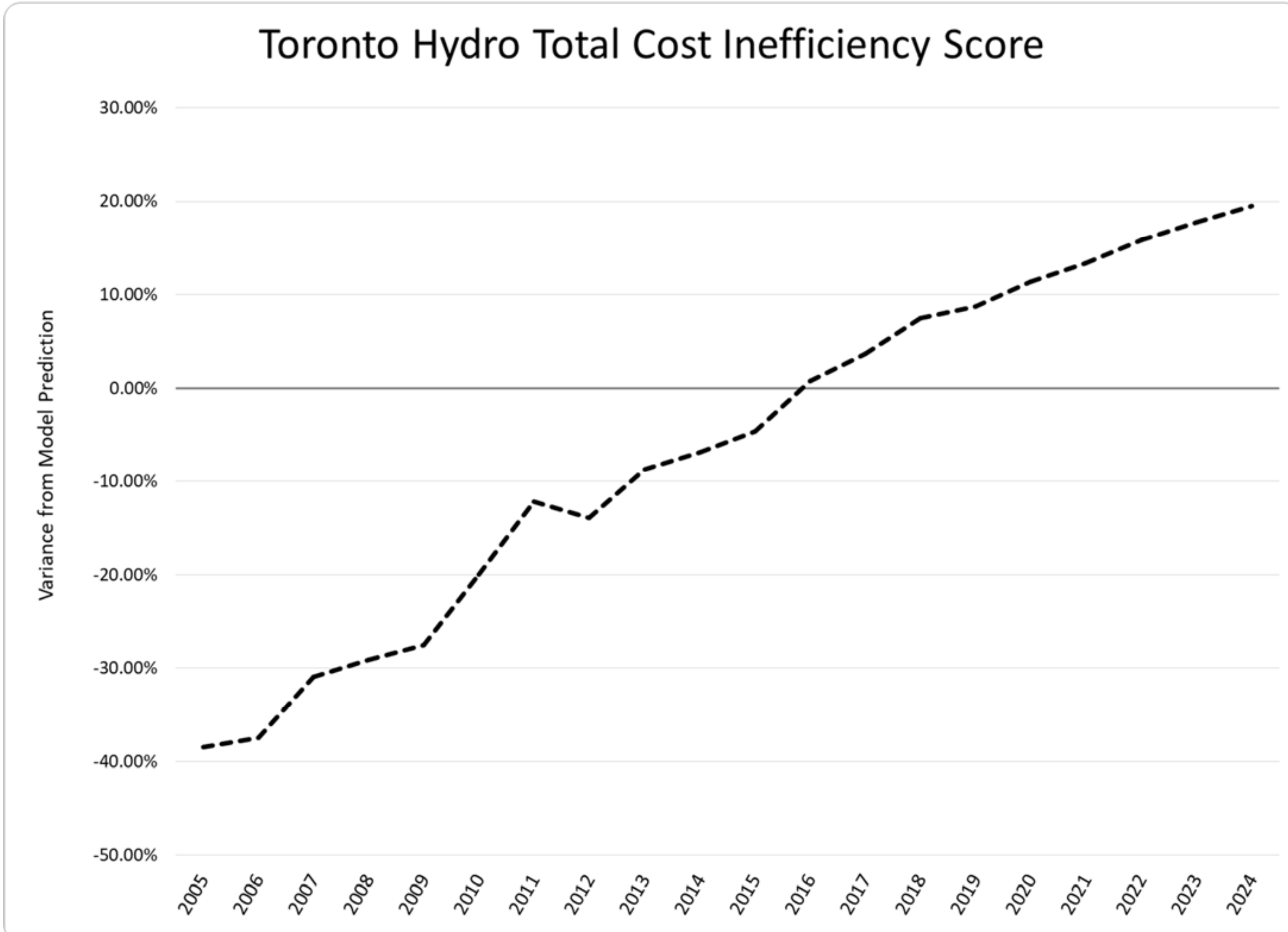

Toronto Hydro Total Cost Inefficiency Score
Variance from Model Prediction
30.00%
20.00%
10.00%
0.00%
-10.00%
-20.00%
-30.00%
-40.00%
-50.00%
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024

Table 11

Year by Year OM&A Cost Benchmarking Results

Year	Percent Difference[1]
2005	-29.9%
2006	-33.5%
2007	-25.8%
2008	-28.9%
2009	-24.6%
2010	-12.1%
2011	-5.5%
2012	-12.9%
2013	-4.9%
2014	-10.7%
2015	-11.1%
2016	-12.5%
2017	-13.1%
2018	*-14.0%*
2019	*-13.2%*
2020	*-11.6%*
2021	*-11.3%*
2022	*-11.9%*
2023	*-12.5%*
2024	*-13.0%*
Annual Averages	
2005-2017	**-17.3%**
2015-2017	**-12.2%**
2020-2024	**-12.1%**

[1] Formula for benchmark comparison is $\ln(Cost^{THESL}/Cost^{Bench})$.

Note: Italicized numbers are projections/proposals.

Figure 4

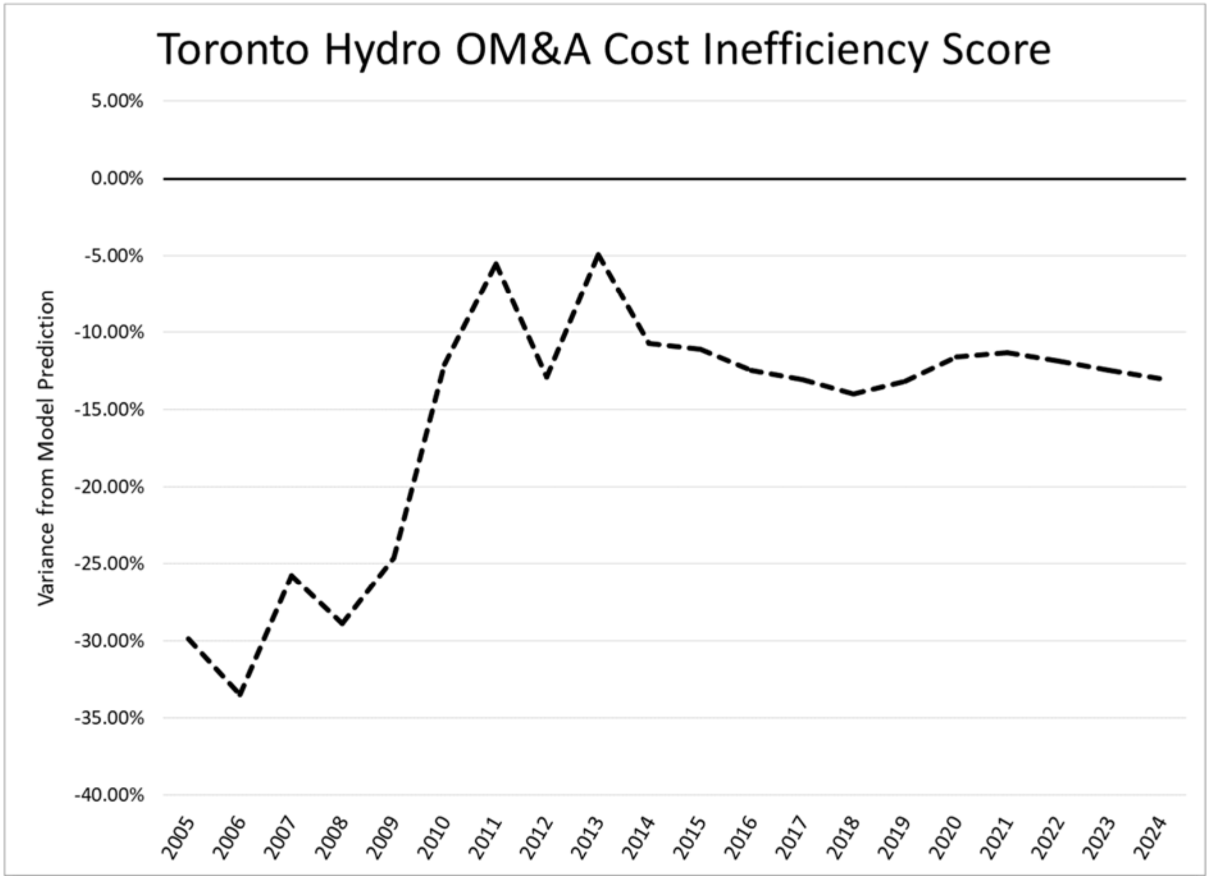

Toronto Hydro OM&A Cost Inefficiency Score
5.00%
0.00%
-5.00%
-10.00%
-15.00%
-20.00%
-25.00%
-30.00%
-35.00%
-40.00%
Variance from Model Prediction
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024

Table 12

Year by Year Capital Cost Benchmarking Results

Year	Percent Difference[1]
2005	-34.9%
2006	-31.3%
2007	-25.2%
2008	-20.1%
2009	-19.5%
2010	-15.1%
2011	-7.2%
2012	-6.4%
2013	-2.2%
2014	3.5%
2015	7.5%
2016	15.4%
2017	20.0%
2018	*25.5%*
2019	*27.2%*
2020	*30.0%*
2021	*32.4%*
2022	*36.0%*
2023	*38.9%*
2024	*41.4%*
Annual Averages	
2005-2017	**-8.9%**
2015-2017	**14.3%**
2020-2024	**35.7%**

[1] Formula for benchmark comparison is $\ln(\text{Cost}^{\text{THESL}}/\text{Cost}^{\text{Bench}})$.

Note: Italicized numbers are projections/proposals.

Figure 5

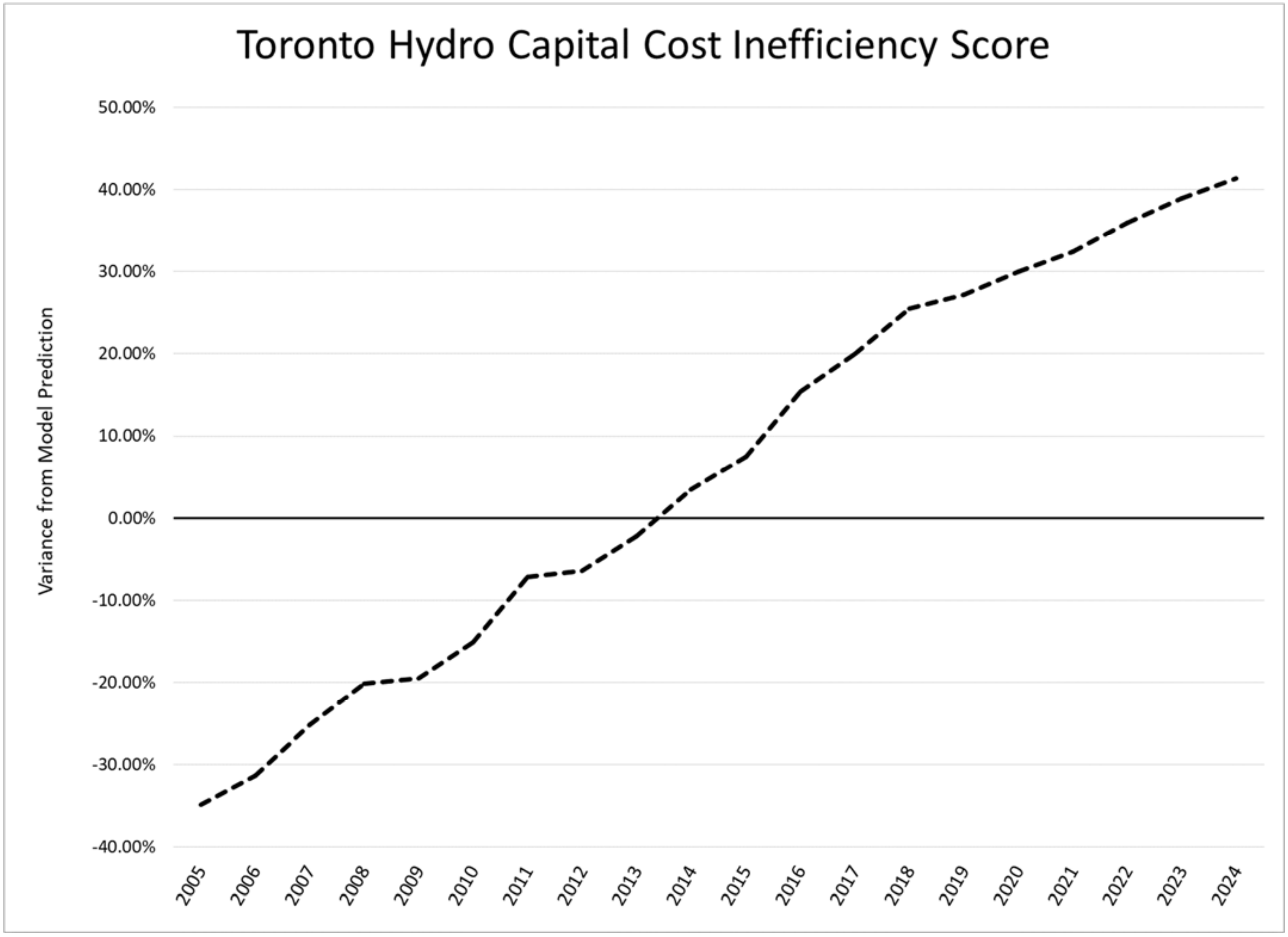

Toronto Hydro Capital Cost Inefficiency Score
Variance from Model Prediction
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
-10.00%
-20.00%
-30.00%
-40.00%
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024

Table 13

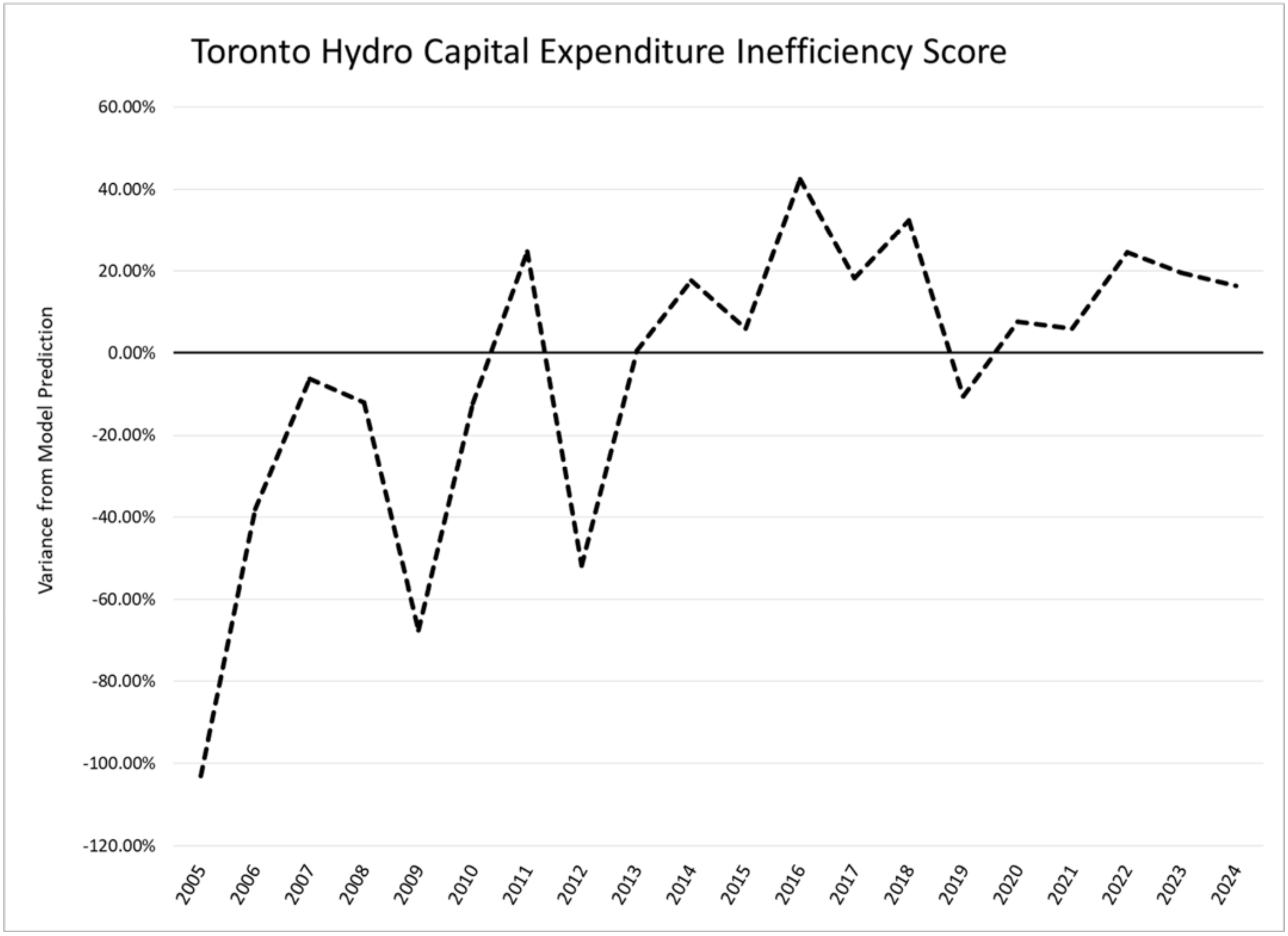
Year by Year Capex Benchmarking Results

Year	Percent Difference[1]
2005	-103.0%
2006	-38.1%
2007	-6.1%
2008	-11.9%
2009	-67.7%
2010	-12.2%
2011	24.9%
2012	-51.9%
2013	0.6%
2014	17.6%
2015	5.9%
2016	42.5%
2017	18.3%
2018	*32.5%*
2019	*-10.4%*
2020	*7.6%*
2021	*6.0%*
2022	*24.6%*
2023	*19.6%*
2024	*16.5%*
Annual Averages	
2005-2017	**-13.9%**
2015-2017	**22.2%**
2020-2024	**14.9%**

[1] Formula for benchmark comparison is $\ln(\mathrm{Cost}^{\mathrm{THESL}}/\mathrm{Cost}^{\mathrm{Bench}})$.

Note: Italicized numbers are projections/proposals.

Figure 6



4.6. Conclusions

On the basis of our research, we believe that a 0.45% stretch factor is indicated for Toronto Hydro provided that the Board is comfortable fixing the stretch factor for the full plan term. A 0% base productivity trend is reasonable given the evidence in the panel's possession but does not include an implicit stretch factor. A 0% base X factor and a 0.45% stretch factor would yield an X factor of 0.45%. The PCI formula would then be growth Inflation - 0.45% net of Y, Z, or growth factors as discussed below.

5. Other Plan Design Issues

The other provisions of the IRM proposed by Toronto Hydro are in some respects uncontroversial. We have noted that the plan is similar to Custom IR plans the Board has previously approved for the Company and other distributors. Some provisions are also consistent with other Board decisions. We are nonetheless concerned about some features of the Company's proposal.

The proposed ratemaking treatment of capital is our chief concern. The C factor would ensure that the Company recovers its projected/proposed capital cost less a perfunctory stretch factor markdown. Any cumulative capex underspend would be returned to the ratepayer. Externally-driven capex such as that due to highway construction would be addressed by a variance account. Hence, capital revenue would chiefly be established on a cost of service basis.

Despite the proposed clawback of capex underspends, Toronto Hydro would still have some incentive to exaggerate capex needs since exaggerations strengthen the case for a C Factor and reduce the pressure on the Company to contain capex. Exaggeration of capex needs may reduce the credibility of Toronto Hydro's forecasts in future proceedings. However, the Company can always claim that it "discovered" ways to economize. British distributors operating under several generations of IR with revenue requirements based on cost forecasts have repeatedly spent less on capex than they forecasted. Toronto Hydro would also be incentivized to "bunch" its deferrable capex in ways that increase supplemental revenue. If, for example, the Company somehow managed to change the timing of its capex so that the $I - X + g$ escalation was compensatory it would obtain no supplemental revenue.

The full clawback of capex underspends and the variance account treatment of externally driven capex would greatly reduce the Company's incentive to contain capex. Incentives to contain capex and OM&A expenses would be imbalanced, creating a perverse incentive to incur excessive capex in order to reduce OM&A costs.

Another problem with the proposal is that while customers must fully compensate Toronto Hydro for expected capital revenue *shortfalls* when capex is high, for reasons beyond its control the Company need not reduce its capital revenue in future plans if capital cost growth is unusually slow for reasons beyond its control. Slow capital cost growth in the future may very well occur, and not just because of good capital cost management. For example, depreciation of recent and prospective surge capex will tend to slow capital cost growth in the future. Customers therefore would never receive the full benefit of the industry's multifactor productivity trend, even in the long run and even when it is achievable.

A related problem is that most of the capex addressed by the C factor and the externally-driven capex variance account would be conventional distributor capex that is similar in kind to that incurred by distributors in past and future productivity research samples used to calibrate X factors.[42] Utilities can then be compensated twice for the same capex: once via the C factor and then again by low X factors in past, present, and future IRMs.

Given the inherent unfairness to customers of asymmetrically funding capital revenue shortfalls, Toronto Hydro's weak incentive to contain capex, and the Company's incentive to exaggerate capex requirements, stakeholders and the Board must be especially vigilant about the Company's capex proposal.[43] This raises regulatory cost. The need for the OEB to sign off on multiyear total capex proposals greatly complicates Custom IR proceedings and is one of the reasons why the Board now requires and reviews distribution system plans --- a major expansion of its workload and that of stakeholders. Despite the extra regulatory cost, OEB staff and stakeholders are often hard-pressed to effectively challenge distributor capex proposals. In essence, the OEB's Custom IR rules have sanctioned British (forecast-based) approaches to determining multiyear capital revenue requirements without making the same investment that the British and Australian regulators have made in the capability for appraising and ruling on capex proposals.[44]

The substantial compensation for full funding of capital revenue shortfalls that has been permitted by the OEB under Custom IR may be more remunerative than that available under the incremental capital modules ("ICMs") in 4th GIRM. ICMs, after all, feature a materiality threshold including a 10% deadband before funding projected capital revenue shortfalls. These thresholds are rationalized on the grounds of reducing regulatory cost. This encourages distributors to choose Custom IR instead of the 4th GIRM. Some distributors may have chosen Custom IR, with its weaker performance

[42] Toronto Hydro would not, however, be compensated during the plan for unexpected capex overruns.

[43] Proposed programs that raise capex and reduce OM&A expenses merit close examination. An example is the proposition to reduce backyard overhead facilities.

[44] Ofgem's own view of a power distributor's required cost growth is assigned a 75% weight in IRM proceedings. This view is supported by independent engineering and benchmarking research.

incentives and higher regulatory cost, even though efficient and compensatory operation under 4th GIRM was feasible.

In pondering this quandary, the following remarks of the OEB in its decision approving Toronto Hydro's last Custom IR plan resonate.

> The record in this case is one of the largest that the OEB has ever seen. It is important to strike a balance between the amount of evidence necessary to evaluate the Application and the goal of striving for regulatory efficiency. It is important to note that it is not the OEB's role, nor the intervenors, to manage the utility or substitute their judgment in place of the applicant's management. That is the job of the utility. The OEB has established a renewed regulatory framework for electricity (RRFE) which places a greater emphasis on outcomes and less of an emphasis on a review of individual line items in an application.[45]

In light of these remarks, it seems desirable to consider how to make Custom IR more mechanistic, incentivizing, and fair to customers while still ensuring that it is reasonably compensatory over time for efficient distributors.

The Alberta Utilities Commission ("AUC") faced a similar challenge following an unhappy experience with capital cost trackers in their first-generation IRMs for provincial gas and electricity distributors. A number of possible reforms to the ratemaking treatment of capital were discussed in the AUC's generic proceeding on second generation IRMs. Based on the record, the AUC eventually chose a means for providing supplemental capital revenue which was much less dependent on distributor capex forecasts.[46] Regulatory cost was reduced thereby, and capex containment incentives were strengthened.

Informed by our research and testimony for a party to that proceeding, as well as by our familiarity with Custom IR, we believe that the following alternatives to Toronto Hydro's proposed ratemaking treatment of capital merit consideration.

- An obvious candidate for a different approach is that chosen by the OEB in the recent Hydro One Dx decision.[47] A special stretch factor would apply only to the calculation of the C factor. A variant on this theme is to calculate the C factor using the (typically slower) productivity growth trend of capital, while the X factor for OM&A revenue could reflect the

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[45] OEB, *Decision and Order*, EB-2014-0116, December 29, 2015, p. 2.

[46] PEG is not recommending this ratemaking treatment for Toronto Hydro.

[47] OEB, *Decision and Order*, EB-2017-0049, March 7, 2019.

(typically faster) productivity trend of OM&A. This would reduce the need for C factors and make escalation of OM&A revenue more reflective of industry OM&A cost trends. Unfortunately, there is no conclusive research available to the panel in this proceeding on OM&A and capital productivity trends of power distributors.

- The C factor could alternatively, like ICMs, be subject to materiality thresholds and dead zones. For example, a company would not be eligible for a C factor unless its capital cost growth exceeded growth in capital revenue by a certain percent. A percentage of the underfunding would not be eligible for supplemental funding. Dead zones could also be added to the materiality thresholds for externally-driven capex.
- The X factor could be raised, in this and the Company's future IRMs, to reduce expected double dipping and give customers a better chance of receiving the benefits of industry productivity growth in the long run. This would be tantamount to having the Company borrow revenue escalation privileges from future plans. Knowledge that there is a price to be paid in the long run for asking for extra revenue now would strengthen Toronto Hydro's capex containment incentives.
- Capital costs that occasion supplemental revenue could be subject to continued tracking in later plans. Customers would then receive the benefit of depreciation of the surge capex between plans. Once again, knowledge that there is a price to be paid in the long run for asking for extra revenue now would strengthen Toronto Hydro's capex containment incentives. The IRMs for the Fortis companies in British Columbia track the cost of all older capital.
- Eligibility of capex for supplemental C factor revenue could be scaled back. For example, capex in the last year of the plan term could be declared ineligible for supplemental revenue because this involves only one year of underfunding.
- The proposed capex budget could be reduced by a material amount, as in the OEB's decisions in the last Toronto Hydro proceeding and the Hydro One distribution IRM proceeding.
- Toronto Hydro could be permitted to keep a share of the value of capex underspends. This would strengthen the Company's incentive to contain capex but also its incentive to exaggerate its capex needs.

If the OEB is prepared to deviate from Toronto Hydro's proposed C factor treatment, we note that the establishment of a materiality threshold and dead zone for supplemental capital revenue in Custom IR plans has many advantages. This could be done in such a manner that the *first* A% of unfunded capital cost (after the X factor markdown) is ineligible for C factoring. However, the materiality threshold and dead zones need not be modelled on those in the ICMs used in 4th GIRM. For example, if proposed capital cost exceeded the materiality threshold, a possibly lower set percentage of *all* unfunded capital cost could be declared ineligible for C factoring. This would strengthen the Company's incentive to contain capital cost *at the margin*. The kind of adjustment to the C factor formula that the Board approved in the Hydro One distribution IRM proceeding has less incentive impact.

Appendix

A.1 Measuring Capital Cost

Monetary Approaches to Capital Cost Measurement

Monetary approaches to the measurement of capital costs and prices have been widely used in statistical cost research. The main components of capital cost are depreciation expenses, the return on investment, and certain taxes. These approaches decompose the growth in capital cost into the growth in consistent capital price and quantity indexes such that

$$Cost^{Capital} = Price^{Capital} \cdot Quantity^{Capital}. \quad \text{[A1]}$$

Capital prices are calculated using data on construction costs and the rate of return on capital. The capital price index is sometimes called the “rental” or “service” price index because, in a competitive market, the trend in the price of rentals would tend to reflect the trend in the cost per unit of capital.

Several monetary methods are well established for measuring capital quantity trends. A key issue in the choice of a monetary method is whether plant is valued in historic or replacement dollars. Another issue is the pattern of decay in the quantity of capital resulting from plant additions. Decay can result from many factors including wear and tear, casualty loss, increased maintenance requirements, and obsolescence.

Three monetary methods have been used in statistical research on utility costs.

- The geometric decay (“GD”) method assumes a replacement (i.e., *current* dollar) valuation of plant and a constant rate of decay. Replacement valuation differs from the historical (aka “book”) valuation used in North American utility accounting and requires consideration of capital gains. The GD specification involves formulae for capital price and quantity indexes that are mathematically simple and easy to code and review.

Academic research has supported use of the GD method to characterize depreciation in many industries.[48] GD has also been widely used in productivity studies, including X factor calibration studies. The U.S. Bureau of Economic Analysis ("BEA") and Statistics Canada both use geometric decay as the default approach to the measurement of capital stocks in the national income and product accounts.[49] PEG has used the GD method in most of its productivity research for the Board, including the research for 4th Generation IRM.

- The one hoss shay method assumes that the quantity of capital from plant additions in a given year does not decay gradually but, rather, all at once as the assets reach the end of their service lives. Plant is once again valued at replacement cost. The one hoss shay method has been used occasionally in research intended to calibrate utility X factors.
- The cost of service ("COS") method is designed to approximate the way that capital cost is calculated in utility regulation. This approach is based on the assumptions of straight-line depreciation and historic valuation of plant. The capital price and quantity formulas are complicated, making them more difficult to code and review. PEG has used this approach in several X factor calibration studies, including two for the OEB.[50]

Benchmark Year Adjustments

Utilities have diverse methods for calculating depreciation expenses that they report to regulators. It is therefore desirable when calculating capital quantities using a monetary method to rely on the reporting companies chiefly for the value of *gross* plant additions and then use a standardized

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[48] See, for example, C, Hulten, and F. Wykoff (1981), "The Measurement of Economic Depreciation," in *Depreciation, Inflation, and the Taxation of Income From Capital*, C. Hulten ed., Washington D.C. Urban Institute and C. Hulton, "Getting Depreciation (Almost) Right", University of Maryland working paper, 2008.

[49] The BEA states on p. 2 its November 2018 "Updated Summary of NIPA Methodologies" that "The perpetual-inventory method is used to derive estimates of fixed capital stock, which are used to estimate consumption of fixed capital—the economic depreciation of private and government fixed capital. This method is based on investment flows and a geometric depreciation formula."

[50] See Lowry, et. al., *Rate Adjustment Indexes for Ontario's Natural Gas Utilities, op. cit.;* Kaufmann, L., Hovde, D., Getachew, L., Fenrick, S., Haemig, K., and Moren, A., *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario*, in EB-2007-0673, (2008); and Lowry, M., Hovde, D., and Rebane, K., *X Factor Research for Fortis PBR Plans,* in BCUC Project 3698719, for Commercial Energy Consumers of British Columbia (2013).

depreciation treatment for all companies. Since some of the plant a utility owns may be 40-60 years old, it is desirable to have gross plant addition data for many years in the past.

For earlier years, the desired gross plant addition data are frequently unavailable. It is then customary to consider the value of all plant at the end of the limited-data period and to estimate the quantity of capital it reflects using construction cost indexes from earlier years and assumptions about the historical capex pattern. The year for which this estimate is undertaken is commonly called the "benchmark year" of the capital quantity index. Since the estimate of the capital cost in the benchmark year is inexact, it is preferable to base capital and total cost research on a sample period that begins many years after the benchmark year. Research on capital and total cost will be less accurate to the extent that this is impossible.

Capital Cost and Quantity Specification

A monetary approach was used in this study to calculate the capital cost of each utility. Geometric decay was assumed.

Data available and previously processed by PEG permitted us to use 1964 as the benchmark year for the U.S. capital cost and quantity calculations. The benchmark year was 1989 for Toronto Hydro. The value of the capital quantity index for each utility in the benchmark year depends on the net value of its plant. We estimated the benchmark year quantity of capital by dividing this book value by a triangularized weighted average of 40 values of an index of power distribution construction cost for a period ending in the benchmark year. The construction cost index ("WKA_t") for each U.S. utilities was the applicable regional Handy-Whitman indexes of cost trends of electric utility distribution construction.[51] A triangularized weighted average places a greater weight on more recent values of the construction cost index. This makes sense intuitively since more recent plant additions are less depreciated and to that extent tend to have a bigger impact on net plant value.

The following GD formula was used to compute values of each capital quantity index in subsequent years.

$$XK_t=(1\text{-}d)\cdot XK_{t-1}+\frac{VI_t}{WKA_t}. \qquad \text{[A2]}$$

[51] These data are reported in the Handy-Whitman Index of Public Utility Construction Costs, a publication of Whitman, Requardt and Associates.

Here, the parameter d is the economic depreciation rate and VI_t is the value of gross additions to utility plant.

The formula for the corresponding GD capital service price indexes used in the research was

$$WKS_t=d \cdot WKA_t+WKA_{t-1}\left[r_t-\frac{(WKA_t-WKA_{t-1})}{WKA_{t-1}}\right]. \quad [A3]$$

The first term corresponds to the cost of depreciation. The second term corresponds to the real rate of return on capital. This term was smoothed to reduce capital cost volatility.

A.2 Econometric Research

This section provides additional and more technical details of our econometric research. We begin by discussing the choice of a form for the econometric benchmarking models. There follow discussions of econometric methods.

Form of the Econometric Cost Model

Specific forms must be chosen for cost functions used in econometric research. Forms commonly employed by scholars include the linear, double log, and translog. Here is a simple example of a *linear* cost model:

$$C_{h,t}=a_0+a_1 \cdot N_{h,t}+a_2 \cdot V_{h,t}. \quad [A4]$$

Here is an analogous cost model of *double log* form:

$$\ln C_{h,t}=a_0+a_1 \cdot \ln N_{h,t}+a_2 \cdot \ln V_{h,t}. \quad [A5]$$

The double log model is so-called because the right- and left-hand side variables are all logged. This specification makes the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, parameter a_1 indicates the percentage change in cost resulting from 1% growth in the number of customers. Elasticity estimates are useful and make it easier to assess the reasonableness of model results. It is also noteworthy that, in a double log model, elasticities are *constant* in the sense that they are the same for every value that the cost and business condition variables might assume. This model specification is restrictive and may be inconsistent with the true form of the cost relationship we are trying to model.

Here is an analogous model of *translog* form:

$$\ln C_{h,t}= a_o + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln V_{h,t} + a_3 \cdot \ln N_{h,t} \cdot \ln N_{h,t} + a_4 \cdot \ln V_{h,t} \cdot \ln V_{h,t} + a_5 \cdot \ln V_{h,t} \cdot \ln N_{h,t} \quad [A6]$$

This form differs from the double log form in the addition of quadratic and interaction terms. Quadratic terms like $lnN_{h,t} \cdot lnN_{h,t}$ permit the elasticity of cost with respect to each business condition variable to vary with the value of the variable. The elasticity of cost with respect to a scale variable may, for example, be lower for a small utility than for a large utility. Interaction terms like $lnV_{h,t} \cdot lnN_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable. For example, the elasticity of cost with respect to growth in peak load may depend on the length of a transmitter's transmission lines.

The translog form is an example of a "flexible" functional form. Flexible forms can accommodate a greater variety of possible functional relationships between cost and the business condition variables. A disadvantage of the translog form is that it involves many more variables than simpler forms like the double log. As the number of variables accorded translog treatment increases, the precision of a model's parameter estimates and cost predictions falls. It is therefore common in econometric cost research to limit the number of variables accorded translog treatment.

In our econometric work for this proceeding, we have chosen a functional form that is translogarithmic only with respect to the two scale variables. This preserves degrees of freedom but permits the model to recognize some nonlinearities. All of the quadratic terms in our model had statistically significant parameter estimates.

Econometric Model Estimation

A variety of parameter estimation procedures are used by econometricians. The appropriateness of each procedure depends on the distribution of the error terms. The estimation procedure that is most widely known, ordinary least squares ("OLS"), is readily available in econometric software. Another class of procedures, called generalized least squares ("GLS"), is appropriate under assumptions of more complicated and realistic error specifications. For example, GLS estimation procedures can permit the variance of the error terms of cost models to be heteroskedastic, meaning that they vary across companies. Variances can, for example, be larger for companies with large operating scale.

Note, finally, that the model specification was determined using data for all sampled companies. However, estimation of parameters and appropriate standard errors for the cost model actually used for benchmarking required that the utility of interest be dropped from the sample. The parameter estimates used in developing the cost model and reported in the various econometric cost model tables above therefore vary slightly from those in the models used for benchmarking.

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Empirical Research for Incentive Regulation of Transmission

4 February 2019

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1. Introduction and Summary

1.1. Introduction

Hydro One Sault Ste. Marie LP ("Hydro One SSM"), a small power transmission utility serving a region east of Lake Superior, recently filed an application with the Ontario Energy Board ("OEB") for an incentive rate-setting mechanism ("IRM") that it calls Revenue Cap Incentive Rate-setting.[1] Over the eight-year 2019-2026 period, the revenue requirement would be escalated by a revenue cap index featuring a custom inflation measure and an X factor of zero. The revenue requirement would thus increase at the rate of inflation. The proposed X factor is supported by a report on transmission productivity and cost benchmarking research by Power System Engineering ("PSE"), a Madison, Wisconsin consulting firm. Steven Fenrick and Erik Sonju were the authors of the PSE report.[2]

Hydro One SSM was created after the acquisition of Great Lakes Power Transmission Inc. in 2016 by Hydro One, Inc. It is now being integrated into the larger transmission operations of Hydro One Networks Inc. ("Hydro One Networks" or "the Company") but its rates are still separately regulated. The PSE report does not consider the performance of Hydro One SSM but addresses both the historical and future total cost performance and multifactor productivity ("MFP") trend of Hydro One Networks' transmission operations. PSE also calculated the transmission MFP trends of a sample of U.S. electric utilities.

The PSE research and testimony merit careful examination in this proceeding for several reasons:

- Ontario's power transmission industry is sizable, and transmission accounts for a material portion of the rate-regulated charges of electric utilities, especially in the industrial sector. The OEB has long expressed an interest in extending incentive regulation ("IR") to this sector.

[1] EB-2018-0218

[2] Mr. Fenrick, a former employee of PEG, recently left PSE and is now a Principal Consultant and Partner of Clearspring Energy Advisors in Madison. Mr. Sonju is the President of PSE.

- No "top down" statistical benchmarking study of Hydro One Networks' transmission cost has ever been filed with the OEB. Neither has a study been filed on the transmission productivity trends of Hydro One Networks or U.S. utilities.
- Hydro One Networks is expected to file a Custom IR proposal for its principal transmission operations in the near future. This proposal is likely to be supported by the same or similar (e.g., updated) transmission productivity and benchmarking research. In addition, the revenue cap index chosen in the proceeding may be used to escalate the Company's 2019 revenue requirement.

Pacific Economics Group Research LLC ("PEG") is North America's leading energy utility productivity consultant. We have in past years done power transmission benchmarking and productivity studies and have recently played a large role in the development of an IRM for transmission services of Hydro-Québec. OEB staff has retained us to review PSE's transmission productivity and cost benchmarking evidence and to prepare alternative studies.

This is our report on this work. Following a brief summary of our findings, Section 2 provides our critique of PSE's empirical research and testimony. Section 3 discusses productivity and benchmarking research by PEG using alternative methods. We provide in Section 4 our stretch factor and X factor recommendations for Hydro One SSM's proposed rate plan. Appendix A of the report discusses at a high level the use of index research in the design of a revenue cap index. Appendix B discusses various topics in the report in more detail.

1.2. Summary

PSE developed an econometric model of transmission cost using a sample of operating data for Hydro One Networks and 56 U.S. electric utilities over the 2004-2016 sample period. This model was used to benchmark the transmission cost of Hydro One Networks over the same historical period as well as the Company's forecasted/proposed cost for the 2017-2022 period. Econometric estimates of scale variable parameters in the model were used to construct a multidimensional scale (or output) index for the productivity research.

Productivity Trends

Using data from Hydro One Networks and 47 U.S. transmitters, PSE also calculated a -**1.71%** average annual MFP growth trend over the full 2005-2016 sample period. Productivity in the use of operation, maintenance, and administration ("OM&A") inputs averaged -0.84% annual growth while capital productivity averaged -1.93% annual growth. PSE nevertheless recommends a **0.00%** base productivity trend for the revenue cap index and Hydro One SSM embraced this proposal. The 1.71% difference is portrayed as an implicit stretch factor.

PSE reports that the transmission productivity growth trend of Hydro One Networks was considerably better during the same period. Annual MFP growth of Hydro One Networks averaged **-0.31%** while OM&A productivity averaged 1.07% annual growth and capital productivity averaged -0.58% growth. Over the 2020-2022 period, PSE reports that the forecasted/proposed total cost of Hydro One Networks would reflect a -1.31% average annual MFP growth. OM&A productivity would average 0.12% annual growth while capital productivity would average -1.67% growth.

Our examination of PSE's research raised concerns about its calculations of U.S. transmission productivity. Here are the most important ones.

- The 2005-16 sample period was one during which U.S. power transmission productivity was strongly influenced by policy initiatives of the U.S. government such as the Energy Policy Act of 2005. Reliability standards were established and enforced that raised costs for many utilities. Incentives to contain cost were weakened by special investment incentives and by the formula rate plans under which a growing number of transmitters operated. We believe that a longer sample period is desirable in a study intended to inform the selection of a base productivity growth trend for Hydro One SSM or Hydro One Networks.
- PSE's productivity index features a multidimensional scale index with cost elasticity weights. This general approach is appropriate for calibrating the X factor of a revenue cap index. However, poor screening by PSE of data resulted in an econometric cost model with unreliable cost elasticity estimates for the scale variables that PSE used to construct its MFP index. As a consequence, less weight was placed on the more rapidly growing variable (peak demand) and more weight on the variable with slower growth (line length).
- PSE's treatment of OM&A expenses doesn't handle structural change in the U.S. transmission industry well. Many sampled utilities have joined independent transmission system operators or regional transmission organizations and this materially affected the reported OM&A expenses of some companies. Exclusion from the calculations of costs that

were especially sensitive to this restructuring produces considerably more rapid productivity growth estimates.

- The calculation of capital costs of the sampled U.S. transmitters was unnecessarily inaccurate. For example, the benchmark year was 1989 whereas a benchmark year of 1964 is possible. Capital cost was not calculated net of capital gains.

These and other concerns prompted us to develop our own U.S. transmission productivity study using preferred methods and data for a similar group of companies over the longer 1996-2016 sample period. We found that growth in the transmission MFP of sampled utilities averaged **-1.82%** over the 2005-2016 sample period chosen by PSE and **-0.34**% over the full sample period. OM&A productivity growth averaged -1.40% over the shorter sample period but -0.53% over the full period. Transmission capital productivity growth averaged -1.73% over the shorter period but -0.21% over the full period. Our estimates of these trends do not reflect any possible improvements in U.S. transmission reliability due to changing federal policies.

Over the 2005-2016 historical sample period over which data are available, we calculated that the annual transmission MFP growth of Hydro One Networks averaged **-1.21** % while its OM&A productivity growth averaged 0.85% and its capital productivity growth averaged -1.86%. Over the first four years of the proposed plan (2019-2022), the Company's cost forecast is consistent with -2.21% average annual MFP growth, -0.60% OM&A productivity growth, and -2.57% capital productivity growth. Forecasted/proposed costs thus reflect productivity growth that is well below long-run U.S. norms.

Hydro One Cost Benchmarking

PSE reports that the total transmission cost of Hydro One Networks was a substantial 27.3% below its cost model's prediction over the three most recent years for which data are available (2014-2016). The Company's forecasted/proposed total cost is 31.8% below the model's predictions during the first four years of the proposed IRM (2019-2022).

We had several major concerns about PSE's cost benchmarking work.

- Calculation of the Company's capital cost was quite crude due to a lack of appropriate capital cost data.

- Calculation of capital costs of the sampled U.S. transmitters was unnecessarily inaccurate

- The short sample period unnecessarily reduced the accuracy of cost model parameter estimates.
- Estimates of the important scale variable parameters are particularly inaccurate due to inadequate screening of the data.
- Data for some U.S. utilities may be non-comparable due to their participation in RTOs .
- U.S. input price indexes were used for Hydro One where Canadian indexes would be better.

These and other concerns prompted us to benchmark Hydro One Networks' total cost with our own econometric model. The longer sample period makes estimates of the parameters of our model more accurate. This model also features our preferred capital cost specification and produces substantially different results for Hydro One Networks. The Company's transmission cost was found to be 9.43% below the model's prediction on average during the three most recent historical years for which data are available. The Company's forecasted/proposed total cost is only 1.23% below our model's prediction on average during the 2019-2022 period.

Stretch Factor

We disagree with PSE's 0% explicit stretch factor recommendation, which is based on the premise that a stretch factor is not warranted because the company is a superior cost performer. One reason we disagree is that we do not have benchmarking results for Hydro One SSM. Another and more important reason is that we do not get such favorable benchmarking results for Hydro One Networks. A third is that our U.S. transmission productivity research does not suggest that a 0% base productivity trend involves a large implicit stretch factor.

In addition, we have long believed that, in addition to utility operating efficiency, stretch factors should reflect the difference between the incentive power of the contemplated IRM and the incentive power of the regulatory system under which utilities in the study used to set the base productivity trend operated. Hydro One SSM proposes to operate under a lengthy multiyear rate plan with limited earnings sharing whereas the formula rate plans and special incentives that many transmitters in the productivity sample operated under materially weakened their cost containment incentives. Based on the formula rates alone, the incentive power research detailed in Appendix B of the report suggests that, if the base productivity trend were based solely on U.S. data for the 2005-2016 period, the indicated stretch factor for HOSSM assuming average cost performance should lie in the [0.50-1.01] range.

X Factor

Our X factor recommendation is to combine a **-0.34%** base productivity trend drawn from our U.S. MFP research for the full sample period with a **0.30%** stretch factor. With rounding this produces an X factor of **0.00%**.

2. Critique of PSE's Research and Testimony

2.1. Industry Productivity Research

PSE calculated the transmission MFP trends of Hydro One and 47 U.S. electric utilities over the twelve-year 2005-2016 period. A -**1.71**% average annual MFP growth trend was reported over this period. OM&A productivity growth averaged -0.84% while capital productivity growth averaged -1.93%.

Growth in operating scale was calculated using a multidimensional index with two scale variables: line length and ratcheted maximum peak demand. The weights for these variables were obtained from PSE's econometric cost research. The weight for line length was 74% whereas the weight for peak demand was 26%.

Capital cost was measured using a variant of the geometric decay monetary method in which capital gains were not considered. The benchmark year in the capital cost computation was 2002 for Hydro One Networks and 1989 for the sampled U.S. industries.

2.2. PEG Critique

Our review of PSE's productivity research raised several concerns. To facilitate the Board's review of the numerous and often complicated issues that arise in productivity studies, we begin this section by highlighting our most important concerns with PSE's methodology. There follows a brief discussion of some of our other concerns.

Major Concerns

<u>Sample Period</u>

We first discuss our concerns with the sample period for the study. A twelve-year sample period is fairly brief for an X factor calibration study, and it is generally desirable to report results for a longer period than the practitioner favors. Our major concern with the 2005-2016 sample period, however, is that transmission MFP growth was strongly influenced during these years by policy initiatives of the U.S. government such as the Energy Policy Act of 2005. These initiatives included ROE premia for some kinds of transmission capex and the creation of new reliability standards that caused transmitters to incur Critical Infrastructure Protection ("CIP") costs. In addition to the fact that the slowdown in productivity growth due to CIP standards is temporary, Hydro One SSM may seek to Z factor any incremental CIP costs that may occur during its IRM, or request incremental capital revenue, if these costs are sizable.

PSE makes no claim in its evidence that productivity results for its chosen sample period are particularly suitable for Hydro One SSM or Hydro One Networks during the period of their upcoming IRMs. In response to OEB staff interrogatory 68, PSE indicates that it is uncertain about the sources of negative productivity growth during this period.

A related concern is that a sizable and growing number of the transmitters operated under formula rate plans approved by the Federal Energy Regulatory Commission ("FERC") during the sample period. These plans feature comprehensive cost trackers that weakened cost containment incentives. PSE acknowledged in response to OEB staff interrogatory 68 that formula rate plans are widely used by U.S. transmitters and weaken their incentives.

While some of the resultant cost increases during this period were necessary, and may lead in the future to productivity gains, incentives for transmitters to contain cost were unusually weak. U.S. government regulation of power transmission is discussed further in the Appendix.

The 2005 start date of the sample period that PSE chose was ostensibly chosen due to the fact that this is the first year that data are available for a peak demand variable that PSE used in its econometric model and scale index. However, we do not believe this variable is essential to the study since an alternative and satisfactory peak demand variable is available for which data are available for additional years.

PSE relied on the Monthly Transmission System Peak Load data reported on page 400 of the FERC Form 1. These data have two limitations. Firstly as noted, the data only began to be reported in 2004, limiting the sample period. Secondly, some companies misreported their peak demand. For example, the Southern Company operating utilities reported the peak demand for the entire transmission system peak of these companies rather than at the individual operating company level.

It is reasonable to instead rely on the Monthly Peaks and Output data, reported on page 401b of the FERC Form 1, to construct a ratcheted peak demand variable. These data do not include non-requirements sales for resale. Non-requirements differ from requirements in that requirements sales for resale are contractually firm enough that the party receiving the power is able to count on this power for system capacity resource planning. Non-requirements sales for resale do not meet this standard and will include economy energy. Unlike requirements sales for resale, the load associated with non-requirements sales for resale can be shed in times of capacity constraints.

Scale Index

We have two major concerns with PSE's scale index. One is that inadequate screening by PSE of the peak load data it used led to spurious econometric estimates of the cost elasticities of the two scale variables that PSE used. PSE acknowledged that this was a consequential problem in response to OEB staff interrogatory number 65.

The cost elasticity of the peak load variable should be as large or larger than that of the line length. As it happens, peak load grew considerably more rapidly than transmission line length during the sample period. These limitations of the scale index therefore tend to bias productivity results downward.

Structural Change

PSE's treatment of OM&A expenses does not handle structural change in the transmission industry well. As discussed further in Appendix B, many U.S. electric utilities joined independent system operators or regional transmission organizations in the last twenty years. These agencies performed some of the functions that the utilities had previously undertaken. Many utilities in the sample began taking transmission service from these agencies, and this could materially affect the reported costs of some companies.

Capital Cost Specification

We have two major concerns about PSE's capital cost specification. One is that a 1989 benchmark year was employed for all sampled U.S. utilities even though the requisite data are available back to 1964. The benchmark year for Hydro One Networks is 2002.[3] We explain in Appendix section A.2 that a recent benchmark year can materially reduce the accuracy of capital cost and quantity estimates. Our other major concern is that PSE does not reduce capital cost by capital gains. Since assets are denominated in current rather than historical dollars, this improperly increases the weight on the capital quantity trend.

[3]Hydro One Networks apparently does not have plant value data that would permit an earlier benchmark year. We understand that this is due in part to historical circumstances beyond the Company's control.

Other Concerns

A number of smaller problems with PSE's power transmission productivity research also merit mention.

An error was made in PSE's benchmark year calculation.

2.3. Hydro One Networks' Cost and Productivity Performance

PSE Research

PSE also calculated the transmission MFP trend of Hydro One Networks over the 2005-2016 period and the MFP trend implicit in forecasted/proposed costs from 2017 to 2022. Over the full historical sample period, the Company's -0.031% average annual MFP growth was more positive than that which PSE reported for the full sample. OM&A productivity averaged 1.07% growth whereas capital productivity averaged -0.58% annual growth. Over the 2020-2022 period the Company's forecasted/proposed costs would produce -1.43% annual MFP growth. OM&A productivity would average 0.12% annual growth while capital productivity would average -1.67% annual growth.

PSE reports that the total transmission cost of Hydro One SSM was a substantial 27.3% below its econometric cost model's prediction on average over the three most recent years for which data are available (2014-2016). The Company's forecasted/proposed total cost is 31.8% below the model's predictions during the first four years of the proposed IRM (2019-2022).

PEG Critique

Our review of PSE's benchmarking work and calculations of Hydro One Networks productivity trends revealed several concerns. Here are the most important ones:

- The relatively short sample period unnecessarily reduces the precision of the econometric benchmarking model parameter estimates.
- Parameter estimates are also degraded by the 1989 benchmarking year for U.S. utilities, which unnecessarily reduces the precision of the capital cost calculations,
- Due to data limitations beyond the control of PSE, the even more recent benchmark year for the Company reduces the accuracy of total cost benchmarking and multifactor productivity results for the Company.
- The capital cost specification excludes capital gains.

- We do not object in principle to the use of a weather-related loading variable but note that it is an example of developing a variable to address a special cost disadvantage of the Company when cost advantages could be ignored. Moreover, the accuracy of the calculation of the value for Hydro One is critically important.
- The accuracy of benchmarking Hydro One Networks is also reduced by our lack of knowledge about Ontario and US practices regarding power transmission customer contributions. This problem is not specific to the PSE study.

Here are some less important but nonetheless notable concerns:

- The scale index is inappropriate for the reasons stated above. However, this does not matter greatly for Hydro One Networks because the trends in the values of the scale variables are similar for the Company.
- Only Toronto values were used to levelize the construction cost index for the Company even though most of the transmission system is located at a considerable distance from Toronto.
- The calculations do not use Ontario inflation indexes. For example, the Handy Whitman Index for power transmission construction costs in the North Atlantic region of the United States was used to deflate the plant values of Hydro One Networks. We believe that the Statistics Canada's implicit price index for the capital stock of the Ontario utility sector is a more appropriate asset price deflator for the Applicants.

3. Alternative Empirical Research by PEG

3.1 Data Sources

The source of data on the transmission cost, transmission system capacity, and peak demand that we used in our benchmarking and productivity research is FERC Form 1. Data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Selected Form 1 data were for many years published by the U.S. Energy Information Administration ("EIA").[4] More recently, these data have been available electronically in raw form from the FERC, and in more processed forms from commercial vendors such as SNL Financial.[5]

Data on U.S. salary and wage prices were obtained from the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor. The gross domestic product price index ("GDPPI") that we used to deflate material and service expenses of U.S. transmitters was calculated by the Bureau of Economic Analysis of the U.S. Department of Commerce. Data on the *levels* of heavy construction costs in various U.S. and Canadian locations were developed by RSMeans. Data on U.S. electric utility construction cost *trends* were purchased from Whitman, Requardt and Associates. Some of the variables used in our econometric cost model were obtained from PSE working papers we examined in the course of this proceeding.

3.2 Sample

Data for Hydro One Networks and 44 U.S. transmitters were used in our productivity research. Data for Hydro One and 56 U.S. transmitters were used in our econometric research. The sample period for our econometric cost research was 1995-2016. The extra years should increase the precision of the econometric parameter estimates. The full sample period for our productivity research was 1996-2016. This should produce an MFP trend that is more pertinent to the calibration of X factors for Hydro One SSM and Hydro One Networks.

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[4] This publication series had several titles over the years. The most recent title is *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*.

[5] PSE evidently used SNL Financial data in its research.

3.3 Variables Used in the Research

Costs

The main task of a power transmitter is the long distance transmission of power. This is undertaken at high voltage to reduce line losses. Transmitters typically own substations that reduce the voltage of power before it is delivered to distribution systems. Many transmitters also own substations that increase the voltage of power received from generating stations. The principal assets used in transmission are thus high-voltage power lines, the towers that typically carry them, and substations. Other notable assets include circuit breakers and land.

The cost of power transmitter services considered in our study was the sum of applicable capital costs and OM&A expenses. The capital costs we included were those for transmission plant and a sensible share of the cost of general plant. We employed a monetary approach to capital cost, price, and quantity measurement which featured a geometric decay specification. Capital cost was the sum of depreciation expenses and a return on net plant value less capital gains. General issues in the measurement of capital cost are discussed in Appendix section A.2. Further details of our capital cost calculations are provided in Appendix section B.1.

The OM&A expenses we used in the study included most of those reported for power transmission and a sensible share of most administrative and general expenses. We excluded the following categories of transmission OM&A expenses because they have been affected by industry restructuring: transmission by others (account 565), load dispatching (accounts 561-561.8), and miscellaneous transmission expenses (566). We also excluded transmission rent expenses because some utilities used this category to report costs of leases on facilities they jointly own.

Pension and benefit expenses are often excluded from utility cost performance studies because they are sensitive to volatile external business conditions such as stock prices. In Canada, an additional problem with including pension and benefit expenses in econometric cost research is the lack of federal labor price indexes that encompass them. On the other hand, Hydro One SSM does not propose to Y factor these expenses. We have excluded pension and benefit expenses from our econometric benchmarking and index research in this proceeding. We also excluded all reported taxes and O&M expenses incurred by the utilities for generation, power procurement, distribution, customer accounts, customer service and information, sales, franchise fees, and gas services.

Input Prices

O&M

Summary OM&A input price indexes were used in our econometric work that featured subindexes for labor and materials and services. PSE provided the price levels for salaries and wages. Values of each company's labor price index for other years were calculated by adjusting these levels for changes in regionalized indexes of employment cost trends for the utilities sector of the economy. These indexes were constructed from BLS Employment Cost Indexes. For Hydro One Networks, we escalated the level value by average weekly earnings in Ontario as reported by Statistics Canada.

For material and service ("M&S") price inflation in the United States we used the U.S. gross domestic product price index ("GDPPI"). This is the U.S. government's featured index of inflation in prices of the economy's final goods and services. Final goods and services include business equipment and exports as well as consumer products. For the M&S price inflation of Hydro One Networks we used the gross domestic product implicit price index for final domestic demand.

In our econometric work we used a summary OM&A input price index constructed by combining the labor and M&S price subindexes using the 38% labor/62% weights that were calculated by PSE. For the U.S. productivity research, we instead used company-specific, time-varying cost share weights that we calculated from FERC Form 1 OM&A expense data. The summary multifactor input price index for each transmitter in our sample was constructed by combining the capital and summary OM&A price indexes using company-specific, time-varying cost share weights.

Capital

Construction cost indexes and rates of return on capital are required in the capital cost research, as we explain in Section B.2 of the Appendix. For the United States rate of return we calculated 50/50 averages of rates of return for debt and equity.[6] For bonds we used the embedded average interest rate on long-term debt as calculated from FERC Form 1 data. For equity we used the average allowed rate of return on equity ("ROE") approved in electric utility rate cases as reported by the Edison Electric

[6] This calculation was made solely for the purpose of measuring productivity *trends* and does not prescribe appropriate rate of return *levels* for utilities.

Institute.[7] For Hydro One Networks, we employed the weighted average cost of capital that PSE used in its study.

As for asset prices, we used the Statistics Canada capital stock deflator for the utility sector to deflate the value of plant additions of Hydro One Networks. Statistics Canada includes in the utility sector power generation and transmission, gas distribution, and water and sewer utilities as well as power distribution. For the United States utilities we used the regional Handy Whitman Indexes of Public Utility Construction Costs for Total Transmission Plant.

U.S./Canada Price Patch

Since transnational data were used in the study, it was necessary to make some adjustments for differences in currencies in the two countries. M&S prices were patched using US/Canadian purchasing power parities ("PPPs") computed by the Organization for Economic Cooperation and Development ("OECD"). Construction and labor price indexes did not require a special patch.

Scale Variables

Two scale variables were used in our econometric cost modelling: length of transmission line and ratcheted maximum peak demand. We used the alternative peak demand data found on page 401b of FERC Form 1 rather than the peak demand data on which PSE relied. Econometric research revealed that a ratcheted peak demand variable constructed using these data had comparable explanatory power to the variable used by PSE. We followed the PSE practice of according the two scale variables a translog treatment by adding quadratic and interaction terms for these variables to the cost model. The translog functional form is discussed further in Appendix Section B.2.

Other Business Condition Variables

Five other business condition variables were used in our econometric cost model. One of these variables was the extent of transmission plant overheading. This was measured as the share of overhead plant in the gross value of transmission conductor, device, and structure (pole, tower, and conduit) plant. System overheading typically involves higher O&M expenses since facilities are more

[7] The Edison Electric Institute is the principal trade association of U.S. electric utilities. The ROE data we used in the study were drawn from the backup data to the *EEI Rate Case Summary* quarterly reports.

exposed to the challenges posed by severe weather (e.g., high winds and ice storms) and flora and fauna. However, capital costs and capex are likely to be lower. The effect on total cost is less clear.

Two variables in the model address dimensions of the transmission system. These are substation capacity per mile of transmission line, and the average voltage of transmission lines. We expect the parameters for both of these variables to have positive signs. The model also includes the construction standards index developed by PSE and the share of transmission plant in the utility's non-general gross plant value. We expect the first variable to have a positive parameter and the second variable to have a negative parameter.

Our model also contains a trend variable. This permits predicted cost to shift over time for reasons other than changes in the specified business conditions. Trend variables thereby capture the net effect on cost of diverse conditions, such as technical change, which are otherwise excluded from the model. Parameters for such variables have often had a negative sign in econometric research on utility cost. However, the expected value of the trend variable parameter in a cost model is *a priori* indeterminate.

3.4 Econometric Cost Research

Econometric Cost Models

We developed an econometric model of the total cost of power transmission. The dependent variable was *real* total cost: the ratio of total cost to the multifactor input price index. This specification enforces a key result of cost theory.

Results of our econometric work are reported in Table 1. This table includes parameter estimates and their associated asymptotic t values. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. These significance tests were used in model development.

Table 1

PEG's Alternative Econometric Model of Transmission Total Cost

VARIABLE KEY

YM =	Miles of Transmission line
D =	Ratched Maximum Demand
MVA =	Substation Capacity per Line Mile in 2010
SUB =	Number of transmission substations per km of line
VOLT =	Average voltage of transmission line
CS =	Construction standards index
PCTOH =	Percent of transmission plant overhead
PCTPTX =	Percent of transmission plant in total plant
Trend =	Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YM	0.436	23.615	0.00
YM * YM	0.348	18.557	0.000
YM * D	-0.199	-15.290	0.000
D	0.566	34.583	0.000
D * D	0.230	13.164	0.000
MVA	0.027	3.233	0.001
VOLT	0.136	10.505	0.000
CS	0.542	26.962	0.000
PCTPOH	-1.251	-11.970	0.000
PCTPTX	0.273	13.937	0.000
Trend	0.000	0.143	0.886
Constant	12.534	164.241	0.000

Rbar-Squared	0.937
Sample Period	1995-2016
Number of Observations	1215

Examining the results in the table, it can be seen that the parameters of the business condition variables have sensible signs and parameter values.[8] Our research indicates that the sampled transmission costs of utilities were higher to the extent that:

- ratcheted peak demand was higher
- utilities had longer and higher voltage transmission lines and more substation capacity
- more transmission plant was underground
- transmission plant constituted a larger share of total non-general plant
- construction standards were higher.

The parameter estimates for the scale variables suggest that ratcheted peak demand had a long-run cost elasticity of 0.566% whereas the cost elasticity of transmission line is 0.436%. The adjusted R-squared for the model is 0.937%. The parameter estimate for the trend variable suggests that cost tended to rise over the full sample period by about 0.29% annually for reasons that aren't explained by the business condition variables in the model.

3.5 Productivity Research

Methodology

We calculated indexes of the transmission OM&A, capital, and multifactor productivity of Hydro One Networks and each U.S. utility in our sample. The annual productivity growth rate of each transmitter was calculated as the difference between the growth of its scale and input quantity indexes. Cost-weighted averages of these growth rates were then calculated. This makes sense when calibrating the X factor of a large utility like Hydro One Networks.

The growth of the scale index was a weighted average of the growth in line kilometers and ratcheted maximum peak demand. The estimated cost elasticities for these two variables from our econometric research were used to establish weights. The weights were 56.5% for ratcheted maximum peak demand and 43.5% for line length.

[8] This remark pertains to the "first" order terms in the model, and not to the parameters of the translog (squared and interaction) terms. These terms are discussed further in Appendix section B.2.

In calculating input quantity indexes for the U.S. utilities we broke down the applicable cost of U.S. utilities into those for transmission capital, general capital, labor, and M&S inputs. Each of these cost groups had its own input quantity subindex. The trend in each company's multifactor input quantity index is a weighted average of the trends in the four subindexes. The weights on these indexes are company-specific and time-varying. The calculation of the input quantity trend for Hydro One instead used a single, consolidated capital quantity index.

Industry Trends

Table 2 reports results of our productivity calculations for the full sample. We found that the growth in the transmission MFP of sampled U.S. utilities averaged **-1.82**% over PSE's chosen 2005-2016 sample period but **-0.34**% over the full 1996-2016 sample period during which the effects of formula rates and changing U.S. transmission policies were less pronounced. OM&A productivity growth averaged -1.40% over the shorter sample period but -0.53% over the full period. Transmission capital productivity growth averaged -1.73% over the shorter sample period but -0.21% over the full sample period.

Our estimates of these trends do not reflect any possible improvements in U.S. transmission reliability due to changing federal policies. Reliability is treated as an output variable in transmission productivity research commissioned by the Australian Energy Regulator. PSE acknowledged in response to OEB staff interrogatory # 63 that reliability can be an output in a productivity study.

Hydro One Networks' Trends

Table 3 reports results of our transmission productivity calculations for Hydro One Networks. Over the 2005-2016 historical sample period for which Hydro One Networks data are available, the annual MFP growth of the Company averaged -1.21 % while its OM&A productivity growth averaged 0.85% and its capital productivity growth averaged -1.86%. Over the first four years of the proposed plan (2019-2022), the Company's forecasted/proposed costs are consistent with -2.21% average MFP growth, -0.60% OM&A productivity growth, and -2.57% capital productivity growth. The Company's forecasted/proposed costs thus reflect productivity growth that is well below industry trends.

Table 2
U.S. Transmission Productivity Results Using PEG's Methods: Cost-Weighted Averages

(Growth Rates)[1]

Year	Scale Index	Input Quantity Index: Summary	Input Quantity Index: O&M	Input Quantity Index: Transmission Capital	Input Quantity Index: Allocated General Plant	Input Quantity Index: Capital	Productivity: MFP	Productivity: O&M	Productivity: Capital	Productivity: Transmission Capital	Productivity: Allocated General Plant
1996	1.19%	-0.66%	-1.08%	-0.73%	-0.16%	-0.69%	1.85%	2.26%	1.88%	1.92%	1.35%
1997	0.85%	-1.28%	-0.16%	-0.80%	-5.16%	-0.89%	2.13%	1.01%	1.74%	1.64%	6.00%
1998	1.47%	-0.95%	0.35%	-1.50%	1.10%	-1.41%	2.41%	1.12%	2.88%	2.97%	0.37%
1999	1.50%	-1.67%	-6.28%	-1.38%	-3.27%	-1.45%	3.16%	7.78%	2.95%	2.88%	4.76%
2000	0.67%	0.14%	6.58%	-0.79%	7.94%	-0.61%	0.54%	-5.90%	1.28%	1.47%	-7.26%
2001	1.63%	-0.03%	1.85%	-0.54%	15.31%	-0.22%	1.66%	-0.21%	1.85%	2.18%	-13.68%
2002	1.42%	-0.97%	-4.72%	-0.24%	-7.58%	-0.31%	2.39%	6.13%	1.73%	1.65%	8.99%
2003	1.51%	0.00%	3.36%	-0.53%	0.91%	-0.49%	1.51%	-1.84%	2.00%	2.04%	0.60%
2004	0.33%	1.21%	4.90%	0.28%	3.36%	0.34%	-0.89%	-4.58%	-0.01%	0.05%	-3.03%
2005	2.41%	1.55%	6.41%	0.33%	1.52%	0.36%	0.86%	-4.00%	2.05%	2.09%	0.90%
2006	1.73%	0.93%	2.19%	0.37%	-4.87%	0.22%	0.80%	-0.45%	1.52%	1.36%	6.60%
2007	1.05%	1.90%	3.89%	1.31%	-4.48%	1.07%	-0.85%	-2.84%	-0.02%	-0.26%	5.53%
2008	0.44%	2.17%	4.35%	1.36%	3.84%	1.44%	-1.74%	-3.91%	-1.01%	-0.93%	-3.40%
2009	-0.17%	2.61%	3.27%	2.47%	0.48%	2.38%	-2.78%	-3.44%	-2.55%	-2.64%	-0.65%
2010	0.64%	2.76%	5.60%	1.91%	-0.48%	1.80%	-2.11%	-4.96%	-1.15%	-1.27%	1.12%
2011	0.32%	1.31%	-2.43%	2.48%	-1.49%	2.36%	-0.99%	2.75%	-2.03%	-2.16%	1.81%
2012	0.57%	2.05%	2.89%	1.79%	7.05%	1.86%	-1.47%	-2.31%	-1.28%	-1.22%	-6.48%
2013	0.27%	4.13%	2.61%	4.56%	8.66%	4.56%	-3.87%	-2.34%	-4.29%	-4.29%	-8.40%
2014	0.84%	3.36%	-3.37%	4.56%	-2.26%	4.41%	-2.51%	4.22%	-3.57%	-3.71%	3.10%
2015	0.61%	3.61%	-2.90%	4.75%	2.38%	4.74%	-3.00%	3.50%	-4.13%	-4.15%	-1.77%
2016	-0.06%	4.11%	2.94%	4.22%	5.69%	4.21%	-4.17%	-3.00%	-4.28%	-4.28%	-5.75%
Average Annual Growth Rates											
1996-2016	**0.91%**	**1.25%**	**1.44%**	**1.14%**	**1.36%**	**1.13%**	**-0.34%**	**-0.53%**	**-0.21%**	**-0.22%**	**-0.44%**
2005-2016	**0.72%**	**2.54%**	**2.12%**	**2.51%**	**1.34%**	**2.45%**	**-1.82%**	**-1.40%**	**-1.73%**	**-1.79%**	**-0.62%**

[1]All growth rates are calculated logarthmically.

3.6 Cost Benchmarking Results

PEG used its own econometric cost model to benchmark the total transmission cost of Hydro One Networks. We used PSE's forecasts for the input prices. Results of our benchmarking work are presented in Table 4. It can be seen that the Company's transmission cost was about 9.43% below the model's prediction on average from 2014 to 2016, the three most recent historical years for which data are available. The Company's forecasted/proposed total costs are about 1.23% below the model's prediction on average during the first four years of the proposed IRM (2019-2022). This research suggests that the Company is an average cost performer.

Table 3

Hydro One Networks' Transmission Productivity Annual Growth Rates

Year	Multifactor Productivity	OM&A Productivity	Capital Productivity	Output Quantity	OM&A Input Quantity	Capital Input Quantity
2005	3.51%	11.61%	1.13%	1.52%	-10.09%	0.39%
2006	-0.31%	-7.69%	2.04%	1.96%	9.65%	-0.08%
2007	-4.04%	-10.39%	-1.71%	0.00%	10.39%	1.71%
2008	3.86%	14.73%	-0.42%	0.08%	-14.66%	0.50%
2009	-5.54%	-12.06%	-2.68%	-0.01%	12.06%	2.67%
2010	-2.30%	1.54%	-4.03%	0.04%	-1.50%	4.06%
2011	-1.28%	3.90%	-3.19%	0.04%	-3.86%	3.23%
2012	-4.30%	0.34%	-5.69%	0.41%	0.07%	6.10%
2013	-1.84%	-2.32%	-1.70%	0.03%	2.35%	1.73%
2014	0.07%	10.86%	-3.04%	-0.05%	-10.91%	2.99%
2015	-2.87%	-10.09%	-0.69%	0.14%	10.22%	0.83%
2016	0.49%	9.74%	-2.29%	0.00%	-9.74%	2.29%
2017	-1.05%	4.97%	-2.56%	-0.54%	-5.51%	2.02%
2018	-1.77%	4.04%	-3.06%	0.58%	-3.46%	3.63%
2019	-1.93%	-2.75%	-1.76%	0.00%	2.75%	1.76%
2020	-2.26%	0.13%	-2.79%	0.00%	-0.13%	2.79%
2021	-2.27%	0.10%	-2.80%	0.01%	-0.10%	2.81%
2022	-2.39%	0.11%	-2.94%	0.01%	-0.10%	2.94%
Average Annual Growth Rates						
2005-2016	**-1.21%**	**0.85%**	**-1.86%**	**0.35%**	**-0.50%**	**2.20%**
2010-2016	**-1.62%**	**2.07%**	**-2.77%**	**0.10%**	**-1.98%**	**2.86%**
2019-2022	**-2.21%**	**-0.60%**	**-2.57%**	**0.00%**	**0.61%**	**2.58%**

Table 4

Transmission Total Cost Performance of Hydro One Networks Using the PEG Econometric Model

[Actual - Predicted Cost (%)][1]

Year	Cost Benchmark Score
2004	-23.40%
2005	-27.00%
2006	-26.40%
2007	-21.90%
2008	-24.80%
2009	-18.70%
2010	-17.00%
2011	-16.90%
2012	-13.40%
2013	-11.20%
2014	-11.30%
2015	-8.00%
2016	-9.00%
2017	-8.10%
2018	-6.70%
2019	-4.70%
2020	-2.30%
2021	-0.10%
2022	2.20%
Average 2004-2016	**-17.62%**
Average 2014-2016	**-9.43%**
Average 2019-2022	**-1.23%**

[1] Formula for benchmark comparison is $\ln(Cost^{HON}/Cost^{Bench})$.

4. Stretch Factor and X Factor Recommendations

4.1 Stretch Factor

We disagree with PSE's 0% stretch factor recommendation, which is based on the contentions that an explicit stretch factor is not warranted because Hydro One Networks is a superior transmission cost performer and there is a large implicit stretch factor. One reason that we disagree is that the plan is for Hydro One SSM and no evidence has been submitted on this company's cost performance. Another and more important reason is that Hydro One Networks' cost performance does not score as well in our study as in the PSE study. A third is that transmission MFP growth is more rapid using our longer sample period and methods.

In addition, we have long believed that, in addition to utility operating efficiency, stretch factors should reflect the difference between the incentive power of the contemplated IRM and the incentive power of the regulatory systems under which utilities in studies used to set the base productivity trend operated. Hydro One SSM proposes to operate under a lengthy multiyear rate plan with limited earnings sharing whereas the formula rate plans and special incentives that many sampled U.S. electric utilities operated under during the years of the productivity studies materially weakened their cost containment incentives.

We have developed an incentive power model with funding from many clients over the years that include the OEB. This model considers the response of a typical pipe or wires utility to operation under alternative stylized regulatory systems. Based on the formula rates alone this model suggests that, if the base productivity trend were based on U.S. data for the 2005-2016 sample period that PSE uses, the indicated stretch factor would lie in the [**0.50** – **1.01**] range for a company with average cost performance. Our incentive power research is discussed further in the Appendix Section B.4.

4.2 X Factor

We recommend that the **-0.34**% trend in the MFP of the U.S. power transmission industry over the full sample period serve as the base productivity trend. This estimate may be understated because it does not reflect any possible improvements in U.S. transmission reliability due to changing federal policies. A **0.30**% stretch factor is warranted if results for our full sample period are used. With rounding, our X factor recommendation is **0.00%.**

Appendix A: Index Research for X Factor Calibration

In this section of the report we discuss pertinent principles and methods for the design of revenue cap indexes. We begin by discussing basic indexing concepts. There follow discussions of the use of indexing research in revenue cap index design and other important methodological issues.

A.1 Principles and Methods for Revenue Cap Index Design

Basic Indexing Concepts

The logic of economic indexes provides the rationale for using price and productivity research to design revenue cap escalators. To review this logic, it may be helpful to ensure that the reader has a high-level understanding of some basic tools of index research.

Input Price and Quantity Indexes

The growth (rate) of a company's cost can be shown to be the sum of the growth of a (cost-weighted) input price index ("Input Prices") and input quantity index ("Inputs").

growth Cost = growth Input Prices + growth Inputs.[9] [A1]

Both of these indexes are typically multidimensional in the sense that they summarize trends in subindexes that are appropriate for particular subsets of cost. The major input groups of a power transmitter include capital, labor, and materials and services.

Productivity Indexes

The Basic Idea A productivity index is the ratio of a scale index ("Scale") to an input quantity index.

$$\mathit{Productivity} = \frac{\mathit{Scale}}{\mathit{Inputs}}. \qquad [A2]$$

It can be used to measure the efficiency with which firms use inputs to achieve their scale of operation.

Some productivity indexes are designed to measure productivity *trends*. The growth of such a productivity index is the difference between the growth in the scale and input quantity indexes.

growth Productivity = growth Scale – growth Inputs. [A3]

[9] Cost-weighted input price and quantity indexes are attributable to the French economist Francois Divisia.

Productivity grows when the scale index rises more rapidly (or falls less rapidly) than the input index. The productivity growth of utilities can be volatile but has historically tended to be positive over long time periods. The volatility is typically due to demand-driven fluctuations in operating scale and/or the uneven timing of certain expenditures. The volatility of productivity growth tends to be much greater for individual companies than the average for a group of companies.

Relations [A1] and [A3] imply that

$$\textit{growth Productivity} = \textit{growth Scale} - (\textit{growth Cost} - \textit{growth Input Prices})$$

$$= \textit{growth Input Prices} - \textit{growth } (\textit{Cost/Scale}).$$

Productivity growth is thus the amount by which a firm's unit cost grows more slowly than its input prices.

The scope of a productivity index depends on the array of inputs that are considered in the input quantity index. Some indexes measure productivity in the use of a single input group such as labor. A *multifactor* productivity index measures productivity in the use of various kinds of inputs. MFP indexes are sometimes called *total* factor productivity ("TFP") indexes, a term that is widely used but often incorrect because some inputs are excluded from the index calculations.

Scale Indexes A scale index of a firm or industry summarizes trends in the scale of operation. These indexes may also be multidimensional. Growth in each dimension of scale that is itemized is then measured by a subindex and the scale index summarizes growth in the subindexes by taking a weighted average of them.

In designing a scale index, choices concerning scale variables (and weights, if the index is multidimensional) should depend on the manner in which the index is used. One possible objective is to measure the impact of growth in scale on *revenue*. In that event, the scale variables should measure growth in *billing determinants* like peak demand and the weight for each itemized determinant should be its share of a utility's base rate revenue.[10]

Another possible objective of scale indexing is to measure growth in dimensions of scale that affect *cost*. In that event, the scale variable(s) should measure dimensions of the "workload" that drive

[10] Revenue-weighted scale indexes are attributable to the French economist Francois Divisia.

cost. If there is more than one scale variable in the index the weight for each variable should reflect its relative cost impact. The sensitivity of cost to a small change in the value of a business condition variable is commonly measured by its cost "elasticity." Cost elasticities of utilities can be estimated econometrically using a sample of data on the costs and operating scale of a group of utilities. These estimates can provide the basis for scale index weights.[11] We denote a productivity index calculated using a cost-based scale index will be denoted as $Productivity^C$.

$$growth\ Productivity^C = growth\ Scale^C - growth\ Inputs. \qquad [A4]$$

This may fairly be described as a "cost efficiency index."

Use of Index Research in Revenue Cap Design

Productivity studies have many uses, and the best research methods for one use may not be best for another. In this section, we discuss the logic for using productivity research in revenue cap index design and consider some implications for the appropriate productivity index.

Revenue Cap Indexes

We begin our explanation of the supportive index logic by considering the growth in the revenue of a firm that earns, in the long run, a competitive rate of return.[12] For such a firm, the long-run trend in revenue equals the long-run trend in cost.

$$trend\ Revenue = trend\ Cost. \qquad [A5]$$

Consider now the following basic result of cost theory:

$$growth\ Cost = growth\ Input\ Prices - growth\ Productivity^C + growth\ Scale^C.^{13} \qquad [A6a]$$

[11] A multidimensional scale index with elasticity weights is unnecessary if econometric research reveals that there is one dominant cost driver.

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

[13] This result can be found in Denny, Michael, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

The growth in the cost of a firm is the difference between the growth in input price and cost efficiency indexes plus the trend in a (consistent) cost-based scale index. This result provides the basis for revenue cap indexes of general form

$$\textit{growth Revenue} = \textit{growth Input Prices} - X + \textit{growth Scale}^{C} \qquad \text{[A6b]}$$

where

$$X = \textit{trend}\ \overline{\textit{Productivity}^{C}} + \textit{Stretch}. \qquad \text{[A6c]}$$

Here *trend Productivity*^{C} is the trend in the productivity indexes of a sample of utilities and *Stretch* is the stretch factor. Notice that a cost-based scale index should be used in the supportive productivity research for a revenue cap index X factor. Moreover, this index should match the scale index in the revenue cap index.

Sample Period

Another important issue in the design of a revenue (or price) cap index is whether it should be designed to track short-run or long-run industry cost trends. Indexes designed to track short-run growth will also track the long run growth trend if this approach is used repeatedly over many years. An alternative approach is to design the index to track only long-run trends.

Different approaches can, in principle, be taken for the input price and productivity components of the revenue cap index and are in most cases warranted. The inflation measure should track short-term input price growth. Meanwhile, productivity research for X factor calibration commonly focuses on discerning the current long-run productivity trend. This is the trend in productivity that is unaffected by short-term fluctuations in operating scale and inputs which are not expected to continue. The long-run productivity trend is faster than the short-run trend during a short-lived surge in input growth but slower than the trend during a short-lived lull in input growth.

This general approach to revenue cap index design has important advantages. The inflation measure exploits the greater availability of inflation data. Making the revenue cap index responsive to short-term input price growth reduces the operating risk of the utility without weakening its performance incentives. Having X reflect the long-run industry productivity trend, meanwhile, sidesteps the need for more timely cost data and annual productivity calculations.

In order to calculate the long-run productivity trend using indexes, it is common to use a lengthy sample period. However, a period of more than twenty years may be unreflective of current business conditions. Moreover, quality data are sometimes not readily available for longer sample periods. The need for a long sample period is lessened to the extent that volatile costs are excluded from the study and the scale index does not assign a heavy weight to volatile scale variables.

Sources of Productivity Growth

Economists have considered the drivers of productivity growth using mathematical theory and empirical methods.[14] The research has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

Economies of scale are another important productivity growth driver. These economies are realized in the longer run if cost has a tendency to grow less rapidly than operating scale. Incremental scale economies (and thus productivity growth) will typically be lower the slower is output growth.

A third driver of productivity growth is X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum possible efficiency. Productivity growth will accelerate to the extent that X inefficiency diminishes. A company's potential for future productivity growth from this source is smaller the greater is its current efficiency level.

System age can drive productivity growth in the short and medium run. For example, productivity growth tends to be greater to the extent that the initial capital stock is large relative to the need to refurbish or replace aging plant. If a utility has a need for unusually high replacement capex, capital productivity can decline. On the other hand, productivity growth tends to accelerate in the aftermath of unusually high capex as the surge capital depreciates.

Productivity growth is also affected by changes in the miscellaneous business conditions, other than input price inflation and output growth, which affect cost. A good example for a power transmitter is a change in the mix of overhead and underground lines.

[14] Denny, Fuss, and Waverman (1981), referenced above, provides a classic discussion of the drivers of productivity growth.

A.2 Key Things to Know About Capital Cost Research

Monetary Approaches to Capital Cost and Quantity Measurement

The capital cost specification is of central importance in research on the MFP of power transmission because its technology is capital-intensive. The cost of capital ("*CK*") includes depreciation expenses, a return on investment, and certain taxes.

Monetary approaches to the measurement of capital prices and quantities are conventionally used in North American productivity research. A monetary approach decomposes capital cost into a consistent capital quantity index ("*XK*") and capital price index ("*WKS*") such that

$$CK = WKS \cdot XK.^{15} \qquad [A7]$$

The capital quantity index is constructed using inflation-adjusted data on the value of utility plant.

It is customary to assume that a capital good provides a stream of services over a period of time that is called the service life of the asset. *XK* is then construed to measure the quantity of this stream. The capital service price index measures the trend in the price of a unit of capital service. In research on the productivity of U.S. energy utilities, Handy Whitman utility construction cost indexes and data on the rate of return on utility capital have traditionally been used in capital price index construction. The product of the capital service price index and the capital quantity index is the annual cost of using the flow of services.

Benchmark Year Adjustments

Utilities have diverse methods for calculating depreciation expenses that they report to regulators. When calculating capital quantities using a monetary method, it is therefore customary to rely on the reporting companies chiefly for the value of *gross* plant additions and then use a standardized decay specification for all companies. Since some of the plant a utility owns may be 40-60 years old, it is desirable to have gross plant addition data for many years in the past.

[15] The *growth rate* of capital cost is thus the sum of the growth rates of the capital price and quantity indexes.

For the earlier years that are pertinent, the desired gross plant addition data are frequently unavailable. It is then customary to take the value of plant of every vintage at the end of this limited-data period and then estimate the quantity of capital that it reflects using construction cost indexes from earlier years and assumptions about the historical plant addition pattern. The year for which this estimate is undertaken is commonly called the "benchmark year" of the capital quantity index. Since the estimate of the capital quantity in the benchmark year is inexact, it is preferable to base capital and total cost research on a sample period that begins many years after the benchmark year. Research on capital and total cost will be less accurate to the extent that this is impossible.

Alternative Monetary Approaches

Several monetary methods have been established for measuring capital quantity trends. A key issue in the choice of a monetary method is the pattern of decay in the quantity of capital after a plant addition.[16] Another issue is whether plant is valued in historic dollars or replacement dollars.

Three monetary methods have been used in North American research to calibrate utility X factors.

- Under the geometric decay ("GD") specification, the flow of services from investments in a given year declines at a constant rate over time. Plant is valued in replacement (i.e., *current*) dollars. This general method has been most commonly used in X factor calibration studies. Replacement valuation differs from the historical (i.e., "book") valuation used in North American utility accounting and requires consideration of capital gains.

- Under the one hoss shay specification, the flow of services from plant additions in a given year is assumed to be constant until the end of their service lives, when it abruptly falls to zero. This is the pattern that is typical of an incandescent light bulb. Plant is once again valued at replacement cost and capital gains are considered.

  The cost of service ("COS") method is designed to approximate the way capital cost is calculated in utility regulation. This approach is based on the assumptions of straight-line depreciation and historic valuation of plant. Capital gains are not considered.

[16] The pattern of decay over time is sometimes called the age-efficiency profile.

Appendix B: Further Detail on Select Topics

B.1 Technical Details of PEG's Productivity Research

This section of Appendix B contains more technical details of our productivity research. We first discuss our input quantity and productivity indexes, respectively. We then address our methods for calculating input price inflation and capital cost.

Input Quantity Indexes

The growth rate of a summary (multidimensional) input quantity index is defined by a formula that involves subindexes measuring growth in the quantities of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and quantity subindexes.

Index Form

We have constructed summary multifactor and OM&A input quantity indexes. Each summary input quantity index is of chain-weighted Törnqvist form.[17] This means that its annual growth rate is determined by the following general formula:

$$\ln\left(\frac{Inputs_t}{Inputs_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1} \right) \cdot \ln\left(\frac{X_{j,t}}{X_{j,t-1}} \right). \qquad \text{[B1]}$$

Here in each year *t*,

$Inputs_t$ = Summary input quantity index

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

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

It can be seen that the growth rate of the index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable cost of each utility in the current and prior years served as weights.

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[17] For seminal discussions of this index form, see Törnqvist (1936) and Theil (1965).

Productivity Growth Rates and Trends

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

$$\ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right) = \ln\left(\frac{Scale_t}{Scale\ Quantities_{t-1}}\right) - \ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right). \quad [B2]$$

The long-run trend in each productivity index was calculated as its average annual growth rate over the full sample period.

Input Price Indexes

The growth rate of an input price index is defined by a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and price subindexes.

Price Index Formulas

The multifactor input price index used in the econometric total cost model was of Törnqvist form. This means that the annual growth rate of each index was determined by the following general formula. For any asset category *j*,

$$\ln\left(Input\ Prices_t / Input\ Prices_{t-1}\right) = \sum_j \frac{1}{2}\cdot\left(sc_{j,t} + sc_{j,t-1}\right)\cdot\ln\left(W_{j,t} / W_{j,t-1}\right). \quad [B3]$$

Here in each year *t*,

$Input\ Prices_t$ = Input price index

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

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

The growth rate of the index is a weighted average of the growth rates of input price subindexes. Each growth rate is calculated as the logarithm of the ratio of the subindex values in successive years. The average shares of each input group in the applicable cost of each utility during the two years are the weights.

Capital Cost and Quantity Specification

A monetary approach was used to measure the capital cost of each utility. Recall from Appendix section A.2 that under this approach capital cost is the product of a capital quantity index and a capital price index.

$$CK = WKS \cdot XK.$$

Geometric decay was assumed in the construction of both of these indexes.

Data available and previously processed by PEG permitted us to use 1964 as the benchmark year for the U.S. capital cost and quantity calculations. The value of each capital quantity index for each utility in 1964 depends on the net value of its plant as reported in FERC Form 1. We estimated the benchmark year quantity of capital by dividing this book value by a triangularized weighted average of 46 values of an index of power transmission construction cost for a period ending in the benchmark year. The construction cost indexes (WKA_t) were developed from the applicable regional Handy-Whitman indexes of cost trends of electric utility transmission construction.[18] A triangularized weighted average places a greater weight on more recent values of the construction cost index. This makes sense intuitively since more recent plant additions are less depreciated and to that extent tend to have a bigger impact on net plant value.

The following GD formula was used to compute values of each capital quantity index in subsequent years. For any asset category *j*,

$$XK_{j,t} = (1-d) \cdot XK_{j,t-1} + \frac{VI_{j,t}}{WKA_{j,t}}. \qquad [B4]$$

Here, the parameter *d* is the economic depreciation rate and VI_t is the value of gross additions to utility plant. The assumed 46-year average service life and 1.65 declining balance rate that were used to set d are the same as in the PSE study.

The formula for the corresponding GD capital service price indexes used in the research was

[18] These data are reported in the Handy-Whitman Index of Public Utility Construction Costs, a publication of Whitman, Requardt and Associates.

$$WKS_{j,t}=[CK_{j,t}^{Taxes}/XK_{j,t-1}]+d\cdot WKA_{j,t}+WKA_{j,t-1}\left[r_t-\frac{\left(WKA_{j,t}-WKA_{j,t-1}\right)}{WKA_{j,t-1}}\right]. \qquad [B5]$$

The first term in the expression corresponds to taxes and franchise fees. The second term corresponds to the cost of depreciation. The third term corresponds to the real rate of return on capital. This term was smoothed to reduce capital cost volatility.

B.2 Econometric Research

This section of Appendix B provides additional and more technical details of our econometric research. We begin by discussing the choice of a form for the econometric benchmarking models. There follow discussions of econometric methods.

Form of the Econometric Cost Model

Specific forms must be chosen for cost functions used in econometric research. Forms commonly employed by scholars include the linear, double log, and translog. Here is a simple example of a *linear* cost model:

$$C_{h,t}=a_0+a_1\cdot N_{h,t}+a_2\cdot V_{h,t}. \qquad [B6]$$

Here is an analogous cost model of *double log* form:

$$\ln C_{h,t}=a_0+a_1\cdot\ln N_{h,t}+a_2\cdot\ln V_{h,t}. \qquad [B7]$$

The double log model is so-called because the right- and left-hand side variables are all logged. This specification makes the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, parameter a_1 indicates the percentage change in cost resulting from 1% growth in the number of customers. Elasticity estimates are useful and make it easier to assess the reasonableness of model results. It is also noteworthy that, in a double log model, elasticities are *constant* in the sense that they are the same for every value that the cost and business condition variables might assume. This model specification is restrictive and may be inconsistent with the true form of the cost relationship we are trying to model.

Here is an analogous model of *translog* form:

$$\ln C_{h,t}= a_o + a_1\cdot\ln N_{h,t} + a_2\cdot\ln V_{h,t} + a_3\cdot\ln N_{h,t}\cdot\ln N_{h,t} + a_4\cdot\ln V_{h,t}\cdot\ln V_{h,t} + a_5\cdot\ln V_{h,t}\cdot\ln N_{h,t} \qquad [B8]$$

This form differs from the double log form in the addition of quadratic and interaction terms. Quadratic terms like $ln N_{h,t} \cdot ln N_{h,t}$ permit the elasticity of cost with respect to each business condition variable to vary with the value of the variable. The elasticity of cost with respect to a scale variable may, for example, be lower for a small utility than for a large utility. Interaction terms like $ln V_{h,t} \cdot ln N_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable. For example, the elasticity of cost with respect to growth in peak load may depend on the length of a transmitter's transmission lines.

The translog form is an example of a "flexible" functional form. Flexible forms can accommodate a greater variety of possible functional relationships between cost and the business condition variables. A disadvantage of the translog form is that it involves many more variables than simpler forms like the double log. As the number of variables accorded translog treatment increases, the precision of a model's parameter estimates and cost predictions falls. It is therefore common in econometric cost research to limit the number of variables accorded translog treatment.

In our econometric work for this proceeding, we have chosen a functional form that is logarithmic only with respect to the two scale variables. This preserves degrees of freedom but permits the model to recognize some nonlinearities. All of the quadratic terms in our model had statistically significant parameter estimates.

Econometric Model Estimation

A variety of parameter estimation procedures are used by econometricians. The appropriateness of each procedure depends on the distribution of the error terms. The estimation procedure that is most widely known, ordinary least squares ("OLS"), is readily available in econometric software. Another class of procedures, called generalized least squares ("GLS"), is appropriate under assumptions of more complicated and realistic error specifications. For example, GLS estimation procedures can permit the variance of the error terms of cost models to be heteroskedastic, meaning that they vary across companies. Variances can, for example, be larger for companies with large operating scale.

Note, finally, that the model specification was determined using data for all sampled companies. However, estimation of parameters and appropriate standard errors for the cost model actually used for benchmarking required that the utility of interest be dropped from the sample. The parameter estimates used in developing the cost model and reported in Table 1 above therefore vary slightly from those in the models used for benchmarking.

B.3 Federal Regulation of U.S. Power Transmission

In the United States, regulation of power transmission rates is undertaken today chiefly by the FERC. It is important to understand how this regulation has evolved.

Unbundling Transmission Service

Transmission regulation prior to the mid-1990s reflected the vertically integrated structure of most investor-owned electric utilities in that era. These utilities typically owned both the transmission and the distribution systems in the areas they served and obtained most of their power supplies from their own generation facilities. There were fewer bulk power purchasers and independent power producers using transmission services than there are today.

Wholesale customers (e.g., municipal utilities) could obtain bundled generation and transmission services from adjacent utilities by negotiating a contract with the utility. Power was sometimes purchased from a third party and delivered over other companies' transmission system. If the contract path for such a purchase passed over multiple transmission systems the customer might have to pay multiple transmitters for service, a phenomenon called “pancaked rates”. Disputes over wholesale contracts for the purchase and transmission of power could be brought to the FERC. Utilities sometimes had the ability to discriminate between their customers regarding the terms of transmission service.

Starting in the 1970s, federal legislation increasingly encouraged proliferation of 3rd party generators and the development of more robust bulk power markets. This increased the demand for public, non-discriminatory tariffs for wholesale transmission service. In 1996, FERC Order 888 required transmitters to provide service under open access transmission tariffs (“OATTs”). To ensure that service was provided on a non-discriminatory basis, the FERC also ordered transmitters to establish an information network to provide network information to transmission customers and procure its native load transmission service solely using the OATT and the publicly available information network. Third parties were provided the option to procure the same types of service at the same quality levels as the transmitter’s native load. Many details of functional unbundling and the information service for transmission customers were addressed in FERC Order 889.

Bulk power markets were also expanded by restructuring of retail markets in many American states. This permitted a larger role for independent power merchandizers and bulk power market purchases by large industrial customers.

Formula Rates

Rates for jurisdictional transmission services can be set by the FERC in periodic rate cases. Transmitters also have the option to request formula rates, wherein rates are reset annually to reflect the changing cost of their service. Formula rates may rely on a transmitters historical cost and revenue data or on forward-looking cost and revenue data with a subsequent true up of forecasts to actual values.

Formula rates have been used at the FERC and its predecessor, the Federal Power Commission, to regulate interstate services of gas and electric utilities since at least 1950. Early FERC rationales for using formula rates included the following.[19]

- Establishment of rates for a new utility;
- Establishment of rates for the transaction of one utility with an affiliated utility; and
- Economies in regulatory cost.

Regulatory cost economies are a major consideration for a commission with jurisdiction over more than 100 electric utilities and dozens of interstate oil and gas pipelines.

Use of FRPs by the FERC was encouraged in the 1970s and early 1980s by rapid input price inflation. Despite slower inflation in more recent years, the FERC's use of formula rates has grown in the power transmission industry. Growing use of OATTs greatly increased the need to set rates for transmission services by some means. Formula rates were also encouraged by national energy policies such as the Energy Policy Act of 2005 which promoted transmission investment and increased attention to reliability. Early adopters of formula rates included Midwestern and New England utilities and the Southern Company. Many of the FRPs approved by the FERC have been the product of settlements.

[19] A useful discussion of early precedents for formula rates at the FERC can be found in a March 1976 administrative law judge decision in Docket No. RP75-97 for Hampshire Gas.

At the 2004 start date of PSE's sample period less than 15 of the 56 sampled transmitters operated under formula rates. By the 2016 end point of PSE's sample period fewer than 15 sampled transmitters *did not* operate under formula rates. PEG is not aware of any transmitters that abandoned formula rate plans during PSE's sample period. Thus, about half of the U.S. transmitters in the PSE sample received approval of formula rate plans during the PSE sample period.

ISOs and RTOs

As another means to promote development of bulk power markets and non-discriminatory transmission service, in 1996 the FERC encouraged electric utilities to transfer operation of their transmission systems to an independent system operator ("ISO"). In this arrangement, the transfer of control was voluntary and utilities retained ownership of their portions of the grid. ISOs have scheduled services, managed transmission facility maintenance, provided transmission system information to all potential customers, ensured short-term grid reliability, and considered remedies for network constraints. ISO services must be provided under an OATT that is not discriminatory to any market participant. These tariffs recover the ISO's cost, which sometimes including the sizable charges of transmission owners for the use of their systems.

In a 1999 order, the FERC pushed for further structural change in the markets for transmission services by encouraging formation of RTOs. The FERC has higher requirements for RTO approval than for ISOs. For example, RTO tariffs must include the transmission owners' cost. RTOs also typically have a larger footprint, serving multiple states while some ISOs serves a single state or Canadian province.

Several ISOs were formed between 1996 and 2000. The FERC has approved applications for RTOs that serve much of the Northeast, East Central, and Great Plains regions of the US. The Midwestern ISO (dba today as Midcontinent ISO) and PJM Interconnection were approved for RTO status in 2001, while the Southwest Power Pool and ISO New England became RTOs in 2004. ISOs that are not RTOs currently operate in some Canadian provinces, New York, Texas, and California.[20] Relatively few utilities in the southeastern and intermountain states are members of an ISO or RTO.[21]

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[20] Texas transmitters in the Electricity Reliability Council of Texas are generally not subject to FERC regulation.

[21] In recent years, several South Central U.S. transmitters joined MISO.

The charges of transmission owners who are members of RTOs may still be reset in periodic rate cases or formula rate plans. All Midcontinent ISO transmission owners have formula rates.

Energy Policy Act of 2005

Beginning in the late 1970s, U.S. transmission capex began to decline in real terms. Part of this decline was due to low generation plant additions, particularly in the late 1990s. Other reasons given for the decline in capex were difficulties in siting transmission lines and poor incentives for transmitters to propose new lines. The grid did not always handle the demands placed on it by growing bulk power market transactions, and congestion costs occurred in some areas. The decline in capex eventually led to concerns by the FERC and other policymakers that transmitters were not sufficiently investing in their networks, thus jeopardizing the success of bulk power markets.

This is the context in which the Energy Policy Act of 2005 was passed. It affected transmission investment and many other aspects of transmitter operations. The Act gave the FERC authority to oversee transmission reliability. The FERC could sanction mandatory reliability standards and penalties. Development of these standards, now called Critical Infrastructure Protection standards, was largely delegated to the North American Electric Reliability Corporation ("NERC"). Numerous NERC Reliability Standards were approved by the FERC in 2007. These standards are intended to prevent reliability issues resulting from numerous sources including operation and maintenance of the system, resource adequacy, cybersecurity, and cooperation between operators.

Concerns about siting of transmission lines were somewhat mitigated by a provision allowing the federal government to designate "national interest electric transmission corridors" to mitigate areas of significant transmission congestion. This provision has proven to be somewhat controversial, as it is viewed as a federal intrusion into an issue that states have traditionally addressed. Nevertheless, it is likely that potential federal oversight of transmission siting encouraged state regulators to expedite transmission siting proceedings.

Concerns about transmission owner incentives were addressed by the addition of a mandate for the FERC to incentivize both transmission investments and participation in an RTO or ISO. The Energy Policy Act of 2005 required FERC to adopt a rule that would accomplish the following:

> ''(1) promote reliable and economically efficient transmission and generation of electricity **by promoting capital investment in the enlargement, improvement, maintenance, and operation**

of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities;

''(2) **provide a return on equity that attracts new investment in transmission facilities** (including related transmission technologies);

''(3) **encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities**; and

''(4) allow recovery of—

> ''(A) all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to section 215; and
>
> ''(B) all prudently incurred costs related to transmission infrastructure development pursuant to section 216.[22]

In FERC Orders 679 and 679-A, released in 2006, the FERC adopted a wide range of incentives to encourage transmission investment. These incentives included the ability for a transmitter to include 100% of CWIP in rate base, ROE premiums for plant additions resulting from some projects (one that is set above the middle of the zone of reasonableness), accelerated depreciation, full cost recovery for abandoned facilities and pre-operation costs, and cost tracking of individual projects. In addition, ROE premiums were permitted for transmitters who joined or remained in an RTO or ISO.

In this framework, a transmission operator would need to file an application and show that the requested incentives were appropriate. These applications could also be tied into a request by a transmitter to switch from a fixed rate adjusted only in a rate proceeding to a formula rate that is updated annually. Between 2006 and 2012, the FERC reviewed more than 80 applications for transmission incentives related to proposed projects.

B.4 Insights from Incentive Power Research

PEG Research has for many years undertaken research on the incentive power of alternative regulatory systems. The work has been sponsored by numerous utilities and regulatory agencies,

[22] Energy Policy Act of 2005, Title XII, Sec. 1241 (b).

including the OEB, two Canadian gas distributors, and the Essential Services Commission in the Australian state of Victoria. Incentive power research can be used to explore IRM design options such as plan terms and earnings sharing mechanisms. Our research in this area was for several years spearheaded by Travis Johnson, a graduate of the Massachusetts Institute of Technology and Stanford Business School who is now a professor at the University of Texas.

This Appendix section first presents a non-technical discussion of the methods used in our incentive power research. We then discuss some pertinent research results.

Overview of Research Program

At the heart of our research is a mathematical optimization model of the cost management of a company subject to rate regulation. We consider a company facing business conditions that resemble those of a typical energy distributor. In the first year of the decision problem, the total annual cost of the company's base rate inputs is around $500 million for a company of average efficiency. Capital accounts for a little more than half of this cost. The annual depreciation rate is 5%, the weighted average cost of capital is 7%, and the income tax rate is 30%.[23]

Some assumptions are made to simplify the analysis. There is no inflation or output growth that would cause cost to grow over time. Under these assumptions, the utility's revenue will be the same year after year in the absence of a rate case. There is thus no need for complicated adjustments in rate cases to the costs incurred in historical reference years or for attrition relief mechanisms between rate cases.

The company is assumed to have opportunities to reduce its cost of service through cost reduction effort. Two kinds of cost reduction projects are available. Projects of the first type lead to temporary (specifically, one year) cost reductions. Projects of the second type involve a net cost increase in the first year in exchange for *sustained* reductions in future costs. Projects in this category vary in their payback periods. The payback periods we consider are one year, three years, and five years, respectively. For projects of each kind, there are diminishing returns to additional cost reduction effort in a given year. In total, we currently consider eight kinds of projects, four for OM&A expenses and four for capex. The company is permitted to pass up each kind of project in a given year but cannot

[23] The comparatively low WACC reflects our assumption that there is no input price inflation.

choose *negative* levels of effort that amount, essentially, to deliberate waste. This is tantamount to assuming that deliberate waste is recognized by the regulator and disallowed.

Companies can increase earnings by undertaking cost containment projects, but the company experiences employee distress and other *unaccountable* costs when pursuing such projects. These costs are assumed for simplicity to occur up front. We have assigned these a value, in the reckonings of employees, that is about one quarter the size of the *accountable* upfront costs.

The company is assumed to choose the cost containment strategy that maximizes the net present value of earnings in a given year, less the distress costs of performance improvement, given the regulatory system, the income tax rate, and the available cost reduction opportunities. We are interested in examining how the company's cost management strategy differs under alternative regulatory systems.

Regulatory Systems

Regarding the regulatory systems considered, we have developed five "reference" systems that constitute useful comparators for multiyear rate plans. One is "cost plus" regulation, in which a company's revenue is exactly equal to its cost. Another is a full externalization of rates, such as might obtain if the company were to embark on a permanent revenue cap regime with no prospect for future cost-based revenue requirement true-ups.

The other three reference regimes try to approximate traditional regulation. In each, there is a predictable rate case cycle. We consider rate case cycles of one, two, and three years.

Various multiyear rate plans can be considered using our research method. All are revenue cap plans. The plans differ with respect to three kinds of plan provisions. One is the term of the plan. We consider terms of five, six, and ten years. There is no stretch factor shaving the revenue requirement mechanistically from year to year.

Plans considered vary, secondly, with respect to the earnings sharing specification. We consider earnings sharing mechanisms that have various company/customer allocations of earnings variances. Company shares considered are 0%, 25%, 50%, and 75%. We will refer to a rate plan that lacks an earnings sharing mechanism as a "basic" rate plan. None of the mechanisms considered have dead bands, as these complicate the calculations. This limits the relevance of the results since many approved mechanisms do have dead bands. An ESM with a 25% company share may generate performance incentives similar to those of a real-world ESM with a dead band.

Our characterization of the rate case is important in modeling both traditional regulation and the MRP regimes. We assume in most runs that rates in the initial year of the new regulatory cycle are, with one qualification, set to reflect the cost of service in the last year of the previous regulatory cycle. The qualification is that any up-front *accountable* costs of initiatives for sustainable cost reductions that are undertaken in the historical reference year are amortized over the term of the plan. This reduces the incentive for the utility to time cost reduction projects to occur in the reference year.

We have also considered the impact of some stylized efficiency carryover mechanisms. In one mechanism the revenue requirement at the start of a new plan is based α% on the cost in the last year of the previous plan and (1-α)% on the revenue requirement in that year. This effectively permits the company to share (1-α)% of any deviation between its cost and the revenue requirement. We consider alternative values of α, ranging from 90% to 50%. [Thus, the externalized share ranges from 10% to 50%].

We also considered an efficiency carryover mechanism in which the revenue requirement in the first year of a new rate plan is adjusted for a percentage of the variance resulting from a benchmarking appraisal that is completely unrelated to past revenue requirements. We suppose that

$$Requirement_t = Cost_{t-1} + Carryover_{t-1}$$

where the carryover is α% of the difference between a benchmark for cost in period t-1 and the actual cost that was incurred.

$$Carryover_t = \alpha \text{ x } (Benchmark_{t-1} - Cost_{t-1})$$

Then

$$Requirement_t = Cost_{t-1} + \alpha \text{ x } (Benchmark_{t-1} - Cost_{t-1})$$

$$= \alpha \text{ x } Benchmark_{t-1} + (1-\alpha) \text{ x } Cost_{t-1}$$

The revenue requirement for the first year of the new PBR plan thus depends only (1-α)% on the cost of service in year t-1. The same result can be achieved by positing that the revenue requirement in year t is based 50/50 on the cost and the benchmark in year t-1.

We have also considered a novel approach to incenting long-term efficiency gains which we will call the "revenue option" approach. It gives the company the option to trade a revenue requirement, for the first year of the next rate plan, which is established by conventional means for a revenue requirement that is established on the basis of a predetermined formula. The formula that we consider is a stretch factor reduction in the revenue requirement that is established in the first year of the preceding rate case.[24]

Another decision that must be made in comparing alternative regulatory systems is what occurs at the conclusion of a plan. Our view is that the best way to compare the merits of alternative systems is to have them repeat themselves numerous times. For example, we examine the incentive impact of five-year plan terms by examining the cost containment strategy of a company faced with the prospect of a lengthy series of five-year plans.

Identifying the Optimal Strategy

Numerical analysis was used to predict the utility's optimal strategy. Under this approach we considered, for each regulatory system and each kind of cost containment initiative, thousands of different possible responses by the company. We chose as the predicted strategy the one yielding the highest value for the utility's objective function.

One advantage of numerical analysis in this application is that it permits us to consider regulatory systems of considerable realism. Another is that it facilitates review of our research by stakeholders. The numerical analysis is intuitively appealing, and verification can focus less on how results are derived and more on how sensible and thorough is our characterization of cost containment opportunities and alternative regulatory systems.

Research Results

Some results of our incentive power research are found in Tables B1-B3. For each of several hypothetical regulatory systems, each table shows the net present value of cost reductions from the operation of the system over many years. In the columns on the right-hand side of the table we report

[24] In a world of input price and output growth, a more complex formula would be required.

the average percentage reduction in the company's total cost that results from the regulatory system. We report outcomes for the first and second plans and the long run and discuss here only the long run results.

Results are presented for 10%, 30% and 50% levels of initial operating efficiency. We focus here on the 30% results since our statistical benchmarking research over the years suggests that this is a normal level of operating efficiency. The 30% results can be found in Table B1.

Results for Reference Regulatory Systems

Inspecting the results for the reference regulatory systems, it can be seen that no cost reduction initiatives are undertaken under true cost plus regulation. This reflects the fact that there is no monetary reward for undertaking these initiatives, all of which involve some kind of cost. At the other extreme, a complete externalization of future rates produces performance improvements relative to cost plus regulation that, over many years, accumulate to an NPV of more than $2 billion.

As for the traditional regulatory systems, U.S. electric utilities typically file a rate case every three years. Table B1 shows that a three-year rate case cycle incents the company to achieve long-run savings with an NPV of about $899 million ---a major improvement over cost plus regulation but less than half of those that are potentially available. Average annual productivity gains rise from 0% to 0.90%. The fact that some cost savings occur under traditional regulation isn't surprising inasmuch as a three-year regulatory cycle permits some gains to be reaped from temporary cost reduction opportunities and from projects to achieve more lasting efficiencies which have shorter payback periods.

Impact of Plan Term

Consider now the effect of extending the plan term beyond the three-year rate case cycle. It can be seen that extending the term from three years to the five-year cycle that is typical in Ontario substantially increases the net present value of cost savings. In the absence of earnings sharing, the average annual performance gain increases by 51 basis points in the longer run. Half of this figure is about 25 basis points.

Table B1
Results from the Incentive Power Model

30% initial inefficiency	**Net Present Value ($m) of Cost Redutions**	**Relative Incentive Power**	**Average Annual Performance Gain*** First two rate cycles	**Average Annual Performance Gain*** Long run
Reference Regulatory Options				
Cost plus	0	**0%**	0.00%	0.00%
2 Year Cost of Service	657	**29%**	1.19%	0.66%
3 Year Cost of Service	899	**39%**	1.22%	0.90%
Full Rate Externalization	2299	**100%**	3.93%	2.71%
Impact of Plan Term				
Term = 3 years	899	**39%**	1.22%	0.90%
Term = 5 years	1318	**57%**	1.93%	1.41%
Term = 6 years	1428	**62%**	1.96%	1.58%
Term = 10 years	1664	**72%**	2.35%	2.23%
Impact of Earnings Sharing Mechanism				
5-year plans				
No Sharing	1318	**57%**	1.93%	1.41%
Company Share = 75%	1075	**47%**	1.29%	1.17%
Company Share = 50%	966	**42%**	1.14%	1.01%
Company Share = 25%	879	**38%**	1.03%	0.88%
Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)				
3-Year Plans, Extern				
Externalized Percentage = 0%	899	**39%**	1.93%	0.90%
Externalized Percentage = 10%	990	**43%**	1.29%	1.07%
Externalized Percentage = 25%	1336	**58%**	1.80%	1.66%
Externalized Percentage = 50%	1799	**78%**	3.41%	2.15%
5-Year Plans, Extern				
Externalized Percentage = 0%	1318	**57%**	1.93%	1.41%
Externalized Percentage = 10%	1469	**64%**	2.07%	1.55%
Externalized Percentage = 25%	1598	**70%**	2.30%	1.76%
Externalized Percentage = 50%	1989	**86%**	3.00%	2.27%
Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)				
3-Year Plans				
Externalized Percentage = 0%	899	**39%**	1.93%	0.90%
Externalized Percentage = 10%	1535	**67%**	2.26%	1.93%
Externalized Percentage = 25%	1824	**79%**	3.68%	2.29%
Externalized Percentage = 50%	2016	**88%**	3.84%	2.54%
5-Year Plans				
Externalized Percentage = 0%	1318	**57%**	1.93%	1.41%
Externalized Percentage = 10%	1621	**70%**	2.34%	1.80%
Externalized Percentage = 25%	1908	**83%**	3.08%	2.31%
Externalized Percentage = 50%	2109	**92%**	3.57%	2.56%
Rate Option Plans				
3-Year Plans				
No rate option	899	**39%**	1.93%	0.90%
Yearly rate reduction = 1%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 1.5%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2.5%	899	**39%**	1.93%	0.90%
5-Year Plans				
No rate option	1318	**57%**	1.93%	1.41%
Yearly rate reduction = 1%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 1.5%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2%	1318	**57%**	1.93%	1.41%
Yearly rate reduction = 2.5%	1318	**57%**	1.93%	1.41%

*** = measured by the average year-over-year percent decrease in costs**

Table B2
Results from the Incentive Power Model

10% initial inefficiency	**Net Present Value ($m) of Cost Redutions**	**Relative Incentive Power**	**Average Annual Performance Gain***	
			First two rate cycles	Long run
Reference Regulatory Options				
Cost plus	0	**0%**	0.00%	0.00%
2 Year Cost of Service	436	**29%**	1.08%	0.57%
3 Year Cost of Service	623	**42%**	1.02%	0.76%
Full Rate Externalization	1496	**100%**	2.64%	2.32%
Impact of Plan Term				
Term = 3 years	623	**42%**	1.02%	0.76%
Term = 5 years	811	**54%**	1.10%	1.15%
Term = 6 years	976	**65%**	1.19%	1.30%
Term = 10 years	1088	**73%**	1.48%	1.73%
Impact of Earnings Sharing Mechanism				
5-year plans				
No Sharing	811	**54%**	1.10%	1.15%
Company Share = 75%	723	**48%**	0.97%	0.97%
Company Share = 50%	653	**44%**	0.87%	0.84%
Company Share = 25%	602	**40%**	0.83%	0.73%
Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)				
3-Year Plans, Extern				
Externalized Percentage = 0%	623	**42%**	1.02%	0.76%
Externalized Percentage = 10%	672	**45%**	1.09%	0.87%
Externalized Percentage = 25%	887	**59%**	1.32%	1.36%
Externalized Percentage = 50%	1123	**75%**	1.87%	1.80%
5-Year Plans, Extern				
Externalized Percentage = 0%	811	**54%**	1.10%	1.15%
Externalized Percentage = 10%	932	**62%**	1.20%	1.27%
Externalized Percentage = 25%	1025	**69%**	1.36%	1.47%
Externalized Percentage = 50%	1239	**83%**	1.91%	1.90%
Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)				
3-Year Plans				
Externalized Percentage = 0%	623	**42%**	1.02%	0.76%
Externalized Percentage = 10%	1037	**69%**	1.65%	1.64%
Externalized Percentage = 25%	1182	**79%**	2.08%	1.94%
Externalized Percentage = 50%	1253	**84%**	2.48%	2.16%
5-Year Plans				
Externalized Percentage = 0%	811	**54%**	1.10%	1.15%
Externalized Percentage = 10%	1033	**69%**	1.42%	1.42%
Externalized Percentage = 25%	1229	**82%**	1.97%	1.83%
Externalized Percentage = 50%	1280	**86%**	2.41%	2.26%
Rate Option Plans				
3-Year Plans				
No rate option	623	**42%**	1.02%	0.76%
Yearly rate reduction = 1%	1496	**100%**	3.93%	2.71%
Yearly rate reduction = 1.5%	1496	**100%**	3.93%	2.71%
Yearly rate reduction = 2%	623	**42%**	1.02%	0.76%
Yearly rate reduction = 2.5%	623	**42%**	1.02%	0.76%
5-Year Plans				
No rate option	811	**54%**	1.10%	1.15%
Yearly rate reduction = 1%	1496	**100%**	2.64%	2.32%
Yearly rate reduction = 1.5%	811	**54%**	1.10%	1.15%
Yearly rate reduction = 2%	811	**54%**	1.10%	1.15%
Yearly rate reduction = 2.5%	811	**54%**	1.10%	1.15%

*** = measured by the average year-over-year percent decrease in costs**

Table B3
Results from the Incentive Power Model

50% initial inefficiency	Net Present Value ($m) of Cost Redutions	Relative Incentive Power	Average Annual Performance Gain*	
			First two rate cycles	Long run
Reference Regulatory Options				
Cost plus	0	**0%**	0.00%	0.00%
2 Year Cost of Service	905	**30%**	1.33%	0.75%
3 Year Cost of Service	1430	**47%**	2.36%	1.05%
Full Rate Externalization	3022	**100%**	4.75%	3.05%
Impact of Plan Term				
Term = 3 years	1430	**47%**	2.36%	1.05%
Term = 5 years	1778	**59%**	2.29%	1.65%
Term = 6 years	2143	**71%**	2.37%	1.82%
Term = 10 years	2520	**83%**	3.29%	2.42%
Impact of Earnings Sharing Mechanism				
5-year plans				
No Sharing	1778	**59%**	2.29%	1.65%
Company Share = 75%	1603	**53%**	2.06%	1.36%
Company Share = 50%	1520	**50%**	1.96%	1.22%
Company Share = 25%	1354	**45%**	1.75%	1.02%
Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)				
3-Year Plans, Extern				
Externalized Percentage = 0%	1430	**47%**	2.36%	1.05%
Externalized Percentage = 10%	1551	**51%**	2.48%	1.21%
Externalized Percentage = 25%	2017	**67%**	3.17%	1.90%
Externalized Percentage = 50%	2481	**82%**	4.08%	2.42%
5-Year Plans, Extern				
Externalized Percentage = 0%	1778	**59%**	2.29%	1.65%
Externalized Percentage = 10%	1979	**65%**	2.52%	1.81%
Externalized Percentage = 25%	2279	**75%**	2.75%	2.02%
Externalized Percentage = 50%	2666	**88%**	3.68%	2.60%
Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)				
3-Year Plans				
Externalized Percentage = 0%	1430	**47%**	2.36%	1.05%
Externalized Percentage = 10%	2202	**73%**	3.58%	2.20%
Externalized Percentage = 25%	2531	**84%**	4.30%	2.61%
Externalized Percentage = 50%	2793	**92%**	4.61%	2.84%
5-Year Plans				
Externalized Percentage = 0%	1778	**59%**	2.29%	1.65%
Externalized Percentage = 10%	2309	**76%**	2.81%	2.04%
Externalized Percentage = 25%	2558	**85%**	3.68%	2.54%
Externalized Percentage = 50%	2880	**95%**	4.35%	2.88%
Rate Option Plans				
3-Year Plans				
No rate option	1430	**47%**	2.36%	1.05%
Yearly rate reduction = 1%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 1.5%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2.5%	3022	**100%**	4.75%	3.05%
5-Year Plans				
No rate option	1778	**59%**	2.29%	1.65%
Yearly rate reduction = 1%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 1.5%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2.5%	1778	**59%**	2.29%	1.65%

*** = measured by the average year-over-year percent decrease in costs**

Impact of Earnings Sharing

With respect to earnings sharing note first that, in plans of a given duration, the addition of earnings sharing mechanisms reduces cost savings modestly compared to a plan of the same duration with no sharing mechanism. For example, in plans with a five-year term, the addition of an earnings sharing mechanism with a 75% company share reduces average annual performance gains by 24 basis points in the longer run. The lower is the company's share of earnings variances, the lower are cost savings. However, plans of longer duration that *have* an earnings sharing mechanism can deliver more cost savings than shorter rate case cycles and no earnings sharing.

Implications for the Hydro One SSM Stretch Factor

Let's consider, now, the implications of our incentive power research for the choice of an X factor for Hydro One SSM. Hydro One SSM is proposing a multiyear rate plan with a lengthy eight-year term. In years 6-10 of the plan, a mechanism would share surplus earnings when the ROE exceeds 300 basis points. There is thus little mechanistic earnings sharing envisioned. Many of the utilities in our U.S. productivity sample, meanwhile, operated under formula rate plans.

Table B1 shows that, for utilities operating under MRPs with six- and ten-year terms, average annual performance gains are 1.58% and 2.23% respectively. The 1.91% average of these is a reasonable estimate of average annual performance gains under an eight-year MRP.

Consider, now, that average annual performance gains are 0.00% under cost plus regulation and 0.90% under cost of service regulation with rate cases held every three years. If we assume that half of the productivity growth observations in PSE's 2005-2016 sample period were for utilities operating under formula rates and the rest sought rate cases every three years on average, our incentive power model suggests that the average annual expected performance gain from the plan is 0.50 x (1.91 - .90) = 1.01. Half of this is 0.50. The explicit stretch factor for a utility of average efficiency should thus lie in the [**0.50** – **1.01**] range if the U.S. MFP trend from 2005-16 provides the basis for the base productivity trend in Hydro One SSM's revenue cap index. Moreover, this analysis does not consider the adverse incentive impact of other FERC policies such as ROE premia.

B.5 PEG Credentials

PEG is an economic consulting firm with headquarters in Madison, Wisconsin USA. We are a leading consultancy on incentive regulation and statistical research on the performance of gas and electric utilities. Our personnel have over sixty years of experience in these fields, which share a common foundation in economic statistics. IRM design and the measurement of utility cost performance are company specialties. Work for a mix of utilities, regulators, government agencies, and consumer and environmental organizations has given us a reputation for objectivity and dedication to good research methods. Our practice is international in scope and has included dozens of projects in Canada.

Mark Newton Lowry, the senior author and principal investigator for this project, is the President of PEG. He has over thirty years of experience as an industry economist, most of which have been spent addressing utility issues. He has prepared productivity research and testimony in more than 30 separate proceedings. Author of dozens of professional publications, Dr. Lowry has chaired numerous conferences on performance measurement and utility regulation. In the last five years, he has played a prominent role in IR proceedings in Alberta, British Columbia, Colorado, Hawaii, Minnesota, and Quebec as well as Ontario. He holds a PhD in applied economics from the University of Wisconsin.

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IRM Design for

Hydro One Networks, Inc.

April 13, 2018

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1. Introduction and Summary

1.1. Introduction

Hydro One Networks, Inc. ("Hydro One" or "the Company") filed a Custom Incentive Rate-setting ("Custom IR") application for its power distributor services on March 31, 2017. Escalation of the proposed revenue cap index is slowed by an X factor. The Company retained Mr. Steven Fenrick of Power Systems Engineering ("PSE") to prepare productivity and econometric benchmarking research and testimony in support the proposed X factor. PSE reported a total factor productivity ("TFP") trend of -1.4% for Hydro One over the 2003-2015 period and an average trend of -0.91% over this period for a broader sample of Ontario power distributors. Hydro One also commissioned unit cost benchmarking studies addressing various Company programs such as pole replacement, substation refurbishment, and vegetation management. The application was updated on June 7, 2017, including updated analyses by PSE.[1]

Hydro One is Ontario's largest power distributor. This increases the payoff from careful appraisal of its Custom IR proposal and supportive statistical cost research. Controversial technical work and IR provisions should be identified and, where warranted, challenged to avoid undesirable precedents for Hydro One and other Ontario utilities in the future. The Ontario Energy Board ("OEB") has commented on productivity and benchmarking methods in past IRM proceedings for all rate-regulated utility sectors.

OEB Staff retained Pacific Economics Group Research LLC ("PEG") to appraise and comment on the productivity and benchmarking research and testimony and if necessary prepare alternative studies. We were also asked to appraise and comment on aspects of the Company's Custom IR proposal. This is the report on our work.

The plan for our report is as follows. We begin by providing pertinent background information. There follow critiques of PSE's productivity and benchmarking evidence and the presentation of some results using alternative methods. We conclude by discussing other features of Hydro One's Custom IR proposal. An Appendix addresses some of the more technical issues in more detail.

---

[1] Further updates to the application were filed in October and December 2017, although these did not affect PSE's evidence or Hydro One's proposed rate adjustment plan.

1.2. Summary

Hydro One has proposed a Custom IRM that features a revenue cap index ("RCI") featuring a 0% Custom Industry Total Factor Productivity Measure and a 0.45% Custom Productivity Stretch Factor. These proposals are supported by TFP trend and total cost benchmarking evidence prepared by PSE. PSE also attempted to update PEG's calculations for the Board, in the fourth generation IRM ("4th Generation IRM") proceeding, of the TFP trend of Ontario's power distribution industry. PSE calculated the TFP trend of Hydro One using an American Handy Whitman construction cost index.

Since this filing is being made towards the end of OEB's 4th Generation IRM plan, PEG understands the Company's (and the OEB's) interest in investigating whether productivity trends of Ontario power distributors have changed in recent years. In measuring the TFP of Hydro One and other distributors, a key issue is how to replace the Electric Utility Construction Price Index ("EUCPI") that Statistics Canada no longer calculates. Mr. Fenrick is a former employee of PEG and his methods are more similar to ours than those of some other productivity witnesses in recent IR proceedings.

PEG nonetheless disagrees with some of the methods PSE used in its productivity research. Here are our biggest concerns.

- We do not recommend using an American Handy Whitman index as the new asset price deflator in Ontario, preferring instead the implicit capital stock deflator for the Canadian utility sector. When our preferred deflator is used, Hydro One's recent historical TFP growth is found to be much slower.
- A study of the TFP trends of Ontario power distributors must control for their transition to International Financial Reporting Standards ("IFRS").
- PSE improperly updated the TFP indexes we developed for the OEB for 4th Generation IRM with respect to metering costs and contributions in aid of construction.
- The TFP indexes developed in 4th Generation IRM are due for methodological upgrades. In addition to a new asset price deflator, a new labor price index should be considered. A different output index is needed to calibrate the X factor of Hydro One's revenue cap index.

Our research using alternative methods suggests that Ontario's recent power distribution TFP trend is fairly close to zero. Growth in the productivity of operation, maintenance, and administration ("OM&A") inputs of Ontario distributors has been more brisk than growth in the productivity of capital inputs. The available evidence suggests that the 0.0% base TFP growth trend established in 4th Generation IRM is still reasonable.

PEG also has reservations about some of the methods PSE used in its benchmarking work. However, our alternative benchmarking runs with methods we prefer produced a similar benchmarking assessment. The total cost forecasting model we developed for 4th Generation IRM suggests Hydro One's cost was about 33% above the benchmark, on average from 2014-2016, but was improving, reaching 25.73% in 2016. Using our adaptations to PSE's model, we found that their performance continued to improve in 2017 and 2018. Hydro One's forecasted/proposed cost for the 2019-2022 period is 23.0% above the benchmarks. However, Hydro One has an incentive to understate its OM&A cost growth in the years after 2018.

On this basis, a 0.45% stretch factor seems reasonable for Hydro One provided that the Board is comfortable fixing the stretch factor for the full plan term. Combined with the recommended 0% base X factor, this would give a combined X factor of 0.45%. The RCI formula would then be growth IPI - 0.45% for the annual adjustment of OM&A, net of Z factors or of any growth factor as discussed below.

The Custom IR plan proposed by Hydro One is, in several respects, uncontroversial. The design is similar to that of the Custom IR which the Board approved for Toronto Hydro in EB-2014-0016. The revenue cap index escalates OM&A revenue, strengthening the Company's performance incentives and avoiding the need for an OM&A cost forecast. An earnings sharing mechanism would asymmetrically share with customers only surplus earnings outside a deadband. A capital in service variance account ("CSVA") would asymmetrically share with customers some capex underspends but not overspends. A Custom Capital Factor ensures recovery of proposed/forecasted capital cost in each year of the plan, but this cost is reduced by the 0.45% stretch factor.

We are nonetheless concerned about some features of Hydro One's proposal. Here are some of our concerns and suggested alternative plan provisions.

- The proposed ratemaking treatment of capital cost is problematic. The C factor would incent Hydro One to exaggerate its need for supplemental revenue, and substantially raises regulatory cost for the OEB and stakeholders. The Company is perversely incented to spend excessive amounts on capital to contain OM&A expenses. The kinds of capex accorded C factor treatment are similar to those incurred by distributors in the productivity studies. The RCI would effectively apply chiefly to revenue for OM&A expenses and provide only a floor for revenue growth even though it is designed to play neither of these roles. We discuss several possible upgrades to the capital cost treatment and conclude that a materiality threshold and dead zone should be added to the C factor mechanism.

- Revenue cap indexes in approved IRMs usually have an escalator for growth in the utility's output. Hydro One's proposed RCI does not. We recommend a customer growth escalator.
- The addition of revenue decoupling to the plan has merit but makes less sense if the LRAM continues.
- With pension and benefit expenses addressed by DVAs, Hydro One has a weak incentive to contain these expenses. This raises oversight costs. Many utilities operating under IRMs do not have DVAs for these costs. Incentive for Hydro One to contain pension and other benefit expenses can be strengthened by adding a materiality threshold and dead zone to the DVA mechanism.

1.3. Credentials

PEG is an economic consulting firm with home offices in Madison, Wisconsin USA. We are a leading consultancy on IR and the measurement of energy utility performance. Our personnel have over sixty years of experience in these fields, which share a common foundation in economic statistics. The University of Wisconsin has trained most of our staff and is renowned for its economic statistics program. Work for a mix of utilities, regulators, government agencies, and consumer and environmental organizations has given PEG a reputation for objectivity and dedication to good research methods. Our practice is international in scope and has included dozens of projects in Canada.

Mark Newton Lowry is the President of PEG. He has over thirty years of experience as an industry economist, most spent on utility issues. Author of numerous professional publications, Dr. Lowry has also chaired several conferences on performance measurement and utility regulation. He has provided productivity research and testimony in over 30 proceedings. His latest study on the productivity tends of US power distributors was published in 2017 by Lawrence Berkeley National

Laboratory ("Berkeley Lab").[2] He has played a prominent role in IR proceedings in Alberta, British Columbia, and Québec as well as Ontario. Dr. Lowry holds a PhD in applied economics from the University of Wisconsin.

[2] Mark Newton Lowry, Matt Makos, and Jeff Deason, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, Lawrence Berkeley National Laboratory, July 2017.

2. Background

Hydro One's proposed Custom IR plan is similar to that which the Board approved in 2015 for Toronto Hydro.[3] The term would be the five years from 2018 to 2022. A revenue cap index applicable to years 2019-2022 would feature two inflation measures: Canada's gross domestic product implicit price index for final domestic demand ("$GDPIPIFDD^{Canada}$") and the average weekly earnings for all businesses in Ontario ("$AWE^{Ontario}$"). The RCI would also have a 0% Custom Industry Total Factor Productivity Measure and a 0.45% Custom Productivity Stretch Factor. Several costs would be addressed by deferral and variance accounts ("DVAs"), including pension and other benefit expenses. A lost revenue adjustment mechanism ("LRAM") would expedite compensation for load losses due to conservation and demand management ("CDM") programs.

A Custom Capital Factor (aka "C Factor") averaging about 2% per year would supplement revenue growth to correct for the Company's expectation that the RCI would otherwise undercompensate it for growth in its capital revenue requirement. The capital revenue requirement would be based on forecasted/proposed cost but adjusted downward for the 0.45% stretch factor.

An asymmetrical earnings-sharing mechanism ("ESM") would share only surplus earnings. An asymmetrical capital in-service variance account ("CSVA") would reduce rates for the bulk of any plant addition underspends. Verifiable productivity gains would be excluded from the CSVA pass-through. In response to Staff interrogatory 123(b), the Company explained that

> Hydro One's productivity governance and associated reporting processes are maintained by Finance. Hydro One has implemented a robust governance structure around productivity reporting to ensure productivity savings are accurately reflected on corporate scorecards and that there is continuity of savings in the Business Plan.
>
> **All productivity initiatives are approved by Finance prior to reporting any actual savings on corporate scorecards and are audited for compliance throughout the year. Approval by Finance ensures that each initiative is tracked using a detailed calculation methodology.**
>
> Finance reviews all productivity reporting to ensure each initiative meets the following criteria:
>
> - Consistently documented (detailed description/logic, identified systems/dependencies, clear calculation methodology/data source and reasonable exclusions/adjustments);
> - Auditable with an applicable baseline for reporting;

[3] EB-2014-0016

- **In line with Hydro One's definition of productivity ('hard' savings and not cost avoidance); and**
- Reviewed and approved by a VP or delegate.

Productivity achievement is reported to the Executive Leadership Team on a monthly basis and is included as a metric on Hydro One's Team Scorecard for management staff.[4] **[Emphasis added]**

[4] Exhibit I/Tab 25/Staff-123 b)

3. PSE Productivity Research

PSE calculated the total factor productivity trend of Hydro One over the 2003-2015 period.[5] It reported a -**1.4%** average annual growth rate (aka "trend") over the full sample period and a **-0.4%** trend in the five-year 2011-2015 period.[6] In response to an undertaking, PSE reported that Hydro One's productivity in the use of OM&A inputs averaged a 1.2% annual decline over the full sample period while capital productivity averaged a 1.5% decline. From 2011 to 2015, capital productivity growth averaged a 1.5% annual decline while O&M productivity growth grew at a brisk +2.0% annual pace.[7] In response to a data request, PSE also measured the TFP trend that is implicit in the Company's proposed cost of base rate inputs during the IRM. PSE reported that TFP will be about the same in 2022 as in 2015.[8]

Unexpectedly, PSE also calculated the TFP trend of a broader sample of Ontario distributors over the 2003-2015 period using a methodology similar to that which PEG used in its work for the Board to calibrate the X factor for 4th Generation IRM. PSE reported a **-0.91%** TFP trend over the full 2003-2015 sample period.[9] TFP declined substantially in all three years that PSE added to the sample.

PEG has reviewed PSE's direct evidence and working papers and has several concerns about the productivity research that PSE conducted. To facilitate the OEB's review of the complicated issues that arise in a productivity study, we highlight here our most serious concerns.

3.1. Asset Value Price Deflator

Power distributors use capital-intensive technologies, so the treatment of capital is a major issue when measuring their total factor productivity. TFP research in North America typically uses a "monetary" approach to capital cost and quantity measurement. Computation of capital quantity

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[5] The TFP indexes PSE calculated for this proceeding are more accurately described as "multifactor" productivity indexes since they track trends in several kinds of inputs but exclude other inputs such as the power and upstream transmission services purchased in the provision of merchant services.

[6] Fenrick, S., Power Systems Engineering (PSE), *Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry*, EB-2017-0049, Exhibit A-3-2, Attachment 1, March 31, 2017, p. 2.

[7] HONI_TC_Undertakings JT1.01-1.07, Undertaking JT 1.3, March 14, 2018, p. 10.

[8] HONI_IRR_B-Custom Application-Issues 7-16, Exhibit I/Tab 8/Staff-31b, February 12, 2018.

[9] Fenrick TFP Study, *op. cit.*, p. 4.

trends using monetary methods involves deflation of asset values that utilities report (e.g., their gross plant additions) using price indexes. Further discussion of monetary methods can be found in the Appendix.

PSE used an American Handy Whitman Electric Utility Construction Cost Index ("HWI") for power distribution in North Atlantic States to deflate Hydro One's asset values. They attempted to make this index more relevant to Canada by adjusting it for the trend in US/Canadian purchasing power parities ("PPPs") obtained from the Organization for Economic Cooperation and Development ("OECD"). However, like PEG in the 4th Generation IRM proceeding, PSE used Statistics Canada's Electric Utility Construction Price Index ("EUCPI") for distribution systems to perform the same function in its research on the TFP of other Ontario power distributors. This is to our knowledge the first time that an Ontario witness has proposed an alternative asset value price deflator in an energy utility productivity study. PSE's choice of an alternative deflator is an important empirical issue in this proceeding.

In response to an information request, PSE provided some criticisms of the EUCPI, including a statement that it didn't apply only to distribution (there were in fact EUCPI sub-indices calculated for "distribution systems" and "substations") and a concern that the EUCPI includes financing costs (there are versions without financing costs and the trends of these indexes are similar).[10]

The HWI has tended to grow much more rapidly than the EUCPI, so use of the HWI to deflate plant values should reduce measured capital quantity growth and accelerate TFP growth. In response to another information request, PSE reported that the TFP trend of the Company was a substantial 90 basis points slower (more negative) if the EUCPI was instead used as the asset value price deflator for the Company's productivity calculation.[11]

The appropriate asset price deflator to use in power distributor productivity research is an issue of growing importance in North American IR. One reason is that Statistics Canada stopped computing EUCPIs after 2014. We also believe that HWIs are due for a critical review.

Since, additionally, PSE used an HWI in its research, PEG has spent considerable time and effort in this project reviewing alternative asset price deflators. We found that HWIs and EUCPIs both have drawbacks. Both were designed many years ago and have some cost-share weights and inflation

[10] Exhibit I/Tab 10/SEC-17.

[11] Exhibit I/Tab 10/SEC-15.

subindexes that are now quite dated. The labor price component of the distribution system EUCPI has for many years grown quite slowly. However, trends in prices of labor and other construction inputs in the North Atlantic states, with their many large urban areas, may not be appropriate for Hydro One and other Ontario utilities.

Alternative asset price indexes are available. Based on our review, our professional opinion is that the most promising replacement for the EUCPI in Ontario productivity research is Statistics Canada's implicit price index for the capital stock of the Canadian utility sector.[12] This is readily computed from Statistics Canada's data on Flows and Stocks of Fixed Non-Residential Capital. This program measures trends in the quantities of various capital assets using a monetary method. Statistics Canada generates this dataset by gathering investment data from the Annual Capital Repair and Expenditures Survey. Mr. Fenrick stated at the technical conference that he did not consider alternative deflators in his work for this proceeding.[13]

3.2. Ontario Industry Productivity Research

PSE's -0.91% TFP trend estimate for the broader Ontario sample from 2003 to 2015 is disappointing if true and would imply that Hydro One's proposed revenue cap index contains a sizable implicit stretch factor. By way of contrast, we reported a **0.23%** trend in the TFP of US power distributors over the 2001-2014 period in our 2017 study for Berkeley Lab.[14] OEB Staff have not commissioned an updated study of productivity trends of power distributors since the 4th GIRM proceeding. Acknowledgment by the Board of a -0.91% trend in this proceeding could complicate a future proceeding on 5th Generation IRM for provincial power distributors.

There are, furthermore, reasons to doubt the accuracy of PSE's -0.91% trend estimate and its relevance for calibration of Hydro One's X factor. Here are some important grounds for concern that the -0.91% estimate may be too low. The biggest driver of the result was TFP declines in excess of 4% in 2012 and 2013. These were chiefly due to sharp declines in *OM&A* productivity. Over the full sample

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[12] Statistics Canada, Table 031-0005, Flows and Stocks of Fixed Non-Residential Capital, CANSIM. The implicit price index is calculated as the ratio of current value of net stock to the corresponding quantity index.

[13] Transcript, OEB, EB-2017-0049, HONI_Technical Conference_Day 1_20180301, p. 30, line 21 to p.31, line 1.

[14] Mark Newton Lowry, Matt Makos, and Jeff Deason, *op. cit.*, p. 6.4.

period, OM&A productivity growth averaged only -0.8% annually despite widespread installation in Ontario of automated metering infrastructure ("AMI") that should have cut OM&A costs.[15] Our Berkeley Lab study found that the OM&A productivity of US power distributors averaged 0.40% annual growth from 2001 to 2014 while capital productivity growth averaged 0.18%.

One reason for the negative OM&A productivity growth in Ontario in recent years which PSE reports has been the adoption by many distributors of new accounting standards. The OEB undertook the necessary work to determine how IFRS should be implemented and the result was a modified IFRS ("MIFRS"). The new standard affected a wide range of issues, but the most important item that impacts this productivity work is the treatment of capitalized overheads. Under Canadian GAAP, distributors were permitted to capitalize more costs than are permitted under IFRS. Not all distributors adopted MIFRS at the same time, and adoption often coincided with cost of service rate applications. Adoption of the OEB's revised capitalization policy sometimes predated full adoption of MIFRS. PSE noted, in response to a data request, that it did little work to gauge the impact of this conversion on productivity results.[16]

PSE used data from the OEB's total cost benchmarking program for its 2013-2015 Ontario productivity update even though these data include contributions in aid of construction ("CIAC") while those for the 4th Generation IRM productivity study did not. This will also tend to slow TFP growth artificially.

Average weekly earnings in Ontario were used in PSE's labor price index, as in PEG's 4th Generation IRM research. There are reasons to believe that this index is inexact. Trends in average weekly earnings are sensitive to trends in overtime and the composition of the labor force such as the share of employees working part-time. This creates aggregation bias in the measurement of labor price trends. A *fixed weighted* index of average hourly earnings of all employees in Ontario is available from Statistics Canada which is less biased.[17] We believe that this alternative labor price index should be used

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[15] Exhibit I, Tab 8, Staff-33.

[16] Exhibit I/Tab 8/Staff-27a.

[17] Statistics Canada. Table 281-0039 - Survey of Employment, Payrolls and Hours (SEPH), fixed weighted index of average hourly earnings for all employees, by North American Industry Classification System (NAICS), monthly (index, 2002=100), CANSIM (database).

in any future Ontario productivity research. This would be more accurate and incidentally grow more rapidly, modestly increasing OM&A and total factor productivity growth.

The output indexes that PEG developed in the 4th Generation IRM proceeding and PSE used in its calculations are multidimensional, and summarize trends in distributor delivery volumes, peak demand, and the number of customers served using cost elasticity weights drawn from our econometric total factor productivity research for the OEB. Growth in volumes and peak demand have been slowed considerably in Ontario by CDM programs encouraged by government policies. The recent growth in system use may well be slower and increase capacity utilization less than was expected when many facilities were built. It may take time for slower growth in system use to produce material distribution capex economies.[18]

We note in the Appendix that elasticity-based scale indexes are useful when the goal of productivity research is to measure cost efficiency trends. However, as Mr. Fenrick notes in his report, the output index developed in 4th GIRM excludes other pertinent measures of output which drive cost. He developed a scale index that also encompasses trends in reliability and safety and describes this work in his productivity report.[19] The enhanced scale index is used to compute “adjusted TFP” results for Hydro One which he discusses on pp. 36-39 of his report. PSE found that the addition of reliability and safety variables to the scale index accelerated the estimated TFP trend of Hydro One over the full sample period by a substantial 90 basis points. We believe that system capabilities that depend on smart grid facilities (e.g., the quality of metering and the ability of distribution systems to handle 2-way power flows) are also legitimate candidates for inclusion in an elasticity-weighted output index. Thus, the scale indexes Mr. Fenrick uses to measure the productivity trends of other Ontario distributors are not ideal for measuring cost efficiency trends.

It is also unclear how appropriate the unadjusted scale index is for an X factor calibration exercise. Hydro One proposes a *revenue* cap index. We explain in the Appendix that the X factors of RCIs are typically calibrated with productivity indexes that use the number of customers to measure output.

[18] It may, alternatively, be the case that many distributors have not trimmed capex to reflect lowered expectations of future system capacity utilization.

[19] Fenrick TFP Study, *op. cit.*, pp. 28-34.

Most other distributors in Ontario operate under *price* cap indexes. Scale indexes used in X factor calibration exercises for price caps should in principle be revenue-weighted. Usage variables sometime receive substantial weights in revenue-weighted indexes. However, Ontario power distributors are transitioning to more fully fixed rate designs for residential customers that cause revenue to be driven increasingly by customer growth. Ontario power distributors also have LRAMs to compensate them for load impacts of CDM programs. Thus, the scale indexes Mr. Fenrick uses to calculate productivity trends of Ontario power distributors may also be inappropriate for determining X factors in future price cap IRMs.

Some other concerns that we have about PSE's Ontario industry productivity research are also important but do not necessarily suggest a higher or lower Ontario TFP trend.

- The EUCPI must be replaced and our research suggests that it has grown too slowly in recent years. Alternative asset value deflators we are considering have grown quite a bit more rapidly than the EUCPI in *recent* years and this could slow recent TFP growth. However, the trend of these alternative indexes in *earlier* years (e.g., before 2002) also affects TFP growth. The net effect on TFP is an empirical issue that we address further below.
- Pension and other benefits expenses are included in PSE's calculations (as they were in PEG's 4th GIRM research), even though these expenses would be Y factored in Hydro One's proposal and Statistics Canada does not maintain a labor price index that includes pension and benefit expenses. It is difficult to properly remove these expenses from the data. One reason is that the OEB has never provided PEG with itemized data on these expenses from the RRR for the full sample period which would be needed to remove them from the study. We are also concerned that some distributors do not consistently itemize these expenses in their reports to the OEB.
- PEG's productivity work in the 4th Generation IRM proceeding excluded all costs of Ontario's extensive AMI buildout, which began in 2007 and ended in 2012. We adjusted reported metering expenses for 2007 and later years to remove those attributable to AMI. These expenses grew over time to constitute almost all metering OM&A expenses by 2012. PEG also removed all reported metering capex for 2007 and later years.

  PSE's productivity update, which started with 2013 data, included all metering and meter reading expenses, causing thereby an artificial surge in OM&A expenses. This is another reason for the plunge in OM&A and total factor productivity in that year. PSE also included all metering capex starting in 2013. Capital costs of AMI installed between 2007 and 2012 were, however, excluded from Mr. Fenrick's productivity research.

If not now, it will soon be time to incorporate the full cost of AMI into calculations of the productivity trends of Ontario power distributors. This complicated exercise is beyond the scope of this project. In any event, it is not clear what the *net* impact of this inclusion would be. Inclusion of AMI capex would accelerate the industry's capital quantity growth from 2007 to 2012, especially if the cost of the older meters is not removed as they were replaced. However, capital quantity growth would be slowed after 2012 if properly measured since the AMI assets, with their relatively short service lives, would briskly depreciate. Metering OM&A expenses would have a more positive trend were they included for all years, and this would also slow TFP growth. However, they would not surge in 2013 as they do in PSE's treatment. Output quantity growth would accelerate were the scale index revised to reflect improved metering capabilities.

- Exclusion of Haldimand and Woodstock from PSE's study of the Company's productivity means that the study does not reflect all distributor operations of Hydro One. The impact of this is not expected to be large.

3.3. Alternative Productivity Runs - Ontario

We did not undertake a full upgrade and update of our Ontario power distribution productivity work for this proceeding. Many issues are best resolved in the upcoming 5th Generation IRM proceeding. However, PEG has undertaken preliminary work to quantify the impact of some of the issues noted above. Starting with the results in the PSE working papers, we introduced adjustments step by step to test the robustness of PSE's productivity results.

Table 1 provides the estimated incremental and cumulative impact of our adjustments on the OM&A, capital, and total factor productivity trends of sampled Ontario distributors over the full 2003-2015 sample period. The table is divided into an area for adjustments and corrections for known inconsistencies with our previous work and another area for upgrades to the methods we used in the 4th Generation IRM proceeding.

Here is a list of adjustments and corrections that we made to PSE's calculations.

- Contributions in aid of construction were removed from data for 2013-2015.

- Smart meter OM&A and capital costs were also removed.

Table 1

Analysis of PSE's Ontario Productivity Study

	OM&A		Capital		TFP	
PSE Productivity Trend (2003-2015)		-0.83%		-0.96%		-0.91%
	Incremental Impact	Revised Trend	Incremental Impact	Revised Trend	Incremental Impact	Revised Trend
Adjustments and Corrections						
Data Comparability Issues						
CIAC	na	-0.83%	0.17%	-0.79%	0.09%	-0.82%
Smart Meter OM&A	0.21%	-0.62%	na	-0.79%	0.09%	-0.73%
Smart Meter Capital	na	-0.62%	0.08%	-0.71%	0.05%	-0.68%
Transition to IFRS Accounting Changes	0.82%	0.20%	na	-0.71%	0.35%	-0.33%
Sample and Merger Issues	-0.01%	0.19%	0.01%	-0.70%	0.00%	-0.33%
Exclude Norfolk	0.00%	0.20%	0.00%	-0.71%	0.00%	-0.33%
Include Lakeland/Parry	-0.01%	0.19%	0.01%	-0.70%	0.00%	-0.33%
Total Impact of Adjustments and Corrections [A]	**1.02%**	**0.19%**	**0.26%**	**-0.70%**	**0.58%**	**-0.33%**
Methodological Upgrades						
Labor Price Index [B]	0.12%	0.31%	na	-0.70%	0.05%	-0.29%
Asset Price Index: Replace EUCPI	na	0.31%	0.10%	-0.61%	0.04%	-0.25%
Use Utility Sector Capital Stock Deflator [D]	na	0.31%	0.10%	-0.61%	0.04%	-0.25%
Use Northeast HW index adjusted for PPP	na	0.31%	1.30%	0.60%	0.79%	0.51%
Output Quantity Adjustment	0.29%	0.61%	0.29%	-0.31%	0.29%	0.05%
Conservation adjustments to volumes and peaks	0.50%	0.81%	0.50%	-0.11%	0.50%	0.25%
Customer only index [C]	0.29%	0.61%	0.29%	-0.31%	0.29%	0.05%
Total Impact of Proposed Upgrades [E]=[B+C+D]	**0.42%**		**0.39%**		**0.38%**	
Total Impact of All Adjustments and Upgrades [A+E]	**1.44%**	**0.61%**	**0.65%**	**-0.31%**	**0.96%**	**0.05%**

- An adjustment was made for the transition to MIFRS accounting. We estimated the 2015 OM&A quantity in the absence of MIFRS transitions. Most companies that recently filed for rebasing have reported the amount by which their OM&A expenses were affected by MIFRS adoption. We were able to identify 14 distributors that clearly identified the impact. These companies as a group showed 12.5% higher OM&A expenses under MIFRS. We then attempted to identify distributors that had either adopted MIFRS by 2015 or indicated that they had previously changed their capitalization policy. We found that companies representing about 81% of OM&A cost had done so. As an adjustment, we therefore used an estimate of what the OM&A input quantity would have been in 2015 in the absence of MIFRS. Our 10.1% markdown is the product of a typical 12.5% reported increase in cost times 81% of costs affected by this issue.

- Adjustments were also made for two mergers.

Here is a list of the changes in our 4th Generation IRM methodology for measuring TFP which we considered.

- We replaced the AWE with the fixed-weight average hourly earnings in Ontario.
- We replaced the EUCPI in turn with two alternative deflators: the implicit price index for the capital stock of the utility sector from Statistics Canada and the Handy Whitman Index of Electric Utility Construction Costs for power distribution in the North Atlantic states.
- We considered replacing the elasticity-weighted output index developed for 4th Generation IRM with 1) the number of customers served and 2) an alternative elasticity-weighted index that includes CDM savings.

As can be seen in the above table, the impact of these issues on the TFP trends of Ontario power distributors varied in importance. Considering first the adjustments and corrections, the correction for the transition to IFRS accounting had the greatest impact. For the full sample period, the OM&A productivity trend accelerated by 82 basis points and the total factor productivity trend accelerated by 35 basis points. While based on valid concerns, adjustments for CIAC and the treatment of meters individually had smaller impacts on the TFP trend. Corrections for two mergers had very little impact. Taken together, all of these steps changed the estimated Ontario distributor TFP trend from -0.91% to -0.33% over the full sample period.

The impacts of the methodological upgrades on the TFP trend also varied. Use of the fixed-weighted labor price index for Ontario raised the OM&A productivity trend by 12 basis points and the TFP trend by five basis points.

Use of the implicit price deflator for the utility sector capital stock instead of the EUCPI raises the TFP trend by 4 basis points.[20] This leaves us at **-0.25%**. This is our best current estimate of the cost efficiency trend of Ontario power distributors. However, other drivers of cost such as reliability, safety, and metering capabilities are excluded from the analysis. If the number of customers were used to measure output, it can be seen that the output and TFP trends would be about 30 basis points higher.[21]

Taken together, our recommended methodological upgrades changed the Ontario TFP trend from -0.33% (after our corrections) to +0.05%, which is an increase of 0.38%. The +0.05% result is similar to the trend in the productivity of US power distributors over a similar period which we reported in our Berkeley Lab study. The total impact of corrections *and* improvements is to move the TFP trend from -0.91% to +0.05%, an increase of 96 basis points after rounding.

It is also interesting to compare the partial factor productivity indexes of OM&A inputs and capital. It can be seen that, after adjustments, corrections, and recommended methodological changes, the **+0.61%** growth trend in the OM&A productivity of Ontario distributors has been much more brisk than the **-0.31%** growth trend in the productivity of capital inputs. Our study for Berkeley Lab also found that the OM&A productivity growth of US power distributors exceeded their capital productivity growth, although by a smaller amount.

In summary, PSE's productivity evidence for Hydro One opens a complicated set of issues on how Ontario power distributor productivity research should be updated and methodologically improved. Our critique and alternative runs suggest that the TFP trend of Ontario power distributors has been much more rapid than -0.91%. However, finalization of many of these issues must await a future 5th GIRM proceeding. We recommend that the OEB not embrace PSE's -0.91% TFP trend estimate in this proceeding. The base TFP growth target of 0% that the Board established in 4th Generation IRM, and which Hydro One proposes, still seems reasonable pending more definitive research on Ontario industry TFP trends.

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[20] It can also be seen that a PPP-adjusted Handy Whitman Index would produce a much larger increase in the Ontario TFP trend, but we are not suggesting that this would be an improvement in the accuracy of the index. We note this result because PSE used a Handy Whitman Index in its Hydro One-specific productivity work.

[21] Adding the impact of CDM on system use had an even larger effect. According to the Ontario Ministry of Energy, the impact of conservation and load control programs has approximately doubled since the 2012 endpoint of the previous study. Should the MW and MWh be adjusted to add back the impact of these programs, the output and TFP trends would be approximately 0.50% higher than measured by PSE.

3.4. Alternative Productivity Runs – Hydro One

We also recalculated the productivity trends of Hydro One. We revised PSE's methodology to use the implicit price deflator for the utility sector capital stock and the fixed-weight average hourly earnings for Ontario. Results of this work are presented in Table 2. It can be seen that the Company's TFP growth declined at a 2.31% average annual growth rate over the full 2003-2015 sample period. This result is quite different from PSE's, and less favorable to Hydro One. Output grew at a sluggish 0.6% average annual rate while input growth averaged 2.9%. OM&A productivity averaged a 1.11% annual decline while capital productivity averaged a more substantial 3.03% annual decline. In the last five years of the sample Hydro One's TFP growth improved, averaging a 1.26% decline. OM&A productivity growth averaged 1.93% annually whereas capital productivity declined by a substantial 3.2% annually.

Table 2

Adjusted Hydro One Productivity Results

					Productivity					
	Input Quantity (PEG Upgrade)			Output	PEG Upgrade			PSE Methodology		
Year	Summary	OM&A	Capital	Quantity[fn]	TFP	OM&A	Capital	TFP	OM&A	Capital
2003	1.5%	-1.2%	3.2%	1.6%	0.1%	2.8%	-1.6%	0.4%	2.7%	-1.0%
2004	-0.8%	-6.3%	2.4%	0.7%	1.5%	7.0%	-1.6%	1.9%	7.2%	-0.9%
2005	3.4%	5.8%	2.0%	1.2%	-2.2%	-4.6%	-0.8%	-1.5%	-4.3%	0.0%
2006	6.1%	10.2%	3.6%	0.3%	-5.8%	-9.9%	-3.2%	-4.8%	-10.4%	-1.8%
2007	9.9%	16.2%	5.6%	1.0%	-9.0%	-15.3%	-4.6%	-7.2%	-15.3%	-2.4%
2008	0.6%	-4.6%	4.2%	0.6%	0.0%	5.2%	-3.6%	0.7%	4.6%	-1.6%
2009	5.0%	5.6%	4.6%	0.0%	-5.0%	-5.6%	-4.6%	-4.1%	-6.7%	-2.8%
2010	4.0%	4.2%	3.8%	0.4%	-3.5%	-3.7%	-3.4%	-2.3%	-3.8%	-1.6%
2011	1.4%	-1.2%	3.2%	0.5%	-1.0%	1.7%	-2.7%	-0.1%	1.5%	-1.0%
2012	0.2%	-4.0%	2.9%	0.5%	0.3%	4.5%	-2.4%	1.1%	4.5%	-0.7%
2013	6.3%	8.4%	4.8%	0.2%	-6.1%	-8.2%	-4.6%	-4.6%	-8.1%	-2.7%
2014	3.2%	3.7%	2.9%	0.0%	-3.2%	-3.7%	-2.9%	-2.1%	-3.5%	-1.4%
2015	-2.9%	-14.6%	4.0%	0.7%	3.6%	15.4%	-3.3%	3.9%	15.3%	-1.6%
2003-2015	**2.9%**	**1.7%**	**3.6%**	**0.6%**	**-2.31%**	**-1.11%**	**-3.03%**	**-1.45%**	**-1.25%**	**-1.49%**
2003-2010	**3.7%**	**3.7%**	**3.7%**	**0.7%**	**-2.97%**	**-3.00%**	**-2.93%**	**-2.12%**	**-3.25%**	**-1.51%**
2011-2015	**1.6%**	**-1.6%**	**3.6%**	**0.4%**	**-1.26%**	**1.93%**	**-3.20%**	**-0.36%**	**1.95%**	**-1.47%**

[fn] The output measure for these calculations was the multidimensional elasticity-weighted output index developed by PEG for the OEB in 4th GIRM.

4. Benchmarking Research

4.1. PSE's Total Cost Benchmarking

PSE also benchmarked the total cost of the Company's distribution base rate inputs. This study appraised Hydro One's historical costs over the 3-year 2014-16 period and its forecasted/proposed costs for the 2017-2022 period. An econometric cost model was used in the study with parameters PSE estimated using US data on power distributor operations of investor-owned utilities ("IOUs") and rural electric cooperatives ("RECs"). This model has a flexible translogarithmic ("translog") functional form that includes quadratic and interaction terms for the output variables.

PSE reported that Hydro One's cost was 24.7% above the model's prediction on average from 2014 to 2016. Its proposed costs during the years of the IRM were about 22.2% above the model's predictions on average. On this basis, and in conformance with the OEB 4th Generation IRM rules, Mr. Fenrick advocated and the Company embraced a fixed 0.45% stretch factor during the years of the plan. Cost performance would decline about 1.3% between 2018 and 2022.[22] Hydro One's component OM&A expenses, capital costs (e.g., depreciation and return on plant value), and capital *expenditures* ("capex") were not separately benchmarked.

We have a number of concerns about PSE's benchmarking study. We highlight first our biggest concerns to facilitate OEB review.

- PSE's benchmarking results are improved by an optimistic forecast of Hydro One's OM&A expenses. These expenses appear to have been forecasted using an inflation – 0.45% formula that includes no growth factor. In addition, the PSE work assumed OM&A input price growth of 2.26%. This would overstate future cost performance if the 2.26% figure is more rapid than the inflation assumption used to generate the cost forecast. It is noteworthy that Hydro One has an incentive to understate its OM&A cost growth for the out years of the IRM because this reduces the stretch factor under its proposal without affecting the base productivity trend or C factor.

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[22] Fenrick, S., Power Systems Engineering (PSE), *Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network*, Exhibit A-3-2, Attachment 2, June 7, 2017, p. 6.

- The challenge posed by low customer density is a major issue when benchmarking the cost of Hydro One. The customer density variable that PSE used is service territory area/customer.[23] Service territory area is difficult to calculate accurately. A threshold issue in these calculations is whether the territory is the area which the utility must *stand ready* to serve if demand arises or the (often much smaller) area it *actually* serves. The former approach is easier to implement but less accurate. In the technical conference, Mr. Fenrick stated that PSE took the former approach.[24] Hydro One's customer density is reported to be far lower than the average for the rural electric cooperatives in the sample. The service territory estimate for Hydro One exceeds the entire land area of Ontario. Alternative density variables are available. PEG used overhead line miles per customer as the density variable in a recent power distributor cost benchmarking study for Alberta's Utilities Consumer Advocate ("UCA").[25] The value of this variable will tend to be high for distributors serving rural areas and low for distributors serving urban areas.
- One cost *advantage* of a rural distributor is extensive overheading of facilities, which saves on capital cost. Our research indicates that distributors with extensive overheading tend to have lower capital cost and total cost. There is no overheading variable in PSE's model.
- The PSE benchmarking study is unusual for including data from numerous US regional electric cooperatives in the sample, yet it excludes data for Ontario distributors that serve rural areas (e.g., Algoma Power) and report their costs in Canadian currency. REC data do have some advantages in a study of the cost performance of Hydro One.
    - RECs typically have low customer density like Hydro One. Inclusion of REC data in the sample to that extent increases the precision of forecasts of the cost of Hydro One. REC data are particularly desirable for estimating the parameter of the cost model's density variable.
    - Data on peak loads of RECs may be better than those available for US IOUs.

The REC data also have noteworthy limitations. Three of these are especially important.

[23] Fenrick, Benchmarking Study, *op. cit*., p. 11.

[24] Transcript, Technical Conference, March 1, 2018, *op. cit.*, p.46, line 17-p.47, line 4.

[25] Pacific Economics Group Research (2018). *Benchmarking the Performance of Alberta Power Distributors*, for Utilities Consumer Advocate of Alberta, February 2018.

- RECs tend to be much smaller than Hydro One.
- REC data are publicly available only through 2011. Inclusion of REC data in the sample to that extent reduces the precision of the trend variable parameter and of cost forecasts for years after 2011. This makes these data less relevant for calculating cost benchmarks for Hydro One in future years. Five years from now, in a possible new benchmarking study, this limitation of REC data would loom even larger.
- Pension and other benefit expenses of RECs are not itemized, so it is necessary to include these expenses for all companies in the benchmarking study, even though itemized data on these expenses are available for Hydro One and the American IOUs. PEG usually excludes pension and other benefit expenses from its benchmarking studies (but did not exclude them from our 4th GIRM study) because they are sensitive to volatile external business conditions that are beyond the control of utility managers.[26] Additionally, Hydro One proposes continuation of existing DVAs for these expenses.[27] We mentioned above that Statistics Canada does not have a labor price index that includes pension and benefit expenses.[28]
- Mr. Fenrick noted during the technical conference that the processing of the REC data was a major cost of the project.[29]

Here are some less important but nonetheless notable REC data problems.

- As is the case for Hydro One (but not for the American IOUs), the OM&A salaries and wages of RECs are not itemized. This reduces the accuracy of the OM&A input price indexes that can be calculated for RECs and used in benchmarking.

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[26] One reason that we did not exclude these costs from our benchmarking study for 4th GIRM is that we did not believe that these had been properly itemized by all companies.

[27] HONI_Update_Ex_F_20170607, Exhibit F1/Tab 3/Schedule 1, p. 2.

[28] PSE addressed this problem by converting an employment cost index for *total* compensation that is obtained from the US Bureau of Labor Statistics (an index which *does* address benefits) to Canadian dollars using PPPs. An Ontario salary price index was, meanwhile, used in PSE's *productivity* research. See Fenrick TFP Study, *op. cit*., p. 21.

[29] Transcript, Technical Conference, March 1, 2018, *op. cit*., p. 50, lines 6-19.

  - RECs are not investor-owned and may therefore have less incentive to contain cost than IOUs.
  - RECs do not itemize net distribution plant value, so this must be estimated when computing the first year of the capital quantity index using crude formulas.

  In view of all these deficiencies, it is questionable whether inclusion of REC data in the sample and PSE's exclusion from the sample of data for Ontario distributors like Algoma Power which serve rural areas was worthwhile.

- PSE used a 2002 benchmark year to calculate the capital cost of *all* utilities in the econometric cost sample, even though the requisite capital data are available since 1989 for most Ontario utilities, since 1995 for US RECs, and since 1964 for major US IOUs. Since capital cost typically accounts for more than 60% of the total cost of distributor base rate inputs in PSE's study, this substantially reduces the accuracy of the benchmarking work. Mr. Fenrick stated at the technical conference that a common 2002 benchmark year was necessary to avoid "bias," but did not explain the expected character of such bias.[30] It is not clear why making research more accurate makes it more biased. In our benchmarking and productivity research for the OEB, PEG has always measured capital quantities starting in the earliest year for which data are available, even though these years vary amongst Ontario distributors. PSE used a mix of benchmark years in its industry productivity update to maintain consistency with PEG's 4th GIRM study.[31]
- As in the productivity research, PSE uses a Handy Whitman construction cost index converted to Canadian dollars.[32]

Here are some smaller concerns we have with PSE's benchmarking study. We do not believe that these problems had a major impact on benchmarking results on balance. However, future benchmarking studies, by Hydro One and other utilities, which steer clear of these problems will have more credibility.

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[30] Technical Conference Transcript Vol. 1, *op. cit.*, p. 50, line 24-p.54, line 5.

[31] Fenrick TFP Study, *op. cit*., p. 23.

[32] *Ibid.*, p.13.

- In the benchmark year, for all US utilities PSE calculated net *distribution* plant value as net *total* plant value multiplied by the share of total *gross* plant value which is distribution.[33] This is needlessly inaccurate since the requisite net distribution plant value data are available for the American IOUs in the sample.
- PSE uses peak demand data as a variable in the cost model. Available US data overstate distribution peak demand, since they can include the demand of a utility's wholesale customers. PSE did not adjust these data to make them more accurate. This made the performances of US distributors look better than they actually were.
- Fixed 70/30 weights were assigned to labor and material and service expenses in the OM&A price index for US utilities even though flexible weights are available for the American IOUs in the sample and a 70/30 split between labor and M&S isn't typical for these companies. Thus, the OM&A input price indexes for American distributors were needlessly inaccurate.
- The labor price levelization for Hydro One uses Ontario-wide data whereas levelization for all other utilities in the sample used labor prices specific to their service territories. The percentage of Hydro One distribution employees that work in large urban areas of Ontario where labor prices are highest is likely lower than the Ontario norm.
- The decision to take the logarithm of business condition variables was done inconsistently.
- No controls were made for large transfers of costs that some companies report between their transmission and distribution operations.[34] This compromises the accuracy of the capital cost estimates for these companies.
- Exclusion of Haldimand and Woodstock from the benchmarking study means that the study does not reflect all distribution operations of Hydro One. Haldimand has been a good performer in the Board's total cost benchmarking studies while Woodstock's performance has been similar to Hydro One's. The effect of these exclusions should not be large.
- PSE uses the US gross domestic product price index, converted to Canadian dollars using PPPs, as the material and services ("M&S") price index for HON. The Canadian GDPIPIFDD was

[33] *Ibid*., p.13.

[34] These transfers can go either way.

meanwhile used to deflate M&S expenses in PSE's research on the productivity of other Ontario power distributors.

PEG's recently completed benchmarking study for the UCA provides the Board with an alternative notion of how a transnational benchmarking study for Hydro One could be conducted. Advantages of our methodology over PSE's include the following.

- There are separate econometric benchmarking models for OM&A expenses, capital cost, capital expenditures, and total cost.
- The sample used in the research includes data for four Alberta distributors and several Ontario distributors (e.g., Hydro One and Algoma Power) as well as numerous investor-owned US electric utilities. Two Alberta distributors (FortisAlberta and ATCO Electric) are good peers for Hydro One because they serve areas with low customer density.
- Pension and other benefit expenses were excluded.
- Weights in the OM&A input price index were company-specific.
- US distributors with large reported transmission/distribution cost transfers were excluded.
- The benchmark year for the capital cost of US utilities was 1964.
- A system overheading variable was included.
- The density variable was not based on service territory area estimates.

4.2. Alternative Benchmarking Results

Mr. Fenrick noted in a response to a data request that Hydro One recently reported high voltage ("HV") plant additions to the OEB that were erroneously high.[35] We recomputed benchmarking results for Hydro One using the corrected capital cost data reported by the company and the total cost econometric model we developed for the OEB in 4th Generation IRM. Results are presented in Table 3. It can be seen that the three-year average cost performance of Hydro One was almost 33% over predicted cost. This level of cost performance is consistent with a 0.60% stretch factor instead of the

[35] Exhibit I/Tab 8/Schedule Staff-23 c).

Table 3

Impact of Revised High Voltage Data on Hydro One Benchmarking Results Using the OEB's Econometric Total Cost Model

	Before Correction	After Correction
2014	28.93%	39.94%
2015	19.68%	33.09%
2016	15.56%	25.73%
Average	21.39%	32.92%

0.45% as previously measured.[36] However, cost performance improved considerably over these years. By 2016, the Company's cost exceeded the model's prediction by 25.73%. We also developed a new econometric model that relies primarily on PSE's data but makes several changes to PSE's methodology to make it more in line with PEG's total cost model in the UCA study. Here are some changes to PSE's methodology that we made.

- REC data were excluded from the sample used in model estimation.
- Since the peak load variable parameter estimate was not statistically significant when the REC data were excluded, we used an alternative measure of peak demand: the volume of power deliveries per residential customer in 2015. Peak demand will tend to be higher where residential use per customer is high. Commercial use per customer is also pertinent but is more difficult to accurately measure. Industrial demand is less pertinent because large industrial customers in the States often receive power directly from the transmission system.
- An overheading variable was included. The variable we used was the share of overhead facilities in the gross value of overhead and underground distribution line plant.

[36] It is the understanding of PEG that it is the policy of the OEB to not revise previously assigned stretch factors due to data revisions. This information is being provided as additional evidence of the cost performance of HONI with the best data currently available. The adjusted results may include other OEB approved data corrections provided by the Company in 2017 relating to years prior to 2016.

- An alternative density variable was used that does not rely on an estimate of the service territory area. This variable was overhead structure miles per customer.[37] The statistical significance of the parameter of our density variable was considerably higher than that for the density variable PSE developed.
- US utilities with large transmission/distribution cost transfers were excluded.
- Scale economies are important when benchmarking the cost of a large distributor like Hydro One. To capture scale economies, our model included quadratic terms for the customer, density, and average use variables. To preserve degrees of freedom, we did not include interaction terms between the scale variables in the model.

The model otherwise used PSE's data, including the forestation, customer service and information, extreme weather, and artificial surface variables that PSE developed.

Details of this new econometric total cost model are reported in Table 4. It can be seen that all of the variables have statistically significant and plausibly-signed parameter estimates. The 0.958 adjusted R-squared for the model is quite high. Note that the trend variable parameter estimate suggests that the cost of sample distributors declined in real terms at a 0.20% annual pace for reasons other than the trends in the model's business condition variables.

Table 5 presents results when our preferred model is used to benchmark the cost of Hydro One. It can be seen that the Company's cost was 24.8% above the model's prediction on average over the three years from 2014 to 2016. Cost performance was a little better on average for forecasted/proposed costs in 2017 and 2018 and averages 23.0% over the 2019-2022 period. These results are similar to those from PSE's model.

[37] The source of data on overhead structure miles is the Utility Data Institute. We computed the ratio of line miles to customers for a single year for each sampled utility. This ratio should be fairly stable over time for most distributors.

Table 4

Details of PEG's Alternative Total Cost Benchmarking Model

VARIABLE KEY

N = Number of Electric Customers Served
F = Percent Forestation in Service Territory
CSI = Percent Cost Customer Service and Information Expenses
XW = Extreme Weather
Art = Percent of Territory that is Artificial Surfaces
OHMILES = Overhead Structure Miles per Customer
PCTOH = Percentage of Line Plant that is Overhead
RESUPC = MWh Deliveries per Residential Customer, 2015
Trend = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.964	288.651	0.000
N*N	0.019	5.040	0.000
OHMILES	0.184	18.527	0.000
OHMILES * OHMILES	0.094	5.856	0.000
RESUPC	0.034	1.955	0.051
RESUPC * RESUPC	-0.474	-3.730	0.000
F	0.151	30.053	0.000
CSI	0.006	2.047	0.041
XW	0.00003	16.798	0.000
Art	1.926	12.735	0.000
PCTOH	-0.107	-6.212	0.000
Trend	-0.002	-2.531	0.012
Constant	11.670	1264.902	0.000

Rbar-Squared	0.958
Sample Period	2002-2015
Number of Observations	942

Table 5

Benchmarking Results for Hydro One Using PEG's Total Cost Model

[Actual - Predicted Cost (%)][1]

Year	*Efficiency Score*
2002	6.9%
2003	5.6%
2004	2.1%
2005	5.4%
2006	12.1%
2007	15.9%
2008	15.8%
2009	20.2%
2010	25.1%
2011	23.8%
2012	23.4%
2013	25.8%
2014	28.2%
2015	23.2%
2016	23.1%
2017	*21.9%*
2018	*22.1%*
2019	*22.6%*
2020	*23.0%*
2021	*23.0%*
2022	*23.3%*
Average 2014-2016	**24.8%**
Average 2019-2022	**23.0%**

[1] Results presented are the log of the ratio of actual cost to the cost predicted by the econometric cost model.

Note: Italicized results are for forecasted costs.

Summing up, the total cost forecasting model we developed for 4th Generation IRM suggests Hydro One's cost was about 33% above the benchmark on average from 2014-2016 but was improving, reaching 25.73% in 2016. Our adaptations to PSE's model reveal a continuation of improved performance after 2016 and a forecasted cost that averages 22.8% above the benchmark during the plan term. We believe that the 22.4% average result for the 2016-18 period is most pertinent for establishing the stretch factor because the incentive that Hydro One had to understate OM&A growth in the 2019-22 period. On this basis, a 0.45% stretch factor seems reasonable for Hydro One provided that the Board is comfortable fixing the stretch factor. Combined with the recommended 0% base X factor, this would give an X factor of 0.45%. The RCI formula would then be IPI - 0.45%, net of Z factors or of any growth factor as discussed elsewhere.

4.3. Program Benchmarking

Hydro One also filed several more granular or "program-based" unit cost benchmarking studies addressing components of its cost. Pole replacement, substation refurbishment, and vegetation management were notable focus areas.

PEG examined the First Quartile/Navigant report. Some advantages of the general approach to benchmarking that these consultancies use can be noted. Benchmarking specialists can confer with colleagues in other companies. Special data can be gathered if and when a need for better data is identified. Participants can learn about best practices.

Traditional peer group benchmarking also has special limitations. Companies outside Ontario will participate only on a voluntary basis and may insist on data confidentiality. Individual consultancies compete to create peer benchmarking groups, but each consultant typically has only 15-30 participants. The utilities that participate in these groups are often quite large (e.g., Southern California Edison) because this increases the cost-effectiveness of participation. It may therefore be difficult to establish appropriate peer groups for Ontario distributors. For example, only three good peers might be available and average results for these peers may not be representative of the norm for companies facing their business conditions. Statistical methods are often crude, due in part to the small size of data samples gathered. Econometric modelling and hypothesis testing are rare.

PEG examined the First Quartile/Navigant study and has several concerns.

- The authors claimed that their peer group was "reasonably representative and useful."[38] In fact, few utilities in the peer group are similar to Hydro One. The sample consisted mostly of US utilities serving large urban areas like Chicago, Dallas, Houston, Los Angeles, and Philadelphia. These utilities were probably easier for the consultants to recruit for the study because of their large size and participation in past First Quartile or Navigant studies. The authors of the report claimed in response to an information request that the peer group is representative of the "industry."[39] However, Hydro One's request for project proposals called, as it should, for peer groups facing business conditions like those of Hydro One.
- Statistical methods were basic and consisted chiefly of simple unit cost metrics adjusted for currency differences between the US and Canadian utilities. Exchange rates, not PPPs, were used to adjust for currency differences. PPPs are generally considered to be more accurate for making international price comparisons.
- Other differences in input prices faced by peer utilities were not considered. Yet many peers served large urban areas where input prices tend to be unusually high. Many Hydro One employees, in contrast, do not work in Ontario's two large metropolitan areas.
- The evidence is not transparent, since utility participation in the study was conditioned on confidentiality.[40] Some results were not made available for scrutiny.[41]
- The sample period for the First Quartile/Navigant study was 2012-2014, which is not very recent.

All in all, we believe it is constructive for Hydro One to participate in some studies of this kind. However, the value of the First Quartile/Navigant report in support of Hydro One's proposed stretch factor was quite limited.

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[38] Navigant Consulting, *Distribution Unit Cost Benchmarking Study Pole Replacement and Substation Refurbishment*, HONI_App_Ex_B_Part2_20170427, B1-1-1, Section 1.6, Attachment 1, p. 5.

[39] HONI_IRR_B-Custom Application-Issues 7-16, Exhibit I, Tab 10, Schedule Staff-51, p. 4.

[40] EB-2017-0049, Exhibit I, Tab 25, Schedule AMPCO-19, part j.

[41] EB-2017-0049, Exhibit I, Tab 10, Schedule SEC-25, part c.

5. Other Plan Design Issues

The IRM proposed by Hydro One is in several respects uncontroversial. The design is similar to that of the Custom IRM that the Board approved for Toronto Hydro-Electric System. A revenue cap index escalates OM&A revenue, strengthening performance incentives and sidestepping the need for an OM&A cost forecast. An earnings sharing mechanism would asymmetrically share with customers only surplus earnings outside the deadband. The CSVA would asymmetrically share with customers some capex underspends but not overspends. A Custom Capital Factor would ensure recovery of the proposed capital cost, but this cost is reduced by the proposed 0.45% X factor.

We are nonetheless concerned about some features of the Company's proposal. We discuss the major areas of our concern in this section and suggest alternative IRM provisions for the Board's consideration.

5.1. Revenue Cap Index

Revenue cap indexes in approved IRMs usually have an escalator for growth in the utility's output. Hydro One's proposed RCI does not. In response to a data request, the Company defended this design on the grounds that the cost of system expansion is addressed by the C Factor.[42] For reasons discussed further below, we believe that it is preferable not to address capital costs by a C factor if it is efficient to address these costs by other means. Adding a growth escalator to the RCI is an efficient way to fund growth-related capex, including the acquisition of utilities. It reduces C-factored cost without increasing regulatory cost or weakening the Company's performance incentives.

On the other hand, Hydro One is not compensated under its proposal for higher OM&A expenses that result from higher output. This constitutes an implicit stretch factor in the Company's proposal. The addition of a scale escalator to the RCI would likely increase Hydro One's allowed revenue for OM&A expenses since there would likely be no offsetting increase in the X factor.

Were the Board to decide that a scale escalator should be added to the Company's RCI, our discussion of alternative scale escalators in the Appendix is pertinent. One option is an elasticity-weighted output index featuring cost driver variables. PEG developed such an index for the Board in the

[42] HONI_IRR_B-Custom Application-Issues 7-16, Exhibit I, Tab 8, Schedule Staff-21, p. 2.

4th Generation IRM proceeding which featured delivery volume, peak demand, and the number of customers served as scale variables.[43] While fresh estimates of cost elasticities would be desirable, it is notable that the elasticity weights in this index are 0.106, 0.289, and 0.606, respectively.[44]

Table 6 considers how this index might serve as a scale escalator using Hydro One forecasts of billing determinants. These forecasts do not include the expected bump in customers when these acquired utilities are integrated into the Company during the plan term. The number of customers is forecasted to average 0.60% growth over the 4-year 2019-2022 period. The max peak is forecasted to be flat while the delivery volume is forecasted to average a 0.49% annual decline. The table shows that this output index would average a modest 0.31% annual growth during the plan term. Even if negative growth in subindexes weren't permitted, the index would grow by only 0.36%. In either case, OM&A revenue would grow by this additional amount. The C factor would fall but allowed capital revenue would likely be unaffected on balance.

Since this scale index tracks trends in volumes and peak load, its addition to the RCI would weaken Hydro One's incentive to encourage CDM. One solution to this problem is to escalate Hydro One's allowed revenue only for customer growth. There is ample precedent for this approach, including revenue cap indexes for Altagas and ATCO Gas in Alberta and a recent IRM of Enbridge Gas Distribution that indexed growth in allowed revenue per customer.[45] Hydro-Québec Distribution will soon begin operating under an RCI with a 0.75 x Customer growth escalator.[46] Many US gas and electric utilities operate under revenue decoupling systems that escalate allowed revenue each year for customer growth.

On balance, we believe that the RCI for Hydro One in this IRM should have a customer growth escalator. This escalator could have a % markdown like the 0.75 in the recently approved escalator for Hydro-Quebec. Setting aside the addition of the three utilities, escalation of allowed revenue for

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[43] This index could, in principle, be expanded to encompass reliability, safety, and/or metering capabilities.

[44] The cost elasticity weights for the two scale variables in PSE's cost benchmarking model for Hydro One are 89% for customers and 11% for peak demand.

[45] Ontario Energy Board, Schedule A to Decision Dated February 11, 2008 Enbridge Gas Distribution Inc., filed in OEB Case EB-2007-0615, p. 8.

[46] La Régie de l'Energie, R-3897-2014, D-2017-043, April 2017.

Table 6

Forecast of Hydro One Scale Variables[1]

	Customers[2]		Volumes[2]		Max Peak[3]		4th GIRM Output Index[4]	
Year	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	PEG	Non-Negative GR Only
2012	1,311,445	0.66%	36,823	0.64%	6.09	0.00%	0.47%	0.47%
2013	1,323,658	0.93%	36,113	-1.95%	6.09	0.00%	0.36%	0.56%
2014	1,323,660	0.00%	36,266	0.42%	6.09	0.00%	0.04%	0.04%
2015	1,331,222	0.57%	35,514	-2.10%	6.09	0.00%	0.12%	0.35%
2016	1,340,493	0.69%	34,732	-2.23%	6.09	0.00%	0.18%	0.42%
2017	1,347,322	0.51%	33,988	-2.17%	6.09	0.00%	0.08%	0.31%
2018	1,355,818	0.63%	33,987	0.00%	6.09	0.00%	0.38%	0.38%
2019	1,363,783	0.59%	33,566	-1.25%	6.09	0.00%	0.22%	0.35%
2020	1,371,760	0.58%	33,491	-0.22%	6.09	0.00%	0.33%	0.35%
2021	1,380,395	0.63%	33,353	-0.41%	6.09	0.00%	0.34%	0.38%
2022	1,388,694	0.60%	33,330	-0.07%	6.09	0.00%	0.36%	0.36%
Annual Average Growth Rate								
2012 - 2017		**0.56%**		**-1.23%**		**0.00%**	**0.21%**	**0.36%**
2019 - 2022		**0.60%**		**-0.49%**		**0.00%**	**0.31%**	**0.36%**

Notes

[1] All growth rates are computed logarithmically. For example, growth rate of X = $\ln(X_t/X_{t-1})$.

[2] Source: *OEB Staff Interrogatory # 219*

[3] Max peak values are taken from PSE's working papers.

[4] The following cost elasticity weights were used in index construction: 0.6057 for customer numbers, 0.1058 for volumes, and 0.2885 for system capacity. The resultant elasticity weights are estimates from PEG's *Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario* , 2013.

customer growth would likely average 0.6% annually if there was no markdown.[47] Once again, the OM&A revenue requirement would rise a little more rapidly but the C factor would fall and capital revenue would be unaffected.

[47] EB-2017-0049, Exhibit I/Tab 46/Schedule Staff-219, Filed: February 12, 2018.

If a customer growth escalator were added to the Company's RCI, we demonstrate in the Appendix that supportive productivity research to calibrate the X factor should use the number of customers as the scale variable.[48] As we showed in Section 3, this would increase the appropriate base productivity trend by about 30 basis points were X based solely on Ontario experience. However, Hydro One's Custom Productivity Measure would likely remain at 0%.

5.2. Capital Cost Treatment

The proposed ratemaking treatment of capital cost is similar to that which the Board approved for Toronto Hydro but nonetheless raises several concerns. The C factor ensures that the Company recovers its proposed capital cost less a perfunctory X factor markdown. Hence, capital revenue is chiefly determined on a cost of service basis. Incentives to contain capex and OM&A expenses are imbalanced, creating perverse incentives to incur excessive capex to reduce OM&A costs. Notwithstanding the proposed claw back of some capex underspends, Hydro One still has some incentive to exaggerate capex needs since this strengthens the case for a C Factor and reduces pressure for capex containment.

Exaggeration of capex needs may reduce the credibility of Hydro One's forecasts in future proceedings. However, utilities can always claim that they "discovered" ways to economize under the force of stronger incentives. British distributors operating under several generations of IR based on cost forecasts have repeatedly spent less on capex than they forecasted.

Distributors are also incentivized to "bunch" their deferrable capex in ways that increase supplemental revenue. The data in Table 7 suggests that Hydro One may be pursuing this strategy now. The table shows that capital additions are forecasted to be higher than the norm for the 2013-2015 period after a three-year lull from 2016 to 2018. Hydro One proposes to build an Integrated System Operating Center right in the middle of the plan term when the impact on the C factor would be close to the greatest possible. The impact on the C factor would be much less if the center were finished in 2019 or 2022.

[48] Christensen Associates used the number of customers to measure output growth in its recent productivity research and testimony in support of a revenue cap index proposal by Eversource Energy, a large Massachusetts power distributor. Massachusetts Department of Public Utilities, DPU-17-05, Direct Testimony of Mark E. Meitzen, *Performance-Based Ratemaking Mechanism*, Exhibit ES-PBRM-1, January 2017.

Table 7

Actual, Forecasted, and Proposed In-Service Capital Additions 2013-2022 ($M)[49]

		Sustaining	Development	Operations	Customer Service	Common & Other	**Total**
Actual	**2013**	296.6	194.1	1.4	13.9	223.4	**729.4**
	2014	324.8	187.6	5	1.4	96.6	**615.4**
	2015	420.2	216.9	7	16.6	100.5	**761.2**
	2016	371.1	168.3	-0.3	6.5	109.3	**654.9**
Bridge	**2017**	310.7	179.1	12.7	12.7	136.7	**651.9**
Proposed	**2018**	292.5	194.4	2.2	30.2	121.5	**640.8**
	2019	335.6	268.9	10.3	0.2	160.6	**775.6**
	2020	361.5	218.9	68.9	0.2	118.6	**768.1**
	2021	384.2	219.2	1.6	0.2	129.1	**734.3**
	2022	427.3	221	20.2	0.2	146.5	**815.2**

Averages						
2013-2015	**347.2**	**199.5**	**4.5**	**10.6**	**140.2**	**702.0**
2016-2018	**324.8**	**180.6**	**4.9**	**16.5**	**122.5**	**649.2**
2019-2022	**377.2**	**232.0**	**25.3**	**0.2**	**138.7**	**773.3**

Another problem with the proposal is that customers must fully compensate Hydro One for expected capital revenue shortfalls when capex is high, even though most of the capex in question is likely to be similar in kind to that incurred by distributors in the productivity research sample used to calibrate X.[50] Utilities can then be compensated twice for the same capex: once via the C factor and then again by a low X factor in this and future IRMs. A similar concern about "double dipping" arises concerning distribution capex costs that are Z factored due to exogenous events such as severe storms and highway construction programs. These costs are also incurred by distributors in the productivity research sample and slow their productivity growth. Customers are asked to provide supplemental compensation for a disadvantageous short term need for high capex but are not offered timely revenue reductions for expected cost reduction opportunities such as the acquisition of other utilities.

Given the inherent unfairness to customers of asymmetrically funding capital revenue shortfalls, and Hydro One's incentives to exaggerate capex requirements, stakeholders and the Board must be especially vigilant about the Company's capex proposal. This raises regulatory cost. The need for the

[49] OEB Proceeding EB-2017-0049, HONI_Update_Ex_D_20170607, Exhibit D1/Tab 1/Schedule 2, pp 1,3.

[50] Hydro One would not, however, be compensated for unexpected capex overruns.

OEB to sign off on multiyear total capex proposals complicates Custom IR proceedings and is one of the reasons why the Board now requires and reviews distribution system plans --- a major expansion of its workload and that of stakeholders. The regulatory cost of Hydro One's C factor proposal is further raised by the provision that it be permitted to keep legitimate capex productivity gains. The Company will be incentivized to pursue its claims under this provision energetically.

Despite the extra regulatory cost, OEB's staff and stakeholders are sometimes hard-pressed to effectively challenge distributor capex proposals. In essence, the OEB's Custom IR rules have sanctioned British (forecast-based) approaches to determining multiyear capital revenue requirements without making the same investment that Ofgem has made in the capability for appraising and ruling on capex proposals.[51]

In pondering this quandary, the following remarks of the OEB in its decision approving IR for Toronto Hydro resonate.

> The record in this case is one of the largest that the OEB has ever seen. It is important to strike a balance between the amount of evidence necessary to evaluate the Application and the goal of striving for regulatory efficiency. It is important to note that it is not the OEB's role, nor the intervenors, to manage the utility or substitute their judgment in place of the applicant's management. That is the job of the utility. The OEB has established a renewed regulatory framework for electricity (RRFE) which places a greater emphasis on outcomes and less of an emphasis on a review of individual line items in an application.[52]

In light of these remarks, it seems desirable to consider how to make Custom IR more mechanistic, incentivizing, and fair to customers while still ensuring that it is reasonably compensatory over time for efficient distributors.

Following an unhappy experience with capital cost trackers in Alberta's first generation IRMs for provincial power distributors, a number of possible reforms to the ratemaking treatment of capital were discussed in the recent Alberta Utilities Commission ("AUC") generic proceeding on second generation IRMs. Based on the record, the AUC eventually chose a means for providing supplemental capital

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[51] Ofgem's own view of a power distributor's required cost growth is assigned a 75% weight in IRM proceedings. This view is supported by independent engineering and benchmarking research. Despite these investments, it is still unclear as to how accurate Ofgem's assessments are.

[52] OEB, *Decision and Order*, EB-2014-0116, Toronto Hydro-Electric System Limited, December 29, 2015, p. 2.

revenue which was less dependent on distributor capex forecasts.[53] Regulatory cost was reduced thereby, and capex containment incentives were strengthened.

Informed by our research and testimony for a consumer group in that proceeding, we believe that the following amendments to Hydro One's proposed ratemaking treatment of capital merit consideration.

- The C factor could, like the ICMs in 4th Generation IRM, be subject to materiality thresholds and dead zones. Dead zones could also be added to materiality thresholds for Z-factored capex.
- The X factor could be raised, in this and Hydro One's future IRMs, to reduce expected double dipping and give customers a better chance of receiving the benefits of industry productivity growth in the long run. This would be tantamount to having the Company borrow revenue escalation privileges from future plans. Knowledge that there is a price to be paid in the long run for asking for extra revenue now would strengthen Hydro One's capex containment incentives.
- Eligibility of capex for supplemental C factor revenue could be scaled back. For example, capex in the last year of the plan term could be declared ineligible because this involves only one year of underfunding.
- The C factor could be calculated using the (slower) productivity growth trend of capital, while the X factor for OM&A revenue could reflect the (faster) productivity trend of OM&A. This would reduce the need for C factors and make escalation of OM&A revenue more reflective of industry OM&A cost trends. However, there is no conclusive research available to the OEB in this proceeding on OM&A and capital productivity trends of power distributors.

If the OEB is prepared to deviate from Hydro One's proposed C factor treatment, we note that the establishment of a materiality threshold and dead zone for supplemental capital revenue in Custom IR plans is most in keeping with its current policies. This could be done in such a manner that the first 10% of unfunded capex (after the X factor markdown) is ineligible for C factoring. However, the materiality threshold and dead zones need not be modelled on those in the incremental capital modules used in 4th GIRM. For example, if proposed capex exceeded the materiality threshold, a set percentage

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[53] PEG is not recommending this ratemaking treatment for Hydro One.

of *all* unfunded capex could be declared ineligible for C factoring. This would strengthen the Company's incentive to contain capex at the margin. A similar idea is for a set number of basis points (e.g., 50) of the otherwise appropriate C factor to be disallowed. The OEB disallowed a 10% share of Toronto Hydro's proposed capex in a recent proceeding.[54] Any of these dead zone approaches can make customers whole for the addition of a growth escalator to Hydro One's RCI.

5.3. Revenue Decoupling

Consider next that Hydro One's proposal includes a revenue cap index but not revenue decoupling. Decoupling is popular in US jurisdictions (and Great Britain) and is often paired with revenue caps. In the absence of decoupling there may be controversy in proceedings to review the billing determinant forecasts that Hydro One will be required to file each year to convert allowed revenue to rates. Decoupling would add a small step to the Company's IRM but would eliminate billing determinant controversy. The need for an LRAM would also be eliminated since revenue as adjusted would be insensitive to the impact of CDM. Decoupling would also encourage the Company to use its AMI to implement time-sensitive rates because it would reduce the risk of demand fluctuations and load shifting that these rates entail. Hydro One's proposed LRAM does not extend to demand management.

On the other hand, the importance of system use forecasts is diminishing in Ontario due to the transition of rate designs for residential customers to fully-fixed pricing. Ontario's government requires that lost revenues do not weaken distributor incentives to embrace DSM but does not require LRAMs to accomplish this.[55] However, the OEB has mandated LRAMs for the 2015-2020 period.[56] These considerations reduce the benefits of adopting decoupling.

5.4. Pension and Benefit DVAs

With pension and benefit expenses addressed by DVAs, Hydro One has a weak incentive to contain these expenses. There is a perverse incentive for the Company to contain salary growth but maintain or sweeten benefits. This increases the need for prudence oversight of these expenses by the

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[54] OEB, *Decision and Order*, EB-2014-0116, *op. cit*., p. 29.

[55] Ontario Executive Council, *Order in Council*, approved and ordered March 26, 2014.

[56] Ontario Energy Board, *Conservation and Demand Management Requirement Guidelines for Electricity Distributors*, EB-2014-0278, December 19, 2014 (Updated August 11, 2016).

OEB and stakeholders, raising regulatory cost. Many IRMs in North America do not have DVAs for pension and other benefit expenses. For example, Enbridge Gas Distribution and Union Gas have not proposed a DVA for these costs in their current IRM proposal.

Incentive for Hydro One to contain pension and other benefit expenses can be strengthened by adding a materiality threshold and dead zone to the DVA mechanism. For example, the first 10% of annual variances can be declared ineligible for rate adjustments. Alternatively, a set percentage of the entire variance can be ineligible if the threshold is exceeded. PEG recently proposed a similar treatment of pension and other benefit expenses in an IRM for Hydro-Québec Distribution.[57]

[57] La Régie de l'Energie, R-4011-2017, Présentation de PEG, C-AQCIE-CIFQ-0057, February 9, 2018, p. 14.

Appendix

Productivity Research and its Use in Regulation

This Appendix considers some technical and theoretical issues that arise in productivity research to support X factor choices in IRMs. We emphasize issues that arise in our appraisal of Hydro One's productivity research and IRM proposal in this proceeding.

Productivity Indexes

The Basic Idea

A productivity index measures the efficiency with which firms use production inputs to achieve certain outputs. The trend in a productivity index is the difference between the trend in an output index ("Outputs") and the trend in an input quantity index ("Inputs").

trend Productivity = trend Outputs – trend Inputs. [A1]

Productivity grows when the output index rises more rapidly than the input index.

Productivity can be volatile but usually has a rising trend in the longer run. The volatility is typically due to fluctuations in outputs and/or the uneven timing of expenditures. The productivity growth of individual companies tends to be more volatile than the average productivity growth of a group of companies.

The scope of a productivity index depends on the array of inputs addressed by the input quantity index. *Partial* factor productivity ("*PFP*") indexes measure productivity in the use of particular kinds of inputs such as capital or labor. A *multifactor* productivity index measures productivity in the use of multiple kinds of inputs. In Ontario, these are usually called *total* factor productivity ("*TFP*") indexes even though such indexes rarely address the productivity of all inputs.

The output (quantity) index of a firm summarizes growth in its outputs. If the index is multidimensional, growth in each output dimension which is itemized is measured by a subindex. Growth in the summary index is a weighted average of the growth in the sub-indices.

In designing an output index, choices concerning sub-indices and weights should depend on the manner in which the index is to be used. One possible objective is to measure the impact of output growth on *revenue*. In that event, the sub-indices should measure trends in *billing determinants* and the weight for each itemized determinant should reflect its share of revenue.[58] A productivity index calculated using a revenue-weighted output index ("*Outputs*^{R}") will be denoted as *Productivity*^{R}.

$$\textit{trend Productivity}^R = \textit{trend Outputs}^R - \textit{trend Inputs}. \qquad [A2a]$$

Another possible objective of output research is to measure the impact of output growth on *cost.* In that event, the index should be constructed from one or more output variables that measure dimensions of "workload" that drive cost. If there is more than one output variable, the weights for these variables should reflect their relative cost impacts. The sensitivity of cost to a small change in the value of a business condition variable is commonly measured by its cost "elasticity." Cost elasticities can be estimated econometrically using data on the operations of utilities. Such estimates provide the basis for elasticity-weighted output indexes.[59] These have been used on several occasions in our previous research for the OEB.[60] A productivity index calculated using a cost-based output index ("*Outputs*^{C}") will be denoted as *Productivity*^{C}.

$$\textit{trend Productivity}^C = \textit{trend Outputs}^C - \textit{trend Inputs}. \qquad [A2b]$$

This may fairly be described as a "cost efficiency index."

Sources of Productivity Growth

Economists have considered the drivers of productivity growth using mathematical theory and empirical methods.[61] This research has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

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[58] This approach to output quantity indexation is due to the French engineer and economist Francois Divisia (1889-1964).

[59] An early discussion of elasticity-weighted output indexes is found in Denny, Michael, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

[60] See, for example, Kaufmann, L., Hovde, D., Kalfayan, J., and Rebane, K*., Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board*, in EB-2010-0379, (2013); Lowry, M., Getachew, L., and Fenrick, S., *Benchmarking the Costs of Ontario Power Distributors* in EB-2006-0268, (2008) and Lowry, M., Hovde, D., Getachew, L., and Fenrick, S., *Rate Adjustment Indexes for Ontario's Natural Gas Utilities* in EB-2006-0606/0615, (2007).

[61] See, for example, Denny, Fuss and Waverman, *op. cit.*

Economies of scale are another important productivity growth driver. These economies are realized in the longer run if cost has a tendency to grow less rapidly than operating scale. Incremental scale economies (and thus productivity growth) will typically be lower the slower is output growth.[62]

A third driver of productivity growth is X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum possible efficiency. Productivity growth will increase to the extent that X inefficiency diminishes. A company's potential for future productivity growth from this source is greater the higher is its current inefficiency level.

Productivity growth is also affected by changes in the miscellaneous business conditions, other than input price inflation and output growth, which affect cost. A good example for a power distributor is forestation. In a suburb or rural area where forestation is increasing, rising vegetation management expenses will cause OM&A and total factor productivity growth to slow.

System age can drive productivity growth in the short and medium run. Productivity growth tends to be greater to the extent that the initial capital stock is large relative to the need to refurbish or replace aging plant. If a utility requires unusually high replacement capex, capital productivity growth can be unusually slow. On the other hand, productivity growth tends to accelerate in the aftermath of unusually high capex as the surge capital depreciates, thereby reducing the rate of return component of capital cost.

A TFP index with a *revenue*-weighted output index ("TFP^R") has an important driver that doesn't affect a cost efficiency index. This is true since

$$\begin{aligned} \textit{trend } TFP^R &= \textit{trend } Outputs^R - \textit{trend Inputs} + (\textit{trend } Outputs^C - \textit{trend } Outputs^C) \\ &= (\textit{trend } Outputs^C - \textit{trend Inputs}) + (\textit{trend } Outputs^R - \textit{trend } Outputs^C) \\ &= \textit{trend } MFP^C + (\textit{trend } Outputs^R - \textit{trend } Outputs^C). \end{aligned} \quad \text{[A3]}$$

Relation [A3] shows that the trend in TFP^R can be decomposed into the trend in a cost efficiency index and an "output differential" that measures the difference between the impact that trends in outputs have on revenue and cost.

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[62] Incremental scale economies may also depend on the current scale of an enterprise. For example, there may be diminishing incremental returns to scale as enterprises grow in size.

The output differential is sensitive to changes in external business conditions such as those that drive system use.[63] For example, the revenue of a power distributor may depend chiefly on system use, while cost depends chiefly on system capacity. In that event, mild weather can depress revenue more than cost, reducing the output differential and slowing growth in TFP^R and earnings.

Use of Index Research in Regulation

Price Cap Indexes

Index logic supports the use of index research in price cap index design. We begin our demonstration by considering the growth in the prices charged by an industry that earns, in the long run, a competitive rate of return.[64] In such an industry, the long-run trend in revenue equals the long-run trend in cost.

$$\textit{trend Revenue} = \textit{trend Cost.} \qquad [A4]$$

The trend in the revenue of any firm or industry can be shown to be the sum of the trends in revenue-weighted indexes of its output prices ("*Output Prices*^{R}") and billing determinants ("*Outputs*^{R}")

$$\textit{trend Revenue} = \textit{trend Outputs}^R + \textit{trend Output Prices}^R. \qquad [A5]$$

The trend in cost can be shown to be the sum of the trends in a cost-weighted input price index ("Input Prices") and input quantity index ("Inputs").

$$\textit{trend Cost} = \textit{trend Input Prices} + \textit{trend Inputs} \qquad [A6]$$

It follows that the trend in output prices that permits revenue to track cost is the difference between the trends in the input price index and a total factor productivity index of TFP^R form.

$$\begin{aligned} \textit{trend Output Prices}^R &= \textit{trend Input Prices} - (\textit{trend Outputs}^R - \textit{trend Inputs}) \qquad [A7] \\ &= \textit{trend Input Prices} - \textit{trend } TFP^R. \end{aligned}$$

The result in [A7] provides a conceptual framework for the design of PCIs of general form

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[63] Note also that companies can sometimes bolster their output differential with better marketing. For example, they can sell more products that have a higher margin between incremental revenue and cost.

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

growth Rates = growth Input Prices – X. [A8a]

Here X, the "X factor," reflects a base productivity growth target ("$\overline{TFP^R}$") that is typically the trend in the TFP^R of the regional or national utility industry or some other peer group. A "stretch factor" is often added to the formula which slows PCI growth in a manner that shares with customers the financial benefits of performance improvements which are expected under the IRM.[65]

$X = \overline{TFP^R} + Stretch$ [A8b]

Since the X factor often includes *Stretch* it is sometimes said that the index research has the goal of "calibrating" (rather than solely determining) X.

Revenue Cap Indexes

Index logic also supports the design of *revenue* cap indexes. Consider first the following basic result of cost theory:

trend Cost = trend Input Prices – trend $Productivity^C$ *+ trend* $Scale^C$. [A9a]

The growth in the cost of a company is the difference between the growth in its input price and cost efficiency indexes plus the trend in a consistent cost-based output index. This result provides the basis for a revenue cap escalator of general form

growth Revenue = growth Input Prices – X + growth $Scale^C$ [A9b]

where

$X = \overline{TFP^C} + Stretch.$ [A9c]

Notice that a *cost*-based scale index should be used in the supportive productivity research.

PEG used an elasticity-weighted output index in its research for the OEB on the productivity growth of Ontario power distributors in the 4th GIRM proceeding. The output variables were delivery volume, peak demand, and the number of customers served. These variables are billing determinants as well as cost drivers. Equations [A9a-c] permit the expansion of an elasticity-weighted output index used

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

in RCI design to include outputs that are not billing determinants. For a power distributor these might include kilometers of line, reliability, safety, and metering capabilities of the system.

A scale escalator that includes volumes and peak demand as output variables diminishes a utility's incentive to promote CDM. This is a strong argument for excluding these variables from an RCI scale escalator. Note also that values of usage variables can decline, materially slowing RCI growth even though cost is largely fixed in the short run with respect to system use.

For gas and electric power distributors, the number of customers served is a sensible scale escalator for a revenue cap index. The number of customers is an important distributor cost driver in its own right and is also highly correlated with peak load. The customers variable typically has the highest estimated cost elasticity amongst the scale variables modelled in econometric research on distribution cost.

We can expand [A6] to obtain the result

$$\begin{aligned} \textit{trend Cost} &= \textit{trend Input Prices} + \textit{trend Input Quantities} + (\textit{trend Customers} - \textit{trend Customers}) \\ &= \textit{trend Input Prices} - (\textit{trend Customers} - \textit{trend Inputs}) + \textit{trend Customers} \\ &= \textit{trend Input Prices} - \textit{trend } TFP^N + \textit{trend Customers} \end{aligned}$$

where TFP^N is a TFP index that uses the number of customers to measure output. This result provides the rationale for the revenue cap index formula

$$\textit{growth Revenue} = \textit{growth Input Prices} - X + \textit{growth Customers} \quad \text{[A10a]}$$

where

$$X = \overline{TFP}^N + \textit{Stretch}. \quad \text{[A10b]}$$

An equivalent formula is

$$\begin{aligned} &\textit{growth Revenue} - \textit{growth Customers} \\ &\quad = \textit{growth } (\textit{Revenue/Customer}) = \textit{growth Input Prices} - X. \end{aligned} \quad \text{[A10c]}$$

This is sometimes called a "revenue per customer" index, and we will for convenience use this expression to refer to revenue cap indexes which conform to either [A10a] or [A10c].

Revenue per customer indexes are currently used in the IRMs of ATCO Gas and AltaGas in Canada. The Régie de l'Energie in Québec has directed Hydro-Québec Distribution and Gaz Métro to develop IRMs featuring revenue per customer indexes. Revenue per customer indexes were previously featured in IRMs for Southern California Gas and Enbridge Gas Distribution, the largest gas distributors in the US and Canada, respectively. In the United States, many gas and electric utilities operate under revenue decoupling systems which escalate allowed revenue for customer growth between rate cases.

TFP Research Methods

Monetary Approach to Capital Cost and Quantity Measurement

Monetary approaches to the measurement of capital costs and quantities have been widely used in TFP research. The main components of capital cost are depreciation expenses, the return on investment, and taxes.[66] These approaches decompose the growth in capital cost into the growth in consistent capital price and quantity indexes such that

$$\textit{growth Cost}^{Capital} = \textit{growth Price}^{Capital} + \textit{growth Quantity}^{Capital}. \qquad \text{[A11]}$$

The capital quantity trend is calculated using deflated data on asset values.

Several monetary methods are well established for measuring capital quantity trends. A key issue in the choice of a monetary method is whether plant is valued in historic dollars or replacement dollars. Another issue is the pattern of decay in the quantity of capital resulting from plant additions. Decay can result from many factors including wear and tear, casualty loss, increased maintenance requirements, and obsolescence.

Three monetary methods have been used in research to calibrate the X factors of IRMs.

- The geometric decay ("GD") method assumes a replacement (i.e., *current* dollar) valuation of plant and a constant rate of decay. Replacement valuation differs from the historical (aka "book") valuation used in North American utility accounting and requires consideration of capital gains. The GD specification involves formulae for capital price and quantity indexes that are mathematically simple and easy to code and review.

[66] The trends in these costs depends on trends in construction prices, tax rates, and the market rate of return on capital. A capital price index should reflect these trends. The capital price index is sometimes called the "rental" or "service" price index because, in a competitive market, the trend in the price of rentals would tend to reflect the trend in the cost per unit of capital.

Academic research has supported use of the GD method to characterize depreciation in many industries.[67] GD has also been widely used in productivity studies, including X factor calibration studies. The US Bureau of Economic Analysis ("BEA") and Statistics Canada both use geometric decay as the default approach to the measurement of capital stocks in the national income and product accounts.[68] PEG has used the GD method in most of its productivity research for the Board, including the research for 4th Generation IRM.

- The one hoss shay method assumes that the quantity of capital from plant additions in a given year does not decay gradually but, rather, all at once as the assets reach the end of their service lives. Plant is once again valued at replacement cost. We have found that productivity results using the one hoss shay method are unusually sensitive to the choice of an average service life. The one hoss shay method has nonetheless been used occasionally in research intended to calibrate utility X factors.

- The cost of service ("COS") method is designed to approximate the way that capital cost is calculated in utility regulation. This approach is based on the assumptions of straight line depreciation and historic valuation of plant. The formulae are complicated, making them more difficult to code and review. PEG has used this approach in several X factor calibration studies, including two for the OEB.[69]

Benchmark Year Adjustments

Utilities have diverse methods for calculating depreciation expenses that they report to regulators. It is therefore desirable when calculating capital quantities using a monetary method to rely

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[67] See, for example, C, Hulten, and F. Wykoff (1981), "The Measurement of Economic Depreciation," in *Depreciation, Inflation, and the Taxation of Income From Capital*, C. Hulten ed., Washington D.C. Urban Institute and C. Hulton, "Getting Depreciation (Almost) Right", University of Maryland working paper, 2008.

[68] The BEA states on p. 2 its November 2015 "Updated Summary of NIPA Methodologies" that "The perpetual-inventory method is used to derive estimates of fixed capital stock, which are used to estimate consumption of fixed capital—the economic depreciation of private and government fixed capital. This method is based on investment flows and a geometric depreciation formula."

[69] See Lowry, et. al., *Rate Adjustment Indexes for Ontario's Natural Gas Utilities, op. cit.;* Kaufmann, L., Hovde, D., Getachew, L., Fenrick, S., Haemig, K., and Moren, A., *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario*, in EB-2007-0673, (2008); and Lowry, M., Hovde, D., and Rebane, K., *X Factor Research for Fortis PBR Plans,* in BCUC Project 3698719, for Commercial Energy Consumers of British Columbia (2013).

on the reporting companies chiefly for the value of *gross* plant additions and then use a standardized depreciation treatment for all companies. Since some of the plant a utility owns may be 40-60 years old, it is desirable to have gross plant addition data for many years in the past.

For earlier years, the desired gross plant addition data are frequently unavailable. It is then customary to consider the value of all plant at the end of the limited-data period and then estimate the quantity of capital it reflects using construction cost indexes from earlier years and assumptions about the historical capex pattern. The year for which this estimate is undertaken is commonly called the "benchmark year" of the capital quantity index. Since the estimate of the capital quantity in the benchmark year is inexact, it is preferable to base capital and total cost research on a sample period that begins many years after the benchmark year. Research on capital and total cost will be less accurate to the extent that this is impossible.

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Managed PEG's Madison office. Developed internationally recognized practice in the field of statistical cost research for energy utility benchmarking and Altreg. Principal investigator and expert witness on numerous projects.

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Dissertation research on the role of speculative storage in markets for field crops. Work included the development of a quarterly econometric model of the U.S. soybean market.

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- Research supporting litigation testimony in an antitrust suit involving natural gas producers and pipelines in the San Juan Basin of New Mexico.

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1. Competition in the Natural Gas Market of the San Juan Basin. Public Service of New Mexico, 1981.
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5. Electric Council of New England, Boston MA, November 1989
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8. National Association of Regulatory Utility Commissioners, Columbus OH, September 1992
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53. Elforsk, Stockholm, Sweden, June 2003
54. Eurelectric, Brussels, Belgium, October 2003
55. CAMPUT, Halifax NS, May 2004
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58. Ontario Energy Board, Toronto ON, June 2006
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60. EUCI, Arlington VA, September 2006 [Conference chair]
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Journal Referee

Agribusiness
American Journal of Agricultural Economics
Energy Journal
Journal of Economic Dynamics and Control
Materials and Society

Association Memberships (active)

International Association of Energy Economist
Wisconsin Public Utilities Institute

FORM A

Proceeding:.....EB-2017-0049.....

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is .Mark Newton Lowry.................(*name*). I live at .Madison.......... (*city*), in the .State.................... (*province/state*) of .Wisconsin............... .

2. I have been engaged by or on behalf of ..Ontario Energy Board.. (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date ..April 5, 2018.......................

Signature

Outstanding Issues in the Design of an MRI for Hydro-Québec Transmission

Mark Newton Lowry, PhD

President

Matt Makos

Consultant II

Zachary Legge

Economist II

9 November 2018

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1. Introduction

The Régie de l'energie ("Régie") has been engaged for several years in the development of *mécanismes de réglementation incitative* ("MRIs") for transmission and distribution services of Hydro-Québec. Decisions concerning many provisions of an MRI for Hydro-Québec Transmission ("HQT" or "the Company") were made in D-2018-001 (January 2018). However, final decisions concerning the X factor and several other plan provisions will be made in the Company's *dossier tarifaire* for 2019.

In April 2018, HQT submitted a report by its consultant, Concentric Energy Advisors ("Concentric"), on the X factor issue. In July 2018 the Company filed a *demande tarifaire* with additional evidence and recommendations on outstanding MRI issues. This evidence included another report by Concentric which addressed MRI issues.

Pacific Economics Group Research LLC ("PEG") personnel have for many years been the leading North American consultants on MRIs for gas and electric utilities. Work for diverse clients that include consumer and environmental groups, regulators, government agencies, utilities, and trade associations has given our practice a reputation for objectivity and dedication to good regulation. In Canada we have played a prominent role in MRI proceedings in Alberta, British Columbia, Ontario, and Québec. The Association Québécoise des Consommateurs Industriels d'Électricité and the Conseil de l'Industrie Forestière du Québec have retained us and the Régie has authorized funding for us to comment on outstanding MRI issues in this proceeding and to provide our own recommendations.

Section 2 of our report reviews pertinent details of HQT's current regulatory system and of the Régie's recent MRI decisions. Outstanding MRI issues in this proceeding are then treated in succession. On each issue, a summary of HQT's position is followed by PEG's response.

2. Background

HQT has for several years filed annual rate cases. For several years the Régie has used a *formule paramétrique* as a tool to appraise HQT's proposed *charges nettes d'exploitation* ("CNE", or operation and maintenance expenses) in *dossiers tarifaires*. This formula has an inflation measure, an X factor, and a growth factor.

A *mécanisme de traitment des écarts de rendement* ("MTÉR" or earnings-sharing mechanism) was established for the Company that shares only positive earnings variances (i.e., surplus earnings). The first 100 basis points of surplus earnings is shared evenly between customers and the Company. 75% of all surplus earnings in excess of 100 basis points are assigned to customers, while the Company keeps 25%.

Article 48.1 of the *Loi sur la Régie de l'énergie* ("the *Loi*") requires MRIs for power transmission and distribution services of Hydro-Québec.[1] These mechanisms must fulfill the following objectives:

1. *l'amélioration continue de la performance et de la qualité du service;*
2. *une réduction des coûts profitable à la fois aux consommateurs et, selon le cas, au Distributeur ou au Transporteur;* and
3. *l'allégement du processus par lequel sont fixés ou modifiés les tarifs du Transporteur d'électricité et les tarifs du Distributeur d'électricité applicables à un consommateur ou à une catégorie de consommateurs.*

In D-2018-001 the Régie issued its final decision in Phase 1 of its proceeding to develop an MRI for HQT. This decision determined the broad outlines of the mechanism. A multiyear rate plan with a four-year term will feature a revenue cap. The revenue requirement for the first year of the plan (2019) will be established in the current *dossier tarifaire*. During the last three years of the plan the revenue

[1] Québec National Assembly, 40th legislature, 1st session, Bill n°25 (2013, Chapter 16): An Act respecting mainly the implementation of certain provisions of the Budget Speech of 20 November 2012, Chapter 1, Division 1 as passed June 24, 2013.

requirement for CNE will be escalated by a *formule d'indexation.*[2] The full list of costs that will be addressed by this formula is unresolved.

The *formule d'indexation* will include an inflation measure ("I"), an X factor, and a growth factor ("C"). The Régie has tentatively chosen the same approach to the general design of the inflation measure which it chose for the revenue cap index of Hydro-Québec Distribution ("HQD"). Growth in the inflation measure would be a weighted average of growth in the *indice des prix à la consommation* ("$IPC^{Québec}$") and the average hourly earnings in Québec as calculated by the *Enquête sur l'emploi, la rémunération et les heures de travail* ("$EERH^{Québec}$").

The growth factor will be the same as that which HQT has used in its *formule paramétrique* for CNE since D-2009-015. This factor is driven by plant additions in the categories "*maintien et amelioration de la qualité du service*" and "*croissance des besoins de la* clientèle". The revenue requirement adjustment is based on the assumption that the present value of CNE growth from plant additions over a 20 year period is 19% of the total costs of the investment.3

A provisional X factor, applicable for at least two years of the MRI, will be determined by a process of informed "*jugement*" and not based, instead or additionally, on a custom power transmission productivity study that uses historical industry operating data. However, HQT was ordered to undertake a study of the productivity of power transmitters during the MRI term, and to present "*la méthodologie et l'échéancier*" for this study in its Phase III evidence.[4]

The Régie decided not to address the revenue requirement for "*éléments de coûts reliés aux investissments*" using the *formule d'indexation*.[5] A cost of service approach will instead be used to escalate the Company's sizable revenue requirement for depreciation and return on rate base. However, the Régie asked HQT to propose a non-binding *formule paramétrique* for these costs as a

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[2] The Régie specified that expenses subject to indexing will include *frais corporatifs*, *achats de service de transport*, *les autres revenus de facturation interne, la facturation externe, and interest reliés au remboursement gouvernemental*.

[3] The assumption is outlined in Attachment J of Hydro-Québec's Open Access Transmission Tariff and has changed over time.

[4] D-2018-001, p. 32, par. 112.

[5] D-2018-001, p. 53, par. 201.

point of comparison to the Company's actual and proposed capital costs during the plan. This formula shall include a growth factor that is applicable to these costs.[6] The Régie expressed interest in the eventual inclusion of capital in the *formule d'indexation* for a transmission MRI.

Supplemental revenue adjustments will be permitted via Y and Z factors. The Régie tentatively proposed that retirement costs be addressed by the indexing formula and not Y factored. It did not rule on the eligibility of several other costs for Y or Z factor treatment. The Régie proposed materiality thresholds of $2.5 million for the Y and Z factors. The suggestion of a $2.5 million threshold was based on a threshold the Régie previously established for HQT's *budgets spécifiques* in D-2012-059.

The materiality thresholds would apply to the creation and continuation of Y factors and to the creation of Z factors. The Régie did not propose to use materiality thresholds as deadbands that make HQT absorb some of the costs.

The plan will have an MTÉR similar to that approved in D-2014-034 and linked to the Company's service quality. HQT's service quality shall be monitored using metrics like those already reported in the Company's *dossiers tarifaires.* These metrics "*devront s'inspirer de ceux utilisés actuellement dans le cadre des dossiers tarifaires*" and should notably address the following four transmission service quality dimensions:[7]

- reliability of service
- availability of the network
- customer satisfaction
- public and employee safety.

The Régie also approved in D-2018-0001 a « *clause de sortie permettant la révision ou interruption du MRI »*.[8] Details of this *clause* and the performance metrics and linkage to the MTÉR are as yet unresolved. No *clause de succession* or *mécanisme de report des gains d'efficience* (« MRE », or efficiency carryover mechanism) were approved.

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[6] D-2018-001, p. 73, par. 299.

[7] D-2018-001, p. 40, par. 158.

[8] D-2018-001, p. 33, par. 121.

3. Revenue Cap Index

3.1 Principles and Methods for Revenue Cap Index Design

In this section of the report we discuss pertinent principles and methods for the design of revenue cap indexes. We begin by discussing basic indexing concepts. There follow discussions of the use of indexing research in revenue cap index design and other methodological issues. Special considerations in the design of a revenue cap index for CNE are highlighted.

Basic Indexing Concepts

The logic of economic indexes provides the rationale for using price and productivity research to design revenue cap escalators. To review this logic, it may be helpful to make sure that the reader has a high-level understanding of some basic tools of index research.

Input Price and Quantity Indexes

The growth (rate) of a company's cost can be shown to be the sum of the growth of an input price index ("Input Prices") and an input quantity index ("Inputs").

growth Cost = growth Input Prices + growth Inputs.[9] [1]

Both of these indexes are typically multidimensional in the sense that they summarize trends in subindexes that are appropriate for particular subsets of cost.

Productivity Indexes

The Basic Idea A productivity index is the ratio of a scale index ("Scale") to an input quantity index.

$$Productivity = \frac{Scale}{Inputs}. \quad [3]$$

It can be used to measure the efficiency with which firms use inputs to achieve their scale of operation.

Some productivity indexes are designed to measure productivity trends. The growth of such a productivity index is the difference between the growth in the scale and input quantity indexes.

growth Productivity = growth Scale – growth Inputs. [4]

[9] Cost-weighted input price and quantity indexes are attributable to the French economist Francois Divisia.

Productivity grows when the scale index rises more rapidly (or falls less rapidly) than the input index. The productivity growth of utilities can be volatile but has historically tended to grow over time. The volatility is typically due to demand-driven fluctuations in operating scale and/or the uneven timing of certain expenditures. The volatility of productivity growth tends to be much greater for individual companies than the average for a group of companies.

Relations [1] and [4] imply that

growth Productivity = growth Scale – (*growth Cost - growth Input Prices*)

= growth Input Prices - growth (*Cost/Scale)*

Productivity growth is thus the amount by which a firm's unit cost grows more slowly than its input prices.

Some indexes are designed to measure only productivity trends. "Bilateral" productivity indexes are designed to compare only productivity levels. For example, the productivity level of HQT in 2016 can be compared to the average for U.S. power transmitters in the same year. Multilateral" productivity indexes are designed to measure *both* trends and levels. These indexes are sometimes used in benchmarking studies.

The scope of a productivity index depends on the array of inputs which are considered in the input quantity index. Some indexes measure productivity in the use of a single input group such as labor. A *multifactor* productivity index [p*roductivité multifactorielle* (“PMF”)] measures productivity in the use of multiple inputs. PMF indexes are sometimes called total factor productivity indexes, a term that is usually a misnomer since in practice some inputs are excluded from the index calculations.

Scale Indexes A scale index of a firm or industry summarizes trends in the scale of operation. These indexes may also be multidimensional. Growth in each dimension of scale that is itemized is then measured by a subindex and the scale index summarizes growth in the subindexes by taking a weighted average of them.

In designing a scale index, choices concerning scale variables (and weights, if the index is multidimensional) should depend on the manner in which the index is used. One possible objective is to measure the impact of growth in scale on *revenue*. In that event, the scale variables should measure growth in *billing determinants* like peak demand and the weight for each itemized determinant should be its share of a utility's base rate revenue.[10]

Another possible objective of scale indexing is to measure growth in dimensions of scale that affect *cost*. In that event, the scale variable(s) should measure dimensions of the "workload" that drive cost.[11] If there is more than one scale variable in the index the weight for each variable should reflect its relative cost impact. The sensitivity of cost to a small change in the value of a business condition variable is commonly measured by its cost "elasticity." Cost elasticities of utilities can be estimated econometrically using data on the costs and operating scale of a group of utilities. A productivity index calculated using a cost-based scale index will be denoted as $Productivity^C$.

$$growth\ Productivity^C = growth\ Scale^C - growth\ Inputs. \quad [5]$$

This may fairly be described as a "cost efficiency index."

Use of Index Research in MRI Design

Productivity studies have many uses, and the best methodology for one use may not be best for another. One use of productivity research is to measure the trend in a utility's operating efficiency. Another is to calibrate the X factor in a rate-cap or revenue-cap index. In this section, we discuss the logic for using productivity research in revenue cap index design and consider some implications for the appropriate design.

Revenue Cap Indexes

We begin our explanation of the supportive index logic by considering the growth in the revenue of a firm that earns, in the long run, a competitive rate of return.[12] For such a firm, the long-run trend in revenue equals the long-run trend in cost.

$$trend\ Revenue = trend\ Cost. \quad [6]$$

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[10] Revenue-weighted scale indexes are attributable to the French economist Francois Divisia.

[11] A multidimensional scale index with elasticity weights is unnecessary if econometric research reveals that there is one dominant cost driver.

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

Consider now the following basic result of cost theory:

$$\textit{growth Cost} = \textit{growth Input Prices} - \textit{growth Productivity}^C + \textit{growth Scale}^C. \qquad [7a]$$

The growth in the cost of a firm is the difference between the growth in input price and cost efficiency indexes plus the trend in a consistent cost-based scale index. This result provides the basis for revenue cap escalators of general form

$$\textit{growth Revenue} = \textit{growth Input Prices} - X + \textit{growth Scale}^C \qquad [7b]$$

where

$$X = \overline{\textit{Productivity}^C} + S. \qquad [7c]$$

Here Productivity^C is the trend in the productivity of a sample of utilities and S is the stretch factor. Notice that a cost-based scale index should be used in the supportive productivity research for a revenue cap index X factor. Moreover, this index should match the scale index in the revenue cap index.

Sample Period

Another important issue in the design of a rate or revenue cap index is whether it should be designed to track short-run or long-run industry cost trends. Indexes designed to track short-run growth will also track the long run growth trend if this approach is used repeatedly over many years. An alternative approach is to design the index to track only long-run trends.

Different approaches can, in principle, be taken for the input price and productivity components of the revenue cap index and are in most cases warranted. The inflation measure should track short-term input price growth. Meanwhile, productivity research for X factor calibration commonly focuses on discerning the current long-run productivity trend. This is the trend in productivity that is unaffected by short-term fluctuations in operating scale and inputs. The long run productivity trend is faster than the short-run trend during a short-lived surge in input growth or lull in output growth but slower than the trend during a short-lived lull in input growth or surge in output growth.

This general approach to revenue cap index design has important advantages. The inflation measure exploits the greater availability of inflation data. Making the revenue cap index responsive to short term input price growth reduces the operating risk of the utility without weakening its performance incentives. Having X reflect the long-run industry productivity trend, meanwhile, sidesteps the need for more timely cost data and annual productivity calculations.

To calculate the long-run productivity trend using indexes it is common to use a lengthy sample period. However, a period of more than twenty years may be unreflective of current business conditions. Quality data are often unavailable for sample periods of even this length. The need for a long sample period is lessened to the extent that volatile costs are excluded from the study and the scale index does not assign a heavy weight to volatile scale variables.

Application to CNE Revenue

Suppose, now, that statistical cost research is being used to design a revenue cap index for CNE revenue. In that case, the pertinent cost growth formula analogous to relation [7a] is

$$growth\ CNE = growth\ Input\ Prices_{CNE} - growth\ Productivity^{C}_{CNE} + growth\ Scale^{C}_{CNE}. \quad [8a]$$

The growth of CNE is the sum of the growth in CNE input prices and a CNE scale index less the growth in CNE productivity. The productivity index should use a cost-based scale index that is consistent with the revenue cap index scale escalator.

This result provides the basis for the following CNE revenue cap index

$$growth\ Revenue_{CNE} = growth\ Input\ Prices_{CNE} - X + growth\ Scale^{C}_{CNE} \quad [8b]$$

where

$$X = \overline{Productivity^{C}}_{CNE} + S. \quad [8c]$$

Here $Productivity^{C}_{CNE}$ is the trend in the CNE productivity of a sample of utilities and S is the stretch factor. Notice that a cost-based scale index should be used in the supportive productivity research for a revenue cap index X factor. This index should match the scale index in the revenue cap index.

Econometric research on drivers of CNE is useful for establishing elasticity weights for the scale index. Cost theory is useful for choosing CNE model variables. It reveals that the minimum cost of CNE is a function of CNE input prices, output variables, and quantities of capital inputs. A scale index for CNE productivity research may thus include measures of the size of the capital stock such as its capacity to provide service. In the case of power transmission CNE, for example, pertinent scale variables include transmission line miles and the MVA of transmission substation capacity. In addition to being potentially important CNE drivers, capacity variables like these are less volatile than some transmission output variables such as peak demand.

Research by PEG in many utility industries has revealed that CNE productivity growth tends to be volatile. This is chiefly due to volatility in expenditures. To the extent that this is true, longer sample periods are needed to capture CNE productivity trends.

Sources of Productivity Growth

Research by economists has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to attain given levels of scale with fewer inputs.

Economies of scale (*economies d'échelle*) are another important source of productivity growth. These economies are available in the longer run if cost has a tendency to grow less rapidly than scale. A company's potential to achieve incremental scale economies is greater the greater is the growth in its scale.

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

Another driver of productivity growth is changes in the miscellaneous business conditions, other than input price inflation and demand, which affect cost. A good example for an electric power transmitter is the share of transmission lines which are underground. An increase in the share of lines which are underground will tend to slow multifactor productivity growth but accelerate growth in the productivity of O&M inputs.

Choosing a Base Productivity Growth Target

Research on the productivity of other utilities can be used in several ways to calculate base productivity growth targets. Using the average historical productivity trend of the entire industry to calibrate X is tantamount to simulating the outcome of competitive markets. The competitive market paradigm has broad appeal.

On the other hand, individual firms in competitive markets routinely experience windfall gains and losses. Our discussion above of the sources of productivity growth implies that differences in the external business conditions that drive productivity growth can cause different utilities to have different productivity trends. For example, power transmitters experiencing brisk growth in the operating scale are more likely to realize scale economies than transmitters experiencing average customer growth.

In the design of rate and revenue cap indexes, there has thus been considerable interest in methods for customizing base productivity growth targets to reflect local business conditions. The most common approach to customization to date has been to use the average productivity trends of similarly situated utilities.

3.2 HQT's Evidence and Proposal

Inflation Measure

HQT presented 11 years of inflation measure calculations, including labor and non-labor weight calculations, using an approach it believes is consistent with that which the Régie approved for HQD in D-2018-067.

X Factor

The Company embraced the **-0.60%** X factor recommendation made by Concentric. This includes a **0%** stretch factor.

PMF Study

HQT presented a schedule for the PMF study but did not present any details of the methodology that the study will use. The Company does not intend to present a methodology until it receives the Régie's X factor decision in this case and retains a consultant to do the study.

3.3 PEG's Response

Inflation Measure

PEG has no objections to the proposed labor price index or weights assigned to the two inflation measures. The gross domestic product implicit price index for final domestic demand ("GDPIPIFDD") is an alternative to the IPC which merits consideration.[13] The GDPIPIFDD is less sensitive than the IPC to irrelevant fluctuations in energy and farm commodity prices. It is routinely used by the Ontario Energy Board in the construction of MRI inflation measures. It is available for Canada and Québec.

A downside of using the GDPIPIFDD is that annual GDPIPIFDD data do not become available for the previous year until the end of the following year (e.g., Annual 2017 data just became available). The November release also incorporates data revisions for the 2 years immediately preceding the data year (e.g., in 2018 that would be 2016 and 2015). After the third year, these data are not normally revised again except when historical revisions are carried out.

Base Productivity Growth Target

The *Jugement* Process

In an earlier stage of the proceeding, Concentric successfully advocated a process of *jugement* for setting the X factor for HQT. However, it notes on p. 38 of its April report that "The broad array of productivity studies (and specifically total factor productivity studies) utilized in distribution programs to set revenue path trajectories are lacking for transmission companies." Its two MRI reports focused on transmission productivity and cost trend information from Europe, Australia, and New Zealand and on a "Kahn method" exercise for calculating X based on HQT data.

The process of informed *jugement* which Concentric recommended for X factor selection works less well for power transmission than for distributor services due to the lack of pertinent transmission productivity studies and X factor rulings. This quandary, readily foreseeable, is all the more unfortunate since a study of the CNE productivity of transmitters --- the issue in this proceeding --- is relatively simple to undertake because the complicated and sometimes controversial tasks of measuring capital costs and the trends in capital prices and quantities are sidestepped.

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[13] Statistics Canada. Table 36-10-0223-01, Implicit price indexes, gross domestic product, provincial and territorial.

Concentric instead relies heavily for its recommendation on statistical cost research and decisions by regulators outside North America. In our view, this review is of limited value in establishing an X factor for the Company's CNE revenue cap index and does not support Concentric's -0.60% X factor recommendation. We discuss research here from each of the regions that Concentric discusses in turn.

European Research

- Concentric notes in its July report that the E3Grid [power transmission] benchmarking study considers total expenditures and not CNE. Since power transmission is a highly capital-intensive business, the E3Grid productivity estimates are very sensitive to capital cost trends. Concentric acknowledges on page 10 of the report that the E3Grid study is not pertinent for setting the Company's X factor for CNE revenue.
- Concentric notes on p. 29 of its April report that the Norwegian regulator has a 1.5% annual "general efficiency requirement".

The "RIIO" form of MRI which is currently used by Great Britain's Office of Gas and Electric Utility Markets ("Ofgem") to regulate power transmitters features multiyear rate plans with 8-year terms. The revenue caps are based in part on projections of required costs which embed productivity growth assumptions. Concentric states that

> Ofgem incorporates a proposed productivity improvement of 0.8% per year applied to total expenditures (Totex). For [National Grid Electricity Transmission], this number is composed of a 0.5% Opex productivity target and 0.8% Capex productivity target, suggesting that Capex is dominating Opex in the Totex. These targets are based on a combination of benchmarking analysis and forecast review by Ofgem.[14]

However, the numbers Concentric reported were actually for Ofgem's appraisal of "Real Price Effects", which is Ofgem's measure of the difference between the trends in industry input prices and the retail price index. Ofgem explained the difference between real price effect and ongoing efficiency assumptions in its cost assessment and uncertainty supporting document to its final proposals for National Grid's transmission service.

> The [real price effects] assumption, and associated ex ante allowance, reflects the expectation that there will be a difference between the change in the [macroeconomic inflation measure]

[14] Concentric, July report, p. 11.

and the change in the price of inputs that the [transmission utilities] will purchase over the price control, most notably labour. The ongoing efficiency assumption reflects the expectation that even the most efficient network company can make productivity improvements, for example by employing new technologies. This assumption represents the potential reduction in input volumes that can be achieved whilst delivering the same outputs.[15]

Ofgem approved an ongoing efficiency assumption of **1.0%** for opex and **0.7%** for capex. These assumptions are based primarily on work that Ofgem undertook using the EU KLEMS dataset. This dataset is published by the Conference Board and provides total and partial factor productivity measures for various sectors of the economy (e.g., construction, agriculture, manufacturing). Ofgem developed its total and partial factor productivity assumptions using KLEMS data for the 1970-2007 period for most industries in the UK.

Ofgem also reviewed several other sources of productivity evidence. For example, it relied on transmitters' own assumptions of ongoing efficiency growth. Another source was a decision by British regulators to set similar ongoing efficiency targets for the British water industry.[16] No study of power transmission productivity was relied upon to support Ofgem's productivity targets.

Concentric downplayed the significance of Ofgem's decision to set a positive opex productivity target by highlighting exclusions to the revenue cap, noting that

there are several adjustments to allowed revenues, providing increased revenue allowances for innovation spending, for volume-based cost drivers including load and non-load related Capex, a provision for "uncertainty mechanisms" and related adjustments.[17]

However, many of these adjustments would not address allowed CNE revenues. For example, the referenced "volume-based cost drivers" are proposed to address specific kinds of capital investments. Ofgem did approve trackers for costs of legacy pensions (e.g., pension plans that have been closed to participants) and provided an opportunity for National Grid to request additional funding for the enhancement of physical security and the roll-out of innovative programs if certain criteria were met.

[15] Ofgem (2012), RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas Cost assessment and uncertainty Supporting Document, p. 22.

[16] Ofgem (2012), RIIO-T1/GD1: Real Price Effects and Ongoing Efficiency Appendix, Final Decision-Appendix, p. 19.

[17] Concentric, July report p. 11.

A recent annual report by Ofgem on the performance of transmitters under the first generation RIIO MRI found that, despite revenue requirements that reflected expectations of positive opex and capex productivity growth, British power transmitters are still expected to overearn during the plan term by more than 200 basis points. The source of more than half of these overearnings has been power transmitters managing to spend less than their allowances

Australian Research

The Australian Energy Regulator ("AER") has jurisdiction over several power transmission utilities. These are regulated using multiyear rate plans that feature revenue caps with inflation – X formulas designed to recover revenue requirements approved on the basis of cost forecasts and statistical cost research. Here are some comments on Concentric's Australian evidence.

- Concentric correctly notes that the X factors chosen by the AER for power transmitters have varied appreciably between the transmitters and over time. The X factors are frequently negative. However, this evidence has limited relevance to the choice of an X factor for CNE revenue. One reason is that these X factors are very sensitive to expected trends in capital cost. Consider also that, as we explained in Section 3.1, the general formula for a revenue cap index is

  growth revenue = inflation – growth productivity + growth scale.

  The terms of this formula can be rearranged as follows

  growth revenue = inflation - (growth productivity – growth scale).

  Since the AER revenue cap indexes do not have scale escalators, the X factors must be set low enough to fund the cost impact of scale growth.

- The AER's studies of power transmission multifactor productivity are also very sensitive to capital cost trends. Moreover, these studies use a controversial "physical asset" approach to capital quantity measurement. For example, substation capacity and the lengths of overhead and underground transmission lines are treated as capital quantities. This approach to capital quantity measurement ignores the tendency of depreciation to slow cost growth.

The physical asset approach to capital quantity measurement has been twice rejected by the Ontario Energy Board ("OEB") in MRI proceedings as a tool for measuring PMF growth.[18] We conclude that the AER PMF index results are not useful in the establishment of X factors for the Company's CNE revenue or its total revenue.

- Concentric notes on p. 15 of its July report that the opex productivity of Australian power distributors averaged -0.64% over the 2006-2016 sample period. Excluding "redundancy payments" for labor downsizings the number falls to -0.39%. Concentric notes on p. 39 of its April report that "the average contribution of OPEX to total factor productivity was estimated at -0.3% over the 2006-2016 period."

  These are pertinent results for the Régie to consider. However, the latest iteration of the AER's opex PFP study featured an output index based on 5 variables: energy throughput (23.1%), ratcheted maximum demand (19.4%), end-user numbers (19.9%), and circuit length (37.6%) less minutes off-supply. These weights have been determined using econometric parameter estimates from a cost function.[19] The same scale index was used in the multifactor productivity indexes.

- Concentric's reports do not discuss the assumption of CNE productivity growth that the AER uses when escalating CNE revenue requirements. The most recent assumed opex productivity growth assumption for power transmitters is **0.00%.** This was used in a draft decision on the CNE revenue requirement for TasNetworks in September 2018. The AER stated in its decision that

  > We have forecast zero productivity growth based on analysis provided previously by our expert consultant, Economic Insights. We consider this reflects a reasonable expectation of the benchmark productivity that an

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[18] OEB proceedings EB-2007-0673, Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, September 17, 2008, p. 12. and EB-2016-0152, Decision and Order, December 28, 2017, pp. 126-127.

[19] Prior to 2017, the weights for the power transmission scale index used by the AER's consultant were energy throughput (21.4%), ratcheted maximum demand (22.1%), voltage-weighted entry and exit connections (27.8%) and circuit length (28.7%) less energy not supplied (weight based on Australian Energy Market Operator's current value of customer reliability). These earlier weights were determined using econometric parameter estimates from a cost function of translog form.

efficient and prudent transmission network can achieve for the forecast period because:

- Economic Insights has previously recommended we forecast productivity growth based on trend growth in opex MPFP performance measured in electricity transmission
- opex MPFP growth, over the period from 2006 to 2016 is negative, but very close to zero, at the industry level. We do not consider this is representative of long term trends and our expectations of forecast productivity in the medium term. The increase in the service provider's inputs, which is a significant factor contributing to negative productivity, is unlikely to continue for the forecast period. [20]

Hydro One Research

In response to a *demande de renseignement* ("DDR") from *Option consommateurs* ("OC"), Concentric referenced a power transmission productivity study submitted in October in an Ontario Energy Board proceeding by Hydro One Sault Ste. Marie ("HOSSM"). HOSSM owns a power transmission system in central Ontario which was formerly part of Great Lakes Power. Following Hydro One's acquisition of and merger with Great Lakes Power Transmission in 2016, HOSSM is now part of the transmission operations of Hydro One Transmission but is still separately rate-regulated. HOSSM is proposing a multiyear rate plan it calls Revenue Cap Incentive Rate-setting for its transmission services. The proposed plan would feature an eight-year term and a revenue cap index with an inflation – 0 formula. Also in October, Hydro One Transmission proposed to use this same revenue cap index to effect a "one-year mechanistic adjustment to Hydro One's 2019 revenue requirement.[21] Hydro One plans to file an MRI for its transmission services next year.

The proposed X factor is supported by productivity research and testimony prepared by Power Systems Engineering ("PSE"), which is based in Madison, Wisconsin. The PSE report does not consider the productivity trend of HOSSM but does present an estimate of the PMF trend of Hydro One Transmission.

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[20] AER Draft Decision, *TasNetworks Transmission Determination 2019-2024*, Attachment 6, Operating expenditure, September 2018, p. 6-18.

[21] OEB Proceeding EB-2018-0130, Exhibit A, Tab 3, Schedule 1, October 26, 2018.

PSE also calculates transmission productivity trends of a sample of 48 U.S. electric utilities over the twelve-year 2005-2016 sample period. Key findings of PSE's productivity research are as follows.

- Over the full sample period, the multifactor productivity trend of the sampled utilities averaged a 1.71% decline. Capital productivity averaged a 1.93% annual decline while CNE productivity averaged a more modest **0.83% annual decline**. Hydro One's PMF averaged a much smaller -0.31% decline during this period. Hydro One's CNE productivity averaged **1.07% annual growth** while its capital productivity averaged a 0.58% annual decline.
- Over the more recent 2010-2016 period, the PMF growth of sampled US transmitters averaged a 2.40% annual decline. Capital productivity averaged a 3.17% annual decline while CNE productivity growth was **flat.** The PMF growth of Hydro One averaged a more modest -0.47% decline. The capital productivity of Hydro One averaged a 1.17% decline while CNE productivity averaged **2.90% growth.** These results run counter to Concentric's narrative that the CNE productivity of transmitters has declined in recent years.
- PSE recommended and HOSSN proposed an X factor of 0.

The Ontario Energy Board retained PEG on October 31st to appraise PSE's research and testimony in this proceeding and provide alternative evidence. The working papers for this work were received the day our testimony in this proceeding was due. DDRs will not be submitted for several weeks. Hydro One will then have several additional weeks to provide answers to questions from PEG, Board staff, and intervenors. Hence, the PSE productivity study will not be properly vetted for some time.

PEG has nonetheless conducted a preliminary review of PSE's evidence in the HOSSM proceeding. Based on this review, we have several concerns about this research. Here are some of the most important ones.

- The transmission productivity study was supervised by Steven Fenrick. While Mr. Fenrick was an employee of PEG for several years and shares our views on some methodological issues, he has not to our knowledge previously prepared a power transmission productivity study.

- The number of companies in the productivity sample is rather small, as many other large investor-owned electric utilities in the United States provide transmission services. Reasons for excluding other companies are unknown and should be carefully examined.
- No attempt is made to choose a peer group facing business conditions that are similar to those facing Hydro One.
- The 2005-2016 sample period for the research is rather short for a CNE productivity trend study. Data are now available through 2017. The 2005 start date is ostensibly due to the fact that this is the first year data are available for a transmission peak demand variable which we are not sure is essential to the study. PSE's productivity results are fairly sensitive to the choice of the sample period.[22]
- Growth in each scale index is a weighted average of growth in ratcheted peak demand and the length of transmission lines. The weights (26% for demand and 74% for lines) were obtained from econometric cost elasticity estimates from a total cost function, not a CNE function.
- Due to Ontario data limitations, the CNE weights for labor and material and service expenses were unnecessarily fixed for all sampled utilities at 38% and 62% respectively. US data permit these weights to vary by year. Chain-weighted quantity indexes are generally more accurate measures of input quantity trends.
- Our experience suggests that the costs excluded from transmission O&M expenses must be thought through carefully due to major changes in the structure of the U.S. transmission industry which occurred during the sample period.
- PSE uses a 1989 benchmark year adjustment to calculate capital cost for US utilities in the sample even though a 1964 benchmark year is feasible for these utilities. This may significantly reduce the accuracy of the capital and multifactor productivity results.

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[22] A similar problem was encountered in the recent Ontario Power Generation MRI proceeding.

- Capital cost is calculated using a methodology that, like geometric decay, features a constant depreciation rate. However, the PSE methodology excludes capital gains, so that the PMF indexes tend to overemphasize the importance of the (more negative) capital productivity trend.

- PSE does not exclude companies from its sample which had sizable transfers of assets between the transmission and distribution sectors of the utility. This is a potential problem when monetary methods are used to calculate capital costs.

Concentric is correct to note on p. 32 of its April report that U.S. power transmission utilities are typically regulated by the Federal Energy Regulatory Commission ("FERC") using formula rate plans. Regulatory Research Associates noted in a recent report that

> FERC policy has been to permit utilities to establish transmission rates using a formula-based approach that updates rates annually through the filing of revised data in a utility's tariff. The annual updates are based primarily on each utility's costs as reported in its annual FERC Form 1 filing. Approximately 100 utilities nationwide currently employ formula rates.[23]

These plans effectively involve comprehensive cost trackers that weaken cost containment incentives. Concentric states in response to DDR 5.1 from PEG that

> In general, a multi-year rate plan contains stronger incentives than an annual adjustment plan (such as the FEC's formula rate).[24]

PEG presented results in an incentive power model in the Appendix of its first MRI report. We reported that the long-run annual efficiency gains achieved under an MRI with a three-year rate case cycle and no MTÉR was 90 basis points higher than under cost plus regulation. This should be taken into account when appraising trends in the productivity of U.S. transmission utilities. HQT's MRI does have a MTÉR but this shares only surplus earnings and has a four-year term.

HQT Kahn Method Research

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[23] Regulatory Research Associates (2018), *RRA Regulatory Focus An Overview of Transmission Ratemaking in ISO New England – 2018 Update*, October 25, p. 2.

[24] R 4058-2018, B-0067, Réponses du Transporteur, 23 October, p. 9.

PEG introduced the Kahn method for calculating X factors in our initial testimony in this proceeding. In its recent July evidence, Concentric used the Kahn method to calculate an X factor using the Company's CNE data and the Régie's prescribed treatments for the inflation measure and scale variable. Concentric notes in its July report that this research produced a **0.57%** X factor for the full 2009-2017 sample period for which data were gathered. A **-0.64%** trend was noted for the more recent 2013-2017 period. The result for this period is deemed by Concentric to be more pertinent for X factor selection. These results include *prestations de travail*. In response to Question 11 of FCEI, the Company reported that when these costs are excluded from the calculations the indicated Kahn X factor was **0.88%** for the full sample period and **-0.94%** for the more recent 2013-2017 sample period. In response to FCEI DDR 11.4, Concentric stated that "Concentric did not review a forecast of HQT costs that would be subject to the X factor."

We believe that the longer sample period that Concentric considered is more pertinent for the following reasons.

- We noted in Section 3.1 that CNE productivity is characteristically volatile, and this speaks to the need for a longer sample period to smooth out fluctuations.
- HQT discussed the recent rapid rise in its CNE in response to DDRs 10.2 and 10.4 of the Régie. They noted that CNE growth was stimulated during the 2013-2017 period by the Company's transition to a new asset management system that raised maintenance expenses. Cost was further raised by the implementation of new critical infrastructure protection ("CIP") standards. HQT refused to answer legitimate questions by SE-AQLPA which were intended to assess whether the recent acceleration in CNE expenses needs to continue.
- An MTÉR was instituted in 2017 which weakened the Company's cost containment incentives. The Company also has an incentive to have high CNE in the base year of the MRI, all the more so since X will likely not be adjusted for the results of a statistical benchmarking study.
- The PMF growth of Canada's economy has accelerated in the last few years. This may have caused IPC^{Canada} to understate the inflation in prices of utility CNE inputs.

We do not agree with Concentric when they say in response to DDR 10.4 of the Régie that "operating expenditures are subject to shorter term operating and economic trends. It is therefore appropriate to consider shorter periods of measurement." To the contrary, the greater volatility of CNE speaks to the need for longer sample periods.

Canadian Utility Sector Productivity

Concentric correctly notes on p. 36 of its April report that the longstanding gap between the PMF trends of the U.S. and Canadian private business sectors has recently narrowed. Canadian PMF has accelerated while U.S. PMF has slowed.

Concentric notes on p. 36 of its April report a "declining productivity growth in the (Canadian) utility sector, as illustrated in the multifactor productivity data provided by Statistics Canada." These trends are also noted in response to information request 10.4 of the Régie. PEG has criticized this research and its pertinence for utility X factors in several past proceedings. In our last MRI evidence for HQD, for example, we explained that *Statistique Canada* has calculated PMF indexes for the "utility" sector of the Canadian economy and two subsectors: "Electric power generation, transmission, and distribution" and "natural gas distribution, water, and other systems".[25] Though *Statistique Canada* continues to maintain the utility sector index, the two subsector indexes were terminated in 2010.

These indexes have been calculated in the past on both a "gross output" and a "value added" basis. The gross output approach is more similar to that conventionally used in productivity studies for X factor calibration because it includes intermediate inputs like materials and services. The value-added approach does not include these inputs because it is intended for use in the calculation of the PMF growth of Canada's aggregate business sector.[26] Only results for the value-added utility PMF index are reported on a timely basis, and it is these results that CEA reports in its April submission.

Results of the value-added utility PMF index that CEA features in its report are of limited relevance in setting an X factor for HQT, for several reasons.

[25] Régie proceeding R 4011-2017, C-AQCIE-QFIC-0024, MRI Design for Hydro-Québec Distribution, January 5, 2018.

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

- A value-added calculation places an unusually heavy weight on capital productivity but ignores productivity in the use of intermediate inputs that are components of CNE.
- The index is sensitive to developments in the generation sector of the electric utility industry. This has little relevance to network industries such as power transmission. For example, the growth in the index has in recent years presumably been slowed by Hydro-Québec projects to develop remote hydroelectric resources.
- The electric utility industry restructured in Alberta and Ontario. It is not clear how well this has been handled by *Statistique Canada*.
- A volumetric scale index is employed that makes results sensitive to changing business conditions, such as slowing growth in average use of natural gas and electricity by residential and commercial customers, which matter little in the design of the Company's *formule paramétrique* for CNE revenue. Dr. Lowry explained in his Phase 1 testimony that the scale specification in a productivity study used to calibrate the X factor of a revenue cap index should ideally be consistent with the scale metric that is used in that index.
- Measured power industry productivity growth is also slowed by growth in expenses for utility conservation and load management programs. These are large in several Canadian provinces but are irrelevant to the design of a CNE revenue cap for the Company.

The *Statistique Canada* PMF indexes for "electric power generation, transmission, and distribution" and "natural gas distribution, water, and other systems" are available on a gross value basis through 2010. On average, the productivity of the gas and water sector grew by 0.55% annually between 1962-2010. For the most recent 20 years (1991-2010) productivity declined by 0.09% per year on average, and for the most recent ten (2001-2010) it declined by 1.44%. Output was once again measured volumetrically, and thereby reflected the material downward trend in the average use of gas by Canadian residential and commercial customers.

As for the PMF index for the "electric power generation, transmission, and distribution," using the gross output approach, Statistics Canada reports a 0.61% average annual growth rate in utility sector productivity for the full 1962-2010 period. For the most recent 20 years (1991-2010), the average growth rate is 0.41%. For the most recent ten years (2001-2010), productivity declines by a modest

0.12% annually. This comparison suggests that the gas and water sector contributed greatly to the negative productivity growth that *Statistique Canada* reported for the full Canadian utility sector.

The Alberta Utilities Commission ("AUC") stated in its decision on first-generation MRI for provincial energy distributors that

> Overall, the Commission considers that while Statistics Canada's MFP indexes . . . can be a useful reference for gauging the general productivity trends of the utilities sector, these analyses cannot be a substitute for a TFP study for either the electric or gas distribution industries.[27]

Concentric's Conclusions

Concentric states on p. 38 of the April report that "the declines in productivity evidenced in North American distribution utility studies are similarly evidenced based on increasing input costs and flat-to-declining outputs (e.g., Australia)." In fact, Concentric never established that the trend in North American distribution utility productivity has been negative, and the Régie chose a 0.3% X factor for HQD. Moreover, Concentric has not provided convincing evidence of a declining trend in the CNE productivity for power transmitters in this proceeding.

Other Concentric Comments

Concentric made several other comments in its X factor discussions which merit note.

- On p. 38 of its April report Concentric states that "cost of service regulation remains the standard for transmission companies in North America, but [MRI] programs for transmission companies have been developed internationally, and some have operated for multiple generations." Multiyear rate plans in Australia, Great Britain, New Zealand, and Norway are discussed. Since Concentric filed its July report, we have noted that Hydro One has proposed an MRI for an Ontario transmission utility and will propose one for its principal Ontario transmission operations next year. Thus, multiyear rate plans which extend to capital cost are widely viewed as being suitable for power transmission. PEG presented the Régie with both hybrid and indexed approaches to the design of a revenue cap for power transmission in prior testimony.

[27] AUC Proceeding No. 566, Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, September 12, 2012, p. 85.

- Power transmission cost is not unusually difficult to benchmark. Evidently, transmission utilities in Australia, Great Britain, continental Europe, and Ontario are benchmarked using statistical methods. HQT participates in some unit cost benchmarking programs.

- A general problem with Concentric's X factor evidence is inadequate emphasis on transmission productivity targets *chosen by regulators*. This was also a problem with Concentric's evidence in the distribution MRI proceeding.

- Concentric states on p. 38 of its April report that "the goal of regulatory efficiency with transmission can be served with multiyear rate plans, or formula rates, such as that adopted by the FERC." While both of these regulatory systems do lower regulatory cost, only multiyear rate plans also have the potential to incentivize improved performance, a requirement of Québec law. Moreover, the regulatory system that the Régie has approved for HQT includes a continuation of cost of service regulation for capital cost. Hence, little reduction in regulatory cost can be anticipated from the MRI for HQT.

PEG's Base Productivity Trend Recommendation

We recommend a base productivity trend of **0.20%** for the Company's CNE revenue index. The following facts are critical to this determination.

- The X factor in HQT's *formule paramétrique* for CNE has been **2.0**% since 2014.

- Unvetted research by PSE reveals that Hydro One Transmission's annual CNE productivity growth averaged **1.07%** over the full 2005-2016 sample period considered and has accelerated in more recent years.

- Ofgem has recently used an ongoing efficiency assumption of **1.0%** for power transmitter CNE.

- Concentric reported a **0.57%** X factor using the Kahn method over the full 2009-2017 sample period. The Kahn X rose to **0.88%** when capitalized O&M expenses were excluded from the calculation.

- The AER's most recent CNE productivity growth assumption for power transmitters is **0.00%.**

- The AER's consultant has reported that the CNE productivity of Australian power transmitters averaged a **0.39%** decline for Australian power transmitters. However, the scale index used in this calculation is not ideal.
- Concentric's Kahn method research suggests that HQT's recent CNE productivity growth may have been negative. However, it is not at all clear whether this trend needs to continue.
- PSE reports that the CNE productivity of US power transmitters averaged a **0.83% annual decline** over the full 2005-2016 sample period. However, this calculation has not been vetted. Most U.S. power transmitters operate under formula rate plans that greatly weaken their cost containment incentives. Our incentive power research suggests that this may have a major productivity impact.
- The available data from Australia, Canada, and the United States do not on balance indicate a recent general decline in transmission CNE productivity.

Stretch Factor

We explained in our R-3897-2014 and R-4011-2017 reports that the stretch factor term of an X factor should reflect an expectation of how the productivity growth of the subject utility will differ from the base productivity growth target. This depends in part on how the performance incentives generated by the plan compare to those in the regulatory systems of utilities in productivity studies that are used to set the base productivity trend. It also depends on the utility's operating efficiency at the start of the MRI.

Initial operating efficiency is often assessed in MRI proceedings by statistical benchmarking studies. The methods used in these studies run the gamut from crude unit cost metrics to sophisticated econometric modelling and data envelopment analysis. In succeeding MRIs, the linkage of the stretch factor to statistical benchmarking of the utility's forward test year cost proposal can serve as an efficiency carryover mechanism that rewards the utility for achieving lasting performance gains and can penalize the utility for a failure to do so.

Initial Operating Efficiency

Regarding HQT's operating efficiency, we note first that the Company has not previously operated under a multiyear rate plan. Rather, it has operated under frequent rate cases for many years, a regulatory system that typically yields weak cost containment incentives. In 2017 and 2018 its cost containment incentives have been further weakened by an MTÉR.

The Régie has used a *formule paramétrique* to appraise HQT's proposed CNE for nearly a decade, but this has not had the incentive impact of a rate or revenue cap index. There is, in any event, no credible argument for setting stretch factors at zero simply because a utility has operated under an MRI. Since rate cases are still fairly frequent under most MRIs and some plans have MTÉRs, the performance incentives generated by these plans are not likely to be strong enough to eliminate the accumulated inefficiencies of subject utilities. Even if incentives provided by such caps were much stronger, it is notable that companies in competitive markets have widely varying degrees of operating efficiency. Any claim to superior operating efficiency should therefore be demonstrated empirically if a utility wishes to avoid a stretch factor.

The cost efficiency of utilities in Australia and Ontario are routinely appraised using econometric benchmarking. Hydro One has recently submitted an econometric benchmarking study of its cost efficiency in support of an Ontario transmission MRI application. This company has a large transmission system and extensive operations on the Canadian shield.

Under the Hydro-Québec Act (sections 7.2 and 20.1), the effectiveness and performance of Hydro- Québec must be assessed by an independent firm every three years, and the results of any such benchmarking studies must appear in the Company's annual reports. Benchmarking results are also discussed periodically in the Company's regulatory proceedings.

For years HQT has participated in benchmarking studies of its customer service and distribution costs which are conducted by benchmarking consultancies and the Canadian Electricity Association. The Company reports simple unit cost metrics and its general position related to the other participants in these studies but does not generally provide extensive detail. Controls for external business conditions in these studies are generally crude. Sophisticated statistical cost benchmarking studies like those considered by regulators in Ontario, Australia, and many European countries have not been presented.

On the basis of available evidence, it is reasonable to assume that HQT's proposed CNE revenue requirement for 2019 reflects average cost performance.

Comparison to Incentives in Other Regulatory Systems

CNE revenue will be subject to a *formule d'indexation*. Since capital cost will not, HQT will have a perverse incentive under the plan to spend higher amounts on capex in order to profit from CNE containment. On the other hand, the MRI will have a term of only four years. An MTÉR will be included that, absent a decline in service quality, will share any surplus earnings between the Company and its customers. The plan will not have an MRE. On balance, the Company's incentives to contain cost under the MRI will be materially stronger than under the formula rate plans common in the U.S. but no stronger than that of overseas transmitters operating under MRIs.

Precedents

Table 4 of our second report in the HQD MRI proceeding presented results of a survey of stretch factors in approved North American MRIs. Here are some pertinent findings.

- Stretch factors averaged **0.29**% for electric utilities and **0.39**% for all energy utilities.
- In Ontario, stretch factors range from **0% to 0.60%** and are typically zero only for superior cost performers.
- In the first-generation MRI in Alberta, the stretch factor for all utilities was 0.20%.
- The current MRIs for gas and electric operations of Fortis in British Columbia are 0.20% and 0.10%, respectively.
- In the current MRI for Eversource Energy the stretch factor is 0.25% if growth in gross domestic product price index exceeds 2%.
- The current first-generation MRI for Ontario Power Generation the stretch factor is 0.30%.

PEG's Stretch Factor Recommendation

Considering all of these factors, we believe that a stretch factor of **0.20%** is reasonable for HQT if its X factor is based on Australian, Canadian, or and European productivity evidence. A considerably higher stretch factor would be warranted were the base productivity growth factor to be driven solely by U.S. power transmission productivity research.

X Factor Summary

Adding a **0.20**% stretch factor to a base productivity trend of **0.20%**, we recommend a **0.40%** X factor for the Company's CNE revenue cap index.

PMF Study

HQT disregarded the Régie's order to present its methodology for the PMF study in its 2019 *demande tarifaire.* In response to information request 1.2.1 of S.E.-AQLPA*,* the Company stated that it did not intend to file a draft *mandat de l'expert* with the Régie.

We believe that establishing some guidelines in advance concerning the scope and methodology for this study can encourage HQT to hire a consultant with the right expertise and to produce a constructive study. In the absence of Régie guidelines, the Company is more likely to produce an inadequate and self-serving study and then argue that requests for additional work are unreasonable.

We believe that the study should consider alternative productivity measurement methodologies and sample periods and thoroughly discuss their pros and cons. Productivity trends in the use of CNE and capital inputs should be considered as well as the trend in multifactor productivity. Productivity trends of HQT should be measured as well as productivity trends of other utilities. Hydro One's recent evidence in proceedings considering MRIs for its transmission and distribution services included estimates of its own productivity trends as well as industry trends.

A decision should also be made whether to require a statistical benchmarking study of HQT's cost level. This could be an econometric benchmarking study like that which Hydro One recently filed in Ontario. Alternatively or in addition, HQT could participate in future E3Grid studies.

Note, finally, that when HQT submits its proposed methodology intervenors should have the opportunity to comment on the proposal. This commentary should aid the Régie as it considers an appropriate response.

4. Other Revenue Cap Issues

4.1 HQT's Evidence and Proposal

Y Factor Eligibility

HQT has proposed to Y factor costs of pensions, taxes, and capitalized labor during the MRI term.

Z Factor Eligibility

The Company also seeks approval, in advance of the plan's commencement, to Z factor costs of several tasks that include replacement of the network control systems and a transmission network backup automation system, diagnosis and corrective actions required to address metal thefts and ensure ground compliance from substations, and compliance costs of North American Electric Reliability Corporation CIP standards. In Table 3 of HQT-6, Document 2, HQT shows that most costs of CIP standards compliance are CNE. CIP standards compliance may require that cybersecurity or physical security measures be undertaken. HQT incurred CIP standard compliance costs to address security concerns with laptops and flash drives that come into contact with important systems. HQT inventoried workstations and applications used on its network, developed and implemented a laptop compliance standard, developed and implemented training to ensure compliance, and implanted monitoring and correction tools to ensure that the Company remains in compliance with this standard.

HQT has also requested that the Régie approve a generic Z factor to record the cost of potential Z factors that are "unpredictable" and not integrated into the Transmitter's revenue requirement. Costs recorded in the generic Z factor would be incorporated into a neutralization account, which the Régie would review in a subsequent *dossier tarifaire* to ensure that the cost is eligible for Z factoring. If deemed eligible, the Régie would also determine how the cost should be addressed.

Materiality Thresholds

HQT supports $2.5 million materiality thresholds for Y factors and Z factors and their application as proposed by the Régie.

4.2 PEG's Response

Y Factor Eligibility

Eligible Costs

PEG has some general concerns about the Y factoring of costs in an MRI. Y factoring can weaken incentives to contain the targeted costs and raise the cost of regulation. Customers can benefit when utilities absorb risks of cost fluctuations. On the other hand, some costs are difficult to address with a revenue cap index, due in part to their sensitivity to volatile external business conditions. Y factoring costs like these can sidestep revenue cap design controversy. By reducing the utility's operating risk, Y factoring can also permit an extension of the plan term. This can strengthen performance incentives for non-tracked costs and reduce regulatory cost on balance. Y factoring costs occasioned by government directives promotes fairness. A pertinent consideration when choosing how many costs to Y factor is how much risk the utility is otherwise exposed to.

Table 1 presents information on accounts that are eligible for Y factoring in recent MRIs of North American energy utilities. It can be seen that diverse costs have been accorded Y factor treatment. Costs commonly eligible for Y factoring include those for energy procurement, upstream transmission, and conservation programs.[28] Retirement costs and taxes have been Y factored in some approved MRIs but not others.

Y factoring HQT's sizable retirement costs is a judgement call, as there are reasonable arguments on both sides. On the downside, tracking these costs weakens the Company's incentive to contain them. Since salary and wage revenue will be indexed, HQT will have some incentive to shift employee compensation from salaries and wages to retirement benefits. Review of the prudence of retirement costs is challenging enough without this complication. The decision on whether to Y factor retirement costs should also depend on the extent to which HQT's regulatory system protects the Company from other kinds of risk. The cost of service treatment of capital cost and the high share of capital cost in HQT's total cost substantially reduces the Company's operating risk. HQT also has an

[28] Some of the sampled utilities that do not Y factor costs of conservation programs do not have such programs.

unusually low risk of stranded cost since the system is chiefly used to transmit low cost power from hydroelectric generating stations.

Table 1

Approved Y Factors in Current North American MRIs[fn]

Company	Jurisdiction	Plan Term	Eligible Costs and Accounts	Citation
Eversource Energy	Massachusetts	2018-2023	Not discussed in decision. Company currently has approved riders to address the costs of DSM programs, pensions, Attorney General Consulting Expenses, pensions and post-employment benefits, state funded renewable programs, solar program, and storm reserves. A Y factor to address the costs of an enhanced vegetation management pilot program was approved in this proceeding.	DPU 17-05
All Distributors	Alberta	2018-2022	All costs that meet the AUC's Y factor criteria. To date, the following costs have been found to meet these criteria: AESO flow-through items Farm transmission costs Accounts that are a result of Commission directions (e.g., AUC assessment fees, intervener hearing costs, UCA assessment fees, AUC tariff billing and load settlement initiatives, Commission-directed Rural Electrification Associations (REA) acquisitions, effects of regulatory decisions) Income tax impacts other than tax rate changes Municipal fees Load balancing deferral accounts Weather deferral account (ATCO Gas only) Production abandonment costs	Decision 20414-D01-2016 (Errata)
Ontario Power Generation	Ontario	2017-2021	Hydroelectric Water Conditions Variance Account Ancillary Services Net Revenues Variance Account – Hydroelectric and Nuclear Sub-Accounts Hydroelectric Incentive Mechanism Variance Account Hydroelectric Surplus Baseload Generation Variance Account Income and Other Taxes Variance Account Capacity Refurbishment Variance Account Pension and OPEB Cost Variance Account Hydroelectric Deferral and Variance Over/Under Recovery Variance Account Gross Revenue Charge Variance Account Pension & OPEB Cash Payment Variance Account Pension & OPEB Cash Versus Accrual Differential Deferral Account Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account	EB-2016-0152
FortisBC	British Columbia	2014-2019	Numerous costs are Y factored including pensions and other post retirement benefits, regulatory hearing costs, accounting standards changes, on-bill financing, interim rate variance	Project #3698719, Decision; September 2014
FortisBC Energy	British Columbia	2014-2019	Numerous costs are Y factored including overhead costs recovered from thermal energy customers, energy policy programs, pensions and other post-employment benefits, midstream gas costs, energy efficiency and conservation, biomethane program, hearing costs, on-bill financing, BCUC assessments, gains and losses on disposition or retirement of property	Project #3698715, Decision; September 2014
Union Gas	Ontario	2014-2018	Upstream gas and transportation costs, incremental DSM costs, LRAM volume reductions for contract rate classes, Unaccounted for Gas Volume Variances, 50% share of tax changes	EB-2013-0202
Incentive Regulation Mechanism Power Distributors except those who opt out	Ontario	2014-2018	**Group 1 includes accounts that do not require a prudence review. This group will include account balances that are cost pass-through and accounts whose original balances were approved by the Board in a previous proceeding.** Low Voltage Account Wholesale Market Service Charge Account Retail Transmission Network Charges Account Retail Transmission Connection Charge Account Power Account Global Adjustment Account **Group 2 includes accounts that require a prudence review.** Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs Other Regulatory Assets - Sub-Account - Incremental Capital Charges Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act Retail Cost Variance Account Board-Approved Conservation and Demand Management Variance Account Others	EB-2010-0239, Filing Requirements For Electricity Distribution Rate Applications (Group 1), EB-2008-0046 and 2018 DVA Continuity Schedule
Hydro One Sault Ste. Marie	*Ontario*	*2019-2026*	*Renewable generation connections, system planning, and infrastructure investment resulting from the Green Energy and Green Economy Act of 2009, variances in payments in lieu of taxes paid to First Nations, Ontario Energy Board Cost Assessment Variances, and IFRS Gains and Losses on Asset Disposals*	*EB-2018-0218*

[fn] Rows in italics are proposed Y factors.

On the other hand, annual retirement costs can be quite variable due to financial market conditions that are beyond HQT's control. The labor price subindex of the inflation measure for the CNE revenue cap index tracks trends in salaries and wages in Québec but not retirement costs. The Régie has decided to Y factor retirement costs of HQD. Based on all of these considerations, PEG recommends that retirement costs should be addressed by the *formule paramétrique*.

Y factoring taxes and *coûts liés aux prestations de travail aux investissment* reduces the incentive to contain these costs. The need to contain risk is reduced by the relatively short four year term of the MRI, low stranded cost risk, and the cost of service treatment of depreciation and the return on rate base. Changes in tax rates are a risk and beyond the Company's control, but these would be potentially eligible for Z factors. Neither of these costs are Y factored in the MRI of HQD. On balance we recommend addressing these costs via the *formule paramétrique*.

Z Factor Eligibility

HQT has asked for preapproval of several specific costs for Z factor eligibility. This is an unusual proposition, and the Regie is not obliged to decide on this issue now. We agree that the *coûts liées aux normes CIP* should be eligible for Z factoring if they pass the materiality threshold, as these are occasioned by third party mandates. However, the other specifically mentioned costs should not be. We oppose the establishment of the proposed general Z factor mechanism. This would save very little time and regulatory cost and may serve to prejudge the issue of Z factor eligibility. We believe that this type of mechanism is rare in MRIs.

Materiality Thresholds

Materiality thresholds have several advantages in a system of cost trackers. These thresholds are chiefly rationalized by regulators as a means to reduce regulatory costs. If properly designed, they can also strengthen a utility's incentive to contain tracked costs and reduce overcompensation for events, such as severe storms, which are routinely encountered by utilities and reflected in the cost data used in productivity studies.

Table 2 presents information on materiality thresholds in contemporary energy utility MRIs. It can be seen that Z factors are more typically subject to materiality thresholds in the surveyed plans than

Table 2

Materiality Thresholds for Y and Z Factors[fn]

Company	Jurisdiction	Plan Term	Y Factor Materiality Threshold	Z Factor Materiality Threshold	Citation
Eversource Energy	Massachusetts	2018-2023	Some Y Factors (e.g., $1.2 million per event for the storm fund) have a materiality threshold	$5 million escalated by GDPPI for each year of the plan for each Z factor event	DPU 17-05
All Alberta Distributors	Alberta	2018-2022	Common threshold for Y factor and Z factors: Dollar value of a 40 basis point change in ROE on an after-tax basis calculated on the distribution utility's equity used to determine the final approved notional revenue requirement on which going-in rates were established (2017). This dollar amount threshold is to be escalated by I-X annually. Z factor materiality is determined on a per event basis.		Decision 20414-D01-2016 (Errata)
Ontario Power Generation	Ontario	2017-2021	O&M materiality threshold not discussed in decision, incremental capital module has threshold and deadband	$10 million	EB-2016-0152
Enmax	Alberta	2015-2017	O&M materiality threshold not discussed in decision, separate capital materiality threshold established	$1.7 million per event per year	Decision 21149-D01-2016 (Errata)
FortisBC	British Columbia	2014-2019	O&M materiality threshold not discussed in decision, separate capital materiality threshold established	0.5% of 2013 Base O&M Expense, approximately $300,000 per Z factor event	Project #3698719
FortisBC Energy	British Columbia	2014-2019	O&M materiality threshold not discussed in decision, separate capital materiality threshold established	0.5% of 2013 Base O&M Expense, approximately $1.15 million per Z factor event	Project #3698715
Union Gas	Ontario	2014-2018	O&M materiality threshold not discussed in decision, $5 million revenue requirement impact for capital projects	$ 4 million per Z factor event	EB-2013-0202
Incentive regulation mechanism power distributors except those who opt out	Ontario	2014-2018	O&M materiality threshold not discussed in decision, incremental capital module has threshold and deadband	Per Z factor event: Utility with Revenue Requirement less than or equal to $10 million: $50,000 Utility with Revenue Requirement between $10 and $200 million: 0.5% of distribution revenue requirement Utility with Revenue Requirement above $200 million: $1 million	EB-2010-0379
Hydro One Sault Ste. Marie	*Ontario*	*2019-2026*	*O&M materiality threshold not discussed in decision, incremental capital module has threshold and deadband*	*$201,277 per Z factor event (0.5% of revenue requirement)*	*EB-2018-0218*

[fn] Rows in italics have not been approved by a regulator.

Y factors. Thresholds are more common for capital cost Y factors and are sometimes substantial. It should also be noted that incentivization of cost trackers by limiting the full true up of revenue requirements to actual costs also occurs in North American regulatory systems that do not feature MRIs.[29]

A materiality threshold for HQT that is comparable to HQD's $15 million threshold using 2019 data is more than $5 million (approximately $5.57 million). HQD's 2019 RR that is subject to the revenue cap index is $2,586.5 million, while HQT's proposed 2019 base for indexing is $960.4

[29] Cost trackers are widely used in U.S. regulation today even in the absence of multiyear rate plans.

million. This calculation assumes that HQT would get all of its Y factors. If it did not, HQT's comparable materiality threshold would increase. We recommend \$5 million thresholds for HQT.

These thresholds should apply on a per event basis to Z factors and to variances between Y factored costs and the corresponding revenue requirements. The first \$5 million should be non-recoverable each year. These thresholds should be escalated annually by the revenue cap index.

5. *Formule Paramétrique* for Capital Cost

5.1 HQT's Evidence and Proposal

Concentric also provided some evidence on possible *formules paramétriques* for the Company's capital cost in its July reports. Precedents from Canadian power distributor MRIs were emphasized in this discussion. Concentric noted the relevance of a formula similar to those in the current MRI of FortisBC but did not develop a specific formula.

HQT proposes a formula for normalized capital cost that is broadly similar to that for the escalation of its CNE revenue. The formula is inflation less an X factor plus a growth factor. The inflation measure would be a weighted average of the growth in the EERH for all Québec industries and the $IPC^{Québec}$. The weights for these two items would be fixed at 0.45% for the labor index and 0.55% for the IPC. A 0.20% X factor is proposed that results from a Kahn Method calculation using the Company's capital cost data for the five-year 2013-2017 period. The Company shows in response to Régie information request 12.1 that similar results are obtained when taxes and *prestations de travail aux investissments* are excluded from the calculations. The proposed growth factor is the estimated capacity of the transmission network. This in turn is apparently derived from an estimate of generation capacity.

5.2 PEG's Response

PEG has the following comments on HQT's evidence.

- The FortisBC *formule paramétrique* pertains to capital expenditures, not capital cost. However, a formula of this general form can also apply to capital cost.
- Concentric mentions the "Custom IR" MRIs used by some Ontario utilities which have a C factor for supplemental capital revenue. It is important to note that the Custom IR option is available to utilities proposing capital cost growth that exceeds that which the rate or revenue cap index can provide. It is not used when a rate or revenue cap index is expected to overcompensate the utility for its capital cost.
- With respect to the inflation measure, we note that the weight for the labor price index in HQD's revenue cap index is the share of CNE labor in the total revenue requirement and

does not include any costs of labor used to achieve gross plant additions. The $IPC^{Québec}$ is the input price subindex designed to represent inflation in capital prices. It is fairly sensitive to labor price trends given the labor-intensive technologies for producing many goods and services in the economy. However, it is subject to irrelevant fluctuations in prices of agricultural and energy commodities. The GDPIPIFDD has the advantage of being insensitive to these price fluctuations.

The true price of capital is a complicated function of trends in the rate of return on capital and historical construction costs. *Statistique Canada* has suspended calculation of its Electric Utility Construction Price Index series.

- Transmission operating scale is multidimensional, so HQT's use of a single scale metric may be one reason that its *formule paramétrique* doesn't fit its cost data better. We developed an econometric model of transmission capital cost to identify additional scale variables and develop cost elasticities and elasticity weights. Data were drawn from a sample of 41 vertically-integrated U.S. electric utilities over the 1996-2016 sample period. The cost data were drawn from FERC Form 1 reports. Capital cost was measured using the geometric decay ("GD") method. The dependent variable in the research was real transmission capital cost, the ratio of nominal capital cost to a GD capital price index. Our research identified four statistically significant measures of transmission operating scale: the number of retail customers (which is highly correlated with expected peak demand), generation capacity, ratcheted peak demand, and transmission line miles. The elasticity estimates and corresponding elasticity weights are reported in the following matrix.

Variable	**Estimated Cost Elasticity**	**Elasticity Share (%)**
Number of Retail Customers	15.6%	14.8%
Generation Capacity	10.4%	9.9%
Ratcheted Peak Demand	43.8%	41.5%
Transmission Line Miles	35.8%	33.9%

Total		100%

It can be seen that the cost elasticity estimates all have the expected positive sign and plausible magnitudes. These results provide the basis for a sensible elasticity-weighted scale index. Details of the econometric research can be found in Table 3.

Table 3

Econometric Model of Transmission Capital Cost

EXPLANATORY VARIABLE	ESTIMATED COST ELASTICITY	T-STATISTIC	P Value
Number of Customers*	0.156	4.935	0.000
Transmission Line Miles*	0.358	17.217	0.000
Generation Capacity (MW)*	0.104	4.850	0.000
Ratcheted Maximum Peak Demand*	0.438	11.606	0.000
Trend*	-0.004	-3.537	0.000
Constant*	16.586	1051.522	0.000
System Rbar-Squared	0.903		
Sample Period	1996-2016		
Number of Companies	41		
Number of Observations	848		

***Estimate is significant at the 99.9% confidence level**

This model can if desired be placed in projection mode and serve as an alternative *formule paramétrique*.

Based on our research, with its limited budget, we recommend the following changes in HQT's proposed *formule paramétrique* for capital.

- The proposed inflation measure should be replaced with the GDPIPIFDD or another macroeconomic Canadian price index that is insensitive to irrelevant commodity price fluctuations.
- The formula should use the elasticity-weighted scale index that results from our econometric cost research, or at least incorporate transmission line miles with a substantial weight.
- The Kahn X factor should be recalculated to reflect these specifications.

6. Treatment of Service Quality and Surplus Earnings

6.1 HQT's Evidence and Proposal

Global Service Quality Indicator

HQT proposes to calculate a summary *indice global du maintien de la qualité du service* ("IMQ") which summarizes changes in the Company's service quality. Quality metrics would address performance in the areas of customer satisfaction, reliability, availability, and safety. The calculations would have two stages. Following a normalization of the results for individual metrics, the indicated changes in performance would be averaged.[30]

Metrics and Targets

Reliability of Service

HQT proposes two reliability metrics: *IC-Opérationel* and the number of outages leading to customer service interruptions. Targets and standard deviations for each of these metrics are calculated based on 5 years of historical data. Each metric has a 12.5% weight in the global index.

IC-Opérationel is a standardized continuity index that measures the average number of hours that the Company's service is interrupted per customer for all customers served. The only outages included in HQT's proposed metric are those directly related to current network operations. Outages that would be counted include those due to equipment failures, operating incidents, and planned outages. In response to information request 1.6.1 of S.E.-AQLPA, HQT noted that this metric would exclude outages due to various external events, including those caused by weather, wildlife, and forest fires.

The second proposed reliability indicator, the number of outages leading to customer service interruptions, is measured as the total number of events that cause a service interruption for customers. This is a measure of outage frequency which includes planned and unplanned outages.

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[30] HQT's normalization of quality metrics is based on the following formula:

$[\,X - mean(X)] \,/\, sd(X)$

where *X* is the value of the current value metric and mean (*X*) and *sd*(*X*) are the Company's mean and standard deviation over a certain sample period.

Availability of the Network

HQT proposes a single network availability metric: the number of forced unavailabilities. Forced unavailabilities are defined as events that create an unexpected reduction in the transmitter's delivery capacity. This metric, which has a 25% weight in the global index, includes incidents that may impact availability on the network but not result in an outage. The target for this metric would change each year and reflect aging of the network and an increased likelihood of forced outages. The standard deviation would be calculated based on the number of HQT's forced unavailabilities for each year of a recent historical 5-year period.

Customer Satisfaction

HQT proposes two metrics for customer satisfaction. These would be based on evaluations completed by point-to-point customers and representatives of HQD responsible for each sectoral agreement with HQT and the Distributor's purchase of point-to-point services.[31] The point-to-point customer satisfaction survey is sent out to the most active point-to-point customers, often resulting in fewer than 10 completed surveys. HQT has proposed 12.5% weights for each of these satisfaction metrics.

The target for the HQD customer satisfaction index is the average of 2 years of historical data (e.g., 2016 and 2017). The evaluation methodology for this index was revised in 2016, resulting in lower scores than in earlier years. The target for the point-to-point customer satisfaction index is based on 5 years of historical data. The standard deviation calculations appear to be based on data for 2011-2015 for the HQD satisfaction index and for 2013-2017 for the point-to-point customer satisfaction index.

Public and Employee Safety

HQT proposes a single metric for this performance area: the number of accidents resulting in lost work time and temporary assignments per 200,000 hours worked. HQT appears to have redefined this metric recently, as it presented data based on its actual reporting and a recalculated version for the

[31] There are 9 sectoral agreements between HQD and HQT. Each deals with a particular issue such as communications during emergencies, management of restrictions on line clearances, and planned interruptions.

most recent 5-year period. The target and variance calculations relied on the recalculated version of this metric.

Linkage to the MTÉR

HQT argues that the purpose of the service quality provisions of the MRI is to maintain quality rather than improve it. The Company further argues that some service quality variation is normal from year to year. The proposed linkage to the MTÉR is thus designed so that IMQ scores could not affect earnings unless they were worse than negative one. This is the score that would result if the deterioration in each quality metric equaled its standard deviation on average. If HQT were overearning and the global index value was between -1 and -2, the Company would forfeit one percent of its surplus earnings for every one hundredth (0.01) that the index is below -1. If the global indicator had a value of -2, all overearnings would be returned to customers. If the value of the global indicator value was worse than -2, there would be no additional effect on the Company's earnings.

6.2 PEG's Response

Here are some areas where we have concerns and comments about HQT's proposed service quality performance incentive system.

Reliability Metrics

HQT has proposed to exclude several reliability metrics that it regularly reports in its annual reports to the Régie and/or in *dossiers tarifaires*. These metrics include the average duration of planned and unplanned outages, all variants of the continuity index except the continuity index that reflects only outages directly related to network operations ("Operational Continuity Index"), Transmission SAIDI ("T-SAIDI"), Transmission SAIFI ("T-SAIFI"), and the number of incidents where an HQ employee or contractor causes damage or an outage on the network.[32] We discuss these metrics in more detail below. HQT acknowledged that only 50% of the total outage duration in 2017 was due to outages from

[32] HQT proposes to include only the normalized version of the Operational Continuity Index.

planned interruptions and equipment failures.[33] However, HQT claims that the average duration of planned and unplanned outages is dependent on major events.[34]

HQT's continuity indexes are reported in raw and normalized forms. Normalization is undertaken using the IEEE's 2.5 beta methodology. A continuity index for transmission measures the average duration of outages in hours per customer due to planned and unplanned outages on the transmission system. This index is broken down into two subindexes: the Operational Continuity Index and the continuity index for all other outages. HQT also reports continuity indexes that identify the average duration of outages in hours per customer for a variety of outage causes including equipment failures, incidents, planned outages, climatic factors, wildlife, environment, and misdeeds.

T-SAIDI is calculated by dividing the total duration of unplanned interruptions on the transmission network by the total number of delivery points. Only outages longer than 1 minute are included. T-SAIFI is calculated by dividing the total number of unscheduled interruptions by the total number of delivery points. There are two variants of T-SAIFI: one that measures sustained interruption frequency and one that measures momentary interruption frequency. An interruption must be at least 1 minute to count as a sustained interruption. In *dossiers tarifaires*, HQT presents high level results from a Canadian Electricity Association program to benchmark these metrics.

HQT stated in response to information request OC DDR 6.3 that it will continue to report the other transmission reliability indicators that it currently reports to the Régie. Thus, the marginal regulatory cost of adding one or two reliability indicators to the IMQ from this list is negligible.

HQT also reports on the number of incidents where an HQ employee or contractor causes damage or an outage to the transmission system. Only incidents rated G1 and G2 are reported. G1 incidents cause a loss of load to an internal or external customer, while G2 incidents cause a loss of equipment.

Notable Precedents

HOSSM is proposing to use the following two reliability metrics in its MRI.

[33] HQT-3, Document 2, p. 7.

[34] HQT performed in the range of 67 and 76 minutes in 3 of the 5 most recent years.

- T-SAIFI is the average number of unplanned interruptions per delivery point. Momentary and sustained interruptions are included.
- T-SAIDI is the average duration of unplanned interruptions per delivery point. Only sustained interruptions are included.

No performance incentive mechanism is proposed.

RIIO has an incentive mechanism that uses electricity not supplied as the metric. Awards are possible as well as penalties. The penalty rate is based on the estimated value of lost load. The maximum penalty on allowed revenue is 3%.

The AER also has a reliability penalty mechanismand the for transmitters. The metrics used are the number of unplanned outages per circuit, the MWh of energy not supplied from unplanned outages/MW of peak demand, and aggregate duration of unplanned outages/number of events. Rewards are available as well as penalties. Awards and penalties are capped.

Safety Metrics

The proposed employee safety metric is similar to those reported by Hydro One Transmission and various U.S. utilities. HOSSM is proposing to report a similar metric in its MRI. It is desirable that the metric be fully comparable to those reported by other North American utilities on a levels basis even though it is used in the IMQ to measure trends.

Weights

The four service quality areas carry equal weight in the calculation of the IMQ. HQT states in response to PEG DDR 8.2 that

> *Le Transporteur n'a pas cherché à prioriser un ou des champs d'intervention au détriment des autres, ou en fonction de l'importance relative de chacun*.[35]

We disagree. The weights should reflect the relative importance of the performance dimensions and the need for penalties to discourage bad performance. The four service quality areas do not deserve equal weights. For example, employee safety does not warrant the same weight as

[35] R 4058-2018, B-0067, Réponses du Transporteur, 23 October, p. 14.

reliability. HQT is already incentivized to mind its employee safety by its exposure to the risk of injury and damage expenses. Customer satisfaction does not warrant the same weight that it does in an MRI for distribution services, and HQD has a potential conflict of interest in grading the performance of HQT.

Financial Provisions

We have several concerns about the service quality performance incentive mechanism.

Linkage to the MTÉR

One concern is the linkage of measured performance to the MTÉR, which does not share earnings shortfalls. While there are good arguments for not sharing earnings shortfalls, and this issue has been resolved, linking service quality to this kind of MTÉR would weaken the Company's incentive to maintain quality in periods of underearning or slight overearnings, which can easily occur.

Maintenance and cost-effective improvement of service quality can be jeopardized under an MRI because relaxed quality effort can bolster earnings. This is a concern whether or not the utility has surplus earnings. If HQT is only marginally overearning, for example, the mechanism may not encourage the Company to maintain its service quality performance, as the cost of compliance may be larger than the forfeited revenue from poor performance.

In our experience, service quality incentives in multiyear rate plans are not typically tied to an MTÉR. HQT stated in response to OC DDR 7.1 that "*aucune utilité au delà de Gazifére lie actuellement les indicateurs de performance au MTÉR*."

Deadband

The substantial deadband in the mechanism linking the IMQ and the MTÉR is also controversial. Effectively, the Company would know that its quality metrics could decline by the amount of the standard deviation with no penalty. One of the rationales for this treatment is that service quality metrics are sensitive to volatile external business conditions. Since there are no rewards for improved quality, volatility tends to hurt HQT. However, these fluctuations should tend to balance out during the course of the plan.

Penalty Rates

HQT provides no evidence that the financial penalties it proposes for poor service quality are appropriate. It would be quite a coincidence if the appropriate penalty for a 200 basis point decline in the IMQ was to eliminate surplus earnings. Unfortunately, rough and ready methodologies are frequently used in the design of MRI performance incentive mechanisms.

Precedents

PEG has reviewed 6 U.S. service quality incentive mechanisms as well as the previously approved mechanisms in MRIs of Gaz Métro and Gazifère. Of the mechanisms outside Québec which we reviewed, only one ties performance results to earnings.[36] Instead, these mechanisms usually tie poor performance to specific revenue penalties regardless of the utility's earnings.[37] In most cases, financial incentives are tied directly to performance on individual metrics. For example, a failure to meet the customer satisfaction index target is linked to a specific penalty. Some mechanisms do incorporate deadbands to allow a utility to have a significant deterioration in performance before penalties are applied.

PEG's Alternative Service Quality Incentive Mechanism Proposal

We recommend the following revisions to HQT's proposed service quality mechanism.

- The weight on the safety metrics and the customer satisfaction surveys should each be reduced to 15%. A reliability and availability category should be established that has a 70% weight. Metrics in this category would have equal weights.
- Consideration should be paid to using T-SAIFI and T-SAIDI as reliability metrics.

[36] This mechanism is part of Mississippi Power's retail formula rate plan. The mechanism ties service quality performance to the allowed ROE and deadband around which rates will be reset. Mississippi Power's service quality performance also affects the amount of surplus/deficit earnings which the utility is allowed to keep/absorb. Superior performance allows for a higher allowed ROE and rates will be reset to a point more favorable to the company, either increasing the surplus earnings the company may retain or reducing deficit earnings. Inferior performance results in a lower allowed ROE and rates being reset such that Mississippi Power is forced to return a greater level of surplus earnings or absorb a higher level of deficit earnings.

[37] Penalties may be expressed in dollars or as basis points of return on equity.

- There is a way to avoid a deadband in the penalization for declining quality. HQT can be subject to a revenue penalty only at the end of the plan if there is an average decline in IMQ scores on balance over the four years of the MRI term. Improvements in quality in some areas would be allowed to offset quality declines in other areas. However, HQT would receive no reward for a rise in the IMQ.
- The Régie should reconsider its decision to penalize HQT for poor quality only when the Company has surplus earnings. In principle, it can approve a supplemental revenue adjustment that doesn't conflict with its decision to link the MTÉR to service quality. Here is an example.
    - Declining service quality will reduce allowed revenue formulaically. To guard against excessive penalties, it is reasonable to place a cap (e.g. 3% of allowed revenue) on these penalties.
    - If the indicated revenue reduction for declining quality is less than HQT's share of surplus earnings under the existing MTÉR formula, the Company's share will be reduced by this amount.
    - If the indicated revenue reduction for declining quality exceeds the Company's share of surplus earnings, it will retain no surplus earnings and allowed revenue will be further reduced by the amount necessary to achieve the indicated revenue reduction.

7. Other Outstanding Issues

7.1 *Clause de Sortie*

HQT's Evidence and Proposal

HQT embraces a proposal from Concentric that the *clause de sortie* be triggered if the Company's rate of return varies by more than 150 basis points from its target in either direction. If the clause is triggered, the MRI would be suspended and HQT would return to cost of service regulation. Concentric further explained in response to PEG DDR 11.1 that

> As a practical matter, the determination that the off-ramp is triggered will not be made until May of the subsequent year when the Annual Report is filed. HQT would file a proposal for new rates based on the forecasted cost of service, with the new rates to take effect on January 1st of the next year. HQT would include a proposal on how to handle the "gap" year during which rates would continue to be established by application of the MRI formula. The Régie would make a final determination as part of the rate case review process.[38]

Concentric contributed a brief report on precedents for MTÉRs and *clauses de sortie* in other Canadian MRIs.

PEG's Response

The proposed *clause de sortie* is too conservative, especially in the event that the Company is underearning. Since HQT has shown little enthusiasm for multiyear rate plans, the Company might even be tempted to acquiesce in a year of low earnings to escape from the MRI and return to cost of service regulation. The cost of service treatment of capital makes extreme earnings outcomes much less likely than in the MRI for HQD. The relatively short four-year term of the plan, Y and Z factors, and the MTÉR also reduce the likelihood of extreme earnings outcomes.

Concentric's survey does not support its *clause de sortie* recommendation.

- In many *clauses de sortie* that Concentric surveyed, the action trigger has been larger than a 150 basis point post MTÉR earnings variance in a single year.

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[38] R 4058-2018, B-0067, Réponses du Transporteur, 23 October, p. 20.

- Several plans surveyed do not have a *clause de sortie.*
- *Clauses de sortie* do not always require suspension of the MRI and a return to cost of service regulation when action is triggered. For example, Concentric stated in response to PEG DDR 11.2 that

> Among the utilities shown in Tables 1 and 2 of our report, ENMAX (in its 2007 plan) and the Ontario utilities have provisions to either "address the issue that triggered the re-opening" or "initiate a regulatory review." Additionally, the generic PBR framework in Alberta warrants "consideration of a reopening and review of a PBR plan" when the basis point threshold is triggered. In British Columbia, before a plan is terminated it is reviewed to address potential remedies.
>
> For gas distributors, as discussed above the generic PBR framework in Alberta warrants "consideration of a reopening and review of a PBR plan" when the basis point threshold is triggered. The specifics of Alberta's PBR reopener provisions are discussed on pages 71-75 of AUC D-20414-D01-2016. The reopener is not automatic, rather it may be initiated by the company or by the Commission.
>
> In British Columbia, FEI's off ramp sets "in motion a two-stage process. The first stage consists of a process before the Commission to assess potential remedies to the situation, including the potential for amending or re-calibrating the PBR plan to allow it to continue. A second stage to the process would be triggered if satisfactory solutions could not be found through modification of the PBR plan. This stage would deal with how to exit from the plan. This could include a variety of options from going back to a cost of service methodology to a redesign of the PBR."
>
> In Ontario, Enbridge's 2008 PBR plan included a provision for the Company to file an application with the OEB for a prospective review of its adjustment formula. In Enbridge's subsequent plan, the OEB is to "monitor Enbridge's results and carry out a review if Enbridge over-earns or under-earns more than 300 basis points." [footnotes omitted][39]

[39] R 4058-2018, B-0067, Réponses du Transporteur, 23 October, p. 21.

PEG recommends a *clause de sortie* similar to that approved in Alberta wherein action is triggered when the pre-MTÉR ROE varies from its target in either direction by 400 basis points in one year or 300 basis points for two consecutive years. The Régie should then review the plan and consider whether to continue with the plan, revise it, or return to cost of service regulation. A year of cost of service regulation should not be automatic.

MRI Design for

Hydro-Québec Distribution

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1. Introduction

The Régie de l'Energie ("Régie") has been engaged for several years in a proceeding (R-3897-2014) to develop *méchanismes de reglementation incitative* ("MRIs") for transmission and distribution services of Hydro-Québec. In April 2017, the Régie's Decision D-2017-043 established some key provisions of the first MRI for Hydro-Québec Distribution ("HQD" or "the Company"). The MRI will take the form of a multiyear rate plan with a revenue cap (*plafonnement des revenus*). Growth in HQD's revenue requirement (*revenu requis*) will be escalated each year by a revenue cap index similar to that which the Régie currently uses in rate cases (*dossiers tarifaires*) to limit growth in the *revenu requis* for operation and maintenance expenses (*charges d'exploitation*). The index formula (*formule d'indexation*) includes a *facteur d'inflation* (measured inflation), a *facteur de productivité* (*X*), a *dividende client* ("stretch factor" or s), and 0.75 x growth in the number of HQD's *abonnements* (customer accounts).

The X factor in the revenue cap escalation formula is a key issue in the proceeding. It will be decided by the Régie without the benefit of new, custom productivity studies. Instead,

> **La Régie retient la méthode basée sur le jugement préconisée par le Distributeur pour déterminer la valeur du Facteur X à inclure dans la Formule d'indexation. À cette fin, le Distributeur devra mettre à la disposition des intervenants les études, analyses et rapports susceptibles d'éclairer la Régie quant à la détermination du Facteur X en phase 3.**[1]

The Régie, paraphrasing remarks by HQD, explained what it meant by a process of *jugement.*

> **Le jugement exercé par la Régie serait basé sur l'étude des valeurs du Facteur X utilisées dans d'autres juridictions, de même que sur l'analyse des gains d'efficience réalisés par le Distributeur à ce jour et du potentiel de réalisation de gains d'efficience supplémentaires dans les années à venir.**[2]

Resolution this and of some other MRI implementation details will occur in Phase III of this proceeding.

[1] Régie de l'Energie, D-2017-043, R-3897-2014 Phase 1, April 2017, p. 43.

[2] Ibid., p. 37.

HQD submitted the requested X factor evidence in June 30 2017.[3] The Company discussed its own cost performance and submitted commentary on productivity evidence and X factor decisions in North American regulation from its consultant, Concentric Energy Advisors ("CEA").[4] HQD may file further X factor evidence on this topic during the Phase 3 proceeding.

> Dans le cadre de la phase 3B de l'établissement de son MRI, le Distributeur procédera à la mise à jour des études, analyses et rapports existants, le cas échéant, et présentera son positionnement quant à la détermination du Facteur X à utiliser pour son MRI.[5]

The Company filed a *dossier tarifaire* for an increase in rates for the 2018-19 tariff year on 31 July 2017.[6] This filing included a section on Phase 3 MRI issues. Only the Y and Z factor issues were discussed at length. HQD may provide further evidence on unresolved MRI design issues in January 2018.

Pacific Economics Group Research LLC has for many years been the leading North American consultancy on MRIs for gas and electric utilities. Work for a diverse client mix that includes regulators, utilities, and consumer groups has given our practice a reputation for objectivity and dedication to good regulation. In Canada, we have played a prominent role in MRI proceedings in Alberta, British Columbia, and Ontario, as well as in Québec. Research and testimony on productivity trends of power distributors and other energy utilities is a company specialty. AQCIE-CIFQ has retained us and the Régie has authorized us to provide Phase 3 comments on the appropriate X factor and other unresolved provisions of the MRI of HQD.

Section 2 of our report provides a brief review of the Régie's Phase 1 decision. There follows in Section 3 a discussion of principles and methods for selecting the X factor and stretch factor.[7] Section 4

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[3] HQD, *Etudes, Analyses et Rapports pour la Determination du Facteur X Deposes dans le Cadre de l'Etablissement du Mechanisme de Reglementation Incitative du Distributeur.* June 2017.

[4] CEA, *Performance-Based Regulation: Productivity Factor for HQD*, 30 June 2017.

[5] HQD, op. cit., p. 12.

[6] HQD, *Implantation d'un Mechanisme de Reglementation Incitative* (MRI) – *Phase 3*, 31 July 2017.

[7] This discussion reorganizes and elaborates on material presented in Section 4 of our report in Phase 1 of this proceeding.

of this report adds to CEA's evidence by providing an independent review of energy utility productivity studies and commission decisions in MRI proceedings. We hope that this review can help the Régie make informed decisions on X and s. Our recommendations concerning the inflation measure, X factor, and stretch factor for HQD follow in Section 5. Section 6 discusses other plan design issues.

2. Background

The Régie made the following additional decisions concerning the design of the MRI for HQD in D-2017-043.

- The basic form of the MRI is a multiyear rate plan. The plan will begin in April 2018 and have a four-year term.
- The initial *revenu requis* will be established in a *dossier tarifaire* that is currently under way.
- The *revenu requis* for most of the cost of HQD's base rate inputs will then be escalated for three years by a revenue cap index. Costs addressed by the index will include *charges d'exploitation* that the Company can control, including fuel expenses (*couts de combustible*) administrative and general expenses (*frais corporatifs*), amortization and depreciation expenses (*amortissement*), the return on rate base (*rendement sur la base de tarification*), and taxes.
- Costs of the Company's autonomous networks will be an integral part of the MRI.
- A study of *productivité multifactorielle* ("PMF") [multifactor productivity] will be undertaken, after the MRI begins, for possible application in the last year of the plan. With respect to this study, "la Régie demande au Distributeur de présenter en phase 3, la méthodologie et l'échéancier rattachés a la realisation d'une etude PMF."[8] Appropriate methods for measuring productivity are thus a key issue in this proceeding.
- The plan will not include revenue decoupling. However, *nivellements pour les aléas climatiques* (weather normalization of revenue) will continue.

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[8] Régie, op. cit., p. 44

- A *clause de sortie* ("off ramp" mechanism) will be included.
- There will be no formal *clause de* succession (plan termination provisions). Instead,

> **La Régie se prononcera au moment opportun, après consultation des participants, quant à la forme du recalibrage, la date et les modalités d'un retour éventuel au coût de service, qu'il soit complet ou partiel.[9]**

- A *méchanisme de traitement des ecarts de rendement* ("MTER", or earning sharing mechanism) will be included.[10] This will likely be the same as that currently used.
- There will be no *méchanisme de report des gains d'efficience* (efficiency carryover mechanism) in this plan.[11]
- No additional marketing flexibility will be granted to HQD.
- Metrics for reliability, customer service quality, and safety will be established and linked to the MTER. HQD should develop during the first-generation MRI a metric addressing short-term energy and demand purchases and underutilization of the patrimonial block of power.

The Régie's decision left for Phase 3 the final resolution of the following MRI provisions:

- Inflation measure formula
- X Factor
- Stretch Factor
- Final list of costs eligible for Y factor and Z factor treatment
- Method for Y factoring the rate of return on capital
- Materiality thresholds for Y and Z
- Specific safety, reliability, and customer service metrics

Determination of some additional details of the MRI will be delayed until the fall of 2018.

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[9] Ibid., p. 103.

[10] Ibid., p. 106.

[11] Ibid., p. 109.

3. Methods and Principles for Revenue Cap Index Design

In this section of the report we discuss methods and principles for the design of revenue cap indexes. We begin by discussing basic indexing concepts. There follow discussions of the use of indexing research in MRI design, capital cost specifications, Kahn X factors, other methodological issues, and the choice of a stretch factor.

3.1 Basic Indexing Concepts

The logic of economic indexes provides the rationale for using price and productivity research to design attrition relief mechanisms. To review this logic, it may be helpful to make sure that the reader has a high-level understanding of basic tools of index research.

Input Price and Quantity Indexes

The growth (rate) of a company's cost can be shown to be the sum of the growth of an input (*intrant*) price index ("Input Prices") and input quantity index ("Inputs").

growth Cost = growth Input Prices + growth Inputs.[12] [1]

These indexes are typically multidimensional in the sense that they summarize trends in subindexes that are appropriate for particular subsets of cost. This is accomplished by taking a cost-share weighted average of the subindex growth. Capital, labor, and miscellaneous materials and services are the major classes of base rate inputs used by electric power distributors. The technology for providing distributor services is capital intensive, so the heaviest weights in these indexes are placed on the capital subindexes.

Calculation of input quantity indexes is complicated by the fact that firms typically use numerous inputs in service provision. This complication is contained when summary input price indexes are readily available for a group of inputs such as labor. Rearranging the terms of [1] we can calculate input quantity growth using the formula

[12] Cost-weighted input price and quantity indexes are attributable to the French economist Francois Divisia.

$$\text{growth Inputs} = \text{growth Cost} - \text{growth Input Prices}. \qquad [2]$$

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

Productivity Indexes

The Basic Idea A productivity index is the ratio of a scale (aka "output") index ("Scale") to an input quantity index.

$$\text{Productivity} = \frac{\text{Scale}}{\text{Inputs}}. \qquad [3]$$

It can be used to measure the efficiency with which firms use inputs to achieve their scale of operation.

Some productivity indexes are designed to measure productivity *trends*. The growth of such a productivity index is the *difference* between the growth in the scale and input quantity indexes.

$$\text{growth Productivity} = \text{growth Scale} - \text{growth Inputs}. \qquad [4]$$

Productivity grows when the scale index rises more rapidly (or falls less rapidly) than the input index. The productivity growth of utilities can be volatile but has historically tended to grow over time. The volatility is typically due to demand-driven fluctuations in operating scale and/or the uneven timing of certain expenditures. The volatility of productivity growth tends to be much greater for individual companies than the average for a group of companies.

Relations [1] and [4] imply that

$$\begin{aligned}\text{growth Productivity} &= \text{growth Scale} - (\text{growth Cost} - \text{growth Input Prices}) \\ &= \text{growth Input Prices} - \text{growth (Cost/Scale)}\end{aligned}$$

Productivity growth is thus the amount by which a firm's unit cost grows more slowly than its input prices.

Some indexes are designed to measure only productivity *trends*. "Bilateral" productivity indexes are designed to compare only productivity *levels*. For example, the productivity level of HQD in 2016 can be compared to the average for U.S. power distributors in the same year. "Multilateral" productivity indexes are designed to measure *both* trends and levels.

The scope of a productivity index depends on the array of inputs which are considered in the input quantity index. Some indexes measure productivity in the use of a single input group such as labor. A *multifactor* productivity index measures productivity in the use of multiple inputs. PMF indexes are sometimes called *total* factor productivity indexes, a term that is usually a misnomer since in practice some inputs are excluded from the index calculations.

Scale Indexes A scale index of a firm or industry summarizes trends in the scale of operation. These indexes may also be multidimensional. Growth in each dimension of scale that is itemized is then measured by a subindex. The scale index then summarizes growth in the subindexes by taking a weighted average of them.

In designing a scale index, choices concerning scale variables (and weights, if the index is multidimensional) should depend on the manner in which the index is used. One possible objective is to measure the impact of growth in scale on *revenue*. In that event, the scale variables should measure growth in *billing determinants* and the weight for each itemized class of determinants should be its share of a utility's base rate revenue.[13] In this report we denote by $Scale^R$ a scale index that is "revenue-based" in the sense that it is designed to measure the impact of growth in scale on revenue. A productivity index that is calculated using $Scale^R$ will be denoted as $Productivity^R$.

$$\text{growth Productivity}^R = \text{growth Scale}^R - \text{growth Inputs.} \qquad [5a]$$

Another possible objective of scale indexing is to measure growth in dimensions of scale that affect *cost.* In that event, the scale variable(s) should measure dimensions of the "workload" that drive cost.[14] A multidimensional scale index with elasticity weights is unnecessary if econometric research reveals that there is one dominant cost driver. A productivity index calculated using a cost-based scale index (which may be unidimensional) will be denoted as $Productivity^C$.

[13] Revenue-weighted scale indexes are attributable to the French economist Francois Divisia.

[14] If there is more than one scale variable in the index, the weights for each variable should reflect its relative cost impact. The sensitivity of cost to a small change in the value of a business condition variable is commonly measured by its cost "elasticity." Cost elasticities of utilities can be estimated econometrically using data on the costs and operating scale of a group of utilities.

$$\text{growth Productivity}^C = \text{growth Scale}^C - \text{growth Inputs.} \quad [5b]$$

This may fairly be described as a "cost efficiency index."

In measuring the productivity growth of U.S. energy distributors the choice of a scale index can have a major effect on results. To understand why, consider first that under legacy rate designs, the volume of deliveries to residential and commercial ("R&C") customers is the major driver of distributor revenue. Meanwhile, econometric research has repeatedly shown that the number of customers served is by far the most important scale-related driver of energy distributor cost. Customer growth affects cost directly, and is highly correlated with the growth of other demand drivers such as peak load. The difference between the growth trends of revenue- and cost-based scale indexes thus depends on the trend in R&C average use.

A second reason why the scale index matters is that growth in the R&C average use of electric utilities has slowed substantially in recent years due to sluggish economic growth and growth in energy efficiency programs. Table 1 is drawn from a recent white paper on multiyear rate plans which PEG prepared for Lawrence Berkeley National Laboratory, a unit of the U.S. Department of Energy.[15] The table shows that growth in average use of power by R&C customers of U.S. electric utilities was in the neighborhood of 1.5% annually over the 1973-2000 period but is now negative.

A third reason why choice of a scale index matters is that the growth of power delivery volumes is much more volatile than customer growth. This makes results using delivery volumes much more sensitive to the choice of a sample period.

[15] Mark Newton Lowry, Matt Makos, and Jeff Deason, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, Lawrence Berkeley National Laboratory, July 2017.

Table 1

Average Use Trends of U.S. Electric Utilities

	Residential[1]		Commercial[1]		Average
	Level	Growth Rate	Level	Growth Rate	Growth Rate
Multiyear Averages					
1927-1930	478	7.06%	3,659	6.67%	6.86%
1931-1940	723	5.45%	4,048	2.00%	3.73%
1941-1950	1,304	6.48%	6,485	5.08%	5.78%
1951-1960	2,836	7.53%	12,062	6.29%	6.91%
1961-1972	5,603	5.79%	31,230	8.79%	7.29%
1973-1980	8,394	2.03%	50,576	2.53%	2.28%
1981-1986	8,820	0.12%	54,144	0.81%	0.46%
1987-1990	9,424	1.39%	60,211	2.29%	1.84%
1991-2000	10,061	1.15%	67,006	1.68%	1.41%
2001-2007	10,941	0.73%	74,224	0.64%	0.68%
2008-2014	11,059	-0.38%	75,311	-0.22%	-0.30%

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

3.2 Use of Index Research in MRI Design

Productivity studies have many uses, and the best methodology for one use may not be best for another. One use of productivity research is to measure the trend in a utility's operating efficiency. Another is to calibrate the X factor in a rate-cap or revenue-cap index. A method that is best for measuring efficiency may not be the best for X factor calibration. In this section, we consider the rationale for using productivity research in rate and revenue cap index design.

Price Cap Indexes

An early use of index research in regulation was to design *price* cap indexes. We begin our explanation of the supportive index logic by considering the growth in the prices charged by an industry that earns, in the long run, a competitive rate of return.[16] In such an industry, the long-run trend in revenue equals the long-run trend in cost.

$$\text{trend Revenue} = \text{trend Cost.} \qquad [6]$$

The growth in the revenue of any firm or industry can be shown to be the sum of the growth in revenue-weighted indexes of its output prices ("*Output Prices^R*") and billing determinants ("*Scale^R*").

$$\text{growth Revenue} = \text{growth Scale}^R + \text{growth Output Prices}^R. \qquad [7]$$

Recollecting from [1] that cost growth is the sum of the growth in cost-weighted input price and quantity indexes, it follows that the trend in output prices which permits revenue to track cost in the longer run is the difference between the trends in an input price index and a multifactor productivity index constructed with a revenue-weighted scale index.

$$\begin{aligned}\text{trend Output Prices}^R &= \text{trend Input Prices} - (\text{trend Scale}^R - \text{trend Inputs}) \\ &= \text{trend Input Prices} - \text{trend PMF}^R. \qquad [8]\end{aligned}$$

This result provides a conceptual framework for the design of price cap indexes of general form

$$\text{trend Rates} = \text{trend Input Prices} - X. \qquad [9a]$$

where

$$X = \overline{PMF^R} + S \qquad [9b]$$

Here X, the "X factor", is calibrated to reflect a base PMF^R growth target ("$\overline{PMF^R}$"). This has been commonly established by calculating the PMF^R trend of a group of utilities. A stretch factor ("S"),

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

established in advance of plan operation, is often added to the formula which, if positive, benefits customers.

Notice that a *revenue*-based scale index is appropriate for the supportive productivity research for price caps. This helps to explain why some productivity indexes used in X factor calibration over the years featured a *volumetric* scale index.

Revenue Cap Indexes

General Result Index logic also supports the design of *revenue* cap indexes. Consider first the following basic result of cost theory:

$$\text{growth Cost} = \text{growth Input Prices} - \text{growth Productivity}^{C} + \text{growth Scale}^{C}. \qquad [10a]$$

The growth in the cost of a company is the difference between the growth in input price and cost efficiency indexes plus the trend in a consistent cost-based scale index. This result provides the basis for a revenue cap escalator of general form

$$\text{growth Revenue} = \text{growth Input Prices} - X + \text{growth Scale}^{C} \qquad [10b]$$

where

$$X = \overline{\text{PMF}^{C}} + S. \qquad [10c]$$

Notice that a *cost*-based scale index should be used in the supportive productivity research for a *revenue* cap X factor.

Application to Energy Distributors For gas and electric power distributors, the number of customers served was noted above to be a sensible scale variable when calculating PMF^{C}. For an energy distributor, $Outputs^{C}$ can thus be reasonably approximated by growth in the number of customers served and there is no need for the complication of a multidimensional output index with cost elasticity weights. It is then approximately true that

$$\begin{aligned}
&\text{growth Cost} \\
&\quad = \text{growth Input Prices} - (\text{growth Customers} - \text{growth Inputs}) + \text{growth Customers} \\
&\quad = \text{growth Input Prices} - \text{growth PMF}^{N} + \text{growth Customers}
\end{aligned}$$

where PMF^N is an PMF index that uses the number of customers to measure output.

This result provides the rationale for the revenue cap index formula

growth Revenue = growth Input Prices – X + growth Customers [11a]

where

$$X = \overline{PMF^N} + \text{Stretch}. \quad [11b]$$

An equivalent formula is

trend Revenue – trend Customers

= trend (Revenue/Customer) = trend Input Prices – X. [11c]

This is sometimes called a "revenue per customer" index, and we will for convenience use this expression below to refer to revenue cap indexes which conform to either [11a or 11c].

Revenue caps using formulas like [11a] and [11c] are currently used in the MRIs of ATCO Gas and AltaGas in Canada. The Régie de l'Energie in Québec has directed Gaz Métro to develop a plan featuring a revenue per customer index. Revenue cap indexes like these were previously used by Southern California Gas and Enbridge Gas Distribution ("EGD"), the largest gas distributors in the U.S. and Canada, respectively.

Consider, finally, that whether or not the PMF^N is a fully satisfactory approximation for PMF^C, when a revenue per customer index is chosen to regulate a utility the following result must hold if revenue is to track cost.

trend Revenue = growth Input Prices - X + growth Customers

= growth Cost

= growth Input Prices + growth Inputs.

The X factor that causes revenue to track cost must then use the number of customers as the output index.

X = trend Customers - trend Inputs.

This means that the decline in R&C use per customer that has occurred in the United States since 2000 is irrelevant in the calculation of the revenue cap index.

Inflation Measure Issues

Our discussion has thus far assumed that any rate or revenue cap index under consideration would use an *input price* index as the inflation measure. Suppose, however, that a *macroeconomic* price index is instead used as the inflation measure. This has been common practice in approved U.S. MRIs. The gross domestic product price index ("GDPPI") has been commonly used for this purpose. This the U.S. government's featured measure of inflation in prices of the economy's final goods and services. Final goods and services consist chiefly of consumer products but also include capital equipment and exports.

When a macroeconomic inflation measure is used in a rate or revenue cap index, the X factor must be calibrated in a special way if it is to reflect industry cost trends. Suppose, for example, that the inflation measure is the GDPPI. In that event we can restate the revenue per customer index in [11c], for example, as

$$\text{growth Revenue/Customer}$$
$$= \text{growth GDPPI} - [\text{trend PMF}^{\text{Industry}} + (\text{trend GDPPI} - \text{trend Input Prices}^{\text{Industry}}) + \text{Stretch}] \quad [12]$$

It follows that a revenue cap index that features GDPPI as the inflation measure can still conform to index logic provided that the X factor effectively corrects for any tendency of GDPPI growth to differ from industry input price growth in addition to reflecting the industry PMF^{N} trend. The term in parentheses in relation [12] is sometimes called the "inflation differential."

Consider now that the GDPPI is a measure of *output* price inflation. Due to the broadly competitive structure of the U.S. economy, we can use relation [8] to reason that the long-run trend in the GDPPI is the difference between the trends in input price and PMF indexes for the economy.

$$\text{trend GDPPI} = \text{trend Input Prices}^{\text{Economy}} - \text{trend PMF}^{\text{Economy}} \quad [13]$$

Relations [12] and [13] can be combined to produce the following formula for a revenue cap index:

$$\text{growth Revenue/Customer}$$
$$= \text{growth GDPPI} - [(\text{trend PMF}^{\text{Industry}} - \text{trend PMF}^{\text{Economy}})$$
$$+ (\text{trend Input Prices}^{\text{Economy}} - \text{trend Input Prices}^{\text{Industry}}) + \text{Stretch}] \quad [14]$$

This formula suggests that when the GDPPI is the inflation measure, the revenue cap index can be calibrated to track industry cost trends when the X factor has two calibration terms: a "productivity differential" and an "input price differential". The productivity differential is the difference between the PMF trends of the industry and the economy. X will be larger, slowing revenue growth, to the extent that the industry PMF trend exceeds the economy-wide PMF trend.

The trend in the GDPPI reflects the PMF trend of the economy provided that the input price trends of the industry and the economy are fairly similar. The growth trend of the GDPPI is then slower than that of the industry-specific input price index by the trend in the economy's PMF growth. In an economy with rapid PMF growth this difference can be substantial. X factor calibration is warranted only to the extent that the input price and productivity trends of the utility industry differ from those of the economy.

PMF trends of the U.S. and Canadian economies are detailed in Table 2. It can be seen that the PMF trend of the U.S. economy was fairly brisk, averaging 1.06% annual growth annually from 1998-2015. A sizable adjustment to the X factor is thus warranted in a U.S. *formule d'indexation* when the GDPPI is used as the inflation measure. The PMF trends of the Canadian and Québec economies have, meanwhile, been much closer to zero.[17] This reality complicates comparisons of X factors in the United States and Canada. It is more useful in the contemplated process of *jugement* to compare U.S. and Canadian commission rulings on industry productivity trends and stretch factors than it is to compare X factors.

The input price differential is the difference between the input price trends of the economy and the industry. X will be larger (smaller) to the extent that the input price trend of the economy is more (less) rapid than that of the industry.[18] In American MRI proceedings, regulators have typically ruled that the input price differential is small (e.g., twenty basis points) or zero.

[17] PMF trends in the two countries have been closer in recent years.

[18] The input price trends of a utility industry and the economy can differ for several reasons. One possibility is that prices in the industry grow at different rates than prices for the same inputs in the economy as a whole. For example, labor prices may grow more rapidly to the extent that utility workers have health care benefits that are better than the norm. Another possibility is that the prices of certain inputs grow at a different rate in some regions than they do on average throughout the economy. It is also noteworthy that the energy distribution industry has a different and more capital-intensive mix of inputs than the economy.

Table 2
PMF Trends of U.S. and Canadian Economies

	United States[1]		Canada[2]		Québec[3]	
	Level	**Growth Rate**	**Level**	**Growth Rate**	**Level**	**Growth Rate**
1997	100		100		100	
1998	101	1.42%	101	0.63%	100	0.28%
1999	103	1.86%	103	2.35%	103	3.00%
2000	105	1.70%	105	2.10%	105	1.79%
2001	106	0.54%	105	0.06%	105	0.16%
2002	108	2.16%	107	1.28%	105	-0.53%
2003	111	2.48%	106	-0.74%	105	0.22%
2004	114	2.61%	106	-0.32%	105	-0.26%
2005	115	1.52%	106	0.04%	104	-0.55%
2006	116	0.40%	105	-0.82%	104	0.24%
2007	116	0.41%	103	-1.15%	104	-0.39%
2008	115	-1.18%	101	-2.33%	103	-1.25%
2009	115	-0.23%	99	-2.60%	102	-0.29%
2010	118	2.85%	100	1.77%	102	-0.17%
2011	118	0.20%	102	1.48%	103	0.98%
2012	119	0.64%	101	-0.61%	103	-0.21%
2013	120	0.52%	102	0.90%	103	-0.29%
2014	120	0.61%	103	1.33%	104	1.04%
2015	121	0.54%	102	-1.00%	104	-0.23%
2016	121	-0.07%	NA	NA	NA	NA
<u>Average Growth Rates:</u>						
1998-2015		**1.06%**		**0.13%**		**0.20%**
2001-2015		**0.94%**		**-0.18%**		**-0.10%**
2006-2015		**0.48%**		**-0.30%**		**-0.06%**

[1] Bureau of Labor Statistics, MFP for Private Business Sector (NAICS 11-81), Series MPU4900012.
[2] Statistics Canada, MFP for Aggregate Business Sector: Canada, Table 383-0021.
[3] Statistics Canada, MFP for Aggregate Business Sector: Québec, Table 383-0026.

Whether or not the X factor properly reflects *long-term* inflation trends, macroeconomic inflation measures vary in their ability to track the input price inflation of utilities from year to year. Some are more volatile than others, and volatility typically results from fluctuation in the prices of commodities, such as food and fuel, which have little relevance to the cost of most energy distributors. Inflation measures with irrelevant volatility needlessly increase utility risk.

Long Run Productivity Trends

Another important issue in the design of a rate or revenue cap index is whether it should be designed to track short-run or long-run industry cost trends. Indexes designed to track short-run growth will also track the long run growth trend if this approach is used repeatedly over many years. An alternative approach is to design the index to track *only* long-run trends. Different approaches can, in principle, be taken for the input price and productivity components of the ARM.

Different treatments of input price and productivity growth are in most cases warranted. The inflation measure should track *short-term* input price growth. Meanwhile, productivity research for X factor calibration commonly focuses on discerning the current *long-run* productivity trend. This is the trend in productivity that is unaffected by short-term fluctuations in outputs and/or inputs. The long run productivity trend is faster than the trend during a short-lived surge in input growth or lull in output growth but slower than the trend during a short-lived lull in input growth or surge in output growth.

This general approach to PCI design has important advantages. The inflation measure exploits the greater availability of inflation data. Making the PCI responsive to short term input price growth reduces utility operating risk without weakening performance incentives. Having X reflect the long run industry PMF trend, meanwhile, sidesteps the need for more timely cost data and avoids the chore of annual PMF calculations.

To calculate the long-run productivity trend using indexes it is common to use a lengthy sample period. However, a period of more than twenty years may be unreflective of current business conditions. Quality data are often unavailable for sample periods of even this length. The need for a long sample period is lessened to the extent that volatile costs are excluded from the study and the scale index does not assign a heavy weight to volatile scale variables such as delivery volumes and system peak demand.

Sources of Productivity Growth

Research by economists has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to attain given levels of scale with fewer inputs.

Economies of scale (*economies d'échelle*) are another important source of productivity growth. These economies are available in the longer run if cost has a tendency to grow less rapidly than scale. A company's potential to achieve incremental scale economies is greater the greater is the growth in its scale.

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

Another driver of productivity growth is changes in the miscellaneous business conditions, other than input price inflation and demand, which affect cost. A good example for an electric power distributor is the share of distribution lines which are underground. An increase in the share of lines that are underground will tend to slow multifactor productivity growth but accelerate growth in the productivity of O&M inputs.

When the goal of productivity research is to calibrate the X factor of a revenue per customer index, another driver of productivity growth is the tendency of the scale index employed in the productivity research to mismeasure the trend in the number of customers served. If a volumetric scale index is employed, for example, the extent of mismeasurement is similar to the trend in R&C average use.

3.3 Capital Cost Specification

Monetary Methods for Capital Cost Measurement

Accurate measurement of trends in the cost and quantity of capital is important in distributor PMF research since the share of capital in the cost of base rate inputs is typically high. The main components of the annual cost of capital are amortization and depreciation expenses, the return on investment, and taxes. "Monetary" approaches to measuring capital costs, prices, and quantities are widely used in productivity research where the requisite data are available. This general treatment of capital cost has a solid basis in economic theory and is widely used in governmental and scholarly empirical work as well in X factor calibration studies.

Monetary approaches decompose capital cost into consistent capital price and quantity indexes such that

$$Cost^{Capital} = Price^{Capital} \times Quantity^{Capital} \quad [15a]$$

and

$$\text{growth } Cost^{Capital} = \text{growth } Price^{Capital} + \text{growth } Quantity^{Capital}. \quad [15b]$$

The capital quantity index is constructed by deflating data on the value of assets. In utility PMF research it is common to deflate the value of utility plant using construction cost indexes. The capital price index should reflect the cost of owning or using a unit of capital. Capital cost depends on asset prices (often proxied by construction costs) and market rates of return on capital. The trend in the capital price index should therefore reflect in some fashion the trends in both of these prices.

It is commonplace in PMF research to treat the capital quantity index as a measure of the flow of services which is drawn from acquired assets. The capital price index is then often treated as a consistent index of prices in a competitive market for the rental of capital services. It is important to note that this treatment is markedly at variance with the reality of utility operations, since utilities typically own most of the plant that they manage.

A key issue in the choice of a monetary method is whether assets are valued in historic dollars or current (aka replacement) dollars. Replacement valuation differs from the historical (aka "book") valuation that is commonly used in North American utility accounting. Replacement valuation makes capital price and quantity indexes simpler but implicit capital gains should be netted off of the cost of capital when asset prices (or construction costs) rise.

Depreciation and Decay Specifications

Another key issue in the choice of a monetary method is the assumed patterns of depreciation of assets and of decay in their quantity once acquired. The capital price and quantity index formulas should both reflect the decay specification. The decline in the quantity of capital from an investment has been called the "age-efficiency profile." Decay can occur for various reasons that include rusting or weathering of materials, wear and tear as assets are used, casualty (e.g. storm and fire) losses, increased maintenance requirements, and technological obsolescence.

Depreciation is the decline in the *value* of assets as they age. This reduces the opportunity cost of asset ownership. In competitive markets, depreciation can result from decay in the flow of services and from the dwindling number of years over which assets provide services.

Consider now that, in North American utility cost accounting, the value of each plant addition depreciates. This reduces the required return on rate base and thereby materially slows growth in the capital revenue requirement. Assets are commonly subject to *straight line* depreciation. However, regulators rarely make explicit assumptions about decay in the flow of services from assets. Rate and revenue cap indexes are intended to adjust utility rates between general rate cases that employ a cost of service ("COS") approach to capital cost measurement. The design of a revenue cap index should therefore reflect depreciation by some means.

Three monetary methods for calculating capital cost have been used in PMF studies used in X factor calibration. These have pros and cons that merit extended discussion here.

Cost of Service COS approaches to capital costing are designed to approximate the way capital cost is calculated in utility regulation. This approach is based on the assumptions of straight line depreciation and historic valuation of plant. The formulae are quite complicated, making them more difficult to code and review. PEG has used COS approaches to capital cost measurement in several X factor calibration and benchmarking studies.

Geometric Decay The geometric decay method assumes a constant rate of decay in the quantity of capital which results from each investment. The capital quantity index is essentially the inflation-adjusted *net* plant value. The geometric decay formulae for the capital price and quantity indexes are mathematically simple, intuitively appealing, and easy to code and review.

Academic research on the value of used assets has supported the geometric decay method to characterize depreciation in many industries.[19] The U.S. Bureau of Economic Analysis ("BEA") and Statistics Canada both use geometric decay as the default approach to measurement of capital stocks in national Income and product accounts.[20] Geometric decay has also been used in numerous productivity

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[19] See, for example, C, Hulten, and F. Wykoff (1981), "The Measurement of Economic Depreciation," in *Depreciation, Inflation, and the Taxation of Income From Capital*, C. Hulten ed., Washington D.C. Urban Institute and C. Hulten, "Getting Depreciation (Almost) Right," University of Maryland working paper, 2008.
[20] The BEA states on p. 2 of its November 2015 "Updated Summary of NIPA Methodologies" that "The perpetual-inventory method is used to derive estimates of fixed capital stock, which are used to estimate consumption of

studies intended for X factor calibration in the energy and telecommunications industries, including many studies prepared for utilities. PEG has used the geometric decay method in most of our utility productivity studies over the years.

One Hoss Shay The one hoss shay method for measuring capital cost is based on the assumption that the quantity of capital that results from plant additions does not decay gradually but, rather, all at once as assets reach the end of their service lives. In the simple one hoss shay method that is most commonly used in utility PMF studies, the capital quantity index is essentially the inflation-adjusted *gross* plant value. This index rises with gross plant additions and falls with retirements. Some PMF practitioners have invoked the one hoss shay methodology to use physical asset measures of capital quantities such as generation capacity and kilometers of distribution line.

Proponents of the one hoss shay approach to capital costing argue that the assumption of a constant service flow from individual assets is more reasonable for electric utilities than the alternative assumption of gradual decline. The one hoss shay method has been used several times in research intended to calibrate utility X factors. It has tended in recent years to be favored by the productivity witnesses retained by utilities.

The one hoss shay approach also has some disadvantages. Here are some of the notable problems.

- Implementation of geometric decay and one hoss shay both require deflation of gross plant *additions*. Deflation of gross additions is facilitated by the fact that the dates of the additions are known. However, implementation of one hoss shay *also* requires deflation of plant *retirements*, which North American utilities value and report in historic dollars. The vintages of these retirements are unknown and must be "guesstimated" in a PMF study using an assumption about the average service life of assets. Research by PEG has found that PMF results using one hoss shay are quite sensitive to the assumption concerning the

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fixed capital—the economic depreciation of private and government fixed capital. This method is based on investment flows and a geometric depreciation formula."

average service life of assets. Seemingly reasonable service life estimates can produce negative capital quantities.[21]

- In real-world productivity studies, capital quantity trends are rarely if ever calculated for individual assets. They are instead calculated from data on the value of plant additions (and, in the case of one hoss shay, retirements) which encompass multiple assets of various kinds. Even if each *individual* asset had a one hoss shay pattern of decay, the profile of the *aggregate* plant additions could be poorly approximated by one hoss shay for several reasons. Different kinds of assets can have markedly different service lives. Assets of the same kind could end up having different service lives. Individual assets, in any event, frequently have components with different service lives. The tires of an automobile, for example, can need replacement before the windshield of the vehicle does. It follows that one hoss shay may not approximate the capital service flow of the composite asset. Alternative capital cost specifications such as geometric decay can provide a better approximation of the service flow of a group of assets that individually have one hoss shay patterns or which are composites of assets with such patterns.

Consistent with these remarks, the authors of a capital research manual for the Organization of Economic Cooperation and Development ("OECD") stated in the Executive Summary that

> In practice, cohorts of assets are considered for measurement, not single assets. Also, asset groups are never truly homogenous but combine similar types of assets. When dealing with cohorts, retirement distributions must be invoked because it is implausible that all capital goods of the same cohort retire at the same moment in time. Thus, it is not enough to reason in terms of a single asset but age efficiency and age-price profiles have to be combined with retirement patterns to measure productive and wealth stocks and depreciation for cohorts of asset classes. An

[21] Sensitivity to service life assumptions under OHS can be reduced by using plant addition and retirement data that are itemized with respect to asset type. Unfortunately, itemizations of FERC Form 1 plant addition and retirement data are not publicly available before 1994, while data on total additions and retirements are available back to 1964.

important result from the literature, dealt with at some length in the Manual is that, for a cohort of assets, the combined age-efficiency and retirement profile or the combined age-price and retirement profile often resemble a geometric pattern, i.e. a decline at a constant rate. While this may appear to be a technical point, it has major practical advantages for capital measurement. *The Manual therefore recommends the use of geometric patterns for depreciation* because they tend to be empirically supported, conceptually correct and easy to implement.[22] [italics in original]

- Alternative patterns of *physical* asset decay involve different patterns of asset value *depreciation*. Trends in used asset prices can therefore shed light on asset decay patterns. Several statistical studies of trends in used asset prices have revealed that they are generally not consistent with the one hoss shay assumption.[23] Instead, depreciation patterns like geometric decay appear to be the norm for machinery and are also generally the case for buildings.[24] One expert has concluded that "the empirical evidence is that a geometric depreciation pattern is a better approximation to reality than a straight line pattern [i.e., the pattern more consistent with one hoss shay decay], and is at least as good as any other pattern."[25] [bracketed remark from PEG]

- One hoss shay formulas are somewhat complicated and lack intuitive appeal.

- Depreciation in the value of assets can affect input quantity trends even under constant capital service flows. Under the one hoss shay assumption, increasing age would cause the values of individual assets to decline in real terms due to the shortening of the remaining service life. The annual capital cost of a utility is the sum of the annual costs of assets of various vintage. Cost tends to be lower for older systems.

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[22] OECD, *Measuring Capital OECD Manual 2009*, Second Edition, p. 12.

[23] For a survey of these studies see Barbara M. Fraumeni, "The Measurement of Depreciation in the U.S. National Income and Product Accounts*," Survey of Current Business*, July 1997, pp. 7-23. A recent Canadian study is John Baldwin, Huju Liu, and Marc Tanguay, "An Update on Depreciation Rates for the Canadian Productivity Accounts", *The Canadian Productivity Review*, Catalogue No. 15-206-X, January 2015.

[24] OECD, op. cit., p. 101.

[25] Fraumeni, op. cit., p. 17.

The trend in the capital quantity index can be calculated as a cost-weighted average of the trends in the quantities of assets of each vintage. A given rate of growth in the quantity has a lower impact on the capital quantity index the older is its vintage because of its lower weight. Growth in the average age of assets will therefore tend to slow capital quantity growth.[26] Under COS regulation, the impact of this phenomenon is magnified because assets are valued in historical dollars.

Common one hoss shay treatments gloss over the importance of vintaging by valuing all capital services by a "user cost" of capital methodology in which the capital service price is a function of prices of *new* assets. This treatment is tantamount to treating capital services from all assets as purchases from a market in which prices of services do not depend on the age of assets. Capital service markets in which asset age doesn't matter greatly may exist for some assets (e.g., transoceanic shipping containers), but the cost and efficiency of firms that supply these markets depends very much on the vintages of their assets. HQD is a manager of assets, leases very few assets, and its cost trend depends greatly on their changing vintage.

These disadvantages of the one hoss shay specification help to explain why alternative specifications are more the rule than the exception in capital quantity research. We have noted that geometric decay is widely used. Statistics Canada uses geometric decay in its multifactor productivity studies for sectors of the economy.[27] The U.S. Bureau of Labor Statistics, the Australian Bureau of Statistics, and Statistics New Zealand instead assume hyperbolic decay, but not one hoss shay, in their sectoral PMF studies.

[26] In much the same manner, a household can (at the risk of higher maintenance expenses), increase its wealth by continuing to drive the family car for a few more years. The resale value of the car falls each year due to depreciation. The household has no control over used car prices or the rate of return on alternative investments. The cost saving is instead achieved by (implicitly) reducing the quantity of cars that the household owns by owning a car with a diminishing resale value. Money freed up can be invested in the stock market or real estate.

[27] For evidence on this see John R. Baldwin, Wulong Gu, and Beiling Yan (2007), "User Guide to Statistics Canada's Annual Multifactor Productivity Program", *Canadian Productivity Review*, Catalogue no. 15-206-XIE – No. 14. p. 41 and Statistics Canada, *The Statistics Canada Productivity Program: Concepts and Methods*, Catalogue no. 15-204, January 2001.

Benchmark Year Adjustments

Utilities have diverse methods for calculating depreciation expenses that they report to regulators. It is therefore desirable when calculating capital quantities using a monetary method to rely on the reporting companies chiefly for the value of *gross* plant additions and then use a standardized depreciation treatment for all companies. Since some of the plant a utility owns may be 40-60 years old, it is desirable to have gross plant addition data for many years in the past.

For earlier years the desired gross plant addition data are frequently unavailable. It is then customary to consider the value of all plant at the end of the limited-data period and then estimate the quantity of capital it reflects using construction cost indexes from earlier years and assumptions about the historical capex pattern. The year for which this estimate is undertaken is commonly called the "benchmark year" of the capital quantity index. The benchmark year adjustment should deflate net plant value if geometric decay is assumed and *gross* plant value if one hoss shay is assumed. Since the estimate of the capital quantity in the benchmark year is inexact, it is preferable to base capital and total cost research on a sample period that begins many years after the benchmark year. Research on capital and total cost will be less accurate to the extent that this is impossible.

3.4 Kahn X Factors

An alternative approach to choosing an X factor was developed by the noted American regulatory economist Alfred Kahn. Dr. Kahn detailed the method in a 1993 testimony for a group of shippers in a FERC proceeding on PBR for interstate oil pipelines.[28] The FERC still uses this method to set X factors for oil pipelines. In the words of Dr. Kahn, "The ideal indexation formula would be one that...tracked as closely as possible the actual average costs of the pipeline industry."[29]

The method is straightforward. Suppose, for example, that we seek an X factor for a revenue cap index with formula

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[28] "Testimony of Alfred E. Kahn on Behalf of a Group of Independent Refiner/Shippers" in Docket No. RM93-11-000 (Revision to Oil Pipeline Regulations Pursuant to the Energy Policy Act of 1992), August 12, 1993.

[29] Ibid., p. 2.

trend Revenue = trend Inflation – X + trend Customers.

We could then calculate the pro forma cost of service trends for a group of utilities over several years and find the value of X that causes hypothetical revenue cap indexes to have the same trends on average. That is, we seek the value of X such that on average

trend Inflation – X + trend Customers = trend Cost.

It can then be shown that

X^{Kahn} = (*trend Inflation – trend Input Prices) + (trend Customers – trend Inputs*).

A Kahn X factor thus reflects inflation as well as changes in productivity. Thus, it is not fully comparable to an PMF trend estimate. However, it sidesteps complicated productivity calculations and produces results consistent with COS accounting. The Kahn method can thus permit X factor calibration without calculating industry input price and PMF indexes. This "indirect" method can yield substantial regulatory cost savings; an ability to avoid calculating capital price and quantity indexes is especially valuable since these calculations are complicated.

In Table 3 we demonstrate the calculation of a Kahn X factor for HQD. The inflation measure reflects growth in labor and non-labor prices in Québec, represented by average weekly earnings and the Consumer Price Index, respectively. These price trends are weighted by the shares labor and non-labor costs represent in the distribution component of HQD's 2016 *revenu requis*. We consider the X factor necessary to track HQD's *revenu requis* from 2005 to 2015.[30] The exercise produces a Kahn X factor of **0.67%**.

3.5 Other Methodological Issues

Choosing a Base Productivity Growth Target

Research on the productivity of other utilities can be used in several ways to calculate base productivity growth targets. Using the average historical productivity trend of the entire industry to

[30] We leave out 2016 since reported costs in that year were apparently affected by a change in accounting standards.

Table 3

Calculating Kahn X Factors for HQD

	Revenu Requis (%) [A]	Inflation (%) [B]	Retail Customers (%) [C]	Implicit X Factor [D = (B + C) - A]
2005	4.34	2.44	1.37	-0.52
2006	5.53	1.69	1.65	-2.19
2007	8.47	2.04	1.40	-5.03
2008	4.74	2.03	1.14	-1.57
2009	5.88	0.70	1.19	-3.99
2010	4.97	1.61	1.31	-2.05
2011	-4.30	2.90	1.21	8.41
2012	0.28	2.14	1.17	3.03
2013	1.56	0.82	1.11	0.38
2014	1.13	1.51	0.91	1.29
2015	-7.50	1.25	0.83	9.58
2016	-7.47	0.81	0.71	8.99
2017	*9.53*	*1.12*	*0.96*	*-7.45*
2018	*-2.32*	*1.72*	*0.79*	*4.83*
Average annual growth rates:				
2005-2015	**2.28**	**1.74**	**1.21**	**0.67**
Sources:	Growth rates are for the distribution component of revenus requis (i.e., they do not include those for Achats d'Électricité or Service de Transport). For years 2004-2015, data are for "années reels" or "années historiques" as reported in the Regie's rate case decisions. Data for 2016 (année historique), 2017 (année de base), and 2018 (année témoin) are from HQD's most recent rate case filing.	Weighted average of labor and non-labor price growth rates. Labor prices are average weekly earnings in Québec, including overtime, for all employees within the industrial aggregate excluding unclassified businesses (Statistics Canada, Table 281-0026); 2017-2018 values are average weekly earnings in Canada as forecast by the Quebec Minister of Finance (2018 Actuarial Report on the Employment Insurance Premium Rate, Office of the Chief Actuary, 22 August 2017, pg. 52). Non-labor prices are represented by the Consumer Price Index - All Items for Québec (Statistics Canada, Table 326-0021); 2017-2018 values are forecasts by TD Economics for Québec (Provincial Economic Forecast, Dec 14, 2017). The labor weight is 0.19. This is the product of two values: 0.43, which is the average weight assigned to growth in salaries when calculating the "facteur d'évolution combiné des charges" used to establish the 2016 and 2017 "enveloppe des charges d'exploitation" (R-3933-2015, HQD-8, Doc. 1, pg. 6; R-3980-2016, HQD-8, Doc. 1, pg. 7), and 0.44, which is the share that the "charges d'exploitation" represent in the 2016 non-energy, non-transmission revenus requis (2017-07-31, HQD-5, Doc. 1, pg. 5).	2002-2009: Growth rates based on data from Rapport annuel 2003 (Ventes et revenus par catégories de tarifs et de clientèles, HQD-2, Doc. 3, p. 7), & Rapport annuel 2011 (Historique des ventes, des produits des ventes, des abonnements et de la consommation, HQD-10, Doc. 2, p. 6) 2010-2016: Growth rates based on data from Rapport annuel 2013 & Rapport annuel 2016 (Historique des ventes, des produits des ventes, des abonnements et de la consommation, HQD-10, Doc. 2, pp. 5 & 6) 2017 (D-2017-022), 2018 (année témoin): R-4011-2017 (Efficience et performance, HQD-2, Doc. 1, pg 19)	[calculated]

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calibrate X is tantamount to simulating the outcome of competitive markets. The competitive market paradigm has broad appeal.

On the other hand, individual firms in competitive markets routinely experience windfall gains and losses. Our discussion above of the sources of productivity growth implies that differences in the external business conditions that drive productivity growth can cause different utilities to have different productivity trends. For example, power distributors experiencing brisk growth in the number of electric customers served are more likely to realize economies of scale than distributors experiencing average customer growth.

In the design of rate and revenue cap indexes, there has thus been considerable interest in methods for customizing base productivity growth targets to reflect local business conditions. The most common approach to customization to date has been to use the average productivity trends of *similarly situated* utilities. Relevant conditions for a power distributor include the pace of electric customer growth, growth in the number of gas customers served, and changes in the extent of undergrounding.

A variety of potential peer groups can merit consideration in an X factor calibration exercise. In choosing among these, the following principles are appropriate. First, the group should either exclude the subject utility or be large enough that the average productivity trend of the peer group is substantially insensitive to its actions. This may be called the externality criterion. It is desirable, secondly, for the group to be large enough that the productivity trend is not dominated by the actions of a handful of utilities. This may be called the sample size criterion. A third criterion is that the group should be one in which external business conditions that influence productivity growth are similar to those of the subject utility. This may be called the "no windfalls" criterion.

Sources of Data for X Factor Calibration Research

United States Data on operations of U.S. electric utilities are well-suited for the PMF research needed to calibrate an X factor for HQD. Standardized data of good quality have been available from federal government agencies for dozens of investor-owned electric utilities for decades. The primary source of these data is the Federal Energy Regulatory Commission ("FERC") Form 1, which collects detailed cost data and some useful data on operating scale. Major investor-owned electric utilities in the United States are required by law to file this form annually. Cost and quantity data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Details of these accounts can be found in Title 18 of the Code of Federal Regulations. The data are credibly itemized, permitting calculations of the cost of power distributor services even for the numerous vertically integrated electric utilities ("VIEUs") in the States.

Itemized data on the net value of power distribution and general plant and the corresponding gross plant additions are available since 1964. This makes U.S. data the best in the world for accurate calculation, using monetary methods, of the consistent capital cost, price, and quantity indexes that are needed to calculate multifactor productivity trends.

Custom productivity peer groups have frequently been used in X factor calibration research, and that practice has by no means been confined to regulatory commissions and consumer advocates. In New England, for example, utilities have proposed and regulators have approved X factors in index-based PBR plans that are calibrated using research on the productivity trends of Northeast utilities.

Canada In Canada, standardized data on utility operations which could be used to accurately measure their productivity trends are not readily available in most provinces including Québec. A notable exception is Ontario. Standardized data are publicly and electronically available on operations of about seventy Ontario power distributors for more than a decade. PEG has used these data to estimate industry productivity trends in X factor calibration work commissioned by the Ontario Energy Board.

Based on our experience, we believe that the Ontario data have some notable disadvantages in an X factor calibration exercise for HQD.

- Plant value data are available for most Ontario distributors only since 1989. For several utilities (including Hydro One Networks), these data are available only since 2002. The benchmark year adjustments must therefore be fairly recent. Data on *gross* plant additions, which we prefer to use to calculate capital costs and quantities, are only available starting in 2013. It is necessary to impute gross plant additions in earlier years using data on changes in the gross value of all plant.[31] These circumstances tend to reduce the accuracy of statistical research on the capital cost and total cost performance of Ontario utilities.

[31] Another problem in measuring Ontario capital costs is that itemized data on distribution and general plant are not readily available.

- Many Ontario distributors are transitioning to International Financial Reporting Standards ("IFRS"). This has reduced capitalization of O&M expenses for some distributors, thereby materially slowing their O&M and multifactor productivity trends in the last few years.

- Itemization of O&M salary and wage and material and service expenses is not available so that company-specific cost share weights cannot be calculated for O&M input quantity indexes.

Due to the limitations of Canadian data, regulators in Alberta and British Columbia have based X factors in their MRIs for gas and electric power distributors on the productivity trends of national samples of U.S. distributors. The Ontario Energy Board used estimates of U.S. productivity trends to choose the productivity target in its third-generation MRIs for power distributors but used Ontario data in two other MRIs.

The complications of basing X on the productivity trends of other utilities have occasionally prompted regulators to base X factors on a utility's *own* recent historical productivity trend. This approach will weaken a utility's incentives to increase productivity growth if used repeatedly. Furthermore, a utility's productivity growth in one five or ten-year period may be very different from its productivity growth potential in the following five years. For example, a ten-year period in which productivity growth was slowed by high capex may be followed by a period of brisk productivity growth.

Data Quality

The quality of data used in index research has an important bearing on the relevance of results for the design of MRIs. Generally speaking, it is desirable to have publicly available data drawn from a standardized collection form such as those developed by government agencies. Data quality also has a temporal dimension. It is customary for statistical cost research used in MRI design to include the latest data available.

3.6 Choosing a Stretch Factor

The stretch factor term of a revenue cap index formula should reflect an expectation of how the productivity growth of the subject utility will differ from the base productivity growth target. This depends in part on how the performance incentives generated by the plan compare to those in force for utilities in the productivity studies used to set the base productivity trend. It also depends on the company's operating efficiency at the start of the PBR plan. Productivity growth should be more rapid to the extent that inefficiency is greater.

Statistical benchmarking should be considered as a means of setting stretch factors. Benchmarking can address O&M expenses, capital cost, total cost, and reliability. Benchmarking is routinely used to set stretch factors for power distributors in Ontario. Benchmarking is also extensively used by Australian and British power distribution regulators. These precedents are noteworthy since these regulators have extensive PBR experience.[32]

4. Review of Productivity and Stretch Factor Evidence

4.1 Salient Proceedings

Productivity trends of energy and telecommunications ("telecom") utilities have often been considered by North American regulators in proceedings in which MRIs with rate or revenue cap indexes are proposed. The earliest proceedings to approve such MRIs for energy utilities took place in New England and California. An MRI with a price cap index was approved for the vertically integrated electric services of Central Maine Power in 1995. Price cap indexes were later twice approved for the company's distributor services after it restructured. Several MRIs with index-based price cap indexes were approved for Massachusetts energy distributors between 1996 and 2006. Massachusetts then rejected proposals by several energy distributors for rate or revenue cap indexes before recently approving one for power distributor services of Eversource Energy. Vermont has on several occasions approved rate plans with escalators for O&M revenue which reflect a multifactor productivity study filed by Central Vermont Public Service in a 2008 proceeding.[33]

[32] PEG Research has prepared transnational power distribution cost benchmarking studies for both the Australia Energy Regulator and the Ontario Energy Board, and benchmarks the costs of all Ontario Power distributors each year using the latest available Ontario data.

[33] Dr. Lowry was the company productivity witness.

MRIs with index-based rate or revenue caps were approved for three California energy utilities between 1996 and 1999. In addition, larger California energy utilities were for many years required to file studies of their own productivity growth in general rate cases. The Sempra companies (San Diego Gas and Electric and Southern California Gas) filed *industry* productivity studies on some of these occasions.[34]

The province of Ontario approved an MRI with price cap indexes in 2000. There have been three successor plans. In one of the four MRIs, the X factor was based on the productivity trends of U.S. power distributors while in two it was based on the productivity trends of Ontario distributors.[35] The Ontario Energy Board has, additionally, approved MRIs with index-based rate or revenue cap indexes twice for Enbridge Gas Distribution and three times for Union Gas.

In Alberta, an MRI with an indexed price cap was approved for ENMAX, the power distributor serving Calgary, in 2009. The Alberta Utilities Commission has since then mandated two generations of MRIs with index-based rate or revenue cap indexes for all of the larger provincial gas and electric power distributors. British Columbia approved MRIs for FortisBC and FortisBC Energy in 2014 with X factors based on U.S. productivity evidence.

Table 4 summarizes results of these proceedings for the Régie's convenience. In considering these results please note the following.

- Regulators do not always itemize their chosen X factors into key components of interest such as base productivity trends and stretch factors. One reason is that the X factors are sometimes the outcomes of settlements between parties where any components of X that might have been agreed to were not itemized.
- Rate and revenue cap indexes in the United States frequently feature macroeconomic inflation measures, as noted above. In these instances, the X factors have on several occasions been lowered to reflect the brisk PMF growth of the U.S. economy.

[34] Dr. Lowry was the productivity witness for the Sempra utilities in these proceedings.

[35] The X factor in a fourth plan was based on Board judgment. Dr. Lowry advised the Board in that proceeding.

Table 4

Index-Based ARMs of North American Energy Utilities[1]

Applicable Service	Utility	Jurisdiction	Term	Cap Form	Inflation Measure (P)	Acknowledged Productivity Trend (A)	Stretch Factor[2] (B)	X-Factor [3]
Bundled Power Service	PacifiCorp (I)	California	1994-1997, extended to 1999	Price Cap	Industry-specific	1.40%	NA	1.40%
Bundled Power Service	Central Maine Power (I)	Maine	1995-1999	Price Cap	GDPPI	NA	NA	0.9% (Average)
Gas Distribution	Southern California Gas	California	1997-2002	Revenue Cap	Industry-specific	0.50%	0.80% (Average)	2.3% (Average)
Power Distribution	Southern California Edison	California	1997-2002	Price Cap	CPI	NA	NA	1.48% (Average)
Gas Distribution	Boston Gas (I)	Massachusetts	1997-2003	Price Cap	GDPPI	0.40%	0.50%	0.50%
Power Distribution	Bangor Hydro Electric (I)	Maine	1998-2000	Price Cap	GDPPI	NA	NA	1.20%
Power Distribution	PacifiCorp (II)	Oregon	1998-2001	Revenue Cap	GDPPI	NA	NA	0.30%
Gas Distribution	San Diego Gas and Electric	California	1999-2002	Price Cap	Industry-specific	0.68%	0.55% (Average)	1.23% (Average)
Power Distribution	San Diego Gas and Electric	California	1999-2002	Price Cap	Industry-specific	0.92%	0.55% (Average)	1.47% (Average)
Power Distribution	All Ontario distributors	Ontario	2000-2003	Price Cap	Industry-specific	0.86%	0.25%	1.50%
Gas Distribution	Bangor Gas	Maine	2000-2009, extended to 2012	Price Cap	GDPPI	NA	NA	0.36% (Average)
Gas Distribution	Union Gas	Ontario	2001-2003	Price Cap	GDPPI	NA	NA	2.50%
Power Distribution	Central Maine Power (II)	Maine	2001-2007	Price Cap	GDPPI	NA	NA	2.57% (Average)
Power Distribution	Southern California Edison	California	2002-2003	Revenue Cap	CPI	NA	NA	1.60%
Power Distribution	EPCOR (I)	Alberta	2002-2005, Terminated at end of 2003	Price Cap	Industry-Specific	NA	NA	15% * Inflation
Gas Distribution	Berkshire Gas	Massachusetts	2002-2011	Price Cap	GDPPI	0.40%	1.00%	1.00%
Gas Distribution	Blackstone Gas	Massachusetts	2004-2009	Price Cap	GDPPI	NA	NA	0.50%
Gas Distribution	Terasen Gas	British Columbia	2004-2009	Revenue Cap	CPI	NA	NA	63% x Inflation (Average)
Gas Distribution	Boston Gas (II)	Massachusetts	2004-2013, terminated in 2010	Price Cap	GDPPI	0.58%	0.30%	0.41%
Power Distribution	All Ontario Distributors	Ontario	2006-2009	Price Cap	GDPIPI	NA	NA	1.00%
Power Distribution	Nstar	Massachusetts	2006-2012	Price Cap	GDPPI	NA	NA	0.63% (Average)
Gas Distribution	Bay State Gas	Massachusetts	2006-2015, terminated in 2009	Price Cap	GDPPI	0.58%	0.40%	0.51%
Power Distribution	ENMAX	Alberta	2007-2013	Price Cap	Industry-specific	0.80%	0.40%	1.20%
Gas Distribution	Enbridge Gas	Ontario	2008-2012	Revenue Cap	GDPPI	NA	NA	47% x Inflation (Average)
Gas Distribution	Union Gas	Ontario	2008-2012	Revenue Cap	GDPPI	NA	NA	1.82%
Power Distribution	Central Vermont Public Service	Vermont	2009-2011, extended to 2013	Revenue Cap	CPI	1.03%	NA	1.00%
Power Distribution	Central Maine Power (III)	Maine	2009-2013	Price Cap	GDPPI	NA	NA	1.00%
Power Distribution	All Ontario Distributors	Ontario	2010-2013	Price Cap	GDPPI	0.72%	0.40% (Average Across Firms)	1.12% (Average Across Firms)
Power Distribution	Green Mountain Power	Vermont	2010-2013	Revenue Cap	CPI	NA	NA	1.00%

Table 4 (continued)

Index-Based ARMs of North American Energy Utilities[1]

Applicable Service	Utility	Jurisdiction	Term	Cap Form	Inflation Measure (P)	Acknowledged Productivity Trend (A)	Stretch Factor[2] (B)	X-Factor [3]
Power & Gas Distribution	All Distributors	Alberta	2013-2017	Price Cap for Power, Revenue per Customer Cap for Gas	Industry-specific	0.96%	0.20%	1.16%
Power Distribution	Green Mountain Power	Vermont	2014-2017	Revenue Cap	CPI	NA	NA	1.00%
Gas Distribution	Union Gas	Ontario	2014-2018	Revenue Cap	GDPPI	NA	NA	60% x Inflation
Power Distribution	All Distributors except those who opt out	Ontario	2014-2018	Price Cap	Industry-specific	0.00%	Range of 0% to 0.6%	Range of 0% to 0.6%
Bundled Power Service	FortisBC	British Columbia	2014-2019	Revenue Cap	Industry-specific	0.93%	0.10%	1.03%
Gas Distribution	FortisBC Energy	British Columbia	2014-2019	Revenue Cap	Industry-specific	0.90%	0.20%	1.10%
Power & Gas Distribution	All Distributors	Alberta	2018-2022	Price Cap for Power, Revenue per Customer Cap for Gas	Industry-specific	NA	NA	0.30%
Power Distribution	Eversource Energy	Massachusetts	2018-2023	Revenue Cap	GDPPI	-0.46%	0.25% if GDPPI growth exceeds 2%	-1.56%
Hydro Power Generation	Ontario Power Generation	Ontario	2017-2021	Price Cap	Industry-specific	0.00%	0.30%	0.30%

Averages*	**Gas Distributors**	**0.63%**	**0.46%**	**1.05%**
	Electric Utilities	**0.65%**	**0.29%**	**0.95%**
	Power Distributors	**0.60%**	**0.32%**	**0.96%**
	All Utilities	**0.62%**	**0.39%**	**1.00%**

*Averages exclude X factors that are percentages of inflation.

[1] Shaded plans have expired.

[2] Some approved X factors are not explicitly constructed from such components as a base productivity trend and a stretch factor. Many of these are the product of settlements.

[3] X factors may not be the sum of the acknowledged productivity trend and the stretch factor, where these are itemized, for the following reasons: (1) a macroeconomic inflation measure is employed in the attrition relief mechanism, (2) a revenue cap index does not include a stand alone scale variable, or (3) the X factor may incorporate additional adjustments to account for special business conditions.

- Some rate and revenue cap indexes take the form of a percentage of measured inflation and thus do not have explicit X factors.

The following results in Table 4 are especially pertinent to the Régie's *jugement* process.

- The average of the utility PMF trends acknowledged by regulators has been **0.60%** for power distributors and **0.63%** for gas distributors.
- A negative base productivity trend has only once been acknowledged by a North American regulator.

- The average approved stretch factor has been **0.39%.**

4.2 A Closer Look at Recent Notable Studies

We now take a closer look at some recent energy utility productivity studies. Key results are summarized in Table 5.

Alberta (2012)

The Alberta Utilities Commission ("AUC") held a generic proceeding from 2010 to 2012 to develop MRIs applicable to multiple provincial gas and electric power distributors. The commission retained Jeff Makholm of National Economic Research Associates ("NERA") in Boston to prepare a study of the productivity trends of U.S. power distributors. Dr. Makholm had filed power distributor productivity studies in two prior MRI proceedings. His study used an unusually lengthy sample period (1973-2009), a volumetric output index, and a simple one hoss shay approach to capital cost measurement. PMF grew much more rapidly in the early years of his sample period than it did after 1998, when it typically declined. Makholm recommended as the PMF growth target the 0.96% trend for the *full* sample period and made no X factor recommendation.

Utilities in this proceeding hired several witnesses to appraise NERA's study. These witnesses embraced most aspects of NERA's methodology but argued that more recent sample periods beginning around the year 2000 were appropriate, during which productivity growth was negative.[36] They had mixed opinions about the need for a stretch factor.

Dr. Lowry of PEG, who had previously done more than a dozen energy utility productivity studies, including several for energy distributors, was retained by the Consumers' Coalition of Alberta in this proceeding. He submitted a study of U.S. *gas* utility productivity trends and recommended a 0.19% stretch factor for all distributors. His gas productivity study used the number of customers as the output measure and a COS approach to capital cost measurement. He reported a 1.32% productivity trend for the full sample but recommended that the X factor for gas distributors be based on the more rapid

[36] They also argued in favor of a national sample that ignored local business conditions in Alberta that are favorable to productivity growth.

Table 5

Survey of Recent Multifactor Productivity Studies

					Author Recommendations				
Proceeding	Industry Studied	Year	Author (Consultancy)	Client	Industry Productivity Trend	Recommended Stretch Factor	X Factor	Previous Known Energy Productivity Studies	Outcome
Ontario Energy Board, Cases EB-2007-0606 and EB-2007-0615	US Gas Distributors	2007	Lowry (PEG)	Ontario Energy Board	1.40% to 1.61%	0.5% for both Revenue per Customer Cap and Price Cap	**Union Gas**: 1.98% for Revenue per Customer Cap and 1.01% for Price Cap **Enbridge Gas:** 2.08% for Revenue per Customer Cap and 0.48% for Price Cap	More than 20 productivity studies submitted as testimony	PBR plan was approved outlined in separate settlements for Union Gas and Enbridge. Union adopted PEG methodology and results. Enbridge's settlement defined the X factor as a share of the inflation measure, which increased in each year of the plan.
			Carpenter & Bernstein (Brattle)	Enbridge Gas Distribution	-0.14% to -0.08%	0.00%	-0.14% to 0.01%	First known Brattle evidence on productivity. Research relied on PEG's database with some changes in methodology	
Alberta Utilities Commission Proceeding 566	US Power Distributors	2010-2012	Makholm & Ros (NERA)	Alberta Utilities Commsision	0.96%	No recommendation	No recommendation	Two prior studies of power distribution productivity	AUC adopted these productivity results for the first generation PBR plan
	US Gas Distributors	2011	Lowry (PEG)	Consumers' Coalition of Alberta	1.32% to 1.84%	0.19%	1.51% to 2.03%	More than 20 productivity studies submitted as testimony	AUC adopted X factor of 1.16%. This was the sum of a 0.96% productivity trend and a 0.20% stretch factor.
Régie de l'énergie, R-3693-2009, Phase 2	Gaz Metro	2011	Lowry (PEG)	Gaz Metro (Task Force)	1.11% to 1.67%	0.2% to 0.5%	1.31% to 2.17%	More than 20 productivity studies submitted as testimony	Gaz Metro's proposal was rejected. Company was ordered to file a revenue per customer indexing plan featuring revenue decoupling.
Québec's Régie de l'énergie, R-3693-2009, Phase 3	US Gas Distributors	2012	Lowry (PEG)	Gaz Metro	0.85% to 1.00%	0.20%	1.05% to 1.20%	More than 20 productivity studies submitted as testimony	Proceeding suspended to address other matters
Ontario Energy Board Case EB-2010-0379	Ontario Power Distributors	2013	Kaufmann (PEG)	Ontario Energy Board	0.00%	0% to 0.6% depending on cost performance	0% to 0.6% depending on cost performance	Previously reported productivity trends for numerous clients including Jamaica Public Service (2008), the Ontario Energy Board (2008), Bay State Gas (2004-05), Boston Gas (2002-03)	OEB adopted PEG results
British Columbia Utilities Commission, Project 3698719	US Power Distributors	2013	Overcast (Black & Veatch)	FortisBC	-3.9% to -5.5%	No explicit recommendation	0% (Company proposed 0.5% X factor)	None	BCUC adopted PEG results and rejected B&V study in its entirety.
			Lowry (PEG)	Commercial Energy Consumers Association of British Columbia	0.93% to 1.18%	0.20%	1.13% to 1.38%	More than 20 productivity studies previously submitted as testimony	
British Columbia Utilities Commission, Project 3698715	US Gas Distributors	2013	Overcast (Black & Veatch)	FortisBC	-3.2% to -4.9%	No explicit recommendation	0% (Company proposed 0.5% X factor)	None	BCUC adopted PEG results with one change and rejected B&V study in its entirety.
			Lowry (PEG)	Commercial Energy Consumers Association of British Columbia	0.96% to 1.13%	0.20%	1.16% to 1.33%	More than 20 productivity studies submitted as testimony	
Ontario Energy Board Case EB-2012-0459	US Gas Distributors	2013	Coyne, Simpson, and Bartos (Concentric)	Enbridge Gas Distribution	-0.32%	No explicit recommendation	0.00%	First publicly-released productivity study	Company proposed a Custom IR plan which did not include an explicit X factor. Much of the company's proposal was accepted.
Massachusetts Department of Public Utilities, D.P.U. 13-90	Northeast US Power Distributors	2013	Lowry (PEG)	Fitchburg Gas & Electric dba Unitil	1.19%	0.20%	0.01%	More than 20 productivity studies submitted as testimony	PBR proposal rejected by Department
			Dismukes (Acadian)	Massachusetts Office of the Attorney General	0.79% to 1.59%	No recommendation	No recommendation	Multiple energy utility productivity studies, all prepared in response to utility proposals	
Maine Public Utilities Commission, Case 2013-00168	Northeast US Power Distributors	2013	Lowry (PEG)	Central Maine Power	0.56% to 1.06%	0.00%	-1.9% to -1.02%	More than 20 productivity studies submitted as testimony	Settlement withdrew PBR plan proposal
Alberta Utilities Commission, Proceeding 20414	US Power Distributors	2016	Brown and Carpenter (Brattle)	ATCO Gas, ATCO Electric, Altagas, Enmax, FortisAlberta	-0.79%	0.00%	-0.79%	First power distributor productivity study. Brattle has not conducted an independent study to date.	AUC adopted an X factor of 0.3%. Meitzen study rejected. Brattle study set lower bound of reasonable X factor range.
			Meitzen (Christensen)	EPCOR	-1.11%	0.00%	-1.11%	First productivity study outside of telecom	
			Lowry (PEG)	Consumers' Coalition of Alberta	0.43% to 1.28%	0.20%	0.63% to 1.48%	More than 20 productivity studies submitted as testimony	

Table 5 (continued)

Survey of Recent Multifactor Productivity Studies

Ontario Energy Board Case EB-2016-0152	US Hydro Generators	2016	Frayer (London Economics)	Ontario Power Generation	-1.18% to -1.01%	No recommendation	No recommendation	Two prior studies on power distribution productivity	OEB adopted Ontario Power Generation proposed productivity trend, but rejected both productivity studies
			Lowry (PEG)	Ontario Energy Board	0.29%	0.30%	0.59%	More than 20 productivity studies submitted as testimony	
Massachusetts Department of Public Utilities, D.P.U. 17-05	US Power Distributors	2017	Meitzen (Christensen)	Eversource Energy	-0.41% (regional) to -0.46% (nationwide)	0%, Company proposed a 0.25% stretch factor if inflation exceeds 2%	-2.64%	Second productivity study outside of telecom, largely reliant on others' methodology	Massachusetts DPU adopted the results of the Meitzen study, An adjustment to X was made to reflect that grid modernization costs would be tracked
			Dismukes (Acadian)	Massachusetts Office of the Attorney General	0.37% to 0.85%	No explicit recommendation	-1.36%	Multiple energy utility productivity studies, all prepared in response to utility proposals	
Lawrence Berkeley National Laboratory	US Power Distributors	2017	Lowry (PEG)	Lawrence Berkeley National Laboratory	0.45%	No recommendation	No recommendation	More than 20 productivity studies submitted as testimony	Productivity study featured in a report about the effectiveness of MRIs.
Ontario Energy Board Case EB-2017-0049	Ontario Power Distributors	2017	Fenrick (PSE)	Hydro One Networks	-0.90%	0.45%	0.6% maximum	We are aware of 2 prior productivity studies Mr. Fenrick has undertaken.	Pending
Ontario Energy Board, Case EB-2017-0307	US Power Distributors	2017	Makholm (NERA)	Enbridge Gas Distribution and Union Gas Limited	0.54%	0.00%	0.00%	3 prior publicly-released productivity studies. First productivity study since 2010.	Pending

1.84% productivity trend of sampled distributors that, like those in Alberta, experienced brisk customer growth.

The AUC ultimately chose a 0.96% base productivity trend and a 0.20% stretch factor for all gas and electric distributors. In its decision, the commission ventured opinions on several methodological issues. With respect to the output specification, for example, the commission stated on page 82 of AUC Decision 2012-237 that

> The Commission agrees with NERA's and PEG's view that when selecting a particular output measure, it must be matched to the type (price cap or revenue-per-customer cap) of a PBR plan….The Commission agrees with Dr. Lowry and his colleagues at PEG that for revenue-per-customer cap plans, the number of customers, rather than a volumetric output measure, is the correct output measure for a TFP study….Using similar logic, the Commission agrees with Dr. Lowry that output measures that place a heavy weight on volumetric and other usage measures should be used for TFP studies that are part of a price cap PBR plan.

Ontario (2013)

The X factors in the Ontario Energy Board's fourth-generation MRIs for most provincial power distributors were based on the average PMF trends of these distributors. PEG senior advisor Larry Kaufmann prepared productivity research and testimony for Board Staff. Dr. Kaufmann had undertaken several previous energy distributor productivity studies. Although this MRI (still in effect) features *price* cap indexes, an *elasticity*-weighted scale index was employed in the productivity research, due in part to the fact that data were not readily available which might provide the basis for a *revenue*-weighted scale index. This treatment placed considerable weight on the trend in system use. A variant on the geometric decay approach to measuring capital cost was employed. With this methodology, Dr. Kaufmann reported an Ontario industry productivity trend of -0.33% for the full sample period but nonetheless recommended a 0% base productivity trend for the price cap indexes due, in part, to data peculiarities in the last sample year.[37] The Board agreed to the 0% base PMF trend, and chose stretch factors for each utility which varied between 0.0 and 0.6% depending on the results of an econometric total cost benchmarking study that PEG prepared.

Maine (2014)

In 2013, Central Maine Power proposed a fourth generation MRI for its power distributor services. The company claimed a need for supplemental revenue to fund high capex after many years of operation under MRIs. Dr. Lowry was retained by the company to prepare productivity research and testimony. The company proposed a revenue cap (and decoupling), and his study used the number of customers as the scale variable. A COS approach to capital cost measurement was featured. Dr. Lowry reported annual PMF trends for two groups of Northeast power distributors which ranged from 0.56% for New York state and New England to 1.06% for the broader Northeast. He proposed a 0.0% stretch factor and a special adjustment to the X factor based on his finding that Northeast distributors with unusually old systems tended to have slow productivity growth. The company's proposal was dropped in the settlement approved by Maine's commission and no decisions on industry productivity trends or the stretch factor were rendered.

Massachusetts (2014)

In 2013, Unitil proposed an MRI for power distributor services of Fitchburg Gas and Electric. It retained Dr. Lowry to undertake research and testimony on the productivity trends of Northeast power distributors. He reported a 1.19% PMF growth trend for Northeast distributors and recommended a 0.20% stretch factor.

The Massachusetts Attorney General's Office retained Dr. David Dismukes of Acadian Consulting to review and comment on Dr. Lowry's study. His review of Dr. Lowry's evidence suggested that the

[37] The trend for 2003-11 period that excludes the last year 0.19%.

PMF trend should lie between 0.79% and 1.59%. He did not comment on the appropriate stretch factor. Unitil's proposal was rejected by the Massachusetts commission and no decisions on industry productivity trends or the appropriate stretch factor were rendered.

British Columbia (2014)

In 2013 FortisBC (formerly West Kootenay Power) and FortisBC Energy (formerly Terasen Gas) proposed MRIs for their gas and electric services which featured index-based revenue caps. Fortis retained a Black and Veatch consultant, who reported no prior productivity research experience, to prepare gas and electric power distribution productivity studies. Black and Veatch reported productivity trends for these industries in the neighborhood of -4% but nevertheless recommended a 0% productivity growth target and a 0% stretch factor for the companies. Notwithstanding the research results of its witness, Fortis recommended a 0.5% X factor for both utilities.

Dr. Lowry was retained by the Commercial Energy Distributors of British Columbia and prepared studies of U.S. gas and electric distributor productivity trends. He reported PMF trends of 0.93% for the full sample of power distributors and 0.96% for the full sample of gas utilities and recommended a 0.20% stretch factor for both companies. The BC commission chose a 0.93% base productivity trend and a 0.10% stretch factor for electric services. For gas it chose a 0.90% base productivity trend and a 0.20% stretch factor. The Black and Veatch study was rejected in its entirety.[38]

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[38] The commission stated in its decisions on the Fortis MRIs that

> The Panel has a number of concerns about the B&V studies and is not persuaded that the TFP trend results reported by B&V can be used as a basis to establish an X-Factor. Dr. Overcast employs a study methodology that is, by his own admission, non-standard. There is no evidence that this methodology has been accepted in any other proceeding. Further, Dr. Overcast has not previously conducted a TFP trend study. The Panel previously found B&V's use of output and input level indexes inappropriate and cannot be relied upon to generate meaningful input and output trends. We have also made determinations in the areas of input cost inflation, the use of arithmetic vs logarithmic measures and the study length. In all cases, we found flaws in the study methodology that tend to understate TFP trends. **Given the number of shortcomings in B&V's methodology and the errors that arise from these shortcomings, the Panel does not accept B&V's study results.**

Reference: British Columbia Utilities Commission (2014), *In the Matter of FortisBC Inc. Multi-Year Performance Based Ratemaking Plan for 2014 Through 2018 Decision*, September 15, p. 56.

Alberta (2016)

The AUC held a proceeding 2015-2016 to resolve key issues in the design of next-generation MRIs for Alberta energy distributors. EPCOR hired Christensen Associates while other utilities hired the Brattle Group to prepare productivity studies. Although Christensen had previously done a few energy utility productivity studies, EPCOR retained Dr. Mark Meitzen, Christensen's expert on *telecommunications* productivity. Both consultancies updated NERA's power distributor study with few adjustments and then advocated basing X on results the later years of the full sample period, when PMF growth was materially negative. National samples were once again embraced. Brattle proposed a base PMF growth trend of -0.79% while Christensen proposed a trend of -1.11%. Both consultancies also proposed a 0% stretch factor.

The Consumers Coalition of Alberta hired Dr. Lowry again, and he prepared an independent study of U.S. power distributor productivity growth. He used the number of customers as the scale variable and a geometric decay approach to measuring capital cost. His sample was substantially larger than that used by the utility witnesses or in his own prior studies. Dr. Lowry reported a 0.43% PMF trend for the full sample of power distributors but recommended basing X on the higher 0.78% trend for rapidly-growing distributors. Lacking persuasive benchmarking evidence, Dr. Lowry recommended a 0.20% stretch factor for all companies.

The sample period was 1997-2014. Dr. Lowry reported a 0.43% PMF trend for the full sample of power distributors but recommended basing X on the higher 0.78% trend for rapidly-growing distributors. Lacking persuasive benchmarking evidence, Dr. Lowry recommended a 0.20% stretch factor for all companies.

Dr. Lowry once again lodged extensive criticisms of NERA's methodology for PMF measurement. His evidence showed that the decline in PMF growth over the full sample period was due chiefly to the slowdown and ultimate decline in average use of power by residential and commercial customers. He argued that this slowdown was irrelevant to the choice of X factors for Alberta's gas distributors, which operated under revenue per customer indexes.

Dr. Lowry also demonstrated that results using NERA's methodology were very sensitive to the assumption concerning the average service life of assets. NERA had assumed a 33-year service life, and this assumption was never well substantiated by Dr. Makholm or the utility witnesses in Alberta.[39] Based on Dr. Lowry's extensive experience, a materially higher average service life was warranted. EPCOR, for example, reported a 37-year average service life in the proceeding.

When various problems with NERA's method were corrected and a 37-year service life was used, the resultant PMF trend was similar to that from Dr. Lowry's method. Thus, the negative PMF trend of recent years was due to an inappropriate service life assumption that, over the *full* sample period, was masked by brisk growth in R&C average use in the earlier years of the sample period. *This evidence by Dr. Lowry, which is provided in Attachment 1 to this report, severely compromised the credibility of NERA's methodology. However, it was not considered by the AUC when it made its X factor decision,* ostensibly because Dr. Lowry had not provided working papers for his final research.[40] Working papers were prepared but not provided on the advice of PEG's client because the evidence was submitted in rebuttal testimony shortly before oral hearings and working papers were never requested by any party. We believe that this evidence is highly pertinent to the Régie's *jugement*

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[39] Dr. Makholm noted the 33-year assumption in his report but did not defend or explain it. When asked to explain the assumption in a data request from PEG, he stated only that "The 33-year service life is a more updated average of the lifetimes of utility capital."

[40] The AUC did not mention this evidence in its decision on the MRI, but stated in the related cost award decision that

> The Commission also considers that there were certain areas of evidence that did not contribute to the Commission's understanding of the issues or was of limited assistance because the supporting information was not provided... Another example is related to PEG's evidence Table 2, "Summary of Corrections and Modifications to NERA/Brattle/LRCA Productivity Calculations," found in Pacific Economics Group's rebuttal evidence. Table 2 shows the steps in reconciling PEG's and NERA-based studies, which effectively resulted in Dr. Lowry's reproduction of the Brattle Group and Dr. Meitzen studies on the record of the original proceeding . . . These papers were not provided on the record to support the Table 2 calculations. Because working papers were not provided, the Commission and parties were unable to test the veracity of the numbers in Table 2 and the Commission was not able to assess the probative value of the information provided. While generally PEG's evidence was of assistance to the Commission, this specific information in Table 2 did not contribute to a better understanding of the total factor productivity to be used in determining X. Accordingly, the Commission cannot approve the hours related to the preparation of Table 2, the corresponding narrative to Table 2, and the associated working papers. (AUC Decision 22082-D01-2017, p. 12)

process and is just as valid as any other evidence that has not yet been completely vetted by opposing parties (e.g., the Fenrick study for Hydro One Networks).

The AUC ultimately chose a 0.30% X factor for both gas and electric power distributors and did not itemize a stretch factor.

Lawrence Berkeley National Laboratory (2017)

Dr. Lowry calculated the PMF trends of a large sample of U.S. power distributors in his recent study on multiyear rate plans for Lawrence Berkeley National Laboratory.[41] The number of customers was the scale variable and geometric decay was assumed with a 37-year average service life. He reported PMF trends of 0.45% for the full 1980-2014 sample period and of 0.39% for the more recent 1996-2014 sample period. Using his method, which is not sensitive to average use trends, there has *not* been a large slowdown in power distributor productivity growth since 2000 and recent productivity growth has not been negative.[42] In a fall 2017 presentation funded by LBNL which Dr. Lowry made to the New England Council of Public Utility Commissions, Dr. Lowry reported that the PMF trend of sampled power distributors for the more recent 1996-2016 sample period was 0.43% per annum for the full U.S. sample and 0.31% for the Northeast U.S.

Massachusetts (2017)

Eversource Energy retained Dr. Meitzen of Christensen Associates to prepare productivity research and testimony in support of an MRI proposal for its power distribution services in Massachusetts. Dr. Meitzen updated NERA's study to 2016, making only a few changes to the methodology. Eversource proposed a *revenue* cap index, and Dr. Meitzen used the number of customers served rather than a volumetric index as his scale variable. However, he did not reconsider the 33-year average service life assumption and did not report results for the earlier years of NERA's sample period. Thus Eversource, a company based in the Boston area, did not hire Boston's most experienced power distribution productivity consultant but instead hired Christensen's telecom

[41] Lowry, op. cit., p. B.18

[42] Slower growth in the number of customers served has, however, produced a modest (e.g., 10 basis point) slowdown in the realization of scale economies

productivity expert to use NERA's methodology for a recent sample period, a practice NERA had opposed. Meitzen reported productivity trends of around -0.40% for both regional and national distributor samples and proposed a 0% stretch factor.

The Massachusetts Office of the Attorney General retained Dr. David Dismukes of Acadian Consulting Group to prepare productivity research and testimony.[43] He reported a +0.37% simple average PMF trend for the full sample, a +0.42% weighted average for the full sample, a +0.71% simple average for the Northeast sample, and a +0.85% weighted average for the Northeast sample. He did not address the stretch factor issue.

In its decision approving an MRI for Eversource, the Massachusetts Department of Public Utilities acknowledged a -0.46% U.S. industry power distributor productivity trend. It also embraced the one hoss shay approach to measuring capital cost.

Ontario (2017)

Ontario Power Generation ("OPG") proposed an MRI for its regulated hydroelectric generating services in 2016. It retained London Economics to prepare a supportive study of trends in the productivity of North American hydroelectric generators. London Economics had done two prior productivity studies and used a "physical assets" approximation to a one hoss shay approach to measuring the capital quantity trend.[44] They reported a PMF trend in the -1.01 to -1.18% range and made no stretch factor recommendation. The company proposed a 0% base productivity trend and a 0.3% stretch factor.

Ontario Energy Board staff retained Dr. Lowry to prepare an independent study of the productivity trends of the company and a sample of U.S. hydroelectric generators. Using generation capacity as the scale metric and geometric decay to measure capital cost, he reported a 0.29% PMF trend and recommended a 0.3% stretch factor. Using a Khan method, Dr. Lowry also showed that the X factor implicit in the company's recent revenue and volume trends from 2008 to 2014 was +1.34%. The

[43] Dr. Lowry was not a witness in this proceeding so many of his criticisms of NERA's method were not considered.

[44] They specifically used generation capacity as the capital quantity index.

propriety of the one hoss shay and related physical asset approaches to capital cost and quantity measurement was a salient issue in the proceeding.

The Board issued a decision last month which approved a 0% base productivity trend and a 0.3% stretch factor. In its decision the Board declined to fully embrace the entire PMF methodology used by either witness but, unlike the AUC in its recent decision, did venture opinions on several methodological issues. In particular, it indicated a preference for Dr. Lowry's method for measuring capital cost stating that

> The OEB questions LEI's physical approach which uses MW capacity as an input, as this measure does not take into account financial considerations, such as the capital costs. Although many hydroelectric generation assets have very long useful lives, the OEB is not convinced that there is no functional depreciation until end of life. In fact, reviews of capital projects to sustain, refurbish and replace hydroelectric stations and assets in OPG's prior payment amount applications confirm that capital expenditures and operating costs are needed to maintain capacity to the end of a station's life. Absent ongoing capital and operating expenditures, hydroelectric generation assets will depreciate over time. In the OEB's view, LEI's physical method, which assumes no depreciation until the end of life, is not a realistic basis for the analysis of productivity of hydroelectric generation facilities.[45]

The Board stated the hope that its opinions on methodological issues would be considered in future productivity studies, stating that

> The OEB expects that OPG and other stakeholders will take into account the OEB's concerns about the approaches and limitations of the experts' analyses on the record in this proceeding. Improvements in methodology and data, and translation of the results of the studies as to how they more directly translate to rate-setting would provide more useful and convincing information on which OPG could make its next proposal and the OEB would make its determination for subsequent IRM plans.[46]

Ontario (2017)

Hydro One Networks filed evidence in 2017 in support of a custom MRI for its power distributor services. The company retained Steve Fenrick of Power Systems Engineering to prepare supportive productivity and benchmarking evidence. Mr. Fenrick had prepared a few previous energy distributor

[45] Ontario Energy Board, EB-2016-0152, Decision and Order, December 28, 2017, pp. 126-127.

[46] Ibid., p. 128.

productivity studies. He updated PEG's Ontario power distributor productivity study to 2015, reporting a -0.90% annual PMF growth trend for the full sample period, and proposed a 0.45% stretch factor based on the result of his total cost benchmarking study. Hydro One proposed a base productivity trend of zero and a 0.45% stretch factor. PEG has been retained by Board Staff to review Mr. Fenrick's submission. However, the project has been delayed and no review has yet been undertaken.

Ontario (2017)

Union Gas and Enbridge recently proposed a merger and an MRI for their consolidating Ontario gas utility operations. The so-called "Amalco" companies retained Dr. Makholm of NERA to update his power distributor PMF study. He reports a 0.54% PMF trend for his full 1973-2016 sample period, but the negative PMF trend in recent years has continued. Notwithstanding his support for basing X factors on results for the full sample period when he was a commission witness, Makholm recommends a 0% base productivity factor for the combined company and a 0% stretch factor. The Amalco made the same recommendations. Dr. Lowry has been retained by Board staff to respond to Makholm's new study. The project is just beginning, however, and Makholm's evidence has not yet been reviewed or challenged.

Canadian Utility Sector Productivity

CEA notes on p. 12 of its June 2017 X factor evidence the declining productivity of the Canadian utility industry as measured by *Statistique Canada*. The pertinence of the Canadian utility industry productivity indexes was discussed at some length by Dr. Lowry in the first Alberta MRI proceeding. He explained that *Statistique Canada* has calculated PMF indexes for the utility sector of the Canadian economy and two subsectors: “Electric power generation, transmission, and distribution” and “natural gas distribution, water, and other systems”. Though *Statistique Canada* continues to maintain the utility sector index, the two subsector indexes were terminated in 2010.

Each index has been calculated on a “gross output” and a “value added” basis. The gross output approach is more similar to that conventionally used in productivity studies for X factor calibration because it includes intermediate inputs like materials and services. The value-added approach does not include intermediate inputs because it is intended for use in the calculation of the PMF growth of Canada's aggregate business sector.[47]

Only results for the value-added utility PMF index are reported on a timely basis, and it is these results that CEA reports on p. 13 of its July submission. Between 1962-2015 this index exhibited a 0.41% average annual growth rate. However, over the last twenty years (1996 to 2015) this index averaged a 0.83% annual decline, and over the last ten years (2006 to 2015), it averaged a 1.75% annual decline.

Results of the value-added utility PMF index that CEA features are of limited relevance in setting an X factor for HQD, for several reasons.

- It is a value-added calculation. As such, it ignores productivity in the use of intermediate inputs.
- It is sensitive to developments in the generation sector of the electric utility industry. This has little relevance to network industries such as power distribution. For example, the growth in the index has in recent years been slowed by Hydro-Québec projects to develop remote hydroelectric resources.
- The electric utility industry restructured in Alberta and Ontario. It is not clear how well this has been handled by *Statistique Canada*.
- A volumetric scale index is employed. This makes results sensitive to changing business conditions including, particularly, the slowing growth in average use of energy. Declining average use has been more pronounced in the gas utility industry than in the electric utility industry.
- Measured productivity growth is slowed by growth in expenses for utility conservation and load management programs, which are large in several Canadian provinces, but will likely be Y factored in HQD's MRI.

The *Statistique Canada* PMF indexes for “electric power generation, transmission, and distribution” and “natural gas distribution, water, and other systems” are available on a gross value basis through 2010. On average, the productivity of the gas and water sector grew by 0.55% annually

[47] It is difficult to use macroeconomic data to compute the PMF of the aggregate private business sector if intermediate inputs are included.

between 1962-2010. For the most recent 20 years (1991-2010) productivity declined by 0.09% per year on average, and for the most recent ten (2001-2010) it declined by 1.44%. Note that output is measured volumetrically, and thereby reflects the material decline in average use of gas by Canadian residential and commercial customers that has been underway for many years.

As for the PMF index for the "electric power generation, transmission, and distribution," using the gross output approach, Statistics Canada reports a 0.61% average annual growth rate in utility sector productivity for the full 1962-2010 period. For the most recent 20 years (1991-2010), the average growth rate is 0.41%. For the most recent ten years (2001-2010), productivity declines by a modest 0.12% annually.

The Center for the Study of Living Standards ("CSLS") retained Statistics Canada to prepare a study of productivity trends at the provincial level. A report on the research was released in 2010.[48] This study reported results only for value-added PMF indexes. After extensive correspondence between PEG Research and principals of this study, the principals conceded that the study used an experimental methodology and is not of a high enough standard to be used in X factor determination.

The AUC stated in its decision on first-generation MRI for provincial energy distributors that

> Overall, the Commission considers that while Statistics Canada's MFP indexes and the CSLS report can be a useful reference for gauging the general productivity trends of the utilities sector, these analyses cannot be a substitute for a TFP study for either the electric or gas distribution industries.

Commentary

This review of recent PMF studies and MRI proceedings prompts several comments.

- Productivity research has various uses, and the methods appropriate for one use may not be appropriate for another. In this proceeding, we seek productivity research that can inform selection of an X factor for a revenue per customer index between *dossiers tarifaires*. A different methodology might be appropriate for a study concerned solely with cost efficiency or the calibration of X in a price cap index.

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

- Commissions that have made X factor decisions often comment on the research methods used by PMF witnesses. This encourages witnesses to use better methods in subsequent MRI proceedings.
- Much of the recent variation in PMF trends reported by witnesses in MRI proceedings is due to research methods that the Régie may find objectionable or inappropriate for application to a revenue cap index. It is reasonable for the Régie to give little or no weight to such evidence in its decision.
- Utilities have frequently hired witnesses in recent years who have little experience in the measurement of PMF trends of energy utilities. It is chiefly these witnesses who have recommended substantially negative productivity growth trends. These witnesses also frequently propose 0% stretch factors.
- The slowdown in productivity growth which utility witnesses often highlight is due chiefly to slowing growth in residential and commercial average use which is irrelevant to the choice of an X factor for HQD. They often conjecture that slow productivity growth is also driven by high capex requirements but provide little evidence to substantiate this notion.
- Commissions are sometimes reluctant to embrace results of one productivity study because they do not prefer every aspect of any one study's methodology. However, this does not mean that they routinely take an average of the recommendations of all witnesses when choosing a base productivity trend or stretch factor. An averaging approach incentivizes parties to produce outlier results that can move the average. Judgement can instead focus on the most recent studies and the best methodologies.

5. Application to HQD

5.1 Inflation Measure

<u>Régie Ruling</u>

The Régie traced the outlines of an inflation measure for HQD's revenue cap index in D-2017-043 but made no final decision. It suggested that the inflation measure should summarize growth in two inflation subindexes: the *indice des prix a la consommation* ("IPC", aka consumer price index) for Québec and the average weekly earnings ("AWE") of Québec industrial workers. Both of these price indexes are calculated by Statistique Canada. The revenue cap index inflation measure would take the average AWE inflation in the last three years ending 31 March and the inflation in $IPC^{Québec}$ for the last year. Cost share weights would be used for these subindexes, following the precedent of the Company's current *formule paramétrique* for the *charges d'exploitation revenu requis.*

> **la Régie retient la proposition du Distributeur à l'effet que le facteur de pondération entre l'inflation et le taux de croissance des salaires soit déterminé selon une méthode similaire à celle utilisée actuellement dans les demandes tarifaires aux fins du calcul de l'enveloppe des charges d'exploitation, soit en fonction de la quote-part de la masse salariale, excluant la portion capitalisable, sur les charges totales couvertes par la formule paramétrique.** [49]

This general approach to the design of a rate or revenue cap inflation measure is sensible and is currently used to regulate energy utilities in Alberta, British Columbia, and Ontario. It helps the revenue cap index track local inflation pressures that utilities experience while sidestepping the complicated issue of capital price measurement which might be encountered with a more complex utility input price index.

We nonetheless have concerns with the Régie's suggested inflation measure treatment in three areas: the choice of a macroeconomic inflation measure, the cost share weights, and the appropriate time period to consider. We discuss these issues in turn.

Macroeconomic Inflation Measure

Table 6 shows trends in six macroeconomic price indexes that are sensible candidates for use in Québec. We also include the average weekly earnings of Canadian and Québec industrial workers. Here are the indexes with brief discussion of noteworthy features.

[49] Régie, op. cit., p. 37.

Table 6

Alternative Inflation Measures for Canada and Québec[1]

	Canada								Québec							
	IPC[1]		GDPIPIs[2]				AWE[3]		IPC[1]		GDPIPIs[2]				AWE[3]	
	All Items		Final Consumption		Final Domestic Demand		All Employees		All Items		Final Consumption		Final Domestic Demand		All Employees	
Year	Level	GR	Level	GR	Level	GR	Level	GR	Level	GR	Level	GR	Level	GR	Level	GR
1982	56.1	10.4%	55.8	10.0%	59.0	9.1%			57.1	10.9%	58.1	10.6%	61.7	9.6%		
1983	59.4	5.7%	59.6	6.6%	62.2	5.4%			60.3	5.4%	61.4	5.6%	64.7	4.8%		
1984	62.0	4.2%	62.3	4.4%	64.9	4.1%			62.8	4.0%	64.4	4.8%	67.6	4.4%		
1985	64.4	3.9%	64.8	3.9%	67.2	3.6%			65.5	4.3%	67.1	4.1%	70.0	3.6%		
1986	67.1	4.0%	67.5	4.1%	69.8	3.8%			68.7	4.7%	69.9	4.1%	72.8	3.9%		
1987	70.0	4.3%	70.3	4.1%	72.8	4.1%			71.6	4.2%	73.0	4.4%	75.9	4.2%		
1988	72.8	3.9%	73.1	3.9%	75.5	3.7%			74.3	3.6%	75.6	3.5%	78.4	3.3%		
1989	76.5	4.9%	76.5	4.5%	78.9	4.4%			77.4	4.2%	78.9	4.2%	81.4	3.8%		
1990	80.2	4.7%	80.1	4.6%	82.0	3.8%			80.8	4.3%	82.4	4.4%	84.6	3.7%		
1991	84.7	5.5%	83.9	4.7%	84.7	3.3%			86.7	7.1%	86.5	4.8%	87.3	3.2%		
1992	85.9	1.4%	85.7	2.1%	86.4	2.0%			88.4	1.9%	87.9	1.7%	88.8	1.6%		
1993	87.5	1.9%	87.4	1.9%	88.0	1.8%			89.5	1.3%	89.3	1.5%	89.9	1.2%		
1994	87.6	0.1%	88.5	1.3%	89.5	1.7%			88.4	-1.3%	89.7	0.5%	90.9	1.1%		
1995	89.6	2.2%	89.8	1.4%	90.5	1.1%			89.9	1.7%	90.5	0.9%	91.7	0.9%		
1996	90.9	1.5%	90.9	1.2%	91.5	1.1%			91.3	1.6%	91.4	1.0%	92.2	0.6%		
1997	92.4	1.7%	92.2	1.5%	93.0	1.6%			92.7	1.4%	92.5	1.2%	93.3	1.2%		
1998	93.4	1.0%	93.5	1.3%	94.3	1.5%			94.0	1.4%	93.6	1.2%	94.4	1.2%		
1999	95.0	1.7%	95.2	1.8%	95.6	1.3%			95.4	1.5%	95.3	1.8%	95.8	1.4%		
2000	97.5	2.7%	97.9	2.8%	98.1	2.6%			97.8	2.4%	98.2	3.0%	98.2	2.5%		
2001	100.0	2.5%	100.0	2.2%	100.0	1.9%	657		100.0	2.3%	100.0	1.8%	100.0	1.8%	623	
2002	102.2	2.2%	102.4	2.3%	102.4	2.4%	673	2.4%	102.0	2.0%	102.2	2.2%	102.2	2.2%	639	2.4%
2003	105.1	2.8%	104.4	2.0%	104.0	1.5%	691	2.7%	104.6	2.5%	104.4	2.1%	103.9	1.6%	657	2.8%
2004	107.1	1.8%	106.1	1.6%	105.9	1.8%	709	2.6%	106.6	1.9%	105.9	1.5%	105.6	1.6%	673	2.4%
2005	109.4	2.2%	108.3	2.1%	108.2	2.1%	737	3.8%	109.1	2.3%	108.2	2.1%	107.6	1.9%	695	3.2%
2006	111.6	1.9%	110.3	1.9%	110.7	2.3%	755	2.4%	110.9	1.7%	109.8	1.5%	109.2	1.5%	707	1.8%
2007	114.0	2.2%	112.5	1.9%	113.4	2.4%	787	4.2%	112.7	1.6%	111.9	1.8%	111.1	1.7%	737	4.1%
2008	116.7	2.3%	114.8	2.1%	116.2	2.5%	810	2.8%	115.0	2.1%	113.5	1.5%	113.3	2.0%	751	1.9%
2009	117.0	0.3%	115.9	0.9%	117.6	1.2%	823	1.5%	115.7	0.6%	114.1	0.5%	114.4	1.0%	759	1.0%
2010	119.1	1.8%	117.4	1.4%	118.8	1.1%	852	3.6%	117.1	1.2%	115.4	1.2%	115.4	0.9%	784	3.3%
2011	122.6	2.9%	120.4	2.5%	121.7	2.4%	874	2.5%	120.7	3.0%	118.3	2.5%	118.2	2.4%	804	2.5%
2012	124.4	1.5%	122.2	1.5%	123.7	1.7%	895	2.5%	123.3	2.1%	120.5	1.8%	120.3	1.8%	823	2.4%
2013	125.6	0.9%	124.4	1.8%	125.9	1.7%	911	1.8%	124.2	0.7%	123.0	2.1%	122.8	2.0%	832	1.2%
2014	128.0	1.9%	126.9	2.0%	128.7	2.2%	935	2.6%	125.9	1.4%	125.2	1.7%	125.2	2.0%	850	2.0%
2015	129.4	1.1%	128.3	1.1%	130.8	1.7%	952	1.8%	127.2	1.0%	126.7	1.2%	127.1	1.5%	868	2.1%
2016	131.3	1.4%	129.6	1.0%	132.5	1.3%	956	0.4%	128.2	0.7%	127.7	0.8%	128.2	0.9%	878	1.2%
Average Annual Growth Rates																
1982-2016		**2.7%**		**2.7%**		**2.6%**		**NA**		**2.6%**		**2.6%**		**2.4%**		**NA**
1997-2016		**1.8%**		**1.8%**		**1.9%**		**NA**		**1.7%**		**1.7%**		**1.6%**		**NA**
2002-2016		**1.8%**		**1.7%**		**1.9%**		**2.5%**		**1.7%**		**1.6%**		**1.7%**		**2.3%**
Standard Deviations																
1982-2016		**1.9%**		**1.9%**		**1.6%**		**NA**		**2.2%**		**2.0%**		**1.7%**		**NA**
1997-2016		**0.7%**		**0.5%**		**0.5%**		**NA**		**0.6%**		**0.6%**		**0.5%**		**NA**
2002-2016		**0.7%**		**0.5%**		**0.5%**		**0.9%**		**0.7%**		**0.5%**		**0.5%**		**0.8%**

[1] All growth rates are logarithmic.
[2] Consumer price index (Statistics Canada, Table 326-0021).
[3] Gross domestic product implicit price index (Statistics Canada, Table 384-0039).
[4] Average weekly earnings, including overtime, for all employees in current dollars (Statistics Canada, Table 281-0026).

- The IPC for Canada is the inflation measure most familiar to Canadian consumers. This type of inflation measure is the norm in British and Australian MRIs. It is less common in North American MRIs because it places a fairly heavy weight on price-volatile consumer commodities like gasoline, natural gas, and food. These commodities make the $\text{IPC}^{\text{Canada}}$ more volatile and have much more impact on the budget of a typical consumer than they do on the cost of a typical energy distributor's base rate inputs.[50] On the other hand, the revenue cap index for HQD may apply to *couts de combustibles* such as *diesel leger*, *diesel arctique*, and *mazout*.
- The IPC for Québec ($\text{IPC}^{\text{Québec}}$) has the drawbacks just noted for the $\text{CPI}^{\text{Canada}}$ but has the advantage of being specific to the province. It should therefore be more sensitive to local business conditions than $\text{IPC}^{\text{Canada}}$.
- Gross domestic product implicit price indexes ("GDPIPIs") track inflation in prices of capital equipment and net exports as well as consumer products. They are periodically updated and are available for Québec as well as Canada. However, the GDPIPI for Québec is released with a considerable lag. In the United States, we noted above that a gross domestic product price index has been preferred over IPCs in MRIs because the impact of price-volatile consumer commodities is watered down. However, in Canada's economy with its sizable reliance on natural resource exports, this stabilizing benefit is offset by the impact of incorporating inflation in commodity exports. The GDPIPIs for final domestic demand ($\text{GDPIPI}^{\text{FDD}}$) remove the inflation impact of price volatile exports. They are available for Québec as well as Canada.

Table 6 shows that these indexes vary in their volatility, which we measure in the last three rows of the table by the standard deviations of their growth rates. The CPIs for Canada and Québec are more volatile than the corresponding GDPIPIs for final domestic demand. In 2009, for instance, the CPI (all items) for Canada and Québec grew only 0.3% and 0.6%, respectively, while the GDPIPIs for final

[50] Non-seasonal CPIs also have the characteristic of not being revised.

domestic demand in Canada and Québec rose by 1.2% and 1.0%. Average weekly earnings of Québec workers are even more volatile.

The table also shows that trends in Québec inflation tend to be fairly similar to those for Canadian inflation. Please also note that, in Canada and Québec alike, the growth trends in average weekly earnings are more rapid than those for the macroeconomic price indexes. This incentivizes utilities to propose heavier weights on the labor price indexes in the inflation measures of rate and revenue cap indexes.

We conclude that the $IPC^{Québec}$ is a reasonable subindex for HQD's inflation measure if the formule d'indexation applies to fuel costs. The GDPIPI for final domestic demand in Canada merits consideration if the Régie decides to add a price subindex for fuel cost to the inflation measure.

Cost Share Weights

The inflation in an input price index was shown in Section 3.1 to be a cost-weighted average of the growth in price subindexes for various input groups. This inflation measure for HQD will apply to most costs of base rate inputs, including capital costs. The weight on the labor price index in the inflation measure should therefore be the share of non-capitalized labor expenses in the applicable portion of the pro forma total cost of service. Table 7 summarizes precedents for inflation measures in current Canadian MRIs. It can be seen that similarly low labor price weights are used in Ontario inflation measures. Our review of HQD's *revenu requis* for 2016 suggests that a labor price index weight of approximately 19% is appropriate. This is roughly the share of labor in *charges d'exploitation* times the share of *charges d'exploitation* in the applicable total *revenu requis*. The weight assigned to labor would be reduced if pension and benefit expenses are Y factored.

Timing

With respect to timing, we recommend that the *revenu requis* of HQD be escalated on April 1 of the new rate year on the basis of historical inflation for the period ending on December 31st of the prior year. The requisite inflation measures should be available by early March.

Table 7

Inflation Measures in Current Canadian MRIs

Jurisdiction	Company	Term	Industry	Labor Price Subindex	Labor Weight	Non-Labor Price Subindexes	Non-Labor Weight
Ontario	Ontario Power Generation	2017-2021	Power Generation	Average Weekly Earnings for Ontario - Industrial Aggregate	12%	Canadian Gross Domestric Product Implicit Price Index - Final Domestic Demand	88%
British Columbia	Fortis BC Inc. and FortisBC Energy Inc	2014-2019	Bundled Power Service and Gas Distribution	Average Weekly Earnings for British Columbia	55%	Consumer Price Index - British Columbia	45%
Ontario	All Ontario Distributors	2014-2018	Power Distribution	Average Weekly Earnings for Ontario	30%	Canadian Gross Domestric Product Implicit Price Index - Final Domestic Demand	70%
Alberta	ATCO Electric, FortisAlberta, EPCOR, AltaGas, ATCO Gas	2018-2022	Power and Gas Distribution	Average Weekly Earnings for Alberta	55%	Consumer Price Index - Alberta	45%

5.2 X Factor

The preponderance of evidence assembled suggests that an X factor of +**0.30%** is just and reasonable for the first-generation MRI of HQD.

- The average power distributor PMF growth trend that North American regulators have acknowledged is **0.60%**. Only one North American regulator (Massachusetts) has ever acknowledged a negative productivity growth target. Dr. Lowry was not a witness in that proceeding.

- The OEB most recently set the base productivity growth target for Ontario power distributors at 0%. However, Ontario power distributor operating data have numerous flaws, and the scale index that the OEB uses assigns a substantial weight to usage variables (e.g., delivery volume) that are sensitive to the large energy efficiency programs in the province.

- With regard to productivity studies (rather than commission decisions), Dr. Lowry's method for measuring the PMF trend of power distributors has been shown to be the most appropriate one for setting an X factor for HQD, for several reasons. The number of customers served is clearly the most appropriate scale variable to use when calibrating the X factor of a revenue per customer index. The geometric decay approach to capital cost measurement has many advantages. His assumptions about the average service life are empirically founded and reasonable, and results using his method are in any event not highly sensitive to the service life assumption. Dr. Lowry's sample includes more companies than those in other studies. He prepares productivity studies for diverse clients, and not just utilities. Dr. Lowry recently reported a **0.39%** power distributor PMF growth trend over the 1996-2014 period in his paper for Berkeley Lab. He reported a **0.43%** trend for his full sample for the more recent 1996-2016 period in a recent presentation for regulators which was funded by Berkeley Lab.

- Studies based on a one hoss shay capital cost specification also merit some consideration by the Régie. The most relevant of these are Dr. Meitzen's recent study for Eversource and Dr. Makholm's recent study for the Amalco gas utilities in Ontario. Both studies incorporate recent data. Dr. Meitzen's study additionally features the number of customers as the scale variable. His estimate of the PMF growth trend of all sampled utilities in recent years is **-0.46%**. Dr. Makholm continues to use a less appropriate volumetric index and reported a 0.54% trend for his full sample period but nonetheless recommended a 0% base PMF trend on the basis of his research.

  Both of these studies use an unrealistic and poorly substantiated 33-year average service life. PMF growth would likely be much higher with a higher and more realistic service life. Dr. Meitzen was under no obligation to use NERA's method and in fact has found errors with other aspects of the method. His failure to reconsider the 33-year average service life assumption in his Eversource testimony despite its being an issue in the Alberta proceeding is therefore noteworthy. In the simple one hoss shay methodology, average service life effectively becomes a "fudge factor" that can be used to produce any result. HQD reports a 39-year average service life in its current rate case.[51]

  It should also be noted that Dr. Meitzen routinely used the geometric decay approach to capital cost measurement in his telecommunications productivity research and testimony.

[51] HQD-3, document 2, p. 10.

All other productivity practitioners at Christensen who have prepared energy utility productivity studies have used geometric decay. Dr. Meitzen lacks the expertise to credibly argue that a one hoss shay approach is somehow relevant to power distribution but not to telecommunications. CEA witness James Coyne employed a geometric decay specification in gas productivity research and testimony for Enbridge Gas Distribution.

- Using the Kahn method, an inflation measure like that which the Régie has discussed, and data on HQD's *revenu requis* and customer trends for the 2005-2015 period, we found that an X factor of **0.67%** is indicated.
- The *cibles d'efficience* (efficiency improvement targets) in the Régie's current *formule paramétrique* for *charges d'exploitation* has risen since 2013 from 1% to 1.5%.
- While some utilities have recently proposed negative X factors on the basis of productivity studies prepared by their witnesses, others have not. For example, Fortis recently proposed an X factor of 0.50% in BC, and Hydro One Networks, Ontario Power Generation, and the gas Amalco have all proposed base productivity growth factors of 0%.

Our review of recent PMF studies and MRI proceedings has implications for the kind of PMF study that is appropriate for HQD after the Company's MRI begins. The study should

- calculate productivity trends in the use of capital and *charges d'exploitation* inputs as well as PMF;
- be based primarily on U.S. data, but also consider productivity trends of HQD;
- use the number of customers served by distributors as the scale variable (though other variables could be examined);
- exclude costs that are Y factored;
- consider a geometric decay capital cost specification, and possibly alternative specifications including one hoss shay;
- assemble solid evidence concerning the average service life of power distributor assets, and consider the sensitivity of productivity results to the service life assumption; and
- include a Kahn X factor exercise as a point of comparison.

5.3 Stretch Factor

We noted in Section 2 that the stretch factor term of an X factor should reflect an expectation of how the productivity growth of the subject utility will differ from the base productivity growth target. This depends in part on how the performance incentives generated by the plan compare to those in force for utilities in the productivity studies that are used to set the base productivity trend. It also depends on the company's operating efficiency at the start of the PBR plan. Statistical benchmarking should be considered as a means of setting stretch factors.

Initial Operating Efficiency

Regarding HQD's operating efficiency, we note first that the Company has not previously operated under a comprehensive MRI. To the contrary, it has operated under frequent rate cases for many years, a system that typically yields week cost containment incentives. Growth in the Company's *revenu requis* for many *charges d'exploitation* has, however, been restricted by a *formule paramétrique* for several years.

In reaction to a marked increase in operating expenses, in 2007 the Régie directed HQD to present an integrated efficiency improvement plan in its next rate case that would control cost growth without compromising service quality or grid reliability.[52] Such a plan was approved in Décision D-2008-024, with the goal of reducing the net *charges d'exploitation* by $10 million on a recurring basis. This represented about 1% of controllable costs. In the same decision, the Régie adopted an ongoing efficiency target of 1% of the *charges d'exploitation*, and stated its expectation that HQD would maintain the average annual growth of a set of indicators below inflation over a moving five-year window going forward. In 2014 the Régie increased the efficiency target from 1% to 1.5%.[53]

The efficiency improvement plan was broadly conceived, and the actions taken were numerous. They can be divided roughly into actions taken by current management and those that are structural in nature. The former refers to minor adjustments to current practices, the implementation of which was

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[52] Décision D-2007-12.

[53] Décision D-2014-037, pg. 80.

to be the responsibility of HQD’s various business units. The latter refers to more major changes, which often required significant up-front investment and were to be individually approved and monitored.

Growth in the Company’s *charges d’exploitation* has been slow in recent years. However, it is difficult to ascertain how its current level of efficiency compares to industry norms. For years HQD has participated in benchmarking studies of its customer services and distribution costs.[54] The company reports simple unit cost metrics and its general position related to the other participants in a benchmarking study but does not generally provide further details, nor describe the characteristics of the firms to which its scores are compared.[55] Controls for external business conditions in these studies are crude. The company refused to provide details of a recent benchmarking study in response to an information request from PEG. Thus, it is difficult to interpret the benchmarking results or know what weight to assign to them. On the basis of available evidence, it is reasonable to assume that the Company is an average cost performer.

There is no credible argument for setting stretch factors at zero just because utilities have operated for a few years under a cap on the *revenu requis* for *charges d'exploitation*.

- The performance incentives generated by this cap are not likely to be strong enough to eliminate the accumulated inefficiencies of utilities.
- Even if incentives provided by this cap were much stronger, it is notable that companies in competitive markets have widely varying degrees of operating efficiency.
- Sophisticated benchmarking studies of total cost performance like those required in Ontario have not been reported.

[54] Décision D-2008-024, pp. 27-30.

[55] Under the Hydro-Québec Act (sections 7.2 and 20.1), the effectiveness and performance of the company must be assessed by an independent firm every three years, and the results of any such benchmarking studies must appear in the company’s annual reports (e.g., Annual Report 2012, pg. 114; Annual Report 2015, pg. 99). Benchmarking results are also discussed periodically in the context of regulatory proceedings.

Comparison to Other Regulatory Systems

The MRI will have a term of only four years. An MTER will be included and will likely share all surplus earnings between the Company and its customers. Meanwhile, the investor-owned utilities whose data are likely to be used in the productivity research have typically averaged rate cases about every three years in recent years. There is therefore not a large difference in the incentive power of HQD's new regulatory system and the systems under which U.S. power distributors have typically operated. Stronger incentives can be hoped for in future MRIs.

Conclusions

Considering all of these factors, and precedents in other jurisdictions, we believe that a stretch factor of **0.20%** is reasonable for HQD.

6. Other Plan Provisions

6.1 Y Factor

Régie Ruling

In D-2017-043, the Régie ruled that Y factor treatment should be permitted for costs that are recurrent but of unpredictable size, sensitive to events outside HQD's control, and in excess of a materiality threshold (*seuil de materialite*). Costs eligible for Y factor treatment shall include HQD's power purchase and transmission expenses and the impact of changes in market rates of return on the weighted average cost of capital (*cout moyen pondere du capital*). The Régie, suggested without rendering a final decision, that retirement costs would be addressed by the *formule d'indexation* but costs of *interventions en efficacite energetique* (*IEE*) would be Y factored. A $15 million materiality threshold was also suggested.[56] The Régie stated that each element of HQD's current variance and deferral accounts [*comptes d' ecarts et reports* (*CER*)] should be examined for eligibility for Y factor or Z factor treatment.

[56] Régie, op. cit., p. 76.

HQD Comments

HQD favors Y factor treatment for its costs of retirement, fuels, *IEE* and support for *Transition energetique Québec* ("TEQ"), bad debt (*mauvaises creances*), low income programs (*strategie por la clientele a faible revenue*), and vegetation management (*maitrise de la vegetation*).

PEG Response

Table 8 presents information on *charges d'exploitation* and accounts that are eligible for Y factoring in contemporary North American energy utility MRIs. It can be seen that diverse costs are typically accorded Y factor treatment. Costs that are commonly eligible for Y factoring include those for energy procurement, upstream transmission, and conservation. Some of the sampled utilities that do not Y factor costs of conservation programs do not have such programs.

PEG has a number of general concerns about the Y factoring of costs in an MRI. Y factoring can weaken incentives to contain the affected costs and raises the cost of regulation. Customers benefit when utilities absorb operating risk. On the other hand, some costs are difficult to address through a rate or revenue cap index because they are sensitive to volatile external business conditions or government directives. Y factoring can materially reduce operating risk.

PEG supports Y factoring all of HQD's costs for IEE and TEQ. These programs can produce material cost savings for HQD's customers. The MRI envisioned in D-2017-043 includes some incentives for the Company to embrace conservation and demand management. These incentives include the revenue cap and the capitalization of some IEE costs. They also include normalization of revenue for weather-induced load variances, since this reduces the risk to HQD from rate designs with high usage charges (including time sensitive rates) that encourage conservation and demand management. However, the incentive to contain load-related distribution capex is weakened in the contemplated MRI by the relatively brief four-year term of the plan, the lack of an efficiency carryover mechanism, the sharing of surplus earnings through the MTER, and the door (discussed further below) which has been opened for the Company to obtain supplemental capital revenue through the Z factor. HQD's incentive to use IEE to contain power supply costs and transmission capex is weakened by the tracking of these costs. Tracking all IEE and TEQ costs would encourage a better balance between Hydro-Québec's incentives to embrace conservation and demand management and its incentives for load-related

Table 8

Approved Y Factors in Current North American MRIs

Company	Jurisdiction	Plan Term	Eligible Costs and Accounts	Citation
Eversource Energy	Massachusetts	2018-2023	Not discussed in decision. Company currently has approved riders to address the costs of DSM programs, pensions, Attorney General Consulting Expenses, pensions and post-employment benefits, state funded renewable programs, solar program, and storm reserves. A Y factor to address the costs of an enhanced vegetation management pilot program was approved in this proceeding.	DPU 17-05
All Distributors	Alberta	2018-2022	All costs that meet the AUC's Y factor criteria. To date, the following costs have been found to meet these criteria: AESO flow-through items Farm transmission costs Accounts that are a result of Commission directions (e.g., AUC assessment fees, intervener hearing costs, UCA assessment fees, AUC tariff billing and load settlement initiatives, Commission-directed Rural Electrification Associations (REA) acquisitions, effects of regulatory decisions) Income tax impacts other than tax rate changes Municipal fees Load balancing deferral accounts Weather deferral account (ATCO Gas only) Production abandonment costs	Decision 20414-D01-2016 (Errata)
Ontario Power Generation	Ontario	2017-2021	Hydroelectric Water Conditions Variance Account Ancillary Services Net Revenues Variance Account – Hydroelectric and Nuclear Sub-Accounts Hydroelectric Incentive Mechanism Variance Account Hydroelectric Surplus Baseload Generation Variance Account Income and Other Taxes Variance Account Capacity Refurbishment Variance Account Pension and OPEB Cost Variance Account Hydroelectric Deferral and Variance Over/Under Recovery Variance Account Gross Revenue Charge Variance Account Pension & OPEB Cash Payment Variance Account Pension & OPEB Cash Versus Accrual Differential Deferral Account Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account	EB-2016-0152
FortisBC	British Columbia	2014-2019	Numerous costs are Y factored including pensions and other post retirement benefits, regulatory hearing costs, accounting standards changes, on-bill financing, interim rate variance	Project #3698719, Decision; September 2014
FortisBC Energy	British Columbia	2014-2019	Numerous costs are Y factored including overhead costs recovered from thermal energy customers, energy policy programs, pensions and other post-employment benefits, midstream gas costs, energy efficiency and conservation, biomethane program, hearing costs, on-bill financing, BCUC assessments, gains and losses on disposition or retirement of property	Project #3698715, Decision; September 2014
Union Gas	Ontario	2014-2018	Upstream gas and transportation costs, incremental DSM costs, LRAM volume reductions for contract rate classes, Unaccounted for Gas Volume Variances, 50% share of tax changes	EB-2013-0202
Incentive Regulation Mechanism Power Distributors except those who opt out	Ontario	2014-2018	**Group 1 includes accounts that do not require a prudence review. This group will include account balances that are cost pass-through and accounts whose original balances were approved by the Board in a previous proceeding.** Low Voltage Account Wholesale Market Service Charge Account Retail Transmission Network Charges Account Retail Transmission Connection Charge Account Power Account Global Adjustment Account **Group 2 includes accounts that require a prudence review.** Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs Other Regulatory Assets - Sub-Account - Incremental Capital Charges Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act Retail Cost Variance Account Board-Approved Conservation and Demand Management Variance Account Others	EB-2010-0239, Filing Requirements For Electricity Distribution Rate Applications (Group 1), EB-2008-0046 and 2018 DVA Continuity Schedule

transmission and distribution capex. PEG also supports Y factoring costs of the *strategie pour la clientele a faible revenu.*

Y factoring retirement costs is a judgement call as there are arguments on both sides. Y factoring these costs can encourage HQD to shift employee compensation from salaries and wages to retirement benefits. Review of these costs can be challenging. On the other hand, these costs are substantial and variable due to business conditions beyond HQD's control. The labor price subindex of the inflation measure tracks trends in salaries and wages but not retirement costs. Retirement costs have been Y factored in several MRIs. The decision on whether to Y factor retirement costs should depend on the extent to which the MRI protects HQD from other kinds of risk.

PEG opposes Y factoring vegetation management, fuel, and bad debt costs. Vegetation management costs are a normal cost of doing business and are very much within a distributor's control. The performance incentive mechanism for reliability should encourage effective vegetation management. Vegetation management is rarely Y factored in MRIs for electric utilities.

Tracking the costs of fuel would weaken the Company's IEE incentives. Indexation of fuel prices is fairly straightforward. Power procurement costs are typically Y factored in MRIs but this is due in part to the difficulty of indexing them in an era of complicated managed power markets. Gasoline prices receive a substantial weight in $IPC^{Québec}$. The inflation measure could, alternatively, include one or more generation fuel price subindexes with appropriate cost share weights. In that event, PEG recommends using the GDPIPI for Canada as the inflation measure for "other" (e.g., capital) inputs.

Bad debt costs rise and fall with the economy but are fairly small. In Québec, the risk of bad debts is limited by the low cost of the patrimonial power block. These costs are not commonly subject to Y factor treatment even in jurisdictions where power supply costs are much more volatile.

The method for Y factoring change in the weighted average cost of capital is up for discussion in Phase 3. PEG believes that, over a plan of only four years, it is necessary to index only the bond yield to market trends. PEG also believes that only 50% of the change in the bond yield should be Y factored since changes in market rates of return on capital are reflected in the IPC in the long run.

6.2 Z Factor

Régie Ruling

In D-2017-043, the Régie ruled that Z factor treatment should be permitted for *elements exogénes* which are particularly difficult to foresee, of unpredictable size, tied to events outside HQD's control, and in excess of a materiality threshold. The Régie also suggested that the Z factor could be used to obtain supplemental revenue for capital, stating that

> **La Régie ne croit donc pas nécessaire, ni souhaitable, d'inclure un mécanisme de suivi des dépenses en immobilisation. Cependant, et tel que le Distributeur le suggère dans son argumentation concernant l'inclusion de l'amortissement, si le Distributeur souhaite réaliser des investissements majeurs et d'une ampleur inhabituelle durant le MRI, il lui sera possible de demander à la Régie de traiter de tels investissements comme un exogène, de type Facteur Z.**[57]

HQD Comments

In its submission last July, Hydro-Québec recommended Z factoring unforeseeable events in the *reseaux autonomes,* unfunded costs of major outages (*pannes majeures*), contributions to connections, and miscellaneous other events including changes in the regulatory regime, demands flowing from decrees or changes in laws, and unforeseen major projects.

PEG Response

PEG supports allowing HQD to request Z factor treatment of unforeseeable events in the *reseaux autonomes*, unfunded costs of major outages (*pannes majeures*) that are attributable to external events, contributions to connections, the *tarif de maintien de la charge*, changes in accounting standards, and miscellaneous other events that include changes in the regulatory regime and demands flowing from decrees or changes in laws. However, PEG is very concerned about the Z factor "loophole" that the Régie has created for supplemental capital revenue. Z factors by their nature provide supplemental revenue for capex resulting from difficult to forecast events such as major storms. The protection afforded by Z factors can be broadened by expanding the eligibility criteria to generally include projects that are mandated for various reasons (e.g., highway relocations) by government agencies. The G factor reduces the risk of unexpectedly rapid growth in the demand for distribution

[57] D-2017-043 p. 64.

services. The term of the MRI is only four years, and underfunding in the last plan years is less problematic. Y factoring changes in the weighted average cost of capital further reduces capital cost risk.

To permit supplemental revenue for other kinds of capex surges opens the door to the several problems that PEG discussed in its Phase I report and responses to information requests. For example, HQD will be incentivized to exaggerate its capital spending requirements and to “bunch” its capex so that it qualifies for tracker treatment. The Company may receive dollar for dollar compensation for capital spending shortfalls when business conditions are unfavorable but receive the full revenue that indexing provides when business conditions are favorable. Customers are not then guaranteed the benefit of industry productivity growth even when it is achievable.

A mechanism for providing supplemental capital revenue such as the Incremental Capital Module in Ontario involves major design challenges and can have unforeseen consequences. In Alberta, a lengthy proceeding was devoted to finalization of capital cost trackers after the outlines of the first-generation MRI were approved. The tracker mechanism ultimately chosen was much more generous to utilities than originally envisioned, and was aggressively used by utilities during the MRI. The scope of capital cost tracking was substantially narrowed by the Commission in the next MRI.

The report and responses to information requests prepared by PEG in Phase 1 provide the Régie with several ideas to make provisions for supplemental capital revenue more reasonable. These include a substantial materiality threshold and the continued tracking of capital costs accorded tracking treatment in subsequent plans. There is currently a 10% adder to the materiality threshold in Ontario's Incremental Capital Module. The X factor can be raised to account for the fact that some large capital projects get Z factor treatment. PEG has addressed the size of X factor adjutments that might be needed in other proceedings.

6.3 Materiality Thresholds

Régie Ruling

In D-2017-043, the Régie suggested $15 million materiality thresholds for Y factors and Z factor events.

PEG Response

Materiality thresholds have several advantages in a system of cost trackers. They can reduce regulatory costs and strengthen a utility's incentive to contain costs. Thresholds can also reduce overcompensation for events (e.g., highway relocations and severe storms) that are routinely encountered by utilities in the productivity growth sample.

Table 9 presents information on materiality thresholds in contemporary MRIs for the Régie's perusal. It can be seen that Z factors are more typically subject to materiality thresholds in the surveyed plans than Y factors. Materiality thresholds are more common for capital cost trackers and are sometimes substantial. It should also be noted that incentivization of cost trackers by limiting the full true up of revenue requirements to actual costs also occurs in North American regulatory systems that do not feature MRIs.[58]

PEG believes that $15 million thresholds are reasonable for a Company of HQD's size. These should apply on a per event basis to Z factors. The first $15 million of variances between Y factored costs and the corresponding revenue requirements should be non-recoverable each year. The thresholds should be escalated annually by the revenue cap index.

6.4 Metrics

Régie Ruling

In D-2017-043, the Régie ruled that the MTER would be linked to an array of service quality and safety metrics.

PEG Response

PEG recommended a performance metric system for HQD in its Phase I report. There should at a minimum be performance incentive mechanisms for the system average interruption duration index, the system average interruption frequency index, various aspects of customer service, and worker safety. There should also be PIMs for analogous itemized reliability indexes for sensible regions of

[58] Cost trackers are widely used in U.S. regulation today.

Table 9

Materiality Thresholds for Y and Z Factors

Company	Jurisdiction	Plan Term	Y Factor Materiality Threshold	Z Factor Materiality Threshold	Citation
Eversource Energy	Massachusetts	2018-2023	Some Y Factors (e.g., $1.2 million per event for the storm fund) have a materiality threshold	$5 million escalated by GDPPI for each year of the plan for each Z factor event	DPU 17-05
All Alberta Distributors	Alberta	2018-2022	Common threshold for Y factor and Z factors: Dollar value of a 40 basis point change in ROE on an after-tax basis calculated on the distribution utility's equity used to determine the final approved notional revenue requirement on which going-in rates were established (2017). This dollar amount threshold is to be escalated by I-X annually. Z factor materiality is determined on a per event basis.		Decision 20414-D01-2016 (Errata)
Ontario Power Generation	Ontario	2017-2021	O&M materiality threshold not discussed in decision, separate capital materiality threshold established	$10 million	EB-2016-0152
Enmax	Alberta	2015-2017	O&M materiality threshold not discussed in decision, separate capital materiality threshold established	$1.7 million per event per year	Decision 21149-D01-2016 (Errata)
FortisBC	British Columbia	2014-2019	O&M materiality threshold not discussed in decision, separate capital materiality threshold established	0.5% of 2013 Base O&M Expense, approximately $300,000 per Z factor event	Project #3698719
FortisBC Energy	British Columbia	2014-2019	O&M materiality threshold not discussed in decision, separate capital materiality threshold established	0.5% of 2013 Base O&M Expense, approximately $1.15 million per Z factor event	Project #3698715
Union Gas	Ontario	2014-2018	O&M materiality threshold not discussed in decision, $5 million revenue requirement impact for capital projects	$ 4 million per Z factor event	EB-2013-0202
Incentive regulation mechanism power distributors except those who opt out	Ontario	2014-2018	O&M materiality threshold not discussed in decision, separate capital materiality threshold established	Per Z factor event: Utility with Revenue Requirement less than or equal to $10 million: $50,000 Utility with Revenue Requirement between $10 and $200 million: 0.5% of distribution revenue requirement Utility with Revenue Requirement above $200 million: $1 million	EB-2010-0379

Québec such as urban and rural areas. IEEE standard 1366 should be used to calculate reliability metrics in order to enhance the comparability of reliability metrics to those of other utilities. HQD already has several customer service quality metrics.

PEG also recommends that some additional metrics be monitored. These metrics include a momentary average interruption frequency index and metrics addressing worst performing circuits. Metrics addressing the quality of service to distributed generation customers are increasingly popular in the United States.

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Statistical Research for Public Service Company of Colorado's Multiyear Electric Rate Plan

Pacific Economics Group Research, LLC

STATISTICAL RESEARCH FOR PUBLIC SERVICE COMPANY OF COLORADO'S MULTIYEAR ELECTRIC RATE PLAN

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1. Introduction and Summary

1.1 Introduction

Public Service Company of Colorado ("Public Service" or "the Company"), a wholly owned regulated utility subsidiary of Xcel Energy, is proposing a multiyear rate plan ("MYP") for its electric services. The plan would set rates for four years from 2018 through 2021. The Company proposes an attrition relief mechanism ("ARM") of hybrid design for escalating its revenue requirement during the plan.

Revenue requirements of Colorado utilities can reflect future business conditions, but in past proceedings some parties have questioned the reasonableness and support for the Company's proposed forward test year revenue requirements. Parties have also claimed that the historical test years ("HTYs") traditionally used in Colorado better incentivize utility cost performance.

The Company's plan also includes revenue decoupling for residential and small commercial customers. Decoupling was recently approved for these customers by Colorado's Public Utilities Commission ("the Commission").[1] However, the Commission rejected an approach to decoupling that would have escalated the revenue requirement automatically for customer growth.

Pacific Economics Group Research LLC ("PEG") personnel have extensive experience in the fields of utility cost research and MYP design. We pioneered the use of rigorous statistical cost research in the regulation of North American energy utilities. Testimony-quality benchmarking and productivity studies are specialties. Mark Newton Lowry, President of PEG and senior author of this report, has testified numerous times on benchmarking, productivity, and MYP design.

Public Service has retained PEG to conduct four empirical research tasks that are relevant to its electric MYP filing. One is to benchmark the Company's proposed revenue requirements for non-fuel operation and maintenance ("O&M") expenses in each plan year. Another is to use index research to develop an escalator for the component of the Company's proposed revenue requirement which compensates it for these expenses. A third task is to demonstrate the need for

[1] Public Utilities Commission of the State of Colorado, Proceeding No. 16A-0546E, Decision No. C17-0557, July 2017.

revenue requirement growth when a utility operates under revenue decoupling. A fourth is to use statistics to consider whether historical test years improve electric utility cost performance.

Following a brief summary of our research in Section 1.2 immediately below, Section 2 provides an introduction to statistical benchmarking. Section 3 discusses our electric service cost benchmarking work for Public Service. Section 4 discusses our work to develop an electric O&M revenue escalator. Section 5 presents empirical research supporting the need for escalation of the electric revenue requirement when companies operate under revenue decoupling. Section 6 considers the impact of historical test years on the cost of electric utilities. Some technical details of the research for this report are presented in the Appendix.

1.2 Summary of Research

We addressed the reasonableness of the Company's proposed revenue requirements for non-fuel electric O&M expenses during the MYP using statistical benchmarking.[2] Two well-established benchmarking methods were employed in the study: econometric modeling and unit cost indexing. Guided by economic theory, we developed a model of the impact various business conditions have on the non-fuel O&M expenses of vertically-integrated electric utilities ("VIEUs"). Parameters of the model which measure the impact of these business conditions on cost were estimated econometrically using historical data on VIEU operations. Models fitted with econometric parameter estimates and the business conditions Public Service expects to face during the MYP years generated revenue requirement benchmarks. We also used a simpler unit cost benchmarking method to evaluate these revenue requirements.

The benchmarking work employed a sample of good quality data on operations of 54 American VIEUs. Data used in the study were drawn from publicly available sources such as Federal Energy Regulatory Commission ("FERC") Form 1 reports. A Uniform System of Accounts has been in force for this form for decades. The sample period for the econometric work was 1996 to 2016. The sample is large and varied enough to permit development of sophisticated cost models in

[2] Some expenses were excluded from the study because they were unusually volatile, difficult to benchmark, substantially beyond utility control, and/or scheduled for separate tracker treatment under the proposed plan.

which several drivers of utility cost are identified. All estimates of the parameters of business condition variables were plausible and statistically significant.

The revenue requirements for non-fuel O&M expenses which Public Service proposes for the 2018-21 period were found to be about 23.6% below the benchmarks generated by our econometric benchmarking model on average. This score is commensurate with a first quartile (specifically number 4 of 54) performance.

As for the unit cost benchmarking, we compared the proposed real (i.e., inflation-adjusted) unit O&M revenue requirements of Public Service during the four plan years to the 2016 unit costs of 12 VIEU peers located chiefly in Great Plains and western states. The unit non-fuel O&M revenues proposed by Public Service were found to be 34.7% below the peer group norm on average. This score is commensurate with a top quartile (specifically number 2 of 13) performance. We conclude from our benchmarking work that the Company's proposed non-fuel O&M revenue requirements for the four MYP years reflect good levels of operating performance.

Indexes have been used in many approved MYPs to escalate utility rates or revenue requirements. In some plans these indexes reflect new information on business conditions which becomes available during a plan. In other plans these indexes are used with forecasts of business conditions to establish a fixed schedule of revenue escalation before the plan begins. Revenue requirement escalation indexes are also useful in rate cases with a single forward test year.

The index formula we developed to escalate revenue for non-fuel O&M expenses that Public Service does not propose to track is

$$growth\ Revenue_{PSCO}^{O\&M} = growth\ Input\ Prices - X + growth\ Scale_{PSCO}.$$

Here *Scale* is an index of growth in the scale of the Company's electric operations. X is the 0.50% long run trend in the non-fuel O&M productivity of the sampled VIEUs. Using this formula and forecasts of O&M input price inflation and growth in the Company's scale, the indicated escalation in the O&M revenue is 2.11%.

During the MYP years, Public Service proposes revenue requirements for non-fuel O&M expenses not slated for tracking which reflect its forecast of the cost of advanced grid and intelligence security ("AGIS"). The salary and wage portion of its revenue requirement for other non-fuel O&M expenses are escalated by 3% to account for expected wage increases in 2017 and then escalated by 2% annually from 2018 to 2021. The revenue requirement for other material and service O&M expenses is frozen.

The difference between the forecasted average annual growth in our O&M revenue escalator in the five years from 2016 to 2021 and the Company's proposed 1.77% growth over the same years in its non-fuel O&M revenue requirement not slated for tracker treatment is an estimate of the stretch factor that is implicit in their proposal. This stretch factor is 0.34%. Approved stretch factors in indexed ARMs of North American energy utilities typically range between 0 and 0.60% today. Stretch factors in the neighborhood of 0.3% are typically reserved today for average cost performers, whereas the Company is a demonstrably *good* non-fuel O&M cost performer.

The Commission recently rejected a feature of the Company's revenue decoupling proposal that would gradually escalate its revenue requirements for services subject to decoupling to reflect growth in the number of customers served. Customer growth is a good proxy for overall growth in the operating scale of an electric utility. Our research shows that the non-fuel revenue requirements of VIEUs typically grow at a pace that well exceeds customer growth.

To test the effect that using historical test years in rate cases have on cost management, we developed an econometric model of the growth in the non-fuel electric O&M expenses of VIEUs. We found no tendency for O&M cost to grow more slowly for utilities that operate in historical test year jurisdictions. We reached similar conclusions in previous studies we filed on this topic in Public Service proceedings.

2. An Introduction to Benchmarking

In this Section of the report we provide a non-technical introduction to cost benchmarking. The two benchmarking methods used in the study are explained. Details of our benchmarking work for Public Service are discussed in Section 3 and the Appendix.

2.1 What is Benchmarking?

The word benchmark originally comes from the field of surveying. The *Oxford English Dictionary* defines a benchmark as

> A surveyors mark, cut in some durable material, as a rock, wall, gate pillar, face of a building, etc. to indicate the starting, closing, ending or any suitable intermediate point in a line of levels for the determination of altitudes over the face of a country.

The term has subsequently been used more generally to indicate something that can be used as a point of comparison in performance appraisals.

A quantitative benchmarking exercise involves one or more activity measures. These are sometimes called performance metrics or indicators. The value of each indicator achieved by an entity under scrutiny is compared to a benchmark value that reflects a performance standard. Given data on the cost of Public Service and a certain cost benchmark we might, for instance, measure its cost performance by taking the ratio of the two values:

$$\textit{Cost Performance} = \textit{Cost}^{PSCo}/\textit{Cost}^{Benchmark}.$$

Benchmarks are often developed statistically using data on the operations of agents engaged in the same activity. In utility cost benchmarking, data on the costs of utilities can be used to establish benchmarks. Various performance standards can be used in benchmarking, and these often reflect statistical concepts. One sensible standard for utilities is the average performance of sampled utilities. An alternative standard is the performance that would define the margin of the top quartile of performers. An approach to benchmarking that uses statistical methods is called statistical benchmarking.

These concepts are usefully illustrated by the process for choosing athletes for the Pro Football Hall of Fame. Statistical benchmarking plays a major (if informal) role in player selection. Quarterbacks, for example, are evaluated using multiple performance indicators that include touchdowns, passing yardage, and interceptions. Values for these metrics which Hall of Fame members like Denver Broncos star John Elway have achieved are far superior to league norms.

2.2 External Business Conditions

When appraising the relative performance of two sprinters, comparing their times in the 100-meter dash when one runs uphill and the other runs on a level surface isn't very informative since runner speed is influenced by the slope of the surface. In comparing costs that utilities incur, it is similarly recognized that differences in their costs depend in part on differences in external business conditions they face. These conditions are sometimes called cost "drivers." The cost performance of a company depends on the cost it achieves given the business conditions it faces. Benchmarks should therefore reflect external business conditions.

Economic theory is useful in identifying cost drivers and controlling for their influence in benchmarking. Under certain reasonable assumptions, cost "functions" exist that relate the cost of a utility to business conditions in its service territory. When the focus of benchmarking is non-fuel O&M expenses, theory reveals that the relevant business conditions include the prices of O&M inputs, the scale of the company's operations, and the quantities of capital inputs. Miscellaneous other business conditions may also drive cost.

The existence of capital input variables in O&M cost functions means that appraising the efficiency of a utility in using O&M inputs requires consideration of the kinds and quantities of capital inputs that it uses. This result is important for several reasons. It is generally more costly to operate and maintain capacity the more of it there is. A utility that has older facilities nearing replacement age will tend to spend more on maintenance than a utility with newer facilities.

Regardless of the particular category of cost that is benchmarked, economic theory allows for the existence of multiple scale variables in cost functions. For example, the cost of a vertically-integrated electric utility depends on the number of customers it serves (as it provides distribution and customer care services) as well as on its generation volume.

2.3 Benchmarking Methods

In this section of our report we discuss the two benchmarking methods we used in this study. We begin with the econometric method to establish a better context for the discussion of the indexing method.

2.3.1 Econometric Modeling

In Section 2.2, we noted that comparing results of a 100-meter sprinter racing uphill to a runner racing on a level course doesn't tell us much about the relative performance of the athletes. Statistics can aid appraisal of their performances. For example, we could develop a mathematical model in which time in the 100-meter dash is a function of conditions like wind speed and surface gradient. The parameters of the model which correspond to each condition would quantify their typical impact on run times. We could then use samples of times turned in by runners under varying conditions to estimate model parameters. The resultant "run-time" model could then be used to predict the typical performance of runners given the track conditions that they faced.

The relationship between the cost of utilities and the business conditions they face (sometimes called the "structure" of cost) can also be estimated statistically. A branch of statistics called econometrics has developed procedures for estimating parameters of economic models using historical data.[3] Parameters of a utility cost function can be estimated using historical data on costs incurred by a group of utilities and business conditions that they faced. The sample used in model estimation can be a time series consisting of data over several years for a single company, a "cross section" consisting of one observation for each of several companies, or a "panel" data set that pools time series data for several companies.

Basic Assumptions

Econometric research involves certain critical assumptions. One is that the value of an economic variable (called the dependent or left-hand side variable) is a function of certain other variables (called explanatory or right-hand side variables) and an error term. The explanatory variables are generally assumed to be independent in the sense that their values are not influenced by the value of the dependent variable. In an econometric cost model, cost is the dependent variable and the cost drivers are the explanatory variables.

The error term in an econometric cost model is the difference between actual cost and the cost predicted by the model. This term is a formal acknowledgement of the fact that the cost model is unlikely to provide a full explanation of the variation in the costs of sampled utilities.

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[3] Estimation of model parameters is sometimes called regression.

Reasons for errors include mismeasurement of cost and external business conditions, exclusion from the model of relevant business conditions, and failure of the model to capture the form of the functional relationship between the economic variables. It is customary to assume that error terms in econometric models are random variables drawn from probability distributions with measurable parameters.

Statistical theory is useful for appraising the importance of explanatory variables in cost models. Tests can be constructed for the hypothesis that the parameter for an included business condition equals zero. A variable can be deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence.

Cost Predictions and Performance Appraisals

A cost function fitted with econometric parameter estimates is called an econometric cost model. We can use such models to predict a company's costs given local values for the business condition variables.[4] These predictions are econometric benchmarks. Cost performance is measured by comparing a company's cost in year *t* to the cost projected for that year by the econometric model. Cost predictions can be made for historical or future years. Predictions of cost in future years can be used to benchmark forecasts or proposed revenue requirements for these costs.

Accuracy of Benchmarking Results

Statistical theory provides useful guidance regarding the accuracy of econometric benchmarks as predictors of the true benchmark. One important result is that a model can yield

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[4] Suppose, for example, that we wish to benchmark the cost of a hypothetical electric utility called Western Power. We might then predict the cost of Western in period t using the following simple model.

$$\hat{C}_{Western,t} = \hat{a}_0 + \hat{a}_1 \cdot N_{Western,t} + \hat{a}_2 \cdot V_{Western,t}.$$

Here $\hat{C}_{Western,t}$ denotes the predicted cost of the company, $N_{Western,t}$ is the number of customers it serves, and $V_{Western,t}$ is its generation volume. The $\hat{a}_0$, $\hat{a}_1$, and $\hat{a}_2$ terms are parameter estimates. Performance might then be measured using a formula like

$$Performance = \ln\left(C_{Western,t} \big/ \hat{C}_{Western,t}\right),$$

where ln is the natural logarithm of the ratio in the parentheses.

biased predictions of the true benchmark if relevant business condition variables are excluded from the model. It is therefore desirable to consider in model development numerous business conditions which are believed to be relevant and for which good data are available at reasonable cost.

Even when the predictions of an econometric model are unbiased they can be imprecise, yielding benchmarks that are too high for some companies and too low for others. Statistical theory suggests that the predictions will be more precise to the extent that

- the model successfully explains the variation in the historical cost data used in model development;
- the size of the sample used in model estimation is large;
- the number of cost-driver variables included in the model is small relative to the sample size;
- business conditions of sampled utilities are varied; and
- business conditions of the subject utility are similar to those of the typical firm in the sample.

These results suggest that econometric cost benchmarking will be more accurate to the extent that it is based on a large sample of good operating data from companies with diverse operating conditions. It follows that it will generally be preferable to use *panel* data in the research, encompassing information from multiple utilities over time, when these are available.

2.3.2 Benchmarking Indexes

In their internal reviews of operating performance utilities tend to employ index approaches to benchmarking rather than the econometric approach just described. Benchmarking indexes are also used occasionally in regulatory submissions. We begin our discussion with a review of index basics and then consider unit cost indexes.

Index Basics

An index is defined in one dictionary as "a ratio or other number derived from a series of observations and used as an indicator or measure (as of a condition, property, or phenomenon)."[5] In utility-performance benchmarking, indexing typically involves the calculation of ratios of the values of performance metrics for a subject utility to the corresponding values for a sample of utilities. The companies for which sample data have been drawn are sometimes called a peer group.

We have noted that a simple comparison of the costs of utilities reveals little about their cost performances if there are large differences in the cost drivers they face. In index-based cost benchmarking, it is therefore common to use as performance metrics the ratios of their cost to one or more important cost drivers. Differences in the operating scale of utilities are typically the greatest source of differences in their cost. It makes sense then to compare ratios of cost to operating scale. Such a ratio is sometimes described as the cost per unit of operating scale or unit cost. In comparing the unit cost of a utility to the average for a peer group, we introduce an automatic control for differences between the companies in their operating scale. This permits us to include companies with more varied operating scales in the peer group.

A unit cost index is the ratio of a cost index to a scale index.

$$\textit{Unit Cost} = \textit{Cost}/\textit{Scale}. \qquad [1]$$

Each index compares the value of the metric to the average for a peer group.[6] The scale index can be multidimensional if it is desirable to measure operating scale using multiple scale variables.

Unit cost indexes do not control for differences in other cost drivers that are known to vary between utilities. Our discussion in Section 2.2 revealed that cost depends on input prices and miscellaneous other business conditions in addition to operating scale. The accuracy of unit cost

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[5] *Webster's Third New International Dictionary of the English Language Unabridged*, Volume 2, p. 1148. (Chicago: G. and C. Merriam and Co. 1966).

[6] A unit cost index for Western Power, for instance, would have the general form

$$\textit{Unit Cost}_t^{\textit{Western}} = \frac{\textit{Cost}_t^{\textit{Western}}/\textit{Cost}_t^{\textit{Peers}}}{\textit{Scale}_t^{\textit{Western}}/\textit{Scale}_t^{\textit{Peers}}}.$$

benchmarking thus depends on the extent to which the cost pressures placed on the peer group by these additional business conditions are similar on balance to those facing the subject utility.

One sensible upgrade to unit cost indexes is to adjust them for differences in the input prices utilities face. The formula for real (price-adjusted) unit cost is

$$Unit\ Cost^{Real} = \frac{Cost\,/\ Input\ Prices}{Scale} \quad . \qquad [2]$$

A productivity index ("Productivity") is the ratio of a scale index to an input quantity index ("Inputs").

$$Productivity = \frac{Scale}{Inputs} \qquad [3]$$

It can be shown that cost is the product of properly-designed input price and quantity indexes:

Cost = Input Prices • Input Quantities. [4]

Relations [2] - [4] imply that

$$Unit\ Cost^{Real} = \frac{Input\ Quantities}{Scale} = 1/Productivity. \qquad [5]$$

Thus, a real unit cost index will yield the same benchmarking results as a productivity index. Low unit cost coincides with high productivity. We discuss productivity indexes further in Section 4.2 below.

Multidimensional Scale Indexes

Indexes can be designed to summarize results of multiple comparisons. Such summaries involve averages of the comparisons. Consumer price indexes are familiar examples. These commonly summarize inflation (year-to-year comparisons) in prices of a market basket of goods and services. The weight for the price of each product is its share of the value of all of the products in the basket. If households typically spend $300 a week on food and $30 on coffee, for instance, 4% growth in the price of food would have a much bigger impact on the CPI than the same growth in the price of coffee.

The scale index of a firm or industry summarizes its scale of operation. Growth in each scale dimension that is itemized is measured by a subindex. One possible objective of scale research is to measure the impact of scale on company *cost.* In that case, the sub-indexes should measure the dimensions of the "workload" that drive cost. If there is more than one pertinent scale variable, the weights for each variable should reflect the relative cost impacts of these drivers. A productivity index calculated using a cost-based scale index may fairly be described as a "cost efficiency index."

To better appreciate advantages of multi-dimensional indexes in utility cost benchmarking, recall from our discussion above that the operating scale of a utility is sometimes most accurately measured using several scale variables. These variables can have different importance even if all are worth considering. Multi-dimensional scale indexes are particularly useful in measuring the performance of *vertically integrated* electric utilities because they provide unusually varied services.

The cost impact of a scale variable is conventionally measured by its cost "elasticity." The elasticity of cost with respect to the number of customers served, for instance, is the percentage change in cost that results from a 1% change in the number of customers served. It is straightforward to estimate elasticities like these using econometric estimates of cost model parameters. The weight for each variable in the scale index for a cost efficiency study can then be its share in the sum of the estimated cost elasticities of the model's scale variables.[7]

[7] For an early discussion of elasticity-weighted scale indexes see Michael Denny, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries,* (Academic Press, New York) pages 179-218.

3. Empirical Research for Public Service

3.1 Data

Cost benchmarking of US electric utilities is facilitated by the detailed, standardized data on their operations which the federal government has gathered for decades from dozens of companies. The primary source of the cost data used in this study was the FERC Form 1. Data reported on Form 1 must conform to the FERC's Uniform System of Accounts.[8] Data on generation capacity were drawn from Form EIA – 860 ("Annual Electric Generator Report") and a predecessor source, Form EIA – 767 ("Steam Electric Plant Operation and Design Report"). Most data on the number of customers served originated in Form EIA 861 ("Annual Electric Power Industry Report"). PEG gathered the data from all these sources which were used in this study.

Data on historical prices of material and service ("M&S") inputs were drawn from the Global Insight *Power Planner*. Data on historical salaries and wages were drawn from the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor. We forecasted the non-fuel O&M input price inflation of Public Service using industry forecasts from the latest edition of *Power Planner*. Forecasts of other business conditions faced by Public Service were provided by the Company.

Data were considered for inclusion in our sample from all major investor-owned U.S. electric utilities that filed the Form 1 during the sample period and had substantial involvement in power production, transmission, and distribution throughout the sample period. To be included in the study, the data were also required to be plausible and not unduly burdensome to process. Data from 54 companies were used in the research. The sampled companies are listed in Table 1. The companies in the Company's unit cost peer group are identified in the table.

The sample period for the econometric cost study was 1996-2016. The resultant dataset had 1,134 observations. This sample is large and varied enough to permit development of a credible econometric model of O&M expenses.

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[8] Details of these accounts can be found in Title 18 of the Code of Federal Regulations.

Table 1
Sample of VIEUs Used in the Empirical Research

Alabama Power	Kentucky Utilities
ALLETE (Minnesota Power)	Louisville Gas and Electric
Ameren Missouri (Union Electric)	MDU Resources Group
Appalachian Power	MidAmerican Energy*
Arizona Public Service*	Mississippi Power
Avista*	Monongahela Power
Black Hills Power	Nevada Power*
Cleco Power	Northern Indiana Public Service
Dayton Power and Light	Northern States Power Company - MN*
Duke Energy Carolinas	Oklahoma Gas and Electric*
Duke Energy Florida	Otter Tail Power
Duke Energy Indiana	Pacific Gas and Electric
Duke Energy Progress	PacifiCorp
El Paso Electric*	Portland General Electric*
Empire District Electric	Public Service Company of Colorado
Entergy Arkansas	Public Service Company of New Mexico
Entergy Mississippi	Public Service Company of Oklahoma
Entergy New Orleans	Puget Sound Energy*
Florida Power & Light	Sierra Pacific Power*
Georgia Power	South Carolina Electric & Gas
Gulf Power	Southern Indiana Gas and Electric
Idaho Power	Southwestern Electric Power
Indiana Michigan Power	Southwestern Public Service
Indianapolis Power & Light	Tampa Electric*
Kansas City Power & Light	Tucson Electric Power*
Kansas Gas and Electric	Virginia Electric and Power
Kentucky Power	Westar Energy

Sample Size = 54 VIEUs

*Indicates a company in the unit cost peer group

3.2 Definition of Variables

3.2.1 Calculating O&M Expenses

The cost addressed in our benchmarking work was total electric O&M expenses less expenses for generation fuel, purchased power, customer service and information, pensions and benefits, and franchise fees.[9] We also excluded certain transmission expenses.

We routinely exclude expenses for fuel, purchased power, and pensions and benefits from our cost benchmarking studies on the grounds that they are large, volatile, and---to a considerable degree---beyond the control of utility management. In addition, Public Service proposes to track energy and pension expenses in the MYP. Customer service and information expenses were excluded because these vary greatly with the extent of demand-side management ("DSM") programs. Utility DSM expenses are not itemized on FERC Form 1 for easy removal and would be tracked in the Company's proposed MYP. Franchise fees also vary greatly between utilities and are substantially beyond their control.

As for transmission expenses, the cost of transmission services purchased from other entities varies widely between utilities and is itemized for easy removal. Some sampled utilities are members of regional transmission organizations ("RTOs") that perform some transmission services (e.g., dispatching and planning) for members that other utilities do themselves. RTOs may additionally charge utilities for their management of regional bulk power markets. It is undesirable to include these expenses in a benchmarking study.

Note also that utilities make purchases and sales in bulk power markets. RTOs charge members for transportation of this power under the terms of RTO tariffs. Member utilities also provide RTOs with transmission services that include making their infrastructure available for use. RTO invoices to member utilities for transmission services may thus include some of the cost of the services these utilities provide. These invoiced sums have sometimes been reported by utilities as O&M expenses, leading to inflated expenses that are offset elsewhere on Form 1 by reported transmission revenues.

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[9] In addition to Purchased Power expenses as reported on the FERC Form 1, we also excluded the Other Expenses category of Other Power Supply Expenses. We believe that large costs related to energy procurement are sometimes reported in this category.

We have accordingly excluded from the cost we studied certain transmission and RTO expenses. The cost categories not considered included transmission of electricity by others (FERC account 565), miscellaneous transmission expenses (FERC account 566), regional market expenses (FERC accounts 575 and 576), and new transmission accounts created at the same time as accounts 575 and 576 (561.1–561.8 and 569.1-569.4).

3.2.2 Scale Variables

Two "classic" measures of utility scale were utilized in our benchmarking work: the annual average number of customers served and the total annual megawatt hours of net generation. Simply put, the greater is the number of customers a utility serves and the generation volume it achieves, the higher is its cost. The parameters of both of these variables are therefore expected to have positive signs. A measure of generation capacity that was used in the model is also scale-related and is discussed in Section 3.2.4 below.

3.2.3 Input Prices

Cost theory also suggests that the prices paid for inputs are relevant business condition variables. We therefore included in the model an index of the prices of non-fuel O&M electric utility inputs. In estimating the model we divide cost by this input price index. This is commonly done in econometric cost research because it simplifies model estimation and ensures that the relationship between cost and input prices predicted by economic theory holds.[10]

The O&M input price index was constructed by PEG and is a weighted average of price subindexes for labor and M&S inputs. Occupational Employment Statistics ("OES") survey data for a recent year were used to construct average wage rates that correspond to each utility's service territory. The wage levels were calculated as a weighted average of the OES pay level for each job category using weights that correspond to the electric utility industry. Values for other years were calculated by adjusting the level in the focus year for changes in regionalized indexes of employment cost trends for the utilities sector of the economy. These indexes were also constructed from BLS data.

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[10]Theory predicts that a 1% increase in the prices of all inputs will raise cost by 1% if all other business conditions are unchanged.

Prices for M&S inputs were assumed to have a 25% local labor content and therefore tend to be a little higher in regions with higher labor prices. We use our labor price index to effect this levelization in the same focus year. The M&S price is then escalated by a summary M&S input price index constructed by PEG from detailed Global Insight electric utility M&S indexes and company-specific, time-varying cost share weights. The O&M input price for each utility is constructed by combining the labor and M&S price subindexes using company-specific, time-varying cost share weights. The cost shares were calculated from FERC Form 1 data.

3.2.4 Other Business Conditions

Eight other business condition variables were included in the cost model. Five pertain to power generation. One is the total nameplate generation capacity owned by the utility, measured in megawatts ("MWs"). Capacity is an important cost driver because ownership of capacity involves O&M expenses even when it is idle. Our research team aggregated the nameplate capacity of each sampled utility's power plants to arrive at a total capacity figure. We expect that O&M expenses will be higher the higher is the amount of generation capacity. The parameter for this variable should therefore have a positive sign.

The model also contains variables that measure the share of generating capacity owned by each utility that is fired by coal or heavy fuel oil, and the share that is nuclear-fueled. These variables are designed to capture any tendency for O&M expenses to vary with the kind of generating capacity that companies own. While the cost impact of these variables cannot be predicted theoretically, our experience in the industry suggests positive signs for their parameters.

The fourth generation-related variable in the model is the percentage of total generating capacity that has scrubbing facilities. This variable takes account of the fact that utilities vary in the extent to which they scrub their generation emissions. The propensity to scrub depends in part on ownership of coal- and oil-fired generation, but companies also vary in the percentage of emissions from such capacity that they scrub. We expect that O&M expenses will be higher the higher is the percentage of generating capacity with scrubbers.

The fifth generation-related variable is the average age of generation capacity. Generation O&M tends to rise as the capacity ages. The parameter of this variable should therefore have a positive sign.

Three model variables address business conditions that affect the cost of power delivery and/or customer care. One of these measures the extent of delivery system overheading. This is measured as the share of overhead plant in the gross value of transmission and distribution ("T&D") conductor, device, and structure (pole, tower, and conduit) plant. System overheading involves higher O&M expenses in most years because facilities are more exposed to the challenges posed by local weather (e.g., high winds and ice storms), flora, and fauna.[11] The sign of this variable's parameter should therefore be positive.

A second model variable related to delivery is the mileage of high voltage ("HV") transmission lines per retail customer in 2012. Lines with a kV rating of 100 or greater are counted in this metric.[12] The source of our transmission line mile data is the FERC Form 1. We would expect that cost would be greater the greater is the value of this variable.

The third model variable related to delivery and customer care services is the share of total gas and electric retail customers that are electric. Simultaneous provision of delivery and customer care services to gas and electric customers provides opportunities to share O&M inputs, which economists call economies of scope. We expect electric O&M expenses to be higher the higher is the value of this variable since a higher value means fewer scope economies.

The econometric model also contains a trend variable. This variable permits predicted cost to shift over time for reasons other than changes in the specified business conditions. The trend variable captures the net effect on cost of diverse conditions, such as technological change, that are otherwise excluded from the model. Parameters for such variables often have a negative sign in statistical cost research. The inclusion of this variable in the model means that our econometric benchmarks for future years include an expectation regarding the residual cost trend.

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[11] Maintenance of underground delivery facilities can be quite costly but occurs less frequently.

[12] Subtransmission (e.g., 69kV) lines are excluded from this variable because some companies classify these lines as distribution facilities and good data on distribution lines were not available for all sampled companies.

3.3 Econometric Parameter Estimates

Estimation results for the cost model are reported in Table 2. This table also reports values of the asymptotic t-ratios that correspond to each parameter estimate. These were used in model development. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. This statistical test requires selection of a critical value for the asymptotic t ratio. In this study, we employed a critical value that is appropriate for a 90% confidence level given a large sample. The value of the t-ratio corresponding to this confidence level was about 1.65.

Table 2
Econometric Model of Electric O&M Cost

N = Number of Retail Customers
CAPTOT = Total Generating Capacity
GNET = Net Generation Volume
AGETOT= Average Age of Generation Plant
PCTDIRT= Percentage of Generation Capacity that is Coal or Heavy Fuel Oil
PCTNUC= Percentage of Generation Capacity that is Nuclear
PCTSCR= Percentage of Generation Capacity that is Scrubbed
PCTELEC= Percentage of Retail Customers who are Electric
TXMIPERCUST= Line Miles per Retail Customers in 2012
PCTPOTD= Percentage of Line Plant that is Overhead
Trend = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE	EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.546	24.558	0.0000	**PCTNUC**	0.275	21.575	0.000
CAPTOT	0.183	7.446	0.0000	**PCTSCR**	0.066	4.369	0.000
GNET	0.122	6.119	0.0000	**PCTELEC**	0.070	2.178	0.030
AGETOT	0.128	4.119	0.0000	**TXMIPERCUST**	0.050	3.516	0.000
PCTDIRT	0.186	6.329	0.0000	**PCTPOTD**	0.131	3.290	0.001
				Trend	-0.005	-4.487	0.000
				Constant	19.616	741.485	0.000

Rbar-Squared	0.955
Sample Period	1996-2016
Number of Observations	1134

Examining the results in Table 2, it can be seen that all of the estimates of business condition parameters are statistically significant and plausible as to sign and magnitude. Non-fuel

O&M expenses were found to be higher the higher were the values of all three scale-related variables. The number of customers served had by far the highest parameter estimate of the three scale variables considered.

The parameter estimates for the other business condition variables were also sensible.

- Expenses were higher the higher was generation capacity age.
- Expenses were higher the greater was the share of total generation capacity fired by coal or heavy fuel oil.
- Expenses were higher the greater was the share of nuclear-fueled capacity.
- Expenses were higher the greater was the share of generation capacity scrubbed.
- Expenses were higher the greater was the number of electric customers served relative to gas customers.
- Expenses were higher the greater was the share of delivery plant overhead.Expenses were higher the greater was the mileage of transmission lines per customer in 2012.
- The estimate of the trend variable parameter suggests a 0.5% annual downward shift in cost over time for reasons other than the trends in the business condition variables. This shift is reflected in our benchmarks for Public Service.

The table also reports the adjusted R^2 statistic for the model. This is a widely used measure of the ability of the model to explain variation in the sampled costs of distributors. Its value was 0.955, suggesting that the explanatory power of the model was high.

3.4 Business Conditions of Public Service

Public Service is a combined gas and electric utility with vertically integrated electric operations. Metropolitan Denver is the heart of its service territory. Electric service is also provided in other areas of Colorado which include the northern Front Range (e.g., Greeley), the Arkansas and San Luis Valleys (e.g., Salida and Alamosa), and parts of central and western Colorado (e.g., Grand Junction).

The Company buys a sizable percentage of the power that it sells but also generates large quantities. Extensive coal-fired generation capacity is a legacy of the proximity of the Company's loads to fields of low-cost coal. A high percentage of coal-fired capacity is scrubbed. Public Service also operates growing fleets of gas-fired and wind-powered capacity. In addition, the Company operates an extensive high voltage transmission system to access power supplies and deliver power to widely scattered regions.

Table 3 compares the values we use for the cost and business condition variables of Public Service in 2018 to the mean values for the full sample in 2016. The last column of the table takes the ratio of the business conditions for Public Service to the sample means.

It can be seen that the proposed non-fuel O&M revenue of Public Service in 2018 is expected to be 0.84 times the sample mean for 2016. In other words, the proposed cost is expected to be about 16% below the mean. The number of customers served would, meanwhile, be 1.62 times the mean, while the Company's net generation volume would be 0.95 times the mean, generation capacity would be 1.01 times the mean, and transmission line miles per customer would be 0.65 times the mean.

Table 3
Comparison of Public Service's Business Conditions in 2018
to Full Sample Norms

Business Condition	Units	Public Service Values, 2018 [A]	Sample Mean, 2016 [B]	2018 Public Service Values / 2016 Sample Mean [A/B]
Non-Energy O&M Expenses (2016 Dollars)	Dollars	429,341,953	514,083,143	0.84
Number of Retail Customers	Count	1,475,083	911,357	1.62
Total Generating Capacity	MW	6,230	6,154	1.01
Net Generation Volume	MWh	22,109,512	23,156,755	0.95
Average Age of Generation Plant	Years	26.24	31.57	0.83
Percentage of Generation Capacity that is Coal or Heavy Fuel Oil	Percent	0.45	0.42	1.06
Percentage of Generation Capacity that is Nuclear	Percent	0.00	0.07	0.00
Percentage of Generation Capacity Scrubbed	Percent	0.45	0.36	1.27
Percent of Total Customers that are Electric	Percent	0.51	0.89	0.57
Miles of Transmission Line Miles per Customer in 2012	Count	0.0029	0.0045	0.65
Percentage of Line Plant that is Overhead	Percent	0.40	0.73	0.55
Price Index for O&M Inputs	2016 Dollars	1.12	1.00	1.12

Public Service has no nuclear capacity but the share of its capacity that is coal- or oil-fired would be 1.06 times the sample mean. The percentage of capacity that is scrubbed would be 1.27 times the sample mean. Generation age would be 0.83 times the mean, suggesting that the Company's fleet is relatively young.

As for the other business condition variables, delivery system overheading would be only 0.55 times the mean. This creates opportunities for delivery O&M economies. Provision of service to gas customers affords the Company opportunities for scope economies in distribution and customer care. The 2018 O&M input prices faced by Public Service would be about 1.12 times the mean for 2016.

3.5 Benchmarking Work

We benchmarked the Company's proposed revenue requirements for non-fuel O&M expenses during the years of the MYP using econometric and indexing methods. In these calculations, we exclude the expected generation volume, capacity, and O&M expenses for the Rush Creek project because the Company proposes to track these expenses.

The Company's proposed revenue requirements for non-fuel O&M expenses would average 1.77% annual growth between the 2016 historical test year and 2021. These revenue requirements reflect the Company's forecast of the cost for AGIS. The salary and wage portion of its revenue requirement for other non-fuel O&M expenses would grow by 3% in the 2016 test year to reflect expected 2017 wage increases and by 2% annually from 2018 to 2021. The revenue requirement for other material and service O&M expenses would be frozen.

3.5.1 Econometric Models

We created econometric benchmarks for the non-fuel O&M expenses of Public Service for each year of the 1996-2021 period. These benchmarks were based on the econometric model parameter estimates in Table 2 and values for the business condition variables which are appropriate for Public Service. For the 2017 to 2021 period most values for business condition variables were forecasted. However, the values for transmission miles/customer and the overhead variable were drawn from a recent historical year. Table 4 shows results of our non-fuel O&M benchmarking using the econometric models. The Company's proposed non-fuel O&M revenue requirements during the 2018-2021 period were found to be about 23.6% below the projections of our O&M cost benchmarking model on average. This score is commensurate with a top quartile (specifically 4 of 54) ranking.

Table 4
Year by Year PSCO Econometric Cost Benchmarking Results
[Actual - Predicted Cost (%)][1]

Year	Cost Benchmark % Difference
1996	-33.3%
1997	-35.3%
1998	-37.7%
1999	-31.6%
2000	-34.3%
2001	-19.5%
2002	-24.3%
2003	-18.2%
2004	-25.3%
2005	-24.7%
2006	-24.2%
2007	-22.4%
2008	-27.9%
2009	-25.6%
2010	-15.5%
2011	-14.9%
2012	-23.8%
2013	-15.3%
2014	-17.9%
2015	-22.4%
2016	-22.1%
2017	-26.0%
2018	-26.1%
2019	-22.6%
2020	-22.2%
2021	-23.3%
Average 2018-2021	**-23.6%**

[1] Formula for benchmark comparison is $\ln(Cost^{PSCO}/Cost^{Bench})$.

3.5.2 Unit Cost Indexes

Table 5 shows the results of benchmarking the proposed 2018-2021 revenue requirements using real unit cost indexes. These indexes featured multidimensional scale indexes with cost elasticity weights. Our econometric research discussed in Section 3.3 shows that the number of customers served, generation capacity, and generation volume are useful scale variables for such indexes. Using the econometric parameter estimates for these variables, the cost elasticity weights for customers and generation capacity and volume in this index were set at 64%, 22%, and 14% respectively.

Table 5
How PSCO's Proposed Unit Electric Non-Fuel O&M Revenue Requirements Compare to the Unit Costs of Peers[1]

	Public Service 2018-2021 Average [A]	Peers 2016 [B]	Comparing Results Ratio [A/B]	Comparing Results Percentage Difference [(A/B)-1]
O&M Cost	429,408,402	394,252,217	1.089	8.9%
Number of Customers	1,496,712	782,795	1.912	91.2%
Total Generation Capacity[2]	6,086	4,990	1.220	22.0%
Net Generation Volume[2]	21,121,412	17,050,340	1.239	23.9%
Summary Scale Index[3]			1.667	66.7%
Dollars per Customer	286.9	503.6	0.570	-43.0%
Dollars per MW	70,555.8	79,014.7	0.893	-10.7%
Dollars per MWh Generated	20.3	23.1	0.879	-12.1%
Summary Unit Cost Index	**0.65**	**1.00**	**0.653**	**-34.7%**

[1] The peers are: Arizona Public Service, Avista, El Paso Electric, MidAmerican Energy, Nevada Power, Northern States Power-Minnesota, Oklahoma Gas & Electric, Portland General Electric, Puget Sound Energy, Sierra Pacific Power, Tampa Electric, and Tucson Electric Power.

[2] Rush Creek capacity and volumes are excluded from these totals.

[3] Scale index for O&M expenses constructed from the scale subindexes and cost elasticity weights based on Table 2 econometric estimates using the formula scale = 0.64* customers + 0.22* capacity + 0.14* net generation.

Comparisons are made to mean values for the peer group in 2016. It can be seen that the Company's proposed real non-fuel O&M revenue was about 35% below the peer group mean on average over the four-year period. This score is commensurate with a first quartile (specifically a number 2 of 13 ranking).

4. Designing an O&M Revenue Escalator

4.1 Revenue Cap Indexes

Index research provides the basis for revenue requirement escalators that can be used in MYPs and forward test year rate cases. The following result of cost theory is a useful starting point:

growth Cost = growth Input Prices – growth Productivity + growth Scale. [6]

The growth rate of cost is the difference between growth in input price and productivity indexes plus growth in a scale index.

This result provides the rationale for a revenue requirement escalator of the following general form:

growth Revenue = growth Input Prices – X + growth Scale [7a]

where

X = trend Productivity + Stretch. [7b]

Here *X*, the "X factor," is calibrated to reflect a base productivity growth target. This is typically the average historical trend in the productivity indexes of a utility peer group. A "stretch factor" is often added to the escalation formula to slow revenue requirement growth in a manner that shares with customers financial benefits of any productivity growth in excess of the peer group norm which is expected during the MYP. The stretch factor is often informed by statistical benchmarking evidence because an inefficient utility can more easily cut costs.

4.2 More on Productivity Indexes

4.2.1 The Basic Idea

The growth trend of a productivity index is the difference between the trends in a scale index and an input quantity index.

trend Productivity = trend Scale – trend Inputs. [8]

It can be shown that the input quantity trend can be measured as the difference between the trends in cost and an input price index.

trend Inputs = trend Cost - trend Input Prices. [9]

Productivity grows when the scale index rises more rapidly (or falls less rapidly) than the input quantity index. Productivity can be volatile but has historically tended to grow over time.

The volatility of O&M productivity is affected by external events (e.g., severe storms) and uneven timing of some routine expenses. The volatility of productivity growth tends to be greater for individual companies than the average growth for a group of companies.

The scope of a productivity index depends on the array of inputs considered in the input quantity index. Some indexes measure productivity in the use of a single input class such as labor. An O&M productivity index measures productivity in the use of various O&M inputs.

$$\textit{trend Productivity}^{O\&M} = \textit{trend Scale - trend Inputs}^{O\&M}. \qquad [10]$$

4.2.2 Sources of Productivity Growth

Research by economists has found the sources of productivity growth to be diverse.[13] One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

Economies of scale are a second source of productivity growth. These economies can be available in the longer run if cost tends to grow more slowly than scale. A company's potential to achieve incremental scale economies depends on growth in its scale.

A third important source of productivity growth is change in X-inefficiency. X-inefficiency is the degree to which a company fails to operate at the maximum efficiency that technology allows. Productivity growth rises (falls) when X-inefficiency diminishes (increases). The lower a company's current efficiency level, the greater is the potential for productivity growth from a change in inefficiency.

Productivity growth is also affected by changes in the miscellaneous external business conditions, other than input price and scale growth, which affect cost. A good example for an electric utility is the share of distribution lines that are undergrounded. An increase in the share of facilities that are undergrounded will tend to accelerate O&M productivity growth since less maintenance is needed. O&M productivity growth also tends to be slower to the extent that a Company's infrastructure is aging.

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[13] For a seminal discussion of sources of productivity growth see Denny, Fuss and Waverman, *op. cit.*

4.3 O&M Productivity Trend of VIEUs

Growth in non-fuel O&M productivity was calculated for each VIEU in our sample as the difference between the growth rates of the utility's scale index and O&M input quantity index. The growth in each scale index was an elasticity-weighted average of the growth in three scale variables: generation volume and capacity and the number of retail customers served. O&M input quantity growth was measured as the difference between growth in applicable non-fuel O&M expenses and growth in the non-fuel O&M input price index that we used in the econometric work.

The full sample period for which productivity trends were calculated was 1997-2016. In other words, 1997 was the earliest year for growth rate calculations.

Table 6 presents results of our O&M productivity research for our full 54-company sample. Over the full 1997-2016 sample period, the average annual growth rate in the O&M productivity of all sampled utilities was 0.50 percent.[14] Growth in operating scale averaged 1.06 percent annually, while O&M input quantity growth averaged 0.56 percent.[15]

4.4 Indicated O&M Revenue Escalation for Public Service

Table 7 shows the construction of the non-fuel O&M revenue escalator we developed using formula [7a], the 0.50% O&M productivity growth trend, and forecasts of input price inflation and the Company's customer growth. No stretch factor is used in the Table 7 calculations since we are using the revenue cap index to calculate an implicit stretch factor. From 2016 to 2021, the non-fuel O&M input price index we used in the benchmarking work is forecasted to average 2.30% growth.[16] Public Service forecasts the number of its electric customers and generation capacity and volume to average 1.03%, -0.63%, and -1.48% annual growth, respectively. The expected decline in generation volume and capacity reflect the Company's disposition of the Valmont and Cherokee units. Rush Creek generation volumes and capacity are not considered because the Company proposes to track the cost of this project. Given, additionally, the 0.50% non-fuel O&M productivity

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[14] This result is in line with the -.005 value of the trend variable parameter estimate in the econometric model.

[15] Over the more recent 2006-2016 period, the average annual growth rate in the non-fuel O&M productivity of all sampled utilities was a little slower, averaging 0.39 percent.

[16] This forecast makes use of forecasts of price subindexes from Global Insight.

trend of sampled VIEUs, it can be seen that our O&M revenue escalator would average 2.11% annual growth.

Table 6
Non-Fuel-O&M Productivity Results For Sampled Utilities

(Growth Rates)[1]

Year	Scale Index	O&M Input Quantity Index	O&M Productivity Index
1997	1.88%	1.21%	0.68%
1998	1.96%	1.46%	0.50%
1999	0.99%	0.74%	0.26%
2000	1.25%	2.71%	-1.46%
2001	0.70%	0.63%	0.07%
2002	1.15%	-0.08%	1.23%
2003	1.63%	-1.46%	3.08%
2004	1.45%	1.20%	0.24%
2005	1.26%	0.06%	1.20%
2006	0.90%	0.33%	0.57%
2007	2.29%	3.37%	-1.08%
2008	0.83%	-1.35%	2.18%
2009	0.02%	-0.55%	0.57%
2010	1.73%	4.77%	-3.04%
2011	0.32%	-3.06%	3.38%
2012	-0.14%	-1.86%	1.72%
2013	1.14%	0.13%	1.01%
2014	1.32%	4.99%	-3.68%
2015	0.25%	-1.99%	2.24%
2016	0.29%	-0.09%	0.38%
Average Annual Growth Rate			
1997-2016	**1.06%**	**0.56%**	**0.50%**
2006-2016	**0.81%**	**0.43%**	**0.39%**

[1]All growth rates are calculated logarthmically.

Table 7
Forecasted Growth in O&M Revenue Cap Index

Variable		**Forecasted Growth 2016-2021**
Input Price Index[1]	I	2.30%
Scale Trend Index[2]	Y	0.31%
Customers	YN	1.03%
Total Generation Capacity	YC	-0.63% [4]
Net Generation Volume	YG	-1.48% [4]
Base Productivity Trend[3]	X	0.50%
Growth in O&M Revenue Requirement	[I + Y - X]	2.11%

[1] Forecast of growth in the summary non-fuel O&M input price index.

[2] Scale index constructed from the Company's forecast of growth in scale subindexes and cost elasticity weights based on Table 1 econometric estimates using the formula growth Y = 0.64*growth YN + 0.22*growth YC + 0.14*growth YG.

[3] X factor is the trend in the non-fuel O&M productivity of U.S. vertically integrated electric utilities in the 1997-2016 sample period as reported on Table 6.

[4] Based on PSCo forecasts.

To calculate the pace of revenue requirement escalation for expenses that aren't tracked which Public Service proposes, we first removed the expected cost savings from Valmont and Cherokee from their 2016 historical test year total since these changes are expected to occur in 2017. Public Service proposes revenue requirements for non-fuel O&M expenses during the MYP which reflect its forecast of the cost of advanced grid and intelligence security ("AGIS"). The salary and wage portion of its revenue requirement for other non-fuel O&M expenses is escalated by 3% to account for expected wage increases in 2017 and then escalated by 2% annually from 2018 to 2021. The revenue requirement for other material and service O&M expenses is frozen. The resultant revenue requirement for non-fuel O&M expenses not slated for tracker treatment averages 1.77% growth in the five years from 2016 (as normalized) to 2021.

The difference between the forecasted average growth in our O&M revenue escalator and the Company's proposed 1.77% growth over the same years is an estimate of the stretch factor that is implicit in their proposal. This stretch factor is 0.34%. Approved stretch factors in indexed ARMs of North American energy utilities typically range between 0 and 0.60% today. Stretch factors in the neighborhood of 0.3% are typically reserved today for average cost performers.

5. Need for Revenue Requirement Escalation when Decoupling

Revenue decoupling adjusts a utility's rates periodically to help its *actual* revenue track its *allowed* revenue more closely. Many revenue decoupling systems have two basic components: a revenue *decoupling* mechanism ("RDM") and a revenue *adjustment* mechanism ("RAM"). The RDM tracks variances between actual and allowed revenue, and adjusts rates to draw down these variances. Meanwhile, the RAM escalates allowed revenue between rate cases to provide relief for growing cost pressures. These mechanisms thus address different sources of financial attrition that utilities experience between rate cases. The RDM addresses *revenue*-related attrition, while the RAM addresses *cost*-related attrition. Other revenue decoupling systems have some automatic revenue escalation built into the RDM.

In the absence of automatic revenue escalation, decoupled revenue will not grow. Growth in billing determinants can cause base rates to fall. Meanwhile, cost tends to rise for various reasons that include growth in input prices and operating scale. For this reason, most approved decoupling systems have some form of automatic revenue escalation. Utilities operating without such escalation in their decoupling systems often file frequent rate cases. When developing a decoupling system, the *need* for automatic revenue escalation is thus less of an issue than its *design*.

Many decoupling systems of gas and electric utilities escalate allowed revenue only for growth in the number of retail customers.[17] The number of customers is an important driver of cost in its own right and is highly correlated with other scale variables that drive cost such as peak demand. The number of customers is usually the most important scale variable in PEG's econometric studies of electric utility cost.

Escalating revenue for customer growth reduces the need for rate cases but rarely eliminates it because cost has several other drivers. Utilities operating under decoupling systems that automatically escalate revenue only for customer growth therefore rarely agree to rate case

[17] This is sometimes accomplished by adjusting rates to hold revenue-per-customer or use per customer constant.

moratoriums. Some utilities have had RAMs that are “broad based” in the sense that they provide enough revenue growth to compensate the utility for several kinds of cost pressures. This can reduce the need for rate cases substantially and thereby serve as the attrition relief mechanism in an MYP.

To illustrate the need for escalation of allowed revenue when a vertically integrated electric utility is subject to decoupling, we gathered data from FERC Form 1 and other publicly available sources on the trend in the pro-forma total cost of base-rate inputs in our sample of 54 American VIEUs. The sample period is 1998-2016. Costs considered in our study included most non-fuel O&M expenses, amortization, depreciation expenses, taxes, and a proforma return on net plant value.

Table 8 and Figure 1 provide results of this work. The table and figure also show the trends in the U.S. gross domestic product price index (“GDPPI”) and the number of retail customers served by the sampled utilities. The GDPPI is the federal government’s featured index of inflation in the prices of final goods and services in the US economy. Final goods and services include consumer products, capital equipment, and exports. The GDPPI tends to grow more slowly than the economy’s input prices due to the brisk productivity growth of the economy.

Inspecting the results it can be seen that, over the full sample period, the 3.86% average annual growth rate in the non-fuel cost of the VIEUs substantially exceeded the corresponding trends in the number of customers served and the GDPPI. We have obtained similar results in analogous studies for energy distribution.[18] This work suggests that regulators can permit escalation of the revenue requirement for customer growth with little concern that it will produce overearning.

[18] See, for example, the testimony by senior author Mark Newton Lowry in Pennsylvania Public Utilities Commission Docket M-2016-2518883 for the Natural Resources Defense Council, February 2016.

Table 8

Comparing Trends in VIEU Cost and Customers and Inflation[19,20]

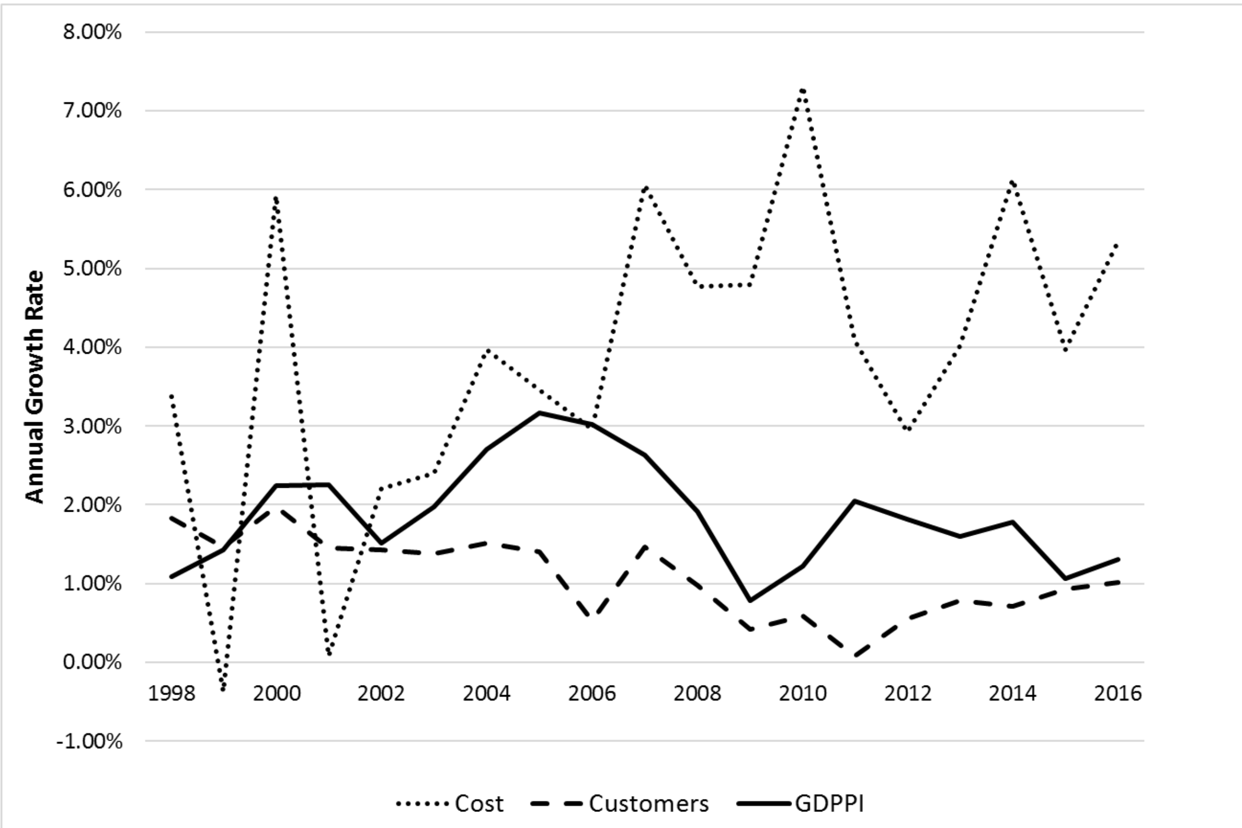
	Non-Fuel Cost [%] [A]	Customers [%] [B]	GDPPI [%] [C]
1998	3.37%	1.83%	1.08%
1999	-0.37%	1.46%	1.42%
2000	5.92%	1.98%	2.25%
2001	0.07%	1.45%	2.26%
2002	2.20%	1.43%	1.52%
2003	2.40%	1.38%	1.98%
2004	3.96%	1.51%	2.71%
2005	3.46%	1.41%	3.17%
2006	2.96%	0.53%	3.02%
2007	6.06%	1.46%	2.63%
2008	4.76%	0.98%	1.91%
2009	4.80%	0.42%	0.78%
2010	7.32%	0.59%	1.22%
2011	4.09%	0.08%	2.04%
2012	2.92%	0.55%	1.82%
2013	4.02%	0.78%	1.60%
2014	6.14%	0.72%	1.78%
2015	3.96%	0.93%	1.06%
2016	5.35%	1.01%	1.31%
Average Annual Growth Rates			
1998-2016	**3.86%**	**1.08%**	**1.87%**
2008-2016	**4.82%**	**0.67%**	**1.50%**

[19] Data Sources: FERC Form 1 (cost data), the Edison Electric Institute (allowed ROE), EIA Form 861 and FERC Form 1 (customers), and the Bureau of Economic Analysis (GDPPI). Cost is calculated as reported O&M expenses less fuel, purchased power, customer service and information, transmission by others, transmission dispatching, regional market, and miscellaneous power supply and transmission expenses plus an estimate of capital cost. Capital cost was calculated as the pro forma return on rate base plus depreciation and tax expenses.

[20] Growth rates are calculated logarithmically.

Figure 1

Comparing Trends in VIEU Cost and Customers and Inflation



6. Performance Impact of Test Years

To address the impact of test years on incentives for good cost management we developed an econometric model of the growth of real non-fuel electric O&M expenses. One driver of real O&M cost growth was identified in this research: growth in the scale trend index we constructed for Table 7. We added to the model a binary variable with a value of one for companies that were subject to historical test years in any and all rate case filings that occurred in the 1997-2016 sample period. If this variable had a negative and statistically significant parameter estimate, it would suggest that historical test years tend to slow annual cost growth.

Results of the exercise can be found in Table 9. It can be seen that the parameter estimate for the scale index was positive and highly significant, indicating that growth in scale tended to accelerate cost growth. The positive value of the constant term indicates a tendency for O&M cost growth to accelerate over time for reasons not captured by other model variables.

The parameter estimate for the historical test year dummy was positive, suggesting that HTYs *accelerated* cost growth, but was close to zero and highly insignificant. We accordingly cannot reject the hypothesis that a historical test year had no effect on real non-fuel cost growth. A similar conclusion was drawn on this subject with respect to vertically integrated electric utilities in our previous testimony for Public Service. These empirical results square with our experience, gathered over many years of incentive regulation research, that the choice of a test year for rate cases has little impact on cost performance incentives.

The explanatory power of the model was low. Cost growth evidently fluctuated from year to year due to miscellaneous business conditions that are difficult to measure. The parameter estimates are nonetheless meaningful and shed light on the test year performance impact.

Table 9
Econometric Model of Vertically Integrated Electric Utility
Real Non-Fuel O&M Cost Growth

VARIABLE KEY

DY = Growth in Elasticity Weighted Scale Index
HTY = Historic Test Year Binary Variable
Trend = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
DY	0.313	3.328	0.001
HTY	0.002	0.277	0.782
Trend	0.000	-0.762	0.446
Constant	0.005	0.806	0.420

Rbar-Squared	0.009
Sample Period	1997-2016
Number of Observations	1080

APPENDIX

This Appendix provides additional and more technical details of our empirical research. We begin by discussing the choice of a form for the econometric benchmarking models. There follow discussions of econometric methods, unit cost indexes, and productivity calculations.

A.1 Form of the Econometric Cost Model

Specific forms must be chosen for cost functions used in econometric research. Forms commonly employed by scholars include the linear, double log, and translog. Here is a simple example of a *linear* cost model:

$$C_{h,t} = a_0 + a_1 \cdot N_{h,t} + a_2 \cdot V_{h,t}\,. \qquad \text{[A1]}$$

Here is an analogous cost model of *double log* form:

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln V_{h,t}\,. \qquad \text{[A2]}$$

In the double log model the dependent variable and the business condition variables (customers and deliveries) are all logged. This specification makes the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, the a_1 parameter indicates the % change in cost resulting from 1% growth in the number of customers.

Elasticity estimates are useful and make it easier to assess the reasonableness of model results. It is also noteworthy that, in a double log model, the elasticities are *constant* in the sense that they are the same for every value that the cost and business condition variables might assume. This model specification is restrictive, and may be inconsistent with the true form of the cost relationship we are trying to model.

Here is an analogous model of *translog* form:

$$\begin{aligned}\ln C_{h,t} &= a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln V_{h,t} + a_3 \cdot \ln N_{h,t} \cdot \ln N_{h,t} \\ &\quad + a_4 \cdot \ln V_{h,t} \cdot \ln V_{h,t} + a_5 \cdot \ln V_{h,t} \cdot \ln N_{h,t}\end{aligned}\,. \qquad \text{[A3]}$$

This form differs from the double log form in the addition of quadratic and interaction terms. Quadratic terms like $\ln N_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to each business condition variable to vary with the value of the variable. The elasticity of cost with respect to an output variable may, for example, be lower for a small utility than for a large utility. Interaction terms like $\ln V_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable. For example, the elasticity of cost with respect to growth in deliveries may depend on the number of customers in the service territory.

The translog form is an example of a "flexible" functional form. Flexible forms can accommodate a greater variety of possible functional relationships between cost and the business condition variables. A disadvantage of the translog form is that it involves many more variables than simpler forms like the double log. As the number of variables accorded translog treatment increases, the precision of a model's cost prediction falls.

A.2 Econometric Model Estimation

A variety of estimation procedures are used by econometricians. The appropriateness of each procedure depends on the distribution of the error terms. The estimation procedure that is most widely known, ordinary least squares ("OLS"), is readily available in econometric software. Another class of procedures, called generalized least squares ("GLS"), is appropriate under assumptions of more complicated and realistic error specifications. For example, GLS estimation procedures can permit the variance of the error terms of cost models to be heteroskedastic, meaning that they vary across companies. Variances can, for example, be larger for companies with large operating scale.

In order to achieve a more efficient estimator, we corrected for autocorrelation and groupwise heteroskedasticity in the error terms. These are common phenomena in statistical cost research. The estimation procedure was developed by PEG using the widely-used R statistical software program.

Note, finally, that the model specification was determined using data for all sampled companies, including Public Service. However, computation of model parameters and standard errors for the prediction required that the utility of interest be dropped from the sample when we estimated the coefficients in the predicting equation. This implies that the estimates used in developing the cost model will vary slightly from those in the model used for benchmarking.

A.3 Unit Cost Indexes

Each summary unit cost index that we calculated for Public Service in an MYP year like 2018 is the ratio of a cost index to an output quantity index.

$$Unit\ Cost_{PSCO,2018} = \frac{Cost_{PSCO,2018}}{Scale_{PSCO,2018}} \quad [A4]$$

The cost index is the ratio of the Company's forecasted 2018 cost, deflated to 2016 dollars, to the mean cost for the peer group in 2016. Each scale index compares the forecasted 2018 values for Public Service to the corresponding sample norms in 2016. Thus,

$$Unit\ Cost_{PSCO,2018} = \left(\frac{Cost_{PSCO,2018}}{\overline{Cost}_{2016}}\right) \Big/ \sum se_i * \frac{Y_{PSCO,i,2018}}{\overline{Y}_{i,2016}} \quad [A5]$$

Here $Cost_{PSCO,2018}$ is the real revenue requirement projected for Public Service, $Y_{PSCO,i,2018}$ is the Company's forecasted value of scale variable *i*, and $\overline{Cost_{2016}}$ and $\overline{Y_{i,2016}}$ are the corresponding 2016 peer group means. The denominator of this formula takes a weighted average of the scale variable comparisons. The weight for each scale variable *i* (se_i) is its share in the sum of the corresponding cost elasticity estimates from the corresponding econometric cost model.

A.4 Additional Details on O&M Productivity Trend Research

We calculated an O&M productivity trend index for each company in our sample. The annual growth rate in each company's productivity index is the difference between the growth rates of its scale and input quantity indexes. These growth rates are calculated logarithmically.

$$\ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right) = \ln\left(\frac{Scale_t}{Scale_{t-1}}\right) - \ln\left(\frac{Inputs_t}{Inputs_{t-1}}\right)$$

The long-run trend in the productivity index was calculated as its average annual growth rate over the full sample period.

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Productivity Research for Green Mountain Power

Pacific Economics Group Research, LLC

PRODUCTIVITY RESEARCH FOR GREEN MOUNTAIN POWER

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Executive Summary

Statistical cost benchmarking has growing use in energy utility regulation. Benchmarking can be used to appraise historical and expected future levels of utility cost and trends in costs. The quality data available in the United States on energy utility operations facilitate benchmarking. Pacific Economics Group Research, LLC is a leading consultancy in the field of utility performance research. Green Mountain Power ("GMP" or "the Company") has retained us to appraise its recent non-power cost and expected 2018 cost.

Introduction to Benchmarking

Statistical cost benchmarking uses statistical methods and utility operating data to benchmark utility cost performance. Differences in the costs that utilities incur depend in part on differences in external business conditions (sometimes called cost “drivers”) that they face. A company’s cost performance depends on the cost it achieves given the business conditions that it faces. Benchmarks should therefore reflect cost drivers. The relevant drivers of cost include input prices and the scale of operations.

A productivity index for a utility is the ratio of an index of its operating scale to an index of the quantities of inputs that it uses. Productivity indexes are cost performance metrics that control for differences in the operating scale and input prices that utilities face. This makes it possible to compare the costs of utilities with different input prices and operating scale. Productivity indexes can be designed to compare productivity levels and trends. Productivity grows when a utility’s real (inflation-adjusted) cost grows more slowly than its operating scale. *Multilateral* productivity (“MFP”) indexes measure productivity in the provision of various inputs (e.g. capital, labor, materials, and services).

Research for GMP

We addressed the reasonableness of GMP's cost using productivity indexes. Operation & maintenance (“O&M”), capital, and multifactor productivity indexes were calculated. Productivity *levels* were considered as well as productivity *trends*.

Our calculations were based on quality data drawn from publicly available sources such as the Federal Energy Regulatory Commission ("FERC") Form 1 reports. A Uniform System of Accounts has been in force for this form for decades. The sample period for the productivity work was 1996 to 2016.

We benchmarked the cost of GMP's power distributor services (defined as distribution and most customer care services) because this is the largest component of the Company's base rate input cost which it can control and is relatively straightforward to benchmark. We compared the productivity levels of GMP in the provision of distributor services to those of a peer group in 2016. We also appraised the productivity implicit in GMP's expected 2018 cost. The peer group consisted of 24 investor-owned electric utilities serving smaller cities, towns, and substantially forested rural areas in eastern and midwestern states.

GMP's multifactor productivity level in 2016 was found to be 6.6% above the peer group norm. Capital productivity was about 2.2% below the norm while O&M productivity was 12.5% above the norm. The multifactor productivity implicit in GMP's expected 2018 cost would be 10.5% above the 2016 peer group norm. Capital productivity would be a slight 1.9% below the norm while O&M productivity would be about 24.4% above the norm.

GMP's multifactor productivity growth trend has been brisk in the last ten years, averaging 2.27% annual *growth* each year while the MFP of the peer group averaged a 0.55% *decline*. MFP growth has been especially rapid since the 2012 merger with Central Vermont Public Service. Rapid growth in the Company's O&M productivity was chiefly responsible for its MFP growth. However, GMP's capital productivity growth has exceeded the peer group norm. Since 1996, GMP has averaged 0.89% annual capital productivity growth while the peer group averaged 0.41% growth. In the last 10 years, GMP has averaged 0.46% annual capital productivity growth while the peer group has averaged a 0.10% *decline*. Were the expected 2018 cost realized, the trend in the Company's MFP since 2012 would average a remarkable 4.5%. O&M productivity growth would average 9.68% while capital productivity growth would average 0.23%.

In summary, GMP has materially improved its cost performance over the years, especially since the merger in 2012. Its multifactor productivity level is now well above that of a sensible utility peer group. O&M productivity has been a particular bright spot but the Company's capital productivity is roughly average and has improved over time.

1. Introduction

Statistical cost benchmarking has growing use in energy utility regulation. Benchmarking can be used to appraise historical and expected future levels of utility cost and trends in costs. The quality data available in the United States on energy utility operations facilitates benchmarking.

Pacific Economics Group Research LLC ("PEG") is a consultancy in the field of utility economics. Statistical research on utility cost is a company specialty. We pioneered the use of rigorous benchmarking and productivity studies in the regulation of North American energy utilities. Mark Newton Lowry, President of PEG and senior author of this report, has testified numerous times on his benchmarking and productivity research. GMP has retained PEG to appraise its recent and expected 2018 cost performance.

Section 2 of this report provides an introduction to statistical performance research. Section 3 discusses our work for GMP. Some technical details of the research are provided in the Appendix.

2. An Introduction to Benchmarking

In this Section of the report we provide a non-technical introduction to cost benchmarking. The benchmarking methods used in the study are explained. Details of our benchmarking work for GMP are discussed in Section 3 and the Appendix.

2.1 What is Benchmarking?

The word benchmark originally comes from the field of surveying. The *Oxford English Dictionary* defines a benchmark as

> A surveyors mark, cut in some durable material, as a rock, wall, gate pillar, face of a building, etc. to indicate the starting, closing, ending or any suitable intermediate point in a line of levels for the determination of altitudes over the face of a country.

The term has subsequently been used more generally to indicate something that can be used as a point of comparison in performance appraisals.

Quantitative benchmarking involves one or more activity measures. These are sometimes called performance metrics or indicators. The value of each metric achieved by an entity under scrutiny is compared to a benchmark value that reflects a performance standard. Given data on the cost of GMP and a certain cost benchmark we might, for instance, measure its cost performance by taking the ratio of the two values:

$$\textit{Cost Performance} = \textit{Cost}^{GMP}/\textit{Cost}^{Benchmark}.$$

Benchmarks are often developed statistically using data on the operations of agents engaged in the same activity. In utility cost benchmarking, data on the costs of utilities can be used to establish benchmarks. Various performance standards can be used in benchmarking, and these often reflect statistical concepts. One sensible standard for utilities is the average performance of the utilities in the sample. An alternative standard is the performance that would define the margin of the top quartile of performers. An approach to benchmarking which uses statistical methods is called statistical benchmarking.

These concepts are usefully illustrated by the process for choosing athletes for the Pro Football Hall of Fame. Statistical benchmarking plays a major (if informal) role in player selection. Quarterbacks, for example, are evaluated using multiple performance indicators that include touchdowns, passing yardage, and interceptions. Values for these metrics which are far above league norms will someday be used to judge the candidacy of New England Patriots star Tom Brady.

2.2 External Business Conditions

When appraising the relative performance of two sprinters, comparing their times in the 100-meter dash when one runs uphill and the other runs on a level surface isn't very informative since runner speed is influenced by the slope of the surface. In comparing costs that utilities incur, it is similarly recognized that differences in their costs depend in part on differences in external business conditions they face. These conditions are sometimes called cost "drivers." A company's cost performance depends on the cost it achieves given the business conditions that it faces. Cost benchmarks should therefore reflect external business conditions.

Economic theory is useful in identifying cost drivers and controlling for their influence in benchmarking. Under certain reasonable assumptions, cost "functions" exist that relate the cost of a utility to business conditions in its service territory. When the focus of benchmarking is total non-power cost, for example, theory reveals that the relevant business conditions include the prices of capital and non-power O&M inputs and the scale of the company's operations. Miscellaneous other business conditions may also drive cost.

2.3 Benchmarking Methods

2.3.1 Benchmarking Indexes

In their internal reviews of operating performance utilities tend to employ index approaches to benchmarking. Benchmarking indexes are also used occasionally in regulatory submissions. We begin our discussion with a review of index basics and then consider productivity indexes.

An index is defined in one dictionary as "a ratio or other number derived from a series of observations and used as an indicator or measure (as of a condition, property, or phenomenon)."[1] In utility-performance benchmarking, indexing typically involves the calculation of ratios of the values of performance metrics for a subject utility to the corresponding values for a sample of utilities. The companies for which data have been drawn are sometimes called a peer group.

We have noted that a simple comparison of the costs of utilities reveals little about their

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[1] *Webster's Third New International Dictionary of the English Language Unabridged*, Volume 2, p. 1148. (Chicago: G. and C. Merriam and Co. 1966).

cost performances if there are large differences in the cost drivers they face. In index-based cost benchmarking, it is therefore common to use as performance metrics the ratios of their cost to one or more important cost drivers. Differences in the operating scales of utilities are typically the greatest source of difference in their cost. It makes sense then to compare ratios of cost to operating scale. Such a ratio is sometimes called the cost per unit of operating scale or unit cost. In comparing the unit costs of utilities, we introduce an automatic control for differences in their operating scale. This permits us to include companies with more varied operating scales in the peer group.

A unit cost index is the ratio of a cost index to a scale index ("Scale").

$$\textit{Unit Cost} = \textit{Cost/Scale}. \qquad [1]$$

Each index compares the value of the metric to the average for a peer group.[2] If operating scale has several dimensions, the scale index can summarize the difference between several scale comparisons by taking an average of them.

Unit cost indexes do not control for differences in other cost drivers that are known to vary between utilities. Our discussion in Section 2.2 revealed that cost depends on input prices and miscellaneous other business conditions in addition to operating scale. The accuracy of unit cost benchmarking thus depends on the extent to which the cost pressures placed on the peer group by these additional business conditions are similar on balance to those facing the subject utility.

One sensible upgrade to unit cost indexes is to adjust them for differences in the input prices that utilities face. The formula for real (price-adjusted) unit cost is

$$Unit\ Cost^{Real} = \frac{Cost\,/\,Input\ Prices}{Scale} \qquad [2]$$

In comparing the real unit costs of utilities, we control automatically for differences in the input prices they face as well as for differences in their scale. This further broadens the available peer data to include costs where input prices are different. These include costs in different countries and time periods.

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[2] A unit cost index for a hypothetical utility called Eastern Power, for instance, would have the general form

$$Unit\ Cost_t^{Eastern} = \frac{Cost_t^{Eastern}/Cost_t^{Peers}}{Scale_t^{Eastern}/Scale_t^{Peers}}.$$

2.3.2 Productivity Indexes

The Basic Idea

A productivity index is the ratio of a scale index to an input quantity index (*Inputs*):

$$Productivity = \frac{Scale}{Inputs}. \qquad [3]$$

It is used to measure the efficiency with which firms convert production inputs into goods and services that they provide. Bilateral productivity indexes are designed to compare productivity levels. Productivity trend indexes are designed to compare trends.

It can be shown that cost is the product of a properly-designed input price index and input quantity index:

Cost = Input Prices • Inputs. [4]

Relations [2] - [4] imply that

$$Unit\ Cost^{Real} = \frac{Inputs}{Scale} = 1/Productivity \qquad [5]$$

Thus, a productivity index will yield the same benchmarking rankings as a real unit cost index. A company with high productivity will have a low real unit cost.

The growth trend of a productivity index can be shown to be the difference between the trends in the scale and input quantity indexes.

trend Productivity = trend Scale - trend Inputs. [6]

Productivity grows when the scale index rises more rapidly (or falls less rapidly) than the input index. Productivity can be volatile but usually grows over time. Volatility in the productivity of power distributors is typically due to the uneven timing of certain periodic expenditures and/or external cost shocks such as severe storms. The volatility of productivity growth tends to be greater for individual companies than the average for a group of companies.

The scale index of a firm or industry summarizes trends in the scale of its operation. One possible objective of scale research is to measure the impact of growth in scale on company *cost.* In that case, the scale index should measure the dimensions of the "workload" that drive cost. A productivity index calculated using a cost-based scale index may fairly be described as a "cost efficiency index."

The scope of a productivity index depends on the array of inputs that are addressed by the input quantity index. Some indexes measure productivity in the use of a single input class such as labor. A *multifactor* productivity ("MFP") index measures productivity in the use of multiple inputs.

Sources of Productivity Growth

Research by economists has found the sources of productivity growth to be diverse.[3] One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

Economies of scale are a second source of productivity growth. These economies are available in the longer run if cost tends to grow more slowly than operating scale. A company's potential to achieve incremental scale economies depends on the growth of its scale. Incremental scale economies (and thus productivity growth) will typically be reduced when growth in scale slows.

A third important source of productivity growth is change in X-inefficiency. X-inefficiency is the degree to which a company fails to operate at the maximum efficiency that technology allows. Productivity growth rises (falls) when X-inefficiency diminishes (increases). The lower the company's current efficiency level, the greater is the potential for productivity growth from a change in inefficiency.

Another driver of productivity growth is changes in miscellaneous external business conditions, other than input price inflation and output growth, which affect cost. A good example for an electric power distributor is the share of distribution lines that are undergrounded. An increase in the share of lines that are undergrounded will tend to slow *multifactor* productivity growth (because of the higher capital requirements) but accelerate *O&M* productivity growth (since there is less line maintenance in most years).

Consider finally that, in the short to medium run, a utility's productivity growth can be driven by the position of the utility in the cycle of asset replacement. A surge in capex is sometimes needed to replace assets that were part of a surge in capex many years ago. Productivity growth will be slower to the extent that the need for replacement capex is large relative to the existing stock of capital.

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[3] A seminal paper in this field is Michael Denny, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries,* (Academic Press, New York) pages 179-218.

3. Empirical Research for GMP

3.1 Data

The primary source of the utility cost data used in this study was the FERC Form 1. Selected Form 1 data were for many years published by the U.S. Energy Information Administration ("EIA").[4] More recently, these data have been available electronically in raw form from the FERC and in more processed forms from commercial vendors. FERC Form 1 data used in this study were obtained directly from government agencies and processed by PEG. Data on the number of customers served were drawn from FERC Form 1 and Form EIA-861 (the *Annual Electric Power Industry Report*). A forecast of the number of customers GMP will serve in 2018 was obtained from the Company.

Data were considered for inclusion in the sample from all major investor-owned electric utilities in the United States which filed the Form 1 in 1964 and that, together with any important predecessor companies, have reported the necessary data continuously since then.[5] To be included in the study the data also were required to be of good quality and plausible. One important quality criterion was that there were no major shifts in reported distribution and transmission costs due to their recategorization.

Data from 86 utilities met our standards and were used in our research for GMP. The sampled companies are listed in Table 1. The companies in the productivity peer group are identified in the table. We believe these data are the best available for rigorous work on the productivity of power distributors. Most broad regions of the United States are well-represented in the sample.[6] The sample period for the productivity research was 1996-2016.

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[4] This publication series had several titles over the years. A recent title is Financial Statistics of Major US Investor-Owned Electric Utilities.

[5] 1964 is the benchmark year for the computation of capital cost, as we discuss further in the Appendix.

[6] Unfortunately, the requisite customer data are not available for most Texas distributors.

Table 1
Sample of Utilities Used in the Productivity Research

Alabama Power	Mississippi Power
ALLETE (Minnesota Power)	*Monongahela Power*
Ameren Illinois	Narragansett Electric
Appalachian Power	Nevada Power
Arizona Public Service	*New York State Electric & Gas*
Atlantic City Electric	Niagara Mohawk Power
Avista	Northern States Power - Minnesota
Baltimore Gas and Electric	Northwestern Energy
Central Maine Power	NSTAR Electric
Cleco Power	Ohio Edison
Cleveland Electric Illuminating	*Ohio Power*
Connecticut Light and Power	Oklahoma Gas and Electric
Dayton Power and Light	*Orange and Rockland Utilities*
Delmarva Power & Light	Otter Tail Power
Duke Energy Carolinas	Pacific Gas and Electric
Duke Energy Florida	PacifiCorp
Duke Energy Indiana	PECO Energy
Duke Energy Kentucky	*Pennsylvania Electric*
Duke Energy Ohio	*Pennsylvania Power*
Duke Energy Progress	Portland General Electric
Duquesne Light	Potomac Electric Power
El Paso Electric	Public Service Electric and Gas
Empire District Electric	Public Service of Colorado
Entergy Mississippi	Public Service of Oklahoma
Entergy New Orleans	Rochester Gas & Electric
Fitchburg Gas and Electric	San Diego Gas & Electric
Florida Power & Light	South Carolina Electric & Gas
Georgia Power	Southern California Edison
Green Mountain Power	*Southern Indiana Gas and Electric*
Gulf Power	Superior Water, Light and Power
Idaho Power	Tampa Electric
Indiana Michigan Power	Toledo Edison
Indianapolis Power & Light	Tucson Electric Power
Jersey Central Power & Light	Union Electric
Kansas City Power & Light	*United Illuminating*
Kansas Gas and Electric	Virginia Electric and Power
Kentucky Power	*West Penn Power*
Kentucky Utilities	Westar Energy (KP&L)
Kingsport Power	*Western Massachusetts Electric*
Louisville Gas and Electric	Wheeling Power
Massachusetts Electric	Wisconsin Electric Power
MDU Resources Group	Wisconsin Power and Light
Metropolitan Edison	*Wisconsin Public Service*

Notes:
Italicized companies are in the peer group.

3.2 Definitions of Variables

3.2.1 Calculating Cost

The major tasks in a U.S. power distributor's operation are the local delivery of power and the reduction of its voltage. Most power is delivered to customers at the voltage at which they consume it. This usually requires distributors to use substations and transformers to step down the voltage of most power delivered from the level at which they receive it from the transmission sector. U.S. distributors also typically provide various customer services such as metering, meter reading, and billing.

The total cost of power distributor services considered in our study was the sum of applicable O&M expenses and capital costs. The capital costs we considered were those for distribution and general plant. We employed a service price approach to capital cost measurement that decomposes capital cost into a price and a quantity index.

$$Cost^{Capital} = Price^{Capital} \bullet Quantity^{Capital}. \qquad [7]$$

Capital cost is the sum of depreciation expenses, a return on the value of net plant, taxes and capital gains. A geometric pattern of depreciation was assumed. This approach is widely used in capital cost research and is explained further in the Appendix.

The O&M expenses we studied included those for distribution and most customer services. We also included a sensible share of administrative and general expenses. Reported costs of any gas services provided by combined gas and electric utilities in the sample were excluded.

We excluded expenses for customer service and information and franchise fees.[7] Customer service and information expenses were excluded because they vary greatly with the extent of demand-side management ("DSM") programs, and expenses for these programs are not itemized on FERC Form 1 for easy removal. Franchise fees also vary greatly between utilities and are substantially beyond their control.

GMP merged with Central Vermont Public Service (“CVPS”) in 2012. For 2012 and years

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[7] Gas service costs of combined gas and electric utilities are itemized on FERC Form 1 for easy removal. We exclude customer service and information expenses because on FERC Form 1 these include DSM expenses.

prior to the merger we consolidated the cost of the two companies.

3.2.2 Scale Variables

We used the number of customers served as our measure of power distributor operating scale. This is an important driver of distributor cost and is highly correlated with other scale-related cost drivers, such as peak demand, for which accurate data are not readily available. A forecast of the number of customers that GMP will serve in 2018 was provided by the Company.

3.2.3 Input Prices

Relation [4] implies that the quantity of inputs a utility uses can be calculated as the ratio of its cost to an input price index. Input price indexes therefore play an important role in our productivity calculations. We constructed O&M input price indexes by taking weighted averages of price indexes for labor and M&S inputs. Occupational Employment Statistics ("OES") survey data for 2008 were used to construct average wage levels that correspond to each utility's service territory. Each wage level was calculated as a weighted average of the OES pay level for each job category using weights that correspond to the electric utility industry. Values for other years were calculated by adjusting the level in the focus year for changes in regionalized indexes of employment cost trends for the utilities sector of the economy. These trend indexes were constructed from BLS employment cost indexes.

Prices for M&S inputs were assumed to have a 25% local labor content and therefore tend to be a little higher in regions with higher labor prices. We use our labor price index to effect this levelization in the same focus year. The M&S price is then escalated by the gross domestic product price index ("GDPPI"). This is the federal government's featured index of inflation in the prices of the economy's final goods and services. The O&M input price for each utility is constructed by combining the labor and M&S price subindexes using company-specific, time-varying cost share weights. The cost shares were calculated from FERC Form 1 data. We forecasted the inflation in the price subindexes to 2018 using Congressional Budget Office forecasts.

3.2.4 Peer Group Selection

A peer group for the benchmarking productivity levels of power distributors should reflect cost pressures other than input prices and operating scale which affect their cost. Several business conditions were considered in the selection of an appropriate productivity peer group for GMP.

One is the extent to which distribution assets are overhead. The extent of overheading varies greatly across America's distribution systems. Generally speaking, overheading is greater in suburban and rural areas and small towns than in the centers of large metropolitan areas. System overheading involves higher O&M expenses in most years because facilities are more exposed to the challenges posed by local weather (e.g., high winds and ice storms), flora, and fauna.[8] However, capital cost is lower.

A second business condition considered in the selection of a productivity peer group was customer density. The low customer density typical of rural areas tends to raise the cost of distributor services. A third business condition considered was the number of customers that the utility provides with natural gas distribution services. Such diversification will typically lower the reported cost of power distribution due to the realization of economies of scope. A fourth business condition variable considered was forestation. We expect forestation to have a positive impact on O&M expenses and total cost. Precipitation is a useful proxy for the extent of forestation.

3.3 Business Conditions of GMP

GMP is an investor-owned electric utility based in Colchester, VT which serves most of central and southern Vermont. Its service territory includes parts of the growing Burlington metropolitan area, Rutland, and many smaller towns and rural areas. Much of the territory is forested, and some is mountainous. There are numerous second homes in rural areas. Winters are often severe.

The Company provides power distributor services and some transmission services. Most of GMP's transmission lines operate at 46kV or less, and most of its substations step down voltages from these subtransmission levels to primary voltage. Higher-voltage transmission services in Vermont are provided by ISO New England ("ISO-NE") and Vermont Electric Power Company ("VELCO") using the facilities of Vermont Transco. GMP owns large shares of VELCO and Vermont Transco but these entities are separately regulated.

GMP purchases most of the power it supplies to its customers but has ownership stakes in some generation facilities. The generation plant GMP owns uses an unusual mix of technologies.

[8] Maintenance of underground delivery facilities occurs less frequently but can be quite costly.

Hydroelectric, nuclear, and fossil-fueled steam facilities are most important. The Company also owns stakes in gas-fired, wood-fired, and wind- and solar-powered generators.[9] Several of these facilities are jointly-owned and managed by other parties. This limits GMP's ability to control the cost of these facilities. These features of GMP's generation operations make it difficult to benchmark the Company's generation performance.

As for other business conditions, the overheading of GMP's distribution system is well above the U.S. norm. So is the extent of service territory forestation. The company serves no gas customers and generation and transmission operations are limited. It follows that GMP cannot enjoy the economies of scope that might be possible with more extensive generation, transmission, and gas operations.

In summary, our research shows that GMP faces a number of natural disadvantages and a few advantages in its efforts to contain the cost of its power distributor services. The disadvantages include a small operating scale, lack of customer density, extensive forestation, and a lack of gas customers and extensive involvement in transmission and generation that might permit the Company to spread general costs. GMP's advantages include a limited need for system undergrounding that reduces its capital cost.

3.4 Productivity Research for GMP

3.4.1 Methodology

We calculated indexes of the O&M, capital, and multifactor productivity of each utility in our U.S. sample in the provision of power distributor services. Levels comparisons were made in 2016 using bilateral productivity indexes. These indexes compared the productivity of each sampled utility to the full sample norm.

We developed a peer group of 24 U.S. electric utilities facing business conditions driving the level of productivity which are like those GMP faces.[10] These utilities serve a mix of smaller cities, towns, and substantially forested rural areas in the Midwest or the East. The productivity of GMP was then compared to the norm for the peer group. This is our measure of the Company's

[9] GMP also leases energy-efficient heat pumps and other energy equipment to customers.

[10] The peer group includes GMP.

productivity level *performance*.

Trend comparisons were made with productivity trend indexes. The annual productivity growth rate of each utility was calculated as the difference between the growth of its scale and input quantity indexes. Simple arithmetic averages of these growth rates were then calculated for GMP and its peer group.

In calculating input quantity indexes we broke down the applicable cost into those for distribution plant, general plant, labor, and M&S inputs. Each cost category had its own input quantity subindex. Growth in the O&M, capital, and multifactor productivity indexes were cost-weighted averages of the growth in the quantity subindexes.

3.5 Research Results

3.5.1 Productivity Levels

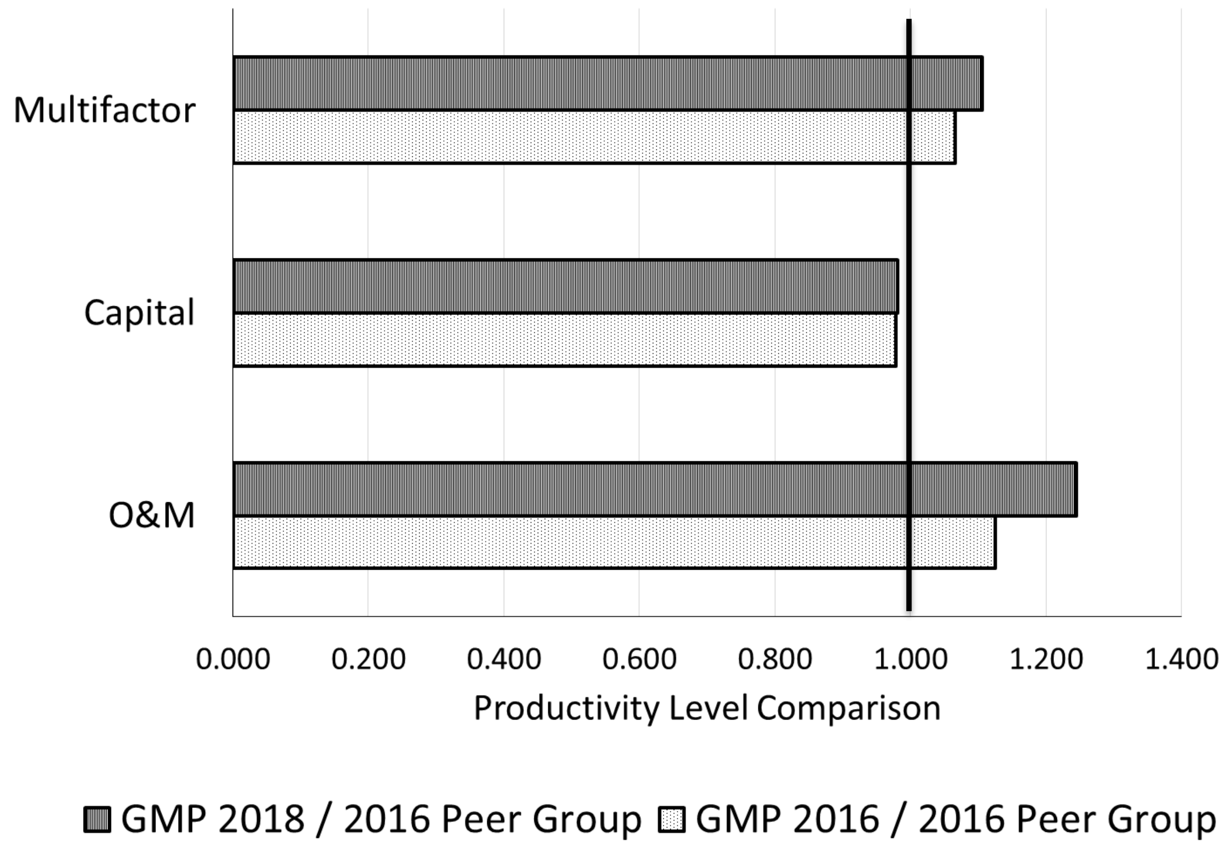
Table 2 and Figure 1 compare the productivity levels of GMP to those of the peer group in 2016. The Company's multifactor productivity level in 2016 was found to be about 6.6% above the peer group norm. Capital productivity was 2.2% below the norm while O&M productivity was 12.5% above the norm.[11]

Table 2
Multifactor Productivity Level Indexes for GMP and Its Peer Group

	Productivity Index Levels					
	Multifactor		Capital		O&M	
	2016	2018	2016	2018	2016	2018
Full U.S. Sample	1.030	NA	1.049	NA	1.071	NA
Peer Group	0.963	NA	1.070	NA	0.867	NA
GMP	1.026	1.064	1.046	1.049	0.975	1.079
GMP / Full Sample in 2016	0.996	1.033	0.997	1.000	0.910	1.007
GMP / Peer Group in 2016	**1.066**	**1.105**	**0.978**	**0.981**	**1.125**	**1.244**

[11] Notice that GMP's peer group had *capital* productivity *above* the norm for the full U.S. sample and *O&M* productivity that was *below* the norm. This makes sense given the low level of undergrounding in peer group distribution systems.

Figure 1
Multifactor Productivity Level Indexes for GMP and Its Peer Group



We also compared the productivity level implicit in GMP's expected 2018 cost to the 2016 peer group norms. Table 2 and Figure 1 show that the Company's multifactor productivity level in 2018 would be 10.5% above the peer group norm. Capital productivity would be a slight 1.9% below the norm while O&M productivity would be a substantial 24.4% above the norm.

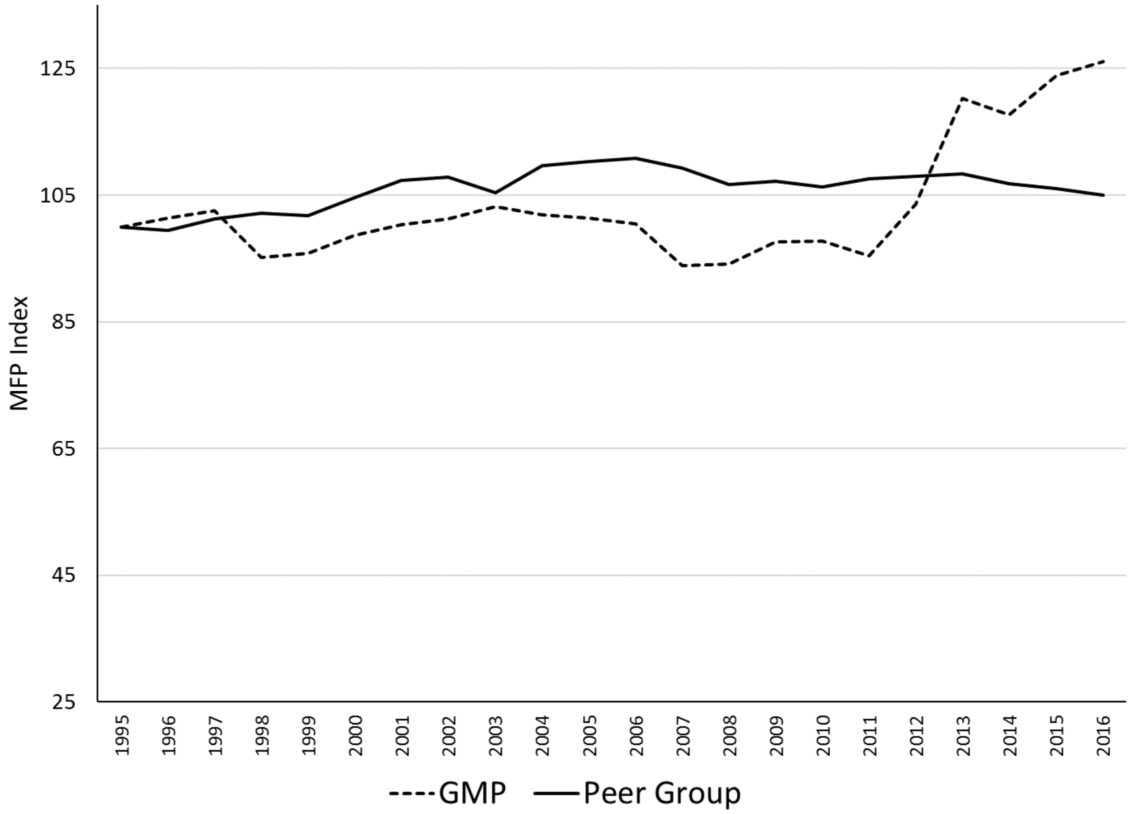
3.5.2 Productivity Trends

Table 3 and Figure 2 compare the multifactor productivity growth trends of GMP in the provision of distributor services to that of the MFP peer group. Table 4 and Figures 3 and 4 present analogous trends for O&M and capital productivity. It can be seen that GMP's multifactor productivity growth has been relatively brisk. In the last ten years it averaged 2.27% annual *growth* while the MFP growth of the peer group averaged a 0.55% *decline*. MFP growth has been especially rapid since the merger with CVPS.

Table 3
Multifactor Productivity Growth Trends of GMP and the Peer Group

	Green Mountain Power			Peer Group		
	Scale Index (Customers)	Input Quantity Index	MFP	Scale Index (Customers)	Input Quantity Index	MFP
1996	0.96%	-0.45%	1.41%	1.22%	1.82%	-0.60%
1997	0.62%	-0.44%	1.06%	1.04%	-0.84%	1.88%
1998	0.73%	8.08%	-7.36%	1.07%	0.23%	0.84%
1999	0.57%	-0.03%	0.60%	1.04%	1.44%	-0.40%
2000	1.21%	-1.72%	2.92%	1.49%	-1.29%	2.77%
2001	1.47%	-0.23%	1.69%	2.75%	0.19%	2.55%
2002	1.21%	0.25%	0.96%	-0.31%	-0.86%	0.55%
2003	1.32%	-0.50%	1.82%	0.98%	3.28%	-2.30%
2004	0.89%	2.05%	-1.17%	0.90%	-2.98%	3.88%
2005	1.47%	2.08%	-0.61%	1.21%	0.61%	0.60%
2006	2.79%	3.59%	-0.81%	0.81%	0.26%	0.55%
2007	0.85%	7.63%	-6.78%	0.92%	2.35%	-1.43%
2008	0.39%	0.22%	0.17%	-0.03%	2.33%	-2.37%
2009	0.33%	-3.29%	3.62%	0.10%	-0.29%	0.39%
2010	0.44%	0.19%	0.26%	0.36%	1.10%	-0.74%
2011	0.46%	2.93%	-2.47%	0.08%	-1.12%	1.20%
2012	0.39%	-7.84%	8.23%	0.07%	-0.19%	0.26%
2013	0.77%	-14.16%	14.93%	0.18%	-0.26%	0.44%
2014	0.02%	2.21%	-2.19%	0.23%	1.71%	-1.48%
2015	0.67%	-4.45%	5.12%	0.34%	1.07%	-0.73%
2016	0.69%	-1.11%	1.79%	-0.62%	0.39%	-1.01%
2017	0.60%	-1.20%	1.80%	NA	NA	NA
2018	0.60%	-1.20%	1.80%	NA	NA	NA
1996-2016	**0.87%**	**-0.24%**	**1.10%**	**0.66%**	**0.43%**	**0.23%**
2007-2016	**0.50%**	**-1.77%**	**2.27%**	**0.16%**	**0.71%**	**-0.55%**
2012-2016	**0.51%**	**-5.07%**	**5.58%**	**0.04%**	**0.54%**	**-0.51%**
2012-2018	**0.53%**	**-3.96%**	**4.50%**	**NA**	**NA**	**NA**

Figure 2
Multifactor Productivity Growth Trends of GMP and the Peer Group



Rapid growth in the Company's O&M productivity has been chiefly responsible for its MFP growth. However, GMP's capital productivity growth has exceeded the peer group norm. Since 1995, the Company's capital productivity growth has averaged 0.89% annually while that of the peer group averaged 0.41%. In the last ten years, GMP has averaged 0.46% capital productivity growth while that of the peer group has averaged a 0.10% *decline*.

Were the expected 2018 cost realized, the Company's multifactor productivity growth since 2011 would average a very brisk 4.5% annually. O&M productivity growth would average a remarkable 9.68% annually while capital productivity growth would average 0.23%.

3.5.3 Conclusions

In summary, GMP has materially improved its cost performance over the years, especially since its merger with CVPS in 2012. The Company's multifactor productivity level now exceeds that of a sensible utility peer group. O&M productivity has been a particular bright spot. However, GMP's capital productivity is roughly average and has improved over time.

Table 4
O&M and Capital Productivity Trends of GMP and the Peer Group

	Green Mountain Power					Peer Group				
	Scale Index	Input Quantity Indexes		Productivity Indexes		Scale Index	Input Quantity Indexes		Productivity Indexes	
	(Customers)	O&M	Capital	O&M	Capital	(Customers)	O&M	Capital	O&M	Capital
1996	0.96%	-3.17%	1.50%	4.13%	-0.54%	1.22%	3.55%	1.03%	-2.33%	0.19%
1997	0.62%	-0.13%	-0.64%	0.75%	1.26%	1.04%	-2.84%	0.28%	3.88%	0.76%
1998	0.73%	19.16%	0.22%	-18.43%	0.51%	1.07%	0.81%	0.11%	0.26%	0.96%
1999	0.57%	-0.02%	-0.04%	0.58%	0.61%	1.04%	3.57%	-0.05%	-2.53%	1.08%
2000	1.21%	-3.41%	-0.38%	4.61%	1.59%	1.49%	-4.66%	0.69%	6.14%	0.80%
2001	1.47%	1.71%	-1.69%	-0.24%	3.15%	2.75%	0.10%	0.17%	2.64%	2.57%
2002	1.21%	0.96%	-0.32%	0.25%	1.54%	-0.31%	-2.69%	-0.13%	2.38%	-0.18%
2003	1.32%	-1.52%	0.38%	2.84%	0.95%	0.98%	8.51%	0.39%	-7.53%	0.59%
2004	0.89%	5.21%	-0.81%	-4.33%	1.70%	0.90%	-7.64%	-0.26%	8.54%	1.16%
2005	1.47%	3.57%	0.46%	-2.09%	1.01%	1.21%	1.10%	0.23%	0.11%	0.97%
2006	2.79%	5.84%	0.39%	-3.05%	2.40%	0.81%	0.03%	0.12%	0.77%	0.69%
2007	0.85%	11.41%	0.45%	-10.55%	0.40%	0.92%	4.81%	0.24%	-3.89%	0.69%
2008	0.39%	0.37%	-0.13%	0.02%	0.52%	-0.03%	3.10%	0.15%	-3.13%	-0.18%
2009	0.33%	-4.79%	-0.11%	5.12%	0.44%	0.10%	-2.88%	0.26%	2.98%	-0.16%
2010	0.44%	0.40%	-0.14%	0.05%	0.58%	0.36%	2.72%	-0.06%	-2.36%	0.42%
2011	0.46%	5.64%	-0.44%	-5.18%	0.90%	0.08%	-1.48%	-0.50%	1.56%	0.57%
2012	0.39%	-14.04%	-1.17%	14.43%	1.56%	0.07%	0.23%	0.07%	-0.17%	0.00%
2013	0.77%	-27.02%	-2.24%	27.79%	3.00%	0.18%	-3.06%	1.40%	3.24%	-1.22%
2014	0.02%	2.06%	2.33%	-2.04%	-2.31%	0.23%	3.84%	0.36%	-3.61%	-0.13%
2015	0.67%	-13.30%	1.87%	13.97%	-1.20%	0.34%	1.59%	0.52%	-1.25%	-0.18%
2016	0.69%	-2.91%	0.01%	3.59%	0.68%	-0.62%	0.45%	0.23%	-1.07%	-0.85%
2017	0.60%	-4.41%	0.68%	5.01%	-0.08%	NA	NA	NA	NA	NA
2018	0.60%	-4.41%	0.68%	5.01%	-0.08%	NA	NA	NA	NA	NA
1996-2016	**0.87%**	**-0.67%**	**-0.02%**	**1.53%**	**0.89%**	**0.66%**	**0.44%**	**0.25%**	**0.22%**	**0.41%**
2007-2016	**0.50%**	**-4.22%**	**0.04%**	**4.72%**	**0.46%**	**0.16%**	**0.93%**	**0.27%**	**-0.77%**	**-0.10%**
2012-2016	**0.51%**	**-11.04%**	**0.16%**	**11.55%**	**0.35%**	**0.04%**	**0.61%**	**0.52%**	**-0.57%**	**-0.48%**
2012-2018	**0.53%**	**-9.15%**	**0.31%**	**9.68%**	**0.23%**	**NA**	**NA**	**NA**	**NA**	**NA**

Figure 3
O&M Productivity Trends of GMP and the Peer Group

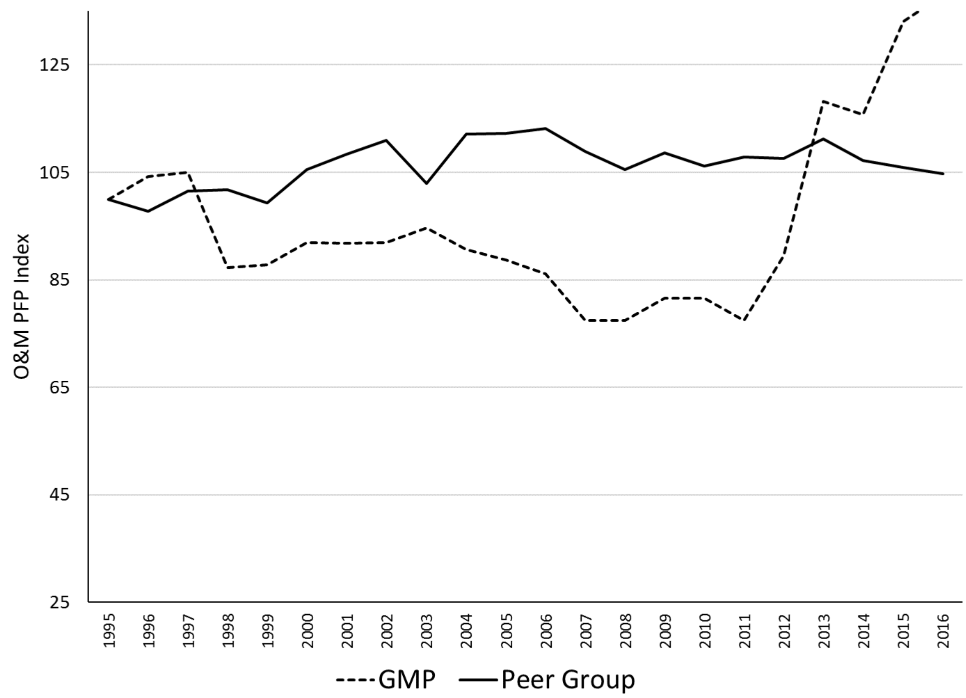
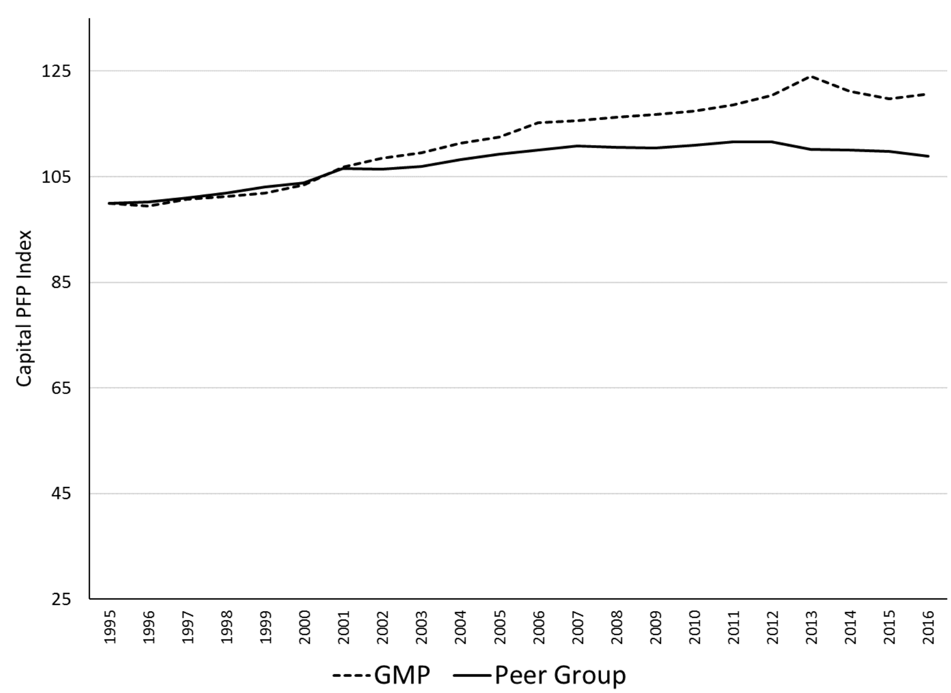


Figure 4
Capital Productivity Trends of GMP and the Peer Group



Appendix

A.1 Input Quantity Indexes

The quantity subindex for labor is the ratio of salary and wage O&M expenses to a regionalized salary and wage labor price index.[12] The quantity subindex for M&S inputs is the ratio of M&S expenses to the GDPPI. Details of the capital quantity index are provided below.

The summary input quantity trend indexes for O&M, capital, and all inputs were of chain-weighted Tornqvist form.[13] This means that their annual growth rate was determined by the following general formula:

$$ln\left(\frac{Inputs_t}{Inputs_{t-1}}\right) = \sum_j \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1}\right) \cdot ln\left(\frac{X_{j,t}}{X_{j,t-1}}\right) \quad \text{[A1]}$$

where for each company in each year *t,*

$Inputs_t$ = Summary input quantity index

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

$sc_{j,t}$ = Share of input category *j* in the applicable cost

The growth rate of each summary index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable cost of each utility in the current and prior years served as weights.

A.2 Productivity Growth Rates and Trends

We calculated productivity indexes for each company in our sample. The annual growth rate in each company's productivity trend index was given by the formula:

$$\ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right) = \ln\left(\frac{Scale_t}{Scale_{t-1}}\right) - \ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right) \quad \text{[A2]}$$

Growth rates were calculated logarithmically.

---

[12] The growth rate of the labor price index was calculated for most years as the growth rate of the national employment cost index ("ECI") for the salaries and wages of the utility sector plus the difference between the growth rates of multi-sector ECIs for workers in the utility's service territory and in the nation as a whole.

[13] For seminal discussions of this index form, see Törnqvist (1936) and Theil (1965).

A.3 Capital Cost and Quantity Measurement

A service price (aka "monetary") approach was used to measure capital costs, prices, and quantities. This approach has a solid basis in economic theory and is widely used in governmental and scholarly productivity research. In the application of the general method used in this study, the cost of a given class of utility plant *j* in a given year *t* ($CK_{j,1}$) is the product of a capital service price index ($WKS_{j,t}$) and an index of the capital quantity at the end of the prior year

$$CK_{j,t} = WKS_{j,t} \bullet XK_{j,\,t-1} \qquad [A3]$$

It can then be shown mathematically that, using logarithmic growth rates,

$$growth\ CK_{j,t} = growth\ WKS_{j,t} + growth\ XK_{j,\,t-1}. \qquad [A4]$$

In constructing the capital price and quantity indexes we used a geometric decay specification. We took 1964 as the benchmark year. The values of the input quantity indexes in the benchmark year were based on the net value of plant as reported in FERC Form 1. We estimated the benchmark year quantity of net distribution plant by dividing this book value by a triangularized weighted average of 44 values of an index of distribution utility construction cost for a period ending in the benchmark year.[14] We estimated the benchmark year (inflation-adjusted) quantity of *general* plant by dividing this book value by a triangularized weighted average of 16 values of an index of utility general plant construction cost for a period ending in the benchmark year. The construction cost index was the applicable regional Handy-Whitman index of the cost of the relevant asset category.[15]

The following formula was used to compute subsequent values of each capital quantity index:

$$XK_{j,t} = (1-d)\cdot XK_{j,t-1} + \frac{VI_{j,t}}{WKA_{j,t}}. \qquad [A5]$$

Here, the parameter *d* is the economic depreciation rate and $VI_{j,t}$ is the value of gross additions to utility plant. The term $WKA_{j,t}$ is the value of the pertinent construction cost index. The economic

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[14] A triangularized weighted average places a greater weight on more recent values of the construction cost index. This make sense intuitively since more recent plant additions are less depreciated and to that extent tend to have a bigger impact on net plant value.

[15] These data are reported in the Handy-Whitman Index of Public Utility Construction Costs, a publication of Whitman, Requardt and Associates.

depreciation rates were set at 4.34% for distribution plant and 10.29 % for general plant. They are based on weighted averages of economic depreciation rates for different types of distributor assets. The depreciation rates also reflect declining balance parameters that were 0.91 for structures and 1.65 for equipment.

Following is the full formula for the capital service price indexes for each asset category:

$$WKS_{j,t} = [CK_{j,t}^{Taxes} / XK_{j,t-1}] + d \cdot WKA_{j,t} + WKA_{j,t-1}\left[r_t - \frac{\left(WKA_{j,t} - WKA_{j,t-1}\right)}{WKA_{j,t-1}}\right]. \qquad [A6]$$

The first term in the expression corresponds to tax expenses ($CK_{j,t}^{Taxes}$). The second term corresponds to the cost of depreciation. The third term corresponds to the real rate of return on capital. This term was smoothed to reduce capital cost volatility.

The calculation of [A6] requires an estimate of the rate of return on capital (r_t). We employed a weighted average of rates of return for debt and equity.[16] We relied on a 50/50 average of the embedded average interest rate on long-term debt as calculated from FERC Form 1 data and the average allowed rate of return on equity approved in electric utility rate cases for each year as reported by the Edison Electric Institute.

[16] This calculation was made solely for the purpose of measuring productivity *trends* and does not prescribe appropriate rate of return *levels* for utilities.

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State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities

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DISCLAIMER

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July 2017

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Executive Summary

Berkeley Lab published a report in 2016 that discussed two approaches to performance-based regulation (PBR) of electric utilities: multiyear rate plans (MRPs) and performance incentive mechanisms (PIMs).[1] The authors described these approaches at a high level and in the context of growing levels of demand-side management (DSM), distributed generation and other distributed energy resources (DERs).

This report presents a more in-depth analysis of the multiyear rate plan approach to PBR for electric utilities, applicable to both vertically integrated and restructured states. The report is aimed primarily at state utility regulators and stakeholders in the state regulatory process. The approach also provides ideas on how to streamline oversight of public power utilities and rural electric cooperatives by their governing boards.

We discuss the rationale for MRPs and their usefulness under modern business conditions. We then explain critical plan design issues and challenges and present results from numerical research that considers the extra incentive power achieved by MRPs with different plan provisions. Next, the report presents several case studies of utilities that have operated under formal MRPs or, for various reasons, have stayed out of rate cases for more than a decade. In these studies we consider the effect of MRPs and rate case frequency on utility cost, reliability and other performance dimensions. Appendices present further information on MRP plan design and some details of the technical work.

What Are MRPs?

MRPs are a comprehensive approach to PBR designed to strengthen general incentives for good utility performance. Two key provisions of MRPs strengthen cost containment incentives and streamline regulation:

1. A rate case moratorium reduces the frequency of rate cases, typically to once every four or five years.

2. An attrition relief mechanism (ARM) escalates rates or revenue between rate cases to address cost pressures such as inflation and growth in number of customers independently of the utility's own cost.

Loosening the link between its own cost and revenue gives a utility an operating environment more like that which competitive markets experience.

Most MRPs feature a performance metric system that includes some PIMs. These PIMs provide awards or penalties, or both, for performance in targeted areas. PIMs are most commonly used in MRPs to strengthen incentives for utilities to maintain or improve reliability and customer service quality. Some plans also include earnings sharing mechanisms, efficiency carryover mechanisms and marketing flexibility.

Provisions are often added to plans to strengthen utility incentives for DSM. For example, utility expenditures on DSM programs are usually tracked, and PIMs can be added to reward utilities for successful DSM programs. Revenue decoupling can mitigate a utility's incentive to boost retail sales and reduce risks of revenue losses from rate designs that encourage DSM.

[1] Lowry and Woolf (2016).

How Prevalent Is This Approach?

MRPs were first widely used in the United States in the 1980s to regulate railroads and telecommunications carriers, industries beset by rising competition. Early adopters of MRPs in the U.S. electric utility industry included California and several northeastern states. Use of MRPs has recently grown among vertically integrated electric utilities in diverse states that include Arizona, Georgia and Washington. Greater use of MRPs for power distributors has been slowed by their requests for accelerated system modernization, which complicate plan design. MRPs are much more common for electric utilities in Canada and countries overseas. The impetus for adopting MRPs in these countries has often come from policymakers rather than utilities.

What Is the Rationale for These Plans?

America's investor-owned electric utility industry was largely built under cost of service regulation (COSR). This regulatory system traditionally adjusted rates that compensate utilities for costs of capital, labor and materials only in general rate cases. The scope of costs eligible for tracker treatment, which expedites cost recovery, has gradually enlarged and sometimes includes capital costs as well as energy expenditures.

The efficacy of COSR varies with external business conditions. When conditions favor utilities (e.g., are conducive to realizing at least the target rate of return), rate cases are infrequent. Performance incentives are then strong and the cost of regulation is quite reasonable. When conditions are less favorable, rate cases are more frequent and more costs are tracked. Performance incentives can then be weak and regulatory cost can be high. These attributes of COSR are worrisome because business conditions today are often less favorable to utilities than in the past.

MRPs are a different approach to regulation that is especially appealing when the alternative is frequent rate cases or expansive cost trackers. The regulatory process is streamlined and better utility performance can be encouraged due to stronger performance incentives and increased operating flexibility. Benefits of better performance can be shared with customers. Recent advances in MRPs such as efficiency carryover mechanisms and statistical benchmarking can "turbocharge" their incentive power and ensure benefits for customers.

What Are Some Disadvantages of MRPs?

MRPs are complex, and their adoption can involve extensive change to the regulatory system. It can be challenging to design plans that strengthen incentives without undue risk and share benefits fairly between utilities and their customers. Some kinds of business conditions (e.g., brisk inflation and declining average use) have proven easier to address using MRPs than others (e.g., capital spending surges). MRPs can invite strategic behavior and controversies over plan design.

Case Studies

This report discusses six case studies of utilities operating under MRPs:

1. Central Maine Power operated under a sequence of MRPs from 1996 to 2013. The plans afforded the company unusual marketing flexibility which it used to develop special contracts with large-volume customers. These contracts helped the company retain their contributions to fixed costs of the system, for the benefit of all customers.

2. California has the nation's longest history with MRPs for retail services of electric utilities. The Public Utilities Commission has limited rate case frequency and staggered plan terms to avoid simultaneous rate cases. Plan provisions have provided strong incentives for utilities to embrace DSM.
3. New York has regulated electric utilities using MRPs since the 1990s. The state's Reforming the Energy Vision proceeding has considered how rate plans should evolve to regulate the "utility of the future."
4. MidAmerican Energy operated under a rate freeze in Iowa from 1997 to 2013. This freeze extended to charges for energy procured as well as for capital, labor and materials.
5. Ontario, Canada, has used MRPs to regulate the dozens of power distributors since the late 1990s. Capital spending surges have posed special plan design challenges. Innovations in Ontario regulation also include incentive-compatible menus and extensive use of benchmarking.
6. Great Britain also has a long history with MRP regulation. The current "RIIO" approach to regulation of energy utilities there has attracted the attention of many North American regulators.

Impact on Cost Performance

This report also addresses the impact of MRPs (and, more generally, rate case frequency) on utility cost performance using two analytical tools: incentive power analysis and empirical research on utility productivity trends. An Incentive Power Model uses numerical analysis to assess the incentive impact of alternative stylized regulatory systems. For North American case studies, we compared productivity trends of utilities operating under MRPs to U.S. norms. We also considered productivity trends of utilities that operated under unusually frequent and infrequent rate cases.

Both lines of research suggest that the frequency of rate cases can materially affect utility cost performance. For example, the multifactor productivity (MFP) growth of the electric, gas and sanitary sector of the U.S. economy was materially slower than that of the economy as a whole from 1974 to 1985, when rate cases were frequent due in part to adverse business conditions, than in the early postwar period, when favorable business conditions encouraged less frequent rate cases. We also found that the MFP growth of utilities that operated for many years without rate cases, due to MRPs or other circumstances, was significantly more rapid than the full sample norm. Cumulative cost savings of 3 percent to 10 percent after 10 years appear achievable under MRPs.

Conclusions

The case studies and incentive power and productivity research presented in this report have important implications. First, utility performance and regulatory cost should be on the radar screen of U.S. regulators, consumer groups and utility managers. Our research shows that key business conditions facing utilities today are less favorable than in the decades before 1973 when COSR worked well and was becoming a tradition. Today's conditions encourage more frequent rate cases and more expansive cost trackers. MRPs can produce material improvements in utility performance which can slow growth in customer bills and bolster utility earnings.

Notwithstanding the potential benefits of MRPs, they are still not used in most American states. COSR is well established and there are many accomplished practitioners. It can be difficult to design MRPs that generate strong utility performance incentives without undue risk, and that share benefits of better performance fairly with customers. MRPs invite strategic behavior and controversies over plan design. Continuing innovation of COSR will occur, and this will slow diffusion of MRPs.

However, MRPs are also evolving and remedies to problems encountered in early plans have been developed. MRPs are well suited for addressing conditions expected in coming years, such as rising input price inflation and DER penetration and increased need for marketing flexibility. For these and other reasons, we foresee expanded use of MRPs in U.S. electric utility regulation in coming years.

Acknowledgments

The work described in this study was funded by the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability, Transmission Permitting and Technical Assistance Division, and the Office of Energy Efficiency and Renewable Energy, Solar Energy Technologies Office, under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231, DOE Grid Modernization Initiative Task 1.4.29 – Future Electric Utility Regulation.

We thank Larry Mansueti, Guohui Yuan and Elaine Ulrich (DOE) for their support of this work. For reviewing drafts of this report and providing comments, we thank Sonia Aggarwal (Energy Innovation), Peter Cappers (Berkeley Lab), Steven Corneli, Asa Hopkins (Synapse Energy Economics), Ronald Lehr, Larry Mansueti (DOE), Andy Satchwell (Berkeley Lab) and Jay Shepherd (Energy Law).

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Glossary of Terms

Attrition Relief Mechanism (ARM): An essential provision of multiyear rate plans that automatically adjusts allowed rates or revenues to address cost pressures without closely tracking the utility's own cost. Methods used to design ARMs include forecasts and indexation to quantifiable business conditions such as inflation and growth in the number of customers served.

Base Rates: The components of a utility's rates that address the costs of non-energy inputs such as labor, materials and capital. Base rates sometimes also include charges for costs of energy inputs like fuel and purchased power, but trackers usually adjust rates so these costs are recovered more exactly.

Capex: Capital expenditures

Cost Tracker: A mechanism providing expedited recovery of targeted costs. An account typically tracks costs that are eligible for recovery. These costs are then typically recovered via rate riders. Tracker treatment was traditionally limited to costs that are large, volatile and largely beyond the control of the utility. The scope of costs eligible for tracking has widened over time. In multiyear rate plans, trackers have been used for costs that are difficult for the ARM to address.

Earnings Sharing Mechanism (ESM): An ESM shares surplus or deficit earnings, or both, between utilities and customers, which result when the rate of return on equity deviates from its commission-approved target. ESMs often have dead bands in which earnings variances are not shared.

Efficiency Carryover Mechanism: A mechanism that allows for a share of lasting performance gains (or losses) to be kept by the utility for a set period of time when a multiyear rate plan expires.

Formula Rate Plan: An approach to ratemaking that uses cost of service formulas to cause a utility's revenue to track its own cost of service closely. This is sometimes accomplished with an earnings true-up mechanism that adjusts rates automatically to eliminate variances between a company's actual and target rate of return on equity. Review of the cost of service may be streamlined.

Lost Revenue Adjustment Mechanism (LRAM): A ratemaking mechanism that compensates utilities for base rate revenue lost from specific causes such as demand-side management programs and distributed generation. Requires estimates of load impacts.

Marketing/Pricing Flexibility: Flexibility afforded to utilities to fashion rates and other terms of service in selected markets. Marketing flexibility is typically accomplished via light-handed regulation of rates and services with certain attributes. Services often eligible for flexibility include optional tariffs for standard services, optional value-added (discretionary) services, and services to competitive markets. Price floors are often established to discourage predation and cross-subsidization.

Multiyear Rate Plan (MRP): A common approach to performance-based regulation that typically features a rate case moratorium for several years, an ARM, and performance incentive mechanisms for service quality.

Off-ramp Mechanism: An MRP option that permits reconsideration of a multiyear rate plan under prespecified conditions such as an extremely high or low rate of return on equity.

Performance-Based Regulation (PBR): An approach to regulation designed to strengthen utility performance incentives.

Performance Incentive Mechanism (PIM): A popular form of performance-based regulation that links utility revenue or earnings to performance in targeted areas. Most PIMs involve metrics, targets (sometimes called *outcomes*) and financial incentives (rewards and penalties). Service quality and demand-side management are common focuses.

Productivity: The efficiency with which a utility converts inputs to outputs, commonly measured by productivity indexes. Labor, operation and maintenance, capital and multifactor productivity are commonly measured. Industry productivity trends are often used in the design of ARMs.

Rate Base: A utility's total "used and useful" plant in service, at original cost, minus accumulated depreciation and deferred income taxes. Rate base includes "working capital" — cash the utility must have available to meet the current cost of operations given the lag between customers receiving electric service and when they pay their electric bills. Regulators may allow other adjustments.

Rate Rider: An explicit mechanism outlined on tariff sheets to allow a utility to receive supplemental revenue adjustments.

Revenue Decoupling Mechanism: A mechanism that periodically adjusts rates to ensure that actual revenue closely tracks allowed revenue. Decoupling can reduce or eliminate the "throughput incentive" that can cause utilities to resist demand-side management.

RIIO: The British approach to PBR. The acronym stands for Revenues = Incentives + Innovation + Outputs. RIIO involves MRPs that include relatively long rate case moratoria (e.g., eight years), a forecast-based ARM, and an extensive set of performance incentive mechanisms.

Statistical Benchmarking: The use of statistics on the operations of utilities to appraise utility performance. Methods commonly used in statistical cost benchmarking include unit cost and productivity indexes and econometric models.

X Factor (Productivity Factor): A term in a rate or revenue cap index that reflects the impact of productivity growth on cost growth. It may also incorporate stretch factors and adjustments for other considerations such as the inaccuracy of the inflation measure.

Z Factor: A term in a rate or revenue cap index that permits rate adjustments for the financial impact of miscellaneous events (e.g., severe storms) that are beyond the utility's control.

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1.0 Introduction

The electric utility industry has made significant contributions to the success of the U.S. economy over the years. Rates and service quality of electric utilities affect both household welfare and the competitiveness of business and industry. The large role played by many U.S. utilities in power generation magnifies their importance.

Utilities today must contain cost growth at a time when many need to modernize aging systems. Major changes are occurring in technologies, customer preferences, load growth, competitive challenges, and federal and state policies and regulations. Most electric utility facilities in the United States are investor-owned and subject to rate and service regulation by state public utility commissions. Regulatory systems under which these utilities operate affect their performance and ability to meet challenges.

Multiyear rate plans have some advantages over traditional rate regulation in today's business environment. This is a form of performance-based regulation (PBR) that suspends general rate cases for several years. Revenue growth between rate cases is to some degree predetermined and independent of a utility's own cost. Better utility performance can sometimes be achieved under MRPs while achieving lower regulatory costs.[2] Benefits can be shared between utilities and their customers. However, plans are complex and their adoption can involve sizable changes in the regulatory system. Designing plans that stimulate performance without undue risk and share benefits fairly can be challenging.

Berkeley Lab prepared a report on PBR in 1995, when it was just beginning.[3] The study appraised some approved PBR plans using an "incentive power index." Thoughtful commentary on PBR included prescient discussion of revenue decoupling, which is now widely used in utility regulation. In 2016, Berkeley Lab published a report comparing MRPs to another popular approach to PBR — targeted performance incentive mechanisms — in the context of growing levels of distributed energy resources.[4] The report focused on advantages and disadvantages from utility shareholders' and customers' perspectives.[5]

This report takes a closer look at MRPs for electric utilities:

- how and where they have been applied to electric utilities in the United States and other countries;
- key plan design and implementation issues;
- metrics used to evaluate and incentivize utility performance; and
- successes, failures and lessons learned.

The focus is on retail services, such as power supply, distribution and customer care, which are regulated by states.

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[2] The impact of PBR on the performance of cooperative and publicly owned utilities is not well understood. However, PBR provides ideas on how to streamline regulation of these utilities. Numerous publicly owned utilities in other countries have operated under PBR.
[3] Comnes et al. (1995).
[4] The report explained that energy efficiency, demand response, and distributed generation and storage can help contain costs of meeting America's energy needs, but can reduce utility earnings.
[5] Lowry and Woolf (2016).

While the authors of the 1995 Berkeley Lab study anticipated restructuring of retail U.S. power markets, vertically integrated electric utilities (VIEUs) still serve retail customers in many states. This report thus considers the situations of VIEUs as well as those of the utility distribution companies (UDCs) that serve regions with restructured retail power markets. The report also provides results from an incentive power model and research on trends in the productivity with which utilities provide their services.

Section 2 of this report provides an introduction to MRPs. Section 3 considers rationales for MRPs and their suitability for electric utilities today. Section 4 drills down into important issues in MRP design. Section 5 discusses results of our research on the incentive power of alternative regulatory systems. Section 6 presents several case studies, and Section 7 discusses lessons learned. Two appendices discuss some topics in greater detail.

2.0 Multiyear Rate Plans

2.1 The Basic Idea

PBR is an approach to utility regulation designed to encourage good performance using strong performance incentives. Multiyear rate plans are a common form of PBR around the world. Berkeley Lab's 2016 report discussed basic features of these plans.[6] General rate cases are typically held every four or five years. Between rate cases, an attrition relief mechanism (ARM) permits revenue (or rates) to grow in the face of cost pressures, without linking relief to a utility's *specific* costs.[7] Some costs may be addressed separately using cost trackers and associated rate riders.

Following is a generic formula for revenue escalation in a multiyear rate plan:

$$\textit{growth Revenue} = \textit{growth ARM} + Y + Z. \qquad [1]$$

The "Y factor" indicates the revenue adjustment for costs, such as fuel and purchased power expenses, which are chosen in advance for tracking treatment. The "Z factor" indicates the revenue adjustment for miscellaneous changes in cost which may occasionally be accorded tracker treatment. The Z factor may address cost changes due to miscellaneous factors outside utility control, such as government mandates (e.g., facility undergrounding requirements) and force majeure events such as severe storms.[8]

MRPs also typically feature performance metric systems. Some metrics provide the basis for targeted performance incentive mechanisms (PIMs) that aid measurement of performance in areas of special concern to customers and the public. Most commonly, PIMs are used to strengthen incentives for utilities to maintain or improve reliability and customer service quality. A broader range of metrics has recently been considered by regulators in several jurisdictions, including Great Britain and New York.[9]

Demand-side management (DSM) can lower the cost of meeting customer energy needs. MRPs often contain provisions that strengthen utility incentives to facilitate DSM. Utility expenditures on DSM programs are usually tracked.[10] Performance incentive mechanisms can reward utilities for successful DSM programs. Revenue decoupling is often added to sever short-term links between a utility's revenue and electricity sales.[11] This shifts the risk of fluctuations in system use to customers but reduces utility incentives to boost throughput between rate cases. Decoupling also reduces the risks of rate designs that encourage DSM and efficient customer-side distributed generation and storage.

Some MRPs feature earnings sharing mechanisms (ESMs) that share surplus or deficit earnings, or both, between utilities and their customers, which result when the rate of return on equity (ROE) deviates from its public utility commission-approved target.[12] Off-ramp mechanisms may permit review of a plan under prespecified outcomes such as extreme ROEs.

Some MRPs have marketing flexibility provisions. These typically involve light-handed regulation of optional rates and services. Utilities also may be permitted (or required) to gradually redesign rates for

[6] Lowry and Woolf (2016).
[7] To simplify the discussion, this report will provide illustrations only for revenue cap escalators.
[8] Z factors are discussed further in Appendix A2.
[9] Ofgem (2014) and New York Public Service Commission (2016a).
[10] Institute for Electric Innovation (2014).
[11] Lazar et al. (2016).
[12] Earnings sharing mechanisms are discussed further in Appendix A1.

standard services in fulfillment of commission-approved goals. Marketing flexibility is discussed further in Appendix A.

Plan review and termination provisions are also important in MRPs. Some plans provide for a midterm review of the MRP toward the end of the plan period. These reviews sometimes result in a plan extension without a general rate case. To bolster incentives to achieve lasting efficiency gains, the true-up of a utility's revenue requirement to its cost is sometimes limited if the plan ends with a rate case. For example, the utility may be permitted to keep a share of the difference between its cost and a cost benchmark. Provisions of the latter kind are sometimes called *efficiency carryover mechanisms.*

2.2 MRP Precedents

MRPs have been used in U.S. rate regulation since the 1980s. They were first used on a large scale for railroads and telecommunication carriers.[13] These companies faced significant competitive challenges that complicated regulation. MRPs streamlined regulation and afforded utilities more marketing flexibility and a chance to earn a superior return for superior performance. Some states still use MRPs to regulate services of telecommunication carriers in less competitive markets.[14] The Federal Energy Regulation Commission (FERC) uses MRPs to regulate oil pipelines.[15]

MRPs have been used in several states to regulate retail services of natural gas and electric utilities.[16] In addition to formal rate plans, several states established extended rate freezes for electric utilities during the transition to retail competition. Rate freezes also have been part of the ratemaking treatment for many mergers and acquisitions. Utilities have occasionally and for various other reasons managed to stay out of rate cases for periods exceeding a decade.

Figure 1 shows states that currently use MRPs to regulate retail services of U.S. electric and gas utilities. The figure shows that MRPs are more common for U.S. electric utilities than for gas distributors. Growth in the use of MRPs to regulate electric power distributors has been slowed by grid modernization challenges that complicate plan design. On the other hand, use of MRPs has recently spread to vertically integrated electric utilities in diverse states that include Arizona, Colorado, Georgia, Virginia and Washington. This reflects in part the slowdown and increased predictability of VIEU cost growth in an era when there is less need for large generation plant additions. Many states also have recently experimented with "mini" MRPs involving only two plan years.

Figure 2 shows that MRPs are widely used to regulate retail energy services of Canadian utilities. Overseas, MRPs are the norm in Australia, Ireland, New Zealand and the United Kingdom. Countries that use MRPs in continental Europe include Austria, Germany, Hungary, Lithuania, the Netherlands, Norway, Romania and Sweden. MRPs are also common in Latin America.

The impetus for adopting MRPs outside the United States has often come from policymakers rather than utilities. For example, provincial law in Quebec requires the Régie de l'Energie to use an approach to regulation which streamlines regulation, encourages continual performance gains and shares benefits

[13] A discussion of early railroad and telecommunication MRPs can be found in Lowry and Kaufmann (2002).
[14] See, for example, California Public Utilities Commission (2015a), and Vermont Public Service Board (2016).
[15] Federal Energy Regulatory Commission (2015).
[16] MRP precedents for gas and electric utilities have been monitored by the Edison Electric Institute in a series of surveys. The latest is Lowry et al. (2015).

fairly with customers.[17] The Régie recently ordered Hydro-Quebec to operate its power distributor services prospectively under an MRP that the company had opposed.[18]

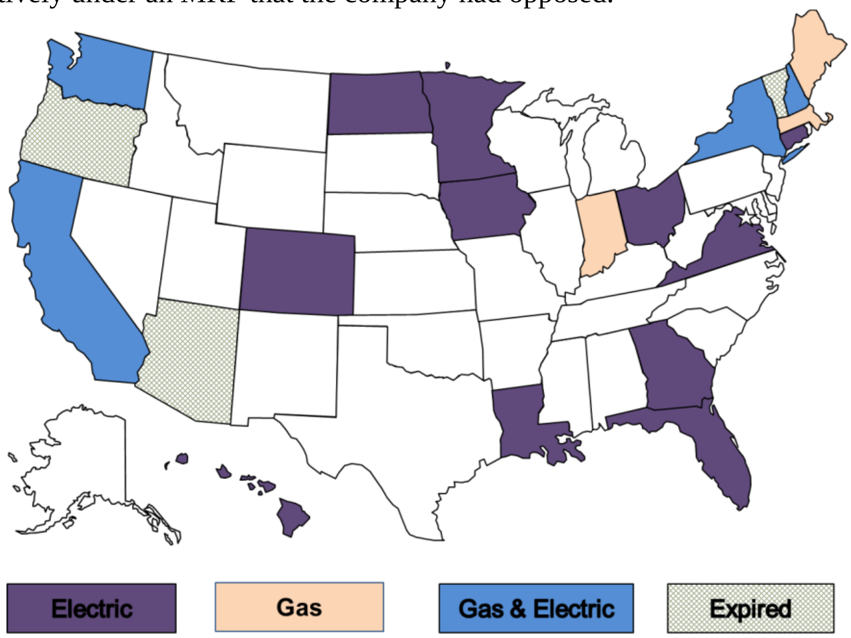

Figure 1. Multiyear Rate Plans in the United States. MRPs are used in many states today to regulate utilities.

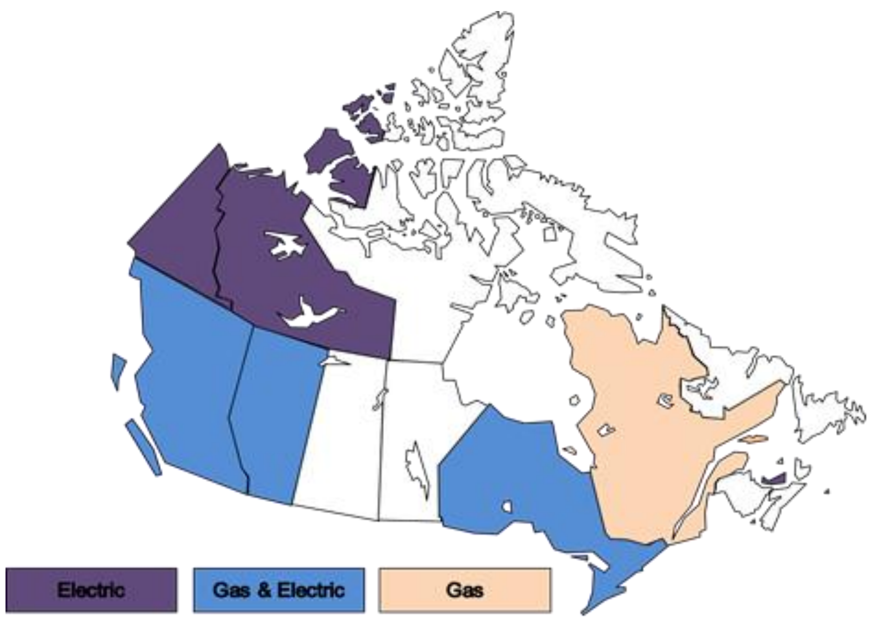

Figure 2. Multiyear Rate Plans in Canada. MRPs have in recent years been used to regulate energy utilities in the most populous Canadian provinces.

[17] Quebec National Assembly (2013, Chapter 16): An Act respecting mainly the implementation of certain provisions of the Budget Speech of 20 November 2012, Chapter 1, Division 1 as passed 14 June, 2013.
[18] Régie de l'Energie, D-2017-043, R-3897-2014 Phase 1, April 7, 2017.

3.0 Rationale for Considering MRPs

To explain rationales for considering MRPs we first consider basic features of traditional cost of service regulation (COSR) approaches which are widely used in the United States and then discuss reasons that some jurisdictions have adopted MRPs. We conclude with a discussion of circumstances under which PBR may make sense for some electric utilities under today's business conditions.

3.1 Traditional Cost of Service Regulation

Under COSR,[19] base rates that address costs of capital, labor and materials are reset periodically in rate cases to more effectively recover the utility's cost of service. Rate cases usually occur at irregular intervals and are typically initiated by utilities when the cost of their base rate inputs is growing faster than the corresponding revenue. Between rate cases, growth in base rate revenue depends chiefly on growth in billing determinants such as delivery volumes and numbers of customers served. Most base rate revenue is drawn from usage charges — e.g., charges per kilowatt-hour (kWh) or kilowatts (kW) of system use. The need for rate cases thus depends on a "horse race" between costs and system use.

In the short and medium terms, costs of base rate inputs are driven more by growth in system capacity (e.g., the capacity to serve peak load and to deliver to multiple locations) than by growth in system use. The number of customers served is highly correlated with peak load and an important cost driver in its own right. [20,21] A convenient proxy for the gap between the growth rates of system use and capacity is thus the growth in volume per customer (average use). Earnings are especially sensitive to trends in average use by residential and commercial customers.

Under legacy rate designs, growth in average use bolsters earnings and reduces the need for rate cases, while a decline has the reverse effect. Rate case frequency also depends on input price inflation and the balance between the declining value of older assets due to depreciation and capital expenditures to replace aging infrastructure.

The regulatory cost of COSR is high (for utilities, public utility commissions and stakeholders) when rate cases are frequent or unusually difficult. Rate cases are frequent to the extent that the jurisdiction regulates numerous utilities or the operating conditions facing utilities are continuously unfavorable. Individual rate cases are more difficult to the extent that utilities are large and rate cases involve complex issues.

Regulators understandably take measures to contain regulation's costs. Some of these measures may have adverse consequences. For example, expanded use of cost trackers and a reduced scope for prudence reviews weaken utility incentives to cut costs.[22] Because frequent rate cases and expansive cost trackers are more likely when business conditions are unfavorable, utility performance under traditional regulation tends to deteriorate just when better performance is most needed to keep customer bills reasonable.

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[19] Bonbright et al. (1988) is an authoritative treatise on COSR. Lowry and Woolf (2016) provides a more extensive discussion of COSR than provided here, emphasizing incentive problems.
[20] This is because the total number of customers is dominated by the number of residential and small commercial customers, and these customers tend to have more peaked loads.
[21] DSM programs can alter this relationship but to date have had more effect on delivery volumes than they have on the peak demand that drives capacity growth.
[22] Cost trackers have the merit of reducing the need for general rate cases.

Regulatory Lag

Regulatory economists acknowledge the incentive problems with traditional regulation that arise when rate cases are frequent or cost trackers are expansive. In the literature, "regulatory lag" is commonly defined as the time period between the moment when a utility's cost changes and the moment when there is a commensurate change in its rates.[23] James Bonbright, for example, states in a classic treatise that:

> There is the so-called "regulatory lag" — the quite usual delay between the time when reported rates of profit are above or below standard and the time when an offsetting rate decrease or rate increase may be put into effect by commission order or otherwise.[24]

The ability of regulatory lag to strengthen a utility's incentive to contain costs has been discussed in the literature. For example, Bonbright states that:

> Quite aside from the recognized undesirability of too frequent rate revisions, commissions recognize the regulatory lag as a practical means of reducing the tendency of a fixed-profit standard to discourage efficient management.[25]

Another noted regulatory economist, Alfred Kahn, suggested that:

> Public utility commissions ought not to even *try* continuously and instantaneously to adjust rate levels in such a way as to hold companies continually to some fixed rate of return; and they probably ought not to try either to hold the rate of return down to the bare cost of capital. The *regulatory lag* — the inevitable delay that regulation imposes in the downward adjustment of rate levels that produce excessive rates of return and in the upward adjustments ordinarily called for if profits are too low — is thus to be regarded not as a deplorable imperfection of regulation but as a positive advantage. Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their opposites: companies can for a time keep the higher profits they reap from a superior performance and have to suffer the losses from a poor one.[26] [emphasis in original]

Under traditional regulation, regulatory lag also delays when rates are changed in response to increasing *external* cost pressures such as input price inflation. For this reason, utility executives and consumer advocates have both emphasized regulatory lag in their rate case evidence despite goals that are often in opposition.

[23] Alternative definitions of "regulatory lag" have been used. One is the period of time between the filing of a request for a rate increase and the increase in rates.
[24] Bonbright et al. (1988).
[25] Ibid., p. 198.
[26] Kahn (1988), p. 48 II.

The Utility Productivity Slowdown of 1973–1986

The productivity growth of a utility is the difference between growth in its operating scale and growth in quantities of inputs that it uses. It is typically measured using an index. Productivity growth reflects changes in diverse business conditions that affect cost, including technological change and realization of scale economies. A multifactor productivity (MFP) index typically considers productivity in use of capital, labor and materials. Appendix B.2 discusses productivity more extensively.

One way to gauge the importance of regulatory lag is to compare utility productivity growth in years when business conditions for utilities were favorable to the growth in years when conditions were unfavorable. Since rate cases tend to be more frequent and cost trackers more expansive when business conditions are unfavorable, productivity growth should be slower. The federal government calculated an index of the MFP of the electric, gas and sanitary sector of the U.S. economy over the 50-year period from 1948 to 1998.[27] We can consider the growth rate of this index during periods of favorable and unfavorable business conditions.

Table 1 presents evidence on two of the most important sources of potential financial attrition for electric and natural gas utilities:

- Trends in the average use of energy by residential and commercial customers
- Price inflation, measured here by the gross domestic product price index (GDPPI)[28]

Average use directly affected MFP growth as measured by the government, but inflation did not.

We constructed summary indicators of potential attrition facing gas and electric utilities. The indicator in each case is the difference between inflation and the average of the growth in average use of energy (gas or electricity) by residential and commercial customers. We report trends over several subperiods between 1927 and 2014.

Results for electric utilities, where data are available for more years, show that these business conditions were quite favorable on balance from the late 1920s until the early 1970s. Except in the 1940s, inflation was generally slow until the late 1960s.[29] Average use of electricity grew rapidly.

These business conditions grew dramatically more adverse for electric utilities in the 1970s and remained so well into the 1980s. Spurred by two oil price shocks, general price inflation was much higher in these years. Inflation in prices of energy commodities such as coal and gas was especially rapid. Combined with slower economic growth, this caused growth in the average use of power by residential and commercial electric customers to slow markedly.

Rate cases were much more frequent.[30] Table 2 reproduces some results of a survey of electric utility rate cases from 1948 through 1977.[31] The table shows that the number of rate cases increased markedly after the mid-1960s and rarely featured a request for rate decreases.

[27] Computation of this index ended in 1998. For a discussion of this research, see Glaser (1993), pp. 34–49.
[28] The GDPPI is the federal government's featured index of inflation in the prices of the economy's final goods and services. It is calculated by the Bureau of Economic Analysis of the U.S. Department of Commerce.
[29] Rapid inflation during the Korean War was offset by slower inflation in later years of the 1950s.
[30] See Joskow and MacAvoy (1975).
[31] Braeutigam and Quirk (1984), p. 47.

Table 1. Indicators of Energy Utility Financial Attrition in the United States (1927–2014)

	Average Annual Electricity Use					Average Annual Natural Gas Use					GDPPI Inflation[4]		Summary Attrition Indicators	
	Residential[1]		Commercial[1]		Average	Residential[2]		Commercial[3]		Average				
Multiyear Averages	Level	Growth Rate	Level	Growth Rate	Growth Rate [A]	Level	Growth Rate	Level	Growth Rate	Growth Rate [B]	Level	Growth Rate [C]	Electric [C]-[A]	Natural Gas [C]-[B]
1927-1930	478	7.06%	3,659	6.67%	6.86%	NA	NA	NA	NA	NA	9.71	-3.92% [5]	-10.79%	NA
1931-1940	723	5.45%	4,048	2.00%	3.73%	NA	NA	NA	NA	NA	7.99	-1.59%	-5.31%	NA
1941-1950	1,304	6.48%	6,485	5.08%	5.78%	NA	NA	NA	NA	NA	11.37	5.26%	-0.52%	NA
1951-1960	2,836	7.53%	12,062	6.29%	6.91%	NA	NA	NA	NA	NA	16.04	2.42%	-4.49%	NA
1961-1972	5,603	5.79%	31,230	8.79%	7.29%	125	1.78% [6]	726	3.97% [6]	2.88% [6]	20.35	2.98%	-4.32%	0.10% [7]
1973-1980[8]	8,394	2.03%	50,576	2.53%	2.28%	117	-2.22%	764	-0.63%	-1.42%	34.74	7.18%	4.90%	8.61%
1981-1986[8]	8,820	0.12%	54,144	0.81%	0.46%	98	-2.67%	651	-3.84%	-3.26%	54.22	4.57%	4.11%	7.82%
1987-1990	9,424	1.39%	60,211	2.29%	1.84%	93	-1.25%	631	1.33%	0.04%	63.32	3.33%	1.49%	3.29%
1991-2000	10,061	1.15%	67,006	1.68%	1.41%	88	-0.37%	639	0.30%	-0.04%	75.70	2.03%	0.62%	2.07%
2001-2007	10,941	0.73%	74,224	0.64%	0.68%	77	-2.12%	594	-1.55%	-1.83%	89.83	2.47%	1.79%	4.30%
2008-2014	11,059	-0.38%	75,311	-0.22%	-0.30%	72	0.58%	597	1.75%	1.17%	103.53	1.60%	1.90%	0.43%

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

[2] Energy Information Administration, Historical Natural Gas Annual 1930 Through 1999 (Table 38. Average Consumption and Annual Cost of Natural Gas per Consumer by State, 1967-1989) (1967-1986); Energy Information Administration series N3010US2, "U.S. Natural Gas Residential Consumption (MMcf)" and Energy Information Administration series NA1501_NUS_8, "U.S. Natural Gas Number of Residential Consumers (Count)" (1987-2014).

[3] Includes vehicle fuel. Sources: Energy Information Administration series NA1531_NUS_10, "U.S. Natural Gas Average Annual Consumption per Commercial Consumer (Mcf)" (1967-1986); Energy Information Administration series N3020US2, "Natural Gas Deliveries to Commercial Consumers (Including Vehicle Fuel through 1996) in the U.S. (MMcf)" (1987-2014), Energy Information Administration series N3025US2, "U.S. Natural Gas Vehicle Fuel Consumption (MMcf)" (1997-2014), Energy Information Administration series NA1531_NUS_8, "U.S. Natural Gas Number of Commercial Consumers (Count)" (1987-2014).

[4] Bureau of Economic Analysis, Table 1.4.4. Price Indexes for Gross Domestic Product, Gross Domestic Purchases, and Final Sales to Domestic Purchasers, Revised October 28, 2016.

[5] Growth rate is for 1930 only. Levels are for 1929 and 1930. Data are not available before 1929.

[6] Levels are for 1967-1972 and growth rates are for 1968-1972. Data are not available before 1967.

[7] Note that the growth rates used to compute this value cover different periods.

[8] Shaded years had unusually unfavorable business conditions.

Table 2. U.S. Electric Utility Rate Cases: 1948–1977[32]

Period	Number of Rate Cases	Company Initiated Rate Cases			PUC Initiated Rate Cases
		Number	Rate Increases	Rate Decreases	
1948-1952	46	45	42	3	1
1953-1957	34	31	28	3	3
1958-1962	43	39	38	1	4
1963-1967	17	16	12	4	1
1968-1972	104	100	96	4	4
1973-1977	119	119	119	0	0

After 1986, inflation slowed to a pace more typical of the 1950s and 1960s. However, sluggish growth in average use continued. Thus, business conditions improved on balance, but were less favorable than those in the decades preceding the first oil price shock.[33]

Table 3 and Figure 3 show the trend in the federal government's index of the MFP of the electric, gas and sanitary sector of the U.S. economy over the 50 years from 1948 to 1998. The MFP growth of the sector was remarkably brisk until the early 1970s, averaging 3.9 percent annually compared to the 2.1 percent trend in the MFP of the entire private business sector of the economy.

[32] Most rate cases are initiated by utilities. However, state regulatory commissions may initiate general rate cases to investigate potential excessive utility earnings.
[33] Average use data for a comparably long period were not found for natural gas distributors. However, average use of natural gas fell briskly during the 1973 to 1986 period, whereas it had risen briskly from 1968 to 1972. Inflation and average use trends were thus extremely unfavorable for gas distributors from 1973 to 1986. While inflation slowed after 1986, declining average use continued so that, on balance, business conditions improved for gas distributors but were less favorable than in the 1960s.

Table 3. Multifactor Productivity Growth of Electric, Gas, and Sanitary Utilities and the U.S. Private Business Sector: 1949–1998

	Electric, Gas, and Sanitary Utilities[1]		U.S. Private Business Sector[2]		MFP Growth Differential
	Level	Growth Rate	Level	Growth Rate	
Year		[A]		[B]	[A - B]
1948	34.67		50.34		
1949	35.23	1.60%	50.93	1.16%	0.45%
1950	37.85	7.16%	54.63	7.03%	0.14%
1951	41.50	9.19%	55.90	2.29%	6.90%
1952	43.27	4.19%	56.39	0.87%	3.32%
1953	44.95	3.81%	57.66	2.22%	1.59%
1954	46.73	3.87%	57.76	0.17%	3.71%
1955	50.37	7.51%	60.49	4.62%	2.89%
1956	52.90	4.89%	60.20	-0.49%	5.37%
1957	54.86	3.64%	61.07	1.45%	2.19%
1958	56.36	2.69%	61.37	0.48%	2.21%
1959	59.91	6.11%	63.51	3.44%	2.67%
1960	61.68	2.92%	63.90	0.61%	2.31%
1961	63.18	2.40%	65.27	2.11%	0.28%
1962	66.26	4.77%	67.61	3.52%	1.24%
1963	67.57	1.96%	69.66	2.99%	-1.03%
1964	71.12	5.12%	72.39	3.85%	1.28%
1965	74.02	3.99%	74.73	3.18%	0.81%
1966	77.01	3.96%	76.98	2.96%	1.00%
1967	79.44	3.11%	77.07	0.13%	2.98%
1968	82.99	4.37%	79.12	2.62%	1.75%
1969	85.23	2.67%	78.63	-0.62%	3.29%
1970	86.64	1.63%	78.54	-0.12%	1.76%
1971	87.66	1.18%	80.98	3.06%	-1.88%
1972	89.16	1.69%	83.41	2.97%	-1.28%
1973	90.84	1.87%	85.66	2.65%	-0.79%
1974	87.85	-3.35%	82.54	-3.71%	0.37%
1975	88.04	0.21%	83.32	0.94%	-0.73%
1976	89.16	1.27%	86.44	3.68%	-2.41%
1977	88.97	-0.21%	87.80	1.57%	-1.78%
1978	88.88	-0.11%	88.98	1.32%	-1.43%
1979	87.85	-1.16%	88.59	-0.44%	-0.72%
1980	87.38	-0.53%	86.63	-2.23%	1.69%
1981	87.38	0.00%	86.73	0.11%	-0.11%
1982	86.54	-0.97%	84.10	-3.08%	2.12%
1983	85.42	-1.30%	86.44	2.75%	-4.05%
1984	88.32	3.34%	89.27	3.22%	0.11%
1985	88.22	-0.11%	90.15	0.98%	-1.08%
1986	88.50	0.32%	91.61	1.61%	-1.29%
1987	88.60	0.11%	91.90	0.32%	-0.21%
1988	92.06	3.83%	92.49	0.63%	3.19%
1989	92.43	0.41%	92.98	0.53%	-0.12%
1990	93.83	1.51%	93.17	0.21%	1.30%
1991	93.64	-0.20%	92.20	-1.05%	0.85%
1992	93.46	-0.20%	94.34	2.30%	-2.50%
1993	95.89	2.57%	94.73	0.41%	2.15%
1994	96.45	0.58%	95.80	1.13%	-0.54%
1995	98.69	2.30%	96.00	0.20%	2.10%
1996	99.91	1.22%	97.56	1.61%	-0.39%
1997	99.91	0.00%	98.73	1.19%	-1.19%
1998	100.00	0.09%	100.00	1.28%	-1.18%
Annual Averages					
1949-1972		3.94%		2.10%	1.83%
1973-1986		-0.05%		0.67%	-0.72%
1987-1998		1.02%		0.73%	0.29%

[1] Bureau of Labor Statistics, Multifactor Productivity, Electric, Gas and Sanitary Utilities (SIC 49).

[2] Bureau of Labor Statistics, Multifactor Productivity, Private Business Sector.

Note: Shaded years had unusually unfavorable business conditions.

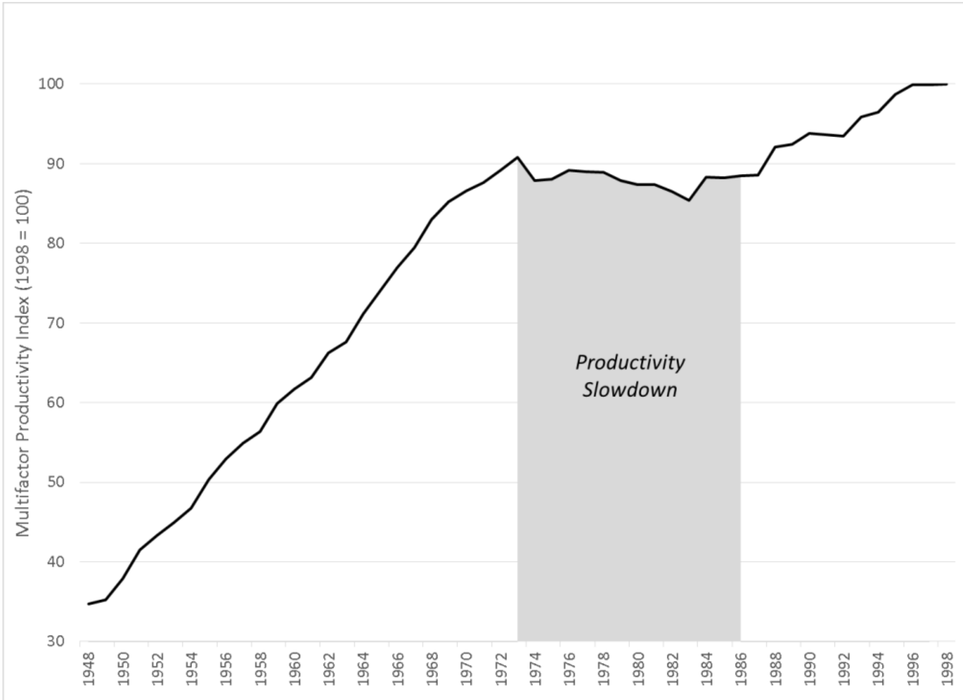

Figure 3. Multifactor Productivity Trend of U.S. Electric, Gas and Sanitary Utilities (1948–1998). MFP growth of U.S. utilities slowed during the period 1973 to 1986 under unfavorable business conditions.

The MFP growth of electric, gas and sanitary utilities fell to zero on average during the following years of markedly unfavorable business conditions, when rate cases were much more frequent. Both capital and labor productivity growth of this utility sector slowed markedly. MFP

growth of the U.S. private business sector exceeded that of electric, gas and sanitary utilities by around 72 basis points annually on average during these years.[34]

The generation sector of the utility industry was a notable problem area during this period. Overbuilding generation capacity and cost overruns and delays on generation plant additions were widespread. Resultant overcapacity boosted sales in wholesale markets and widened the gap between wholesale and retail power prices. This gap was one of the factors that ultimately led to restructuring of retail power markets in many states.

MFP growth of utilities resumed at a slower 1.02 percent average annual pace from 1987 to 1998, a period during which the frequency of rate cases slowed. Utility MFP trends exceeded private business sector MFP trends by a modest 29 basis points on average.

The MRP Alternative

Advantages

A core advantage of MRPs is their potential to strengthen cost containment incentives.[35] The attrition relief mechanism can provide timely, predictable rate escalation that permits an extension of the period

[34] A basis point is one-hundredth of 1 percent.
[35] For further discussions of the rationale for MRPs see Lowry and Kaufmann (2002), Lowry and Woolf (2016), Comnes et al. (1995), and Kaufmann and Lowry (1995).

between rate cases. Escalation is based on cost forecasts, industry cost trends or both, rather than the utility's *specific* costs. Regulatory lag is thus achieved without sacrificing the timeliness of rate relief, increasing opportunities for a utility to bolster earnings from efforts to contain costs addressed by the ARM (i.e., costs that are not tracked). A well-designed efficiency carryover mechanism can magnify the incentive "power" of the MRP.[36] Loosening the link between a utility's cost and its revenue gives it an operating environment more like that which producers in competitive markets experience.

MRPs can also encourage more operating flexibility in areas where the need for flexibility is recognized. Reduced rate case frequency means that the prudence of management strategies must be considered less frequently. Utilities are more at risk from bad outcomes (e.g., needlessly high capex) and can gain more from good outcomes (e.g., low capex). This potential advantage of MRPs in facilitating operating flexibility has been most thoroughly developed in the area of marketing flexibility (see Appendix A for further discussion).

PIMs play a special role in multiyear rate plans. The plans can strengthen incentives to contain costs.[37] These include costs incurred to maintain or improve service quality and worker safety. In competitive markets, a producer's revenue can fall abruptly if the quality of its offerings falls. PIMs can keep utilities on the right path by strengthening their incentives to maintain or improve service quality and safety.[38]

Advantages of MRPs in encouraging utilities to consider cost-effective DSM and other distributed energy resources (DERs) are not widely recognized. MRPs can strengthen incentives to use DERs to contain load-related costs that are reflected in retail rates. The combination of an MRP, revenue decoupling, PIMs to encourage efficient DSM, and the tracking of DER-related costs can provide four "legs" for the DER "stool."[39] MRPs can reduce the need for complicated measurement of load and cost savings from DERs.

With stronger performance incentives and greater operating flexibility, MRPs can encourage better utility performance. Benefits of better performance can be shared with customers via earnings sharing mechanisms, plan termination provisions and careful ARM design. Customers can also benefit from more market-responsive rates and services. The strengthened performance incentives and reduced preoccupation with rate cases which MRPs provide can create a more performance-oriented corporate culture at utilities. This may increase the likelihood of success in mergers, acquisitions and unregulated market ventures in which utility companies engage.

MRPs also can increase the efficiency of regulation. Rate cases can be less frequent and better planned and executed. MRPs also facilitate scheduling rate cases so that proceedings overlap less. Streamlining ratemaking processes can reduce cost burdens on ratepayers and free up resources in the regulatory community to more effectively address other important issues, such as rules of prospective application. Senior utility managers have more time to attend to their basic business of providing quality service cost-effectively. Streamlined regulation has special appeal in situations where costs of regulation are especially high due to numerous utilities, large utilities or especially difficult regulatory issues. It is not surprising, then, that several commissions with unusually large regulatory burdens (e.g., Ontario and Germany) have been MRP leaders.

[36] See Sections 4 and 5 and Appendix A1 for further discussion of efficiency carryover mechanisms.
[37] See, for example, Comnes et al. (1995).
[38] Alberta Utilities Commission (2012), p. 186.
[39] A three-legged stool for DSM consisting of revenue decoupling, performance incentive mechanisms, and DSM cost trackers is discussed in York and Kushler (2011).

Disadvantages

MRPs are complex regulatory systems. The transition to these plans can be challenging in some jurisdictions. As we discuss at some length in Section 4, it can be difficult to design plans that incentivize better performance without undue risk and share benefits fairly between utilities and their customers. Controversies can arise in plan design, as they do in COSR. Poorly designed plans can create opportunities for strategic behavior that reduces plan benefits for customers. For these and other reasons, most American jurisdictions have not yet adopted MRPs for gas and electric utilities. The concluding section of this report provides a more extensive discussion of reasons for the continued popularity of COSR.

3.2 How MRPs Can Help Address Contemporary Challenges

Benefits of MRPs tend to be greatest where traditional regulation is especially disadvantageous. These include situations where rate cases are especially frequent, a large number of utilities are regulated, marketing flexibility is especially desirable, and regulators have numerous other issues to attend to. We discuss here the extent to which these conditions are present today.

Need for Rate Cases and Expansive Cost Trackers

Table 1 shows that key business conditions that cause utility attrition are considerably less favorable today on balance than they were in the decades before 1973. Since the start of the Great Recession, sluggish economic growth and energy efficiency gains have caused unusually slow growth in average use of electricity by residential and commercial customers.[40] The financial stress on utilities of this development has been partly offset to date by unusually slow input price inflation.[41] However, inflation may be higher in the future due, for example, to rising bond yields. Increased penetration of DERs could further slow growth in average use.

The need for frequent rate cases varies among electric utilities. Variation in capex requirements is a major reason. In a period of sustained high capex, utilities need brisk escalation in rates, especially when the capex does not automatically produce new revenue. Some utilities need high capex today to replace aging distribution assets. This kind of capex does not, like distribution system extensions, typically produce new revenue without a rate case or cost tracker. Technological change has created opportunities for “smart grid” capex that improves utility performance but may not trigger much new revenue.[42]

Distribution capex induces less growth in the total cost of a VIEU than it does in the cost of a UDC. Furthermore, slow demand growth and interest by some state regulatory commissions for VIEUs to rely on power purchase agreements rather than build and own more power plants is reducing the need for new VIEU generation capacity. On the other hand, some VIEUs are refurbishing or replacing old power plants.

[40] Demand growth in some states has also been affected by distributed generation and deindustrialization.
[41] Reduction in utility revenue due to declines in average electricity use can, in any event, be addressed by targeted remedies such as revenue decoupling.
[42] Some of these expenditures do, however, produce offsetting operation and maintenance cost savings.

Technological Change

Technological change is creating new ways to meet the energy needs of customers. Well-designed MRPs can, by strengthening performance incentives and increasing operating flexibility, drive utilities to embrace these technologies where they are cost effective. However, when new technologies involve sizable up-front capex with little automatic revenue growth they can complicate MRP design.

Number of Utilities

The number of utilities that a state public utility commission regulates rarely grows, but sometimes falls due to mergers and acquisitions. Several states (e.g., California, New York, Pennsylvania and Texas) still regulate five or more electric utilities, and states must typically also regulate natural gas, telecommunications and water utilities.[43] Mergers and acquisitions have caused the number of utilities owned by some companies to rise over the years. Multi-utility companies have more incentive to adopt MRPs and other economical approaches to regulation.[44]

Marketing Flexibility

Marketing flexibility is increasingly useful to utilities in order to fashion time-sensitive rates, green power services, and miscellaneous new services enabled by new technologies. VIEUs may have greater need for marketing flexibility than UDCs. One reason is that the large-load customers whose demand has traditionally been most sensitive to the terms of service make a much larger contribution to a VIEU's base rate revenue. Another reason is that VIEUs may benefit more from renewable energy and electric vehicle options than UDCs since VIEUs may provide the power from company-owned generation. In addition, time-sensitive pricing can contain generation costs as well as transmission and distribution capacity needs.

Instability Concerns

We noted above that traditional regulation provides weaker incentives for cost management when business conditions are especially adverse. This idiosyncrasy of traditional regulation raises questions about its ability to cope with increased penetration of customer-side distributed generation and storage. Penetration slows growth in average electricity use. To the extent that this leads to more frequent rate cases and more expansive cost trackers, utility performance deteriorates. Utilities may, for example, choose such a time for high replacement capex. The end result can be higher rates that further discourage use of grid services.[45] This is a source of potential instability in the utility industry. The contrast to competitive markets is striking. In a period of weak demand, prices fall in competitive markets and firms scramble to cut their costs.

[43] In contrast, regulation outside the United States is often conducted at the national level.

[44] Minneapolis-based Xcel Energy is an example of a multi-utility company that has publicly embraced MRPs. See Xcel Energy's "Strategic Plan for Growth," May 2015, http://investors.xcelenergy.com/Cache/1500071832.PDF?O=PDF&T=&Y=&D=&FID=1500071832&iid=4025308, and Xcel Energy's SEC Schedule 14A filed April 2015, http://investors.xcelenergy.com/Cache/28758163.PDF?O=PDF&T=&Y=&D=&FID=28758163&iid=4025308.

[45] For further discussion of the potential for a utility "death spiral," see Graffy and Kihm (2014).

Competing Needs for Regulatory Resources

Regulatory resources that are currently devoted to rate cases have many alternative uses in this era of rapid change. Among the areas where thoughtful review is currently needed are rate design, distribution system planning, and the terms of compensation for customer-side DER services.

Difficulty of MRP Implementation

The difficulty of implementing MRPs changes over time and varies considerably among utilities. One key challenge is the identification of a reasonable ARM. Implementation of index-based ARMs has traditionally been easier for UDCs than for vertically integrated utilities. The cost of UDC base rate inputs tends to grow gradually and predictably as the economies UDCs serve gradually expand. In contrast, VIEUs have in the past had “stair step” cost trajectories with large rate increases when large power plants came into service alternating with periods of slow cost growth as new units depreciated. Another complication for VIEUs was that the exact timing of major plant additions was often uncertain, due in part to construction delays.

However, many UDCs have in recent years proposed accelerated grid modernization programs involving several years of high capex. The need for these programs is often difficult for regulators to judge in an era of rapid technological change and shifting demand. VIEUs, meanwhile, are experiencing *more gradual* cost growth because fewer generation capacity additions are needed and capacity that is built tends to be more modular natural gas-fired or wind-powered units. Depreciation of older generation plant meanwhile slows rate base growth.[46] Figures 4 and 5 illustrate the changing needs for rate escalation for UDCs and VIEUs.

Consider also that jurisdictions vary in their regulatory traditions and human capital (the experience and the expertise of regulatory practitioners). Generally speaking, adoption of MRPs is easier for jurisdictions that have experience with the use of forward test years in rate cases. Accumulation of experience with MRPs in the United States and improvements in MRP design will facilitate broader implementation.

Conclusions

Our analysis suggests that unusually slow inflation since the Great Recession of 2008 has thus far offset declining residential and commercial average use to contain the need for electric utilities to file frequent rate cases. However, these business conditions are still less favorable on balance than they were before 1972 when COSR worked well and became a tradition. Resumption of normal inflation and accelerated penetration of customer-side DERs may well occur and would spark more interest in MRPs. MRPs can also address the need for marketing flexibility.

Whereas the need for multiyear rate plans may be greater for UDCs with high capex, the ease of implementing these plans is often greater for VIEUs today. VIEUs also may have stronger interest in marketing flexibility. This helps to explain why use of MRPs is growing most rapidly in the United States for VIEUs.

[46] However, some utilities are building new, cleaner generating facilities (including emissions control equipment) or modernizing older generation plants. Aging generating capacity (especially nuclear capacity) can have rising operating costs.

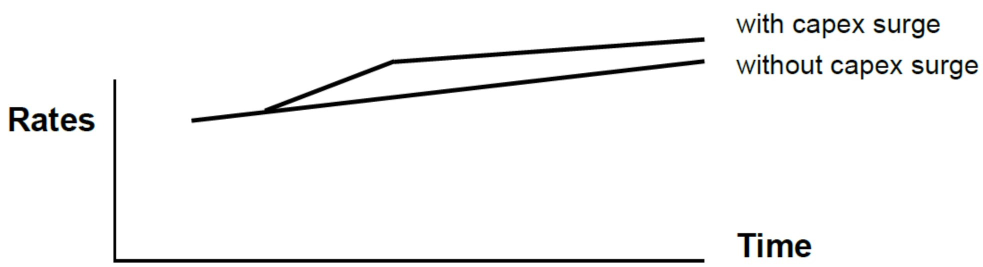

Figure 4. Rate Escalation Requirements for UDCs. Capex surges can accelerate the normally gradual escalation of UDC rates.

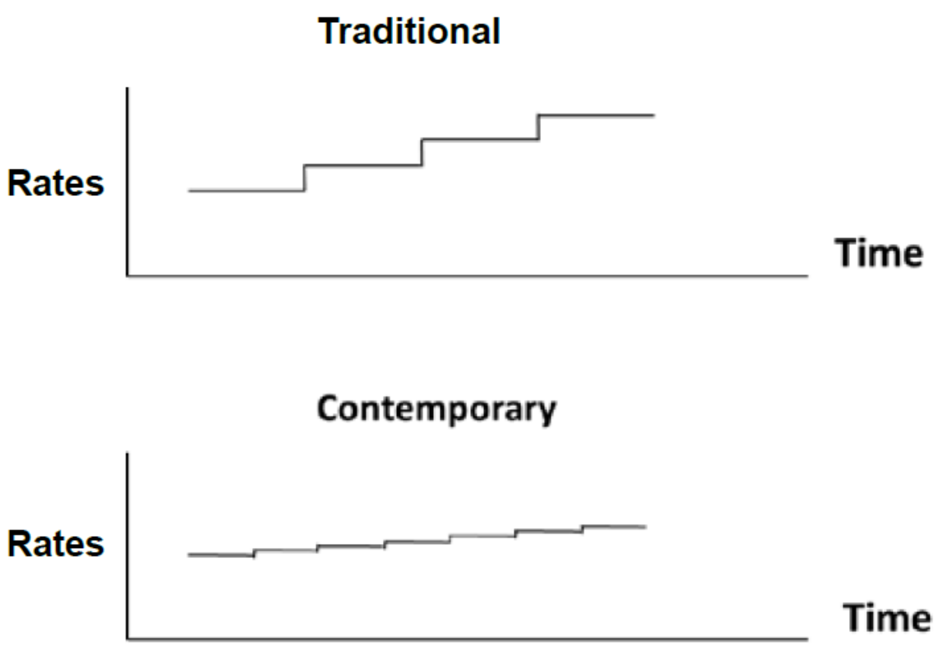

Figure 5. Rate Escalation Requirements for VIEUs. Rate escalation requirements of VIEUs are becoming more gradual.

Growing familiarity with best practices in the design of plans for UDCs may encourage greater use in this utility sector. Use of MRPs for UDCs may also increase as they complete accelerated grid modernization programs that complicate plan design and return to gradual cost growth. Companies and commissions with unusually large regulatory burdens gain special advantages from streamlined regulation. Some of these companies and commissions are likely to be MRP leaders.

4.0 MRP Design Issues

This section takes a deeper look at important issues in MRP design. We first consider how attrition relief mechanisms (ARMs) can cap rate and revenue growth and then discuss major approaches to ARM design. Following are discussions of cost trackers, decoupling, performance metric systems and efficiency carryover mechanisms.

4.1 Attrition Relief Mechanisms

Rate Caps vs. Revenue Caps

ARMs can escalate allowed rates or revenue. Limits on rate growth are sometimes called *price caps.*[47] In price cap plans, allowed rate escalation is often applied separately to multiple service "baskets." For example, there might be separate baskets for small-load (e.g., residential and general service) and large-load customers. The utility can typically raise rates for services in each basket by a common percentage that is determined by the ARM, cost trackers and any earnings sharing adjustments.[48] Customers in each basket are insulated from the discounts and demand shifts going on with services in other baskets, except as these developments influence shared earnings or cost trackers.

Price caps have been widely used to regulate utilities, such as telecommunications carriers, which are encouraged to promote use of their systems. In the electric utility industry, legacy rate designs feature usage charges that are well above the utility's short-run marginal cost of service provision.[49] With less frequent rate cases, price caps can therefore make utility earnings more sensitive to the kWh and kW of system use, strengthening utility incentives to encourage greater use.

Under revenue caps, the focus is on limiting growth in allowed revenue (the revenue requirement).[50] Services may still be grouped in baskets. Revenue caps are often paired with a revenue decoupling mechanism that relaxes the link between revenue and system use.

Methods for ARM Escalation

Several well-established approaches to ARM design can, with sensible modifications, be used to escalate rate or revenue caps. We use revenue cap examples in the following discussion.

<u>Indexing</u>

An indexed ARM is developed using index and other statistical research on utility cost trends. For example, a revenue cap index for a power distributor might take the following form:

$$growth\ Revenue = Inflation - X + growth\ Customers + Y + Z \qquad [2]$$

The inflation measure in such a formula is often a macroeconomic price index such as the Gross Domestic Product Price Index. However, custom indexes of utility input price inflation are sometimes

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[47] A notable early discussion of price caps for electric utilities is Lowry and Kaufmann (1994).
[48] In some plans, slower growth in rates for some services in a basket can, within limits, permit more rapid rate growth for other services in the same basket.
[49] Marginal cost is the additional cost incurred to provide a small increment of service.
[50] The allowed revenue yielded by a revenue cap escalator must be converted into rates, requiring assumptions for billing determinants.

used in ARM design. X, the productivity or "X" factor, usually reflects the average historical trend in the multifactor productivity of a group of peer distributors. A stretch factor (sometimes called *consumer dividend*) is often added to X to guarantee customers a share of the benefit of the stronger performance incentives that are expected under the plan.

Index-based ARMs compensate utilities automatically for important external cost drivers such as inflation and customer growth. This provides timely rate relief that reduces attrition and operating risk without weakening performance incentives. Between rate cases, customers can be guaranteed benefits of productivity growth which equals (or, with a stretch factor exceeds) industry norms. Controversies over cost forecasts can be avoided.

On the other hand, index-based ARMs are typically based on long-run cost trends. They may therefore undercompensate utilities when capex is surging and overcompensate them on other occasions, such as the years following a surge. Capex surges can be addressed by cost trackers, but trackers involve their own complications, as we discuss further below. Design of indexed ARMs applicable to capital cost sometimes involve statistical cost research that is complex and sometimes controversial.[51] Consultants will seek entry to the field by advocating unusual values for X which serve the interests of their clients. However, base productivity trends chosen by North American regulators for X factor calibration have tended to lie in a fairly narrow range to date (e.g., zero to 1 percent).

Forecasts

A forecasted ARM is based on multiyear cost forecasts. An ARM based solely on forecasts increases revenue by predetermined percentages in each plan year (e.g., 4 percent in 2018, 5 percent in 2019 and 3 percent in 2020). The outcome is much like that of a rate case with multiple forward test years.

Familiar accounting methods can be used to forecast growth in capital cost. The trend in the cost of older capital is relatively straightforward to forecast since it depends chiefly on mechanistic depreciation.[52] The more controversial issue is the value of plant additions during the plan.

Shortcuts are sometimes taken in preparing forecasts for ARM design. For example, forecasted plant additions may be set for each plan year at the utility's average value in recent years [53] or at its value for the test year of the most recent rate case. Operation and maintenance (O&M) expenses are sometimes forecasted using index-based formulas similar to equation [2].

One important advantage of forecasted ARMs is their ability to be tailored to unusual cost trajectories. For example, a forecasted ARM can provide timely funding for an expected capex surge. Some forecasted ARMs make no adjustment to rates during the plan if the actual cost incurred differs from the forecast. This approach to ARM design can generate fairly strong cost containment incentives despite the use of company-specific forecasts.

On the downside, forecasted ARMs do not protect utilities from unforeseen changes in inflation and operating scale.[54] The biggest problem with forecasted ARMs, however, is that it can be difficult to establish just and reasonable multiyear cost forecasts. It is often difficult to ascertain the value to

[51] For example, productivity studies filed in proceedings to establish an MRP often use mathematically stylized representations of capital costs which differ from those used in traditional ratemaking. Witnesses have disagreed on the appropriate capital cost treatment and sample period for a productivity study.
[52] Note, however, that salvage value and decommissioning costs are sometimes controversial.
[53] The practice of basing a utility's plant addition budgets on its historical plant additions may weaken its capex containment incentives if used repeatedly.
[54] Operating scale risk can be reduced by forecasting unit costs (e.g., cost per customer) and then truing up for actual scale growth.

customers in a given cost forecast. Resources that the regulatory community may expend on benchmarking and engineering studies to develop competent independent views of needed utility cost growth can be sizable.

Hybrids

"Hybrid" approaches to ARM design use a mix of indexing and other escalation methodologies.[55] The most popular hybrid approach in the United States involves separate treatment of revenues (or rates) that compensate utilities for their O&M expenses and capital costs. Indexes address O&M expenses while forecasts address capital costs.

Indexation of O&M revenue provides protection from hyperinflationary episodes and limits the scope of forecasting evidence. Good data on O&M input price trends of electric (and gas) utilities are available in the United States. The forecast approach to capital costs, meanwhile, accommodates diverse capital cost trajectories. The complicated issue of designing index-based ARMs for capital revenue is sidestepped. On the other hand, capex forecasts are required and can be controversial.

Rate Freezes

Some MRPs feature a rate freeze in which the ARM provides no rate escalation during the plan. Revenue growth then depends entirely on growth in billing determinants and tracked costs. Freezes usually apply only to base rates but have occasionally applied to rates for energy procurement. An analogous concept for a plan with revenue decoupling is the revenue/
customer freeze, which permits revenue to grow at the (typically gradual) pace of customer growth.

4.2 Cost Trackers

Basic Idea

A cost tracker is a mechanism for expedited recovery of specific utility costs. Balancing accounts are typically used to track unrecovered costs that regulators deem prudent. Costs are then recovered by tariff sheet provisions called *riders.*

A cost tracker helps a utility's revenue track its own costs more closely. While this is contrary to the spirit of PBR — which focuses on strengthening incentives — it can make it easier for a utility to operate under an MRP, which has an ARM for other costs of base rate inputs. Where cost containment incentives generated by trackers are a concern, methods are available to address them. For example, tracked costs can be subject to especially intensive prudence review.[56] Tracker mechanisms can be incentivized, as we discuss further below.

Capital Cost Trackers

Capital cost trackers compensate utilities for annual costs (e.g., depreciation, return on asset value, and taxes) that capex (or plant additions) give rise to. Such trackers are sometimes used in MRPs to address capex surges that are difficult to address with an ARM. Capex surges are sometimes needed — for

[55] A "hybrid" designation can in principle be applied to a number of ARM design methods, including the design used in Great Britain. However, it would not apply to regulatory systems, such as those used in Vermont, which index O&M revenue but use cost of service regulation for capital cost.
[56] The reduction in rate cases that MRPs make possible frees up resources to review these costs.

example, when VIEUs make large additions to generating capacity, replace large components of existing generating plants, or add extensive emission control systems. VIEUs and UDCs alike may need high capex for rapid build-out of AMI or other smart grid technologies, to meet increased safety and reliability standards, and to replace facilities built in earlier periods of rapid system growth.

Forecasted and hybrid ARMs can address expected capex surges better than index-based ARMs. Thus, capital cost trackers are more commonly combined with index-based ARMs. However, MRPs with forecasted or hybrid ARMs sometimes permit utilities to request supplemental revenue for unforeseen capex, or for capex with uncertain completion dates.[57]

Ratemaking Treatments of Tracked Costs

Supplemental revenue that capital cost trackers produce is often based on capex forecasts. Treatment of variances from approved budgets then becomes an issue. Some capital cost trackers return all capex underspends to ratepayers promptly. As for overspends, some trackers permit conventional prudence review treatment. In other cases, no adjustments are subsequently made between rate cases if capex exceeds budgets. Mechanisms also have been approved in which deviations from budgeted amounts that are in prescribed ranges are shared formulaically (e.g., 50-50) between the utility and its customers.

Appraising the Need for Trackers

A key question in approvals of capital cost trackers is the need for tracking. This question involves two issues: the need for high capex and the need for tracking the capex. It can be challenging to ascertain the need for high capex. For example, trackers for energy distributors sometimes address costs of accelerated system modernization. The need for a particular plan of modernization can be more challenging to appraise than the need for other kinds of capex surges, such as those for new generation capacity or emissions control facilities.[58] Accelerated distribution modernization plans involve many decisions about emerging technology and consumer expectations, as well as timing and scale issues, and regulators in some jurisdictions may not have much expertise in evaluating them.

Determining the need for a capital cost tracker is complicated for a utility operating under an ARM that provides some compensation for capex. An indexed ARM, for example, escalates revenue associated with an older plant between rate cases even though the cost of that plant tends to decline due to depreciation. Furthermore, the X factor in the escalator reflects productivity growth by peer group utilities which has been slowed by capex.[59] If the utility is given dollar-for-dollar compensation for substandard productivity growth when normal kinds of capex surge, but the X factor in the revenue cap formula reflects only the industry productivity trend when capex does not surge, customers are not ensured the benefit of the industry productivity trend in the long run, even if it is achievable.

Ratemaking Treatment of Other Costs

Another issue that arises when considering a capital cost tracker is the ratemaking treatment of costs not included in the tracker. Separate recovery of certain capex costs means that the cost of residual capital —

[57] For example, trackers have been used in conjunction with hybrid or forecasted ARMs to address costs of new generating facilities, major generator refurbishments and AMI.

[58] Generation plant additions also require discretion, but regulators of VIEUs have years of experience considering both the need for new capacity and the types of generation technology. Many states require integrated resource planning or a certificate of public convenience and necessity, or both, before additions to generation capacity can proceed. In addition, there are often competitive alternatives to a utility's proposal to increase capacity. Proponents of these alternatives press their cases in these hearings.

[59] Capex often slows growth in multifactor productivity, even while accelerating O&M productivity.

consisting mainly of gradually depreciating older plant — tends to rise more slowly and predictably. If *all* capex cost flows through trackers, the residual capital cost is that of older plants and may *decline* due to depreciation. Additionally, productivity growth of electric O&M inputs may be brisk. For these reasons, expansive capex trackers often coincide with freezes on rates addressing costs of other inputs.[60] This "tracker/freeze" approach to MRP design has recently been used by VIEUs in Arizona, Colorado, Florida, Louisiana and Virginia.[61]

Capital Cost Tracker Precedents

There are numerous precedents for capital cost trackers in the regulation of retail rates for U.S. gas, electric and water utilities.[62] The popularity of such trackers reflects in part the generally traditional approach to regulation in U.S. jurisdictions. Most capital cost trackers in the United States are not embedded in MRPs with ARMs that provide automatic rate escalation for cost pressures. The alternative to these trackers for regulators is thus more frequent rate cases that require review of costs of *all* base rate inputs and weaken utilities' incentives to contain them. Note also that many trackers are approved in jurisdictions that do not have fully forecasted test years.

Capital cost trackers have been components of a number of MRPs. Plans in California and Maine, for example, have had trackers for costs of AMI.[63] Plans in Alberta and Ontario have permitted cost trackers for a broader range of distributor capex.[64]

Capital cost trackers are occasionally incentivized. In California, for example, the AMI cost trackers of Southern California Edison and San Diego Gas & Electric have involved preapproved multiyear cost forecasts. Each company has been permitted to recover 100 percent of its forecasted cost up to a cap without further prudence review. Above the cap, each company can recover 90 percent of incremental overspends in a certain range without a prudence review. Beyond this range, recovery of incremental overspends requires a prudence review. San Diego Gas & Electric was permitted to keep 10 percent of its underspends.

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[60] In an MRP with a revenue cap, the analogous ratemaking treatment is a revenue per customer freeze.
[61] See, for example, Arizona Corporation Commission (2012), Colorado Public Utilities Commission (2015), Florida Public Service Commission (2013), Louisiana Public Service Commission (2014), and Virginia Acts of Assembly (2015).
[62] Lowry et al. (2015).
[63] California Public Utilities Commission (2007a), California Public Utilities Commission (2008b), and Maine Public Utilities Commission (2008).
[64] See Alberta Utilities Commission (2012), for a discussion of capital cost trackers in Alberta distribution regulation and Section 6.7 of this report for a discussion of capital cost trackers in Ontario power distribution regulation.

Decoupling Under an MRP

Revenue decoupling can improve utility incentives to adopt a wide array of initiatives to encourage cost-effective DSM and other DERs.[65] In addition to eliminating the utility's short-term incentive to increase retail sales, decoupling can reduce the utility's risk in using retail rate designs that encourage efficient DERs. For example, decoupling reduces risks of revenue loss when customers are offered time-sensitive usage charges that shift loads away from peak demand periods.

When average use is declining for any reason, decoupling reduces the needed frequency of rate cases. Decoupling also reduces controversy over billing determinants in rate cases with future test years because prices will adjust — up or down — based on actual utility sales.

A recent power industry survey found revenue decoupling in use in 14 jurisdictions.[66] DSM is aggressively encouraged by policymakers in many of these jurisdictions. Decoupling is used in tandem with MRPs in California, Minnesota and New York.

Decoupling is much more widely used by gas distributors. This reflects the fact that gas distributors have often experienced declining average use, due chiefly to external forces such as the improved efficiency of furnace technologies. Some utilities have decoupling for some services and lost revenue adjustment mechanisms (LRAMs) for others.[67]

4.3 Performance Metric Systems

Metrics (sometimes called *outputs*) quantify utility activities that matter to customers and the public.[68] These metrics can alert utility managers to key concerns, target areas of poor (or poorly incentivized) performance, and reduce costs of oversight. Target ("benchmark") values are usually established for some metrics. Performance can then be measured by comparing a utility's values for these metrics to the targets. A performance incentive mechanism links utility revenue to the outcome of one or more performance appraisals. "Scorecards" summarizing performance metric results are sometimes tabulated. These may be posted on a publicly available website or included in customer mailings.

Service Quality PIMs

Service quality PIMs are used in multiyear rate plans to improve the incentive balance between cost and quality. This can simulate connections between revenue and product quality that firms in competitive markets experience. Service quality PIMs for electric utilities have addressed both reliability and customer service.[69]

Reliability metrics have addressed systemwide reliability, reliability in subregions, and the success of restoration efforts after major storms. System reliability metrics are most likely to provide the basis for PIMs. The most common system reliability metrics are the system average interruption duration index

[65] For further discussion of revenue decoupling, see Lazar et al. (2016).
[66] Lowry, Makos and Waschbusch (2015).
[67] Electric utilities with decoupling for most customers and LRAMs for some large-volume customers include Portland General Electric, Duke Energy Ohio and AEP Ohio.
[68] Whited et al. (2015).
[69] For a survey of reliability PIMs, see Kaufmann et al. (2010). For a survey of customer service PIMs, see Kaufmann (2007).

(SAIDI) and system average interruption frequency index (SAIFI).[70] Customer service PIMs have addressed customer satisfaction, customer complaints to the regulator, telephone response times, billing accuracy, timeliness of bill adjustments, and the ability of the utility to keep its appointments.

Performance on service quality metrics is usually assessed through a comparison of a company's current year performance to its recent historical performance. Because of limited availability and lack of standardization of service quality data, benchmarking a company's performance on service quality using data from other utilities is difficult.

Demand-Side Management PIMs

Demand-side management PIMs link utility revenue to reward (or penalize) utilities for their performance on DSM initiatives. Metrics on load savings are often used in these PIMs. Compensation for load savings can take several forms:

- *Shared savings.* This approach grants the utility a share of the estimated net benefits that result from DSM. It can therefore encourage utilities to choose more cost-effective programs and manage them more efficiently. However, estimation of net benefits can be complex and controversial. *Ex post* and *ex ante* appraisals of net benefits (or a mix of the two) may be used in net benefit calculations.

- *Management fees.* This alternative grants the utility an incentive equal to a share of program expenditures. The incentive calculation depends on costs incurred (specifically, expenditures by the utility) but not on benefits achieved. Thus, the utility is rewarded for spending money, which is not necessarily well correlated to desired policy outcomes. However, the simplicity of management fees makes them an attractive option in some contexts. This approach is commonly used when net benefits are difficult to measure but are believed to be positive (e.g., public education programs), and its ease of administration has encouraged its use for other DSM programs as well.

- *Amortization.* DSM expenditures can be amortized so that the utility earns a return on them like capital expenditures. Premiums are sometimes added to the rate of return on equity (ROE) for these expenditures, and these premiums may be contingent on achieving certain DSM performance goals.

Most DSM PIMs require estimates of load savings. These savings can be estimated using engineering models, typical savings documented in technical reference manuals (deemed savings), or statistical analyses of customer billing data. Even with high-quality data, reliably estimating savings can be challenging. The complications include free riders (customers who would have implemented the efficiency measure without the program, or would have taken alternative measures), spillovers (additional savings due to the program that are not measured), and rebound effects (behavioral changes that counteract the direct effects of the program, such as using more lighting in the home because light bulbs are more efficient and thus less costly to operate).

DSM initiatives vary with respect to the difficulty of measuring load savings and the scale of expenditures that can produce material management fees and amortization. Some DSM PIMs encourage utilities to design programs with more measurable impacts or larger expenditure requirements. Other DSM initiatives that are equally or more cost-effective may be neglected. Such initiatives may include changes

[70] Other reliability metrics include the customer average interruption duration index (CAIDI) and the momentary average interruption duration index (MAIFI).

in default retail rate designs, cooperation with third-party vendors of energy services and products, support for upgraded state appliance efficiency standards and building codes, and other efforts to transform energy service markets.

Pros and Cons of Demand-Side Management PIMs

Demand-side management PIMs can be a useful addition to multiyear rate plans. Under these plans, utilities may still lack sufficiently strong incentives to encourage DSM. For example, most MRPs accord tracker treatment to fuel and purchased power expenses. Transmission costs may also be tracked. MRPs may provide some incentive to contain load-related capex, but not to levels found in unregulated markets.

Performance incentive mechanisms for DSM can strengthen utility incentives to use DSM as a cost management tool. Such PIMs also can address the utility's short-term throughput incentive in an MRP that does not include revenue decoupling or an LRAM. Well-designed demand-side management PIMs can encourage more cost-effective DSM programs.

Still, demand-side management PIMs have drawbacks. For example, they can involve complex calculations that may complicate regulatory proceedings. Shared savings PIMs are particularly complex. By motivating utilities to improve their performance in relation to specific programs, PIMs may lead to a deterioration in other aspects of DSM performance that are not measured.[71] In addition, utility rewards for load savings can sometimes become sizable over the years.

Precedents for Demand-Side Management PIMs

A 2014 survey by the Edison Foundation Institute for Electric Innovation found that DSM PIMs are quite common in the United States.[72] In all, 29 states had some form of DSM PIM. Among them, all but five had also adopted decoupling or LRAMs. Demand-side management PIMs were included in more than half of the U.S. electric MRPs identified. Among DSM PIMs, those focused on conservation and energy efficiency programs were the most common, and some states have decades of experience with them. PIMs also may address peak load management.

Despite their relative complexity, shared savings mechanisms have been the most popular PIM compensation approach for many years. However, management fees are also widely used. In some cases, regulators have approved more than one compensation approach (e.g., shared savings for programs with quantifiable benefits; management fees for education and marketing programs).

Most DSM PIMs approved to date have pertained to programs serving customers across broad areas of a utility's service territory. However, PIMs can also be targeted to specific geographic areas, such as those where substantial transmission and distribution capex will be needed in the near future to replace aging assets or accommodate growing load. We discuss some examples of these programs in Section 6.

4.4 Efficiency Carryover Mechanisms

Efficiency carryover mechanisms limit true-ups of a utility's revenue to its cost when an MRP concludes. These mechanisms encourage utilities to achieve long-term performance gains that can benefit customers after a plan's conclusion. They can also counteract some adverse incentives that can result under MRPs from periodic rate cases that set a utility's revenue requirement equal to its cost. Due to compression of

[71] New York and other jurisdictions are for this reason considering less program-specific DSM performance metrics like normalized volume per customer.
[72] Institute for Electric Innovation (2014).

the period during which benefits of long-term performance gains improve their bottom line, utilities may have less incentive in later years of a plan to limit upfront costs needed to achieve such gains. In addition, rate cases provide disincentives to contain costs that influence the revenue requirement in the first year of the next plan. For example, there may be less incentive to strike hard bargains with vendors. Given the different incentives to contain cost in early and later plan years, utilities may also be incentivized to defer certain expenditures in the early years of the plan so that these expenses show higher totals in the MRP test year. Customers may then "pay twice" for some costs that are funded by the ARM.

To counteract such incentives, efficiency carryover mechanisms can be designed that reward utilities for offering customers good value in later plans. Such mechanisms can also penalize utilities for offering customers poor value. One kind of efficiency carryover mechanism involves a comparison of revenue requirements in the test year of the next rate case to a benchmark. The mechanism may take the form of a targeted PIM. The revenue requirement in a forward test year could, for example, correspond to the following formula:

$$RR_{t+1} = Cost_{t+1} + \alpha \cdot (Benchmark_{j,t+1} - Cost_{j,t+1})$$

where α is a share of the value implied by benchmarking and takes a value between 0 and 1.[73] Variance between benchmark and actual costs can, alternatively, be used to adjust the X factor in the next plan if it has an index-based ARM.

Choice of a benchmark is an important consideration in design of this kind of efficiency carryover mechanism. One approach is to use as the benchmark the revenue requirement established by the expiring MRP (extended by one year in the case of a forward test year). Cost (or the proposed revenue requirement) may, alternatively, be compared to a benchmark based on statistical cost research which is completely independent of the utility's cost.

[73] Note that the formula allows for the possibility that only a subset (j) of the total cost is benchmarked. This could be the subset that is easier to benchmark.

Efficiency Carryover Mechanisms: An Example From New England

National Grid, a company with utilities that have long operated under MRPs in Britain, incorporated efficiency carryover mechanisms in plans for several power distributors in the northeast United States. For example, in Massachusetts, New England Electric System and Eastern Utilities Associates were in the process of merging when they were acquired by National Grid. In 2000 the Massachusetts Department of Telecommunications and Energy approved a settlement which, among other things, detailed an MRP under which the surviving power distributors of the merging companies (Massachusetts Electric and Nantucket Electric) would operate for 10 years.[74]

The settlement did not require rates to be reset in a rate case at the conclusion of the rate plan. However, the settlement limited over a 10-year "Earned Savings Period" the extent to which rates established in future rate cases could reflect the benefits of cost savings achieved during the plan. These "earned savings" were to conform to the following formula:

Earned Savings = Distribution revenue under rates applicable in March 2009

- *pro forma cost of service (COS)*

The focus on 2009 reflects the fact that Massachusetts has historical test years, so this was expected to be the first year in which cost could provide the basis for post-plan rates. During the Earned Savings Period, Massachusetts Electric was permitted to add to its cost of service during any rate case the lesser of $66 million and 100 percent of earned savings achieved in 2009 up to $43 million, plus 50 percent of any earned savings above $43 million. Thus, if there were no earned savings there would be no revenue requirement adjustment. Any earned savings would be capped at $66 million.

At the end of the plan period, National Grid requested a large revenue requirement increase. This was explained in part by the need to replace aging infrastructure. The utility did not include an allowance for earned savings in its 2009 rate request.

Regulators in Australia, Britain and Ontario routinely take an approach to cost benchmarking which uses econometric methods in rate setting. In the United States, econometric benchmarking studies have occasionally been filed by U.S. utilities. Public Service of Colorado, for example, has filed econometric benchmarking studies of its forward test year revenue requirement proposals for the cost of its gas and electric operations.[75] We discuss econometric benchmarking further in Appendix B.3.

Experience around the world with efficiency carryover mechanisms has been less extensive than experience with some other MRP provisions. Australia has been a leader, using these mechanisms in both power transmission and distribution regulation. The Alberta Utilities Commission uses efficiency carryover mechanisms in MRPs for provincial energy distributors.

[74] See Settling Parties in Massachusetts (1999).
[75] Lowry, Hovde, Kalfayan, Fourakis, and Makos (2014).
Lowry, Hovde, Getachew, and Makos (2010).
Lowry, Hovde, Getachew, and Makos (2009).

4.5 Menus of MRP Provisions

Some MRPs contain menus of provisions from which utilities can choose. Menus typically include a key ARM provision and another plan provision affecting utility finances. In a plan with an indexed ARM, a utility might, for example, have a choice between (1) a low X factor and an earnings sharing mechanism and (2) a higher X factor and no earnings sharing.

An "incentive compatible" menu incentivizes a utility to reveal, by its choice between menu options, its potential for containing cost growth. This approach to MRP design has been discussed in the academic regulatory economics literature since the 1980s. Major theoretical contributions have been made by Michael Crew, Paul Kleindorfer and Nobel prize-winning economist Jean Tirole.[76]

The Federal Communications Commission used a menu approach to MRP design in a 1990 price cap plan for interstate access services of large local telecommunications exchange carriers.[77] The menu embedded in the Information Quality Incentive of British regulators is explained in Appendix A.4.

[76] Laffont and Tirole (1993), Crew and Kleindorfer (1987), Crew and Kleindorfer (1992), and Crew and Kleindorfer (1996).
[77] Federal Communications Commission (1990).

5.0 Incentive Power Research

Pacific Economics Group has developed an Incentive Power model to explore the incentive impact of alternative regulatory systems such as multiyear rate plans. The model addresses the situation of a hypothetical energy distributor that has several kinds of initiatives available to improve its cost performance. Using numerical analysis, the model can predict the cost savings that will occur under various regulatory systems. The regulatory systems considered are stylized but resemble real-world options in use today. Appendix B.1 provides details of the research.

Key results of our incentive power research include the following:

- *Cost containment incentives depend on the frequency of rate cases.* Today, utilities in the United States typically hold rate cases every three years.[78] For a utility with normal operating efficiency, our model finds that long-run cost performance on average improves 0.51 percent more rapidly each year in an MRP with a five-year term and no earnings sharing than it does under traditional regulation when rate cases occur every three years. This means that cost will be about 5 percent lower after 10 years under the MRP. For a utility with an annual revenue requirement of $1 billion, this would be an annual cost saving of $50 million in real terms.

- *If rate cases under traditional regulation occur more frequently, the incremental incentive impact of an MRP is higher.* For example, the long-run impact of MRPs with five-year terms is 0.75 percent additional annual cost containment if rate cases would otherwise be held every two (rather than three) years. This kind of comparison is more relevant to regulators when the alternative to an MRP is frequent rate cases or extensive use of cost trackers.

- *Earnings sharing mechanisms weaken incentives produced by an MRP.* For example, MRPs with a five-year term and 75/25 sharing of all earnings variances between utilities and their customers produce only 0.27 (rather than 0.51) percent annual performance gains compared to a three-year rate case cycle.

- *Performance gains from more incentivized regulatory systems are greater (smaller) for companies with a low (high) initial level of operating efficiency.*

- *Incentives generated by an MRP can be materially strengthened by a well-designed efficiency carryover mechanism or system of menu options.* Suppose, for example, that when rates are rebased the utility absorbs 10 percent of the variance between its own cost and a statistical benchmark of cost. Our model finds that annual performance gains increase by 90 basis points in a plan with a five-year term relative to those from traditional regulation with a three-year rate case cycle. This means a 9 percent lower cost after 10 years.

Our incentive power research has a number of implications. It shows that a utility's performance incentives and performance can be materially affected by the regulatory system under which it operates. This means that more incentivized regulatory systems such as well-designed MRPs can provide material cost savings that can be shared between utilities and their customers. New MRP design provisions such as efficiency carryover mechanisms and menu options can materially increase incentive power.

[78] Lowry and Hovde (2016), p. 44.

Utility performance is materially affected by the frequency of rate cases, and the frequency of rate cases is affected by the adversity of business conditions. Our incentive power research thus supports the notion that performance of utilities under COSR tends to decline under adverse business conditions. When business conditions are adverse, regulators should be especially vigilant about utility operating prudence and consider how to strengthen performance incentives. That can be particularly important given that utilities typically advocate for expedited recovery of their costs when business conditions are adverse, and often are successful.

6.0 Case Studies

This section presents case studies of multiyear rate plans. Each case study discusses the nature of MRPs enacted, identifying important provisions and controversies and rationales for utility regulators to choose PBR. We also consider effects of PBR on cost performance using power distributor productivity indexes. These indexes consider productivity in the provision of customer services such as billing and distribution services. We compare productivity trends of utilities operating under rate plans, or less formal rate case stayouts, to contemporaneous utility norms. Appendix B.2 provides details of our utility productivity research.

6.1 Central Maine Power

The Maine Public Utilities Commission was for many years a leader in energy utility PBR.[79] Central Maine Power (CMP) is Maine's largest electric utility. From 1995 to 2013, it operated under a succession of three MRPs called *alternative rate plans.* Full rate cases did not occur between plans. The first plan took place while the company was still vertically integrated, while later plans applied to CMP's distributor services after restructuring. All three plans were outcomes of settlements between CMP and other parties.

In a 1993 rate case decision, the Commission encouraged CMP to operate under an alternative rate plan. This decision took into consideration CMP's recent history of rapid rate escalation and losses of margins from large-volume customers. The Commission expressed concern that CMP's management had spent "greater attention on a reactive strategy of deflecting blame than on proactively cutting costs."[80] The Commission also noted in its decision general problems with continued use of traditional regulation for CMP. These problems included:

> 1) the weak incentive provided to CMP for efficient operation and investments; 2) the high administrative costs for the Commission and intervening parties from the continuous filing of requests for rate changes; 3) CMP's ability to pass through to its customers the risks associated with a weak economy and questionable management decisions and actions; 4) limited pricing flexibility on a case-by-case basis, making it difficult for CMP to prevent sales losses to competing electricity and energy suppliers; and 5) the general incompatibility of traditional [COSR] with growing competition in the electric power industry.[81]

The Commission outlined its views of potential costs and benefits of MRPs (presumed to feature price caps) in its decision:

> Based on the evidence presented in this proceeding, the Commission finds that multi-year price-cap plans is [sic] likely to provide a number of potential benefits: (1) electricity prices continue to be regulated in a comprehensible and predictable way; (2) rate predictability and stability are more likely; (3) regulatory "administration" costs can be reduced, thereby allowing for the conduct of other important regulatory activities and for CMP to expend more time and resources in managing its operations; (4) Risks can be shifted to shareholders and away from ratepayers (in a way that is manageable from the utility's financial

[79] Thomas Welch, a former telecommunications lawyer, chaired the Commission during these years.
[80] Maine Public Utilities Commission (1993), pp. 14–15.
[81] Maine Public Utilities Commission (1993), p. 126.

> perspective); and (5) because exceptional cost management can lead to enhanced profitability for shareholders, stronger incentives for cost minimization are created.[82]

The decision discussed the marketing flexibility benefits of MRPs at some length:

> Price caps coupled with pricing flexibility allow a regulated firm to compete on a more equal basis with other suppliers that threaten its markets: a firm is given wide pricing discretion and the opportunity to offer new services in the absence of case-by-case regulatory approval.
>
> An important benefit of price caps lies with protecting the so-called "core customers" from competition encountered in other markets. For example, if separate price caps are placed on each class of customer, whatever revenues the utility earns in the more competitive industrial markets would not directly affect the price it can charge (say) residential customers… In contrast, under [COSR] a firm is generally given the opportunity to receive revenues corresponding to its revenue requirement. This implies that whenever the firm receives fewer revenues from one group of customers, it would have the right to petition for increased revenues from others by proposing to raise their prices….[83]

Plan Designs

Attrition Relief Mechanism

All three of CMP's plans featured price caps with index-based escalators. The caps applied to both base and energy rates for vertically integrated service in the first plan, and to base rates for distributor services in later plans. Evidence on input price and productivity trends of Northeastern U.S. electric utilities was presented and debated in each proceeding to inform the choice of an X factor.[84] Macroeconomic price indexes were used as inflation measures. The accuracy of such measures as proxies for utility input price inflation was a prominent issue in one proceeding.

Marketing Flexibility

When CMP was vertically integrated, it had a special need for flexibility in its marketing to pulp and paper customers, some of whom had cogeneration options or were economically marginal, or both. Maine's legislature passed a law allowing the Commission to authorize pricing flexibility plans which permit utilities to discount their rates with limited or no Commission approval. The Commission also encouraged utilities to develop special contracts with customers.

The Commission noted the following in approving the first alternative rate plan for CMP:

Because CMP will have substantial exposure to revenue losses due to discounting, the Company will have a strong incentive to avoid giving unnecessary discounts, and it will have a strong incentive to find cost savings to offset any such losses. Pricing flexibility gives CMP the opportunity to use price to compete to retain customers.[85]

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[82] Maine Public Utilities Commission (1993), p. 130.
[83] Maine Public Utilities Commission (1993), p. 130.
[84] X factors in Maine were commonly referred to as "productivity offsets."
[85] Maine Public Utilities Commission (1995), p. 19.

Marketing flexibility provisions in this plan included these features:

- For core customers, CMP was free to set rates between the rate cap and a rate floor based on an estimate of long-term marginal cost.
- CMP could receive expedited approval of new targeted services.
- CMP could also receive expedited approval of special rate contracts with individual customers. Different provisions applied for short-term and long-term contracts.
- Revenue lost during a plan as a result of discounts was recoverable from other customers only through the earnings sharing mechanism (ESM). In the first plan, a cap of 15 percent was placed on overall lost revenues that could be recovered through the ESM.

Subsequent plans did not make substantial changes to these pricing flexibility provisions.

Other Plan Provisions

Earnings sharing mechanisms and penalty-only service quality PIMs were included in all three plans. Service quality benchmarks for these PIMs became more demanding over time.

The first-generation plan also featured a tracker for DSM costs and a DSM PIM. These latter features were subsequently removed with restructuring and establishment of a third-party DSM program administrator in Maine.

Outcomes

Cost Performance

Table 4 and Figure 6 compare the trends in O&M, capital and multifactor productivity of the company's power distributor services to the average for U.S. electric utilities in our sample from 1980 to 2014. The table shows that from 1980 to 1995, before MRP regulation, the company's MFP growth was a little slower than that of the full sample on average. Over the 1996 to 2013 period during which CMP operated under alternative rate plans, it averaged 0.92 percent annual MFP growth, while the full sample of U.S. electric utilities averaged 0.42 percent annual MFP growth. The MFP growth differential thus averaged 50 basis points. Table 4 also shows that CMP accomplished this through much more rapid *capital* productivity growth. This is notable given the interest of many regulators today with capex containment. O&M productivity trends of CMP and the sample were more similar.

Nuclear Problems

At the start of PBR, when CMP was still vertically integrated, it owned 38 percent of Maine Yankee Atomic Power Co., owner and operator of a nuclear generating station. CMP relied on this station for a sizable share of its power supply. The station experienced an extended outage during the plan. The plan did not fully compensate CMP for the increased costs for repairs, decommissioning and purchased power expenses that resulted from the Maine Yankee outage. This resulted in lower earnings for CMP, which in 1998 triggered the lower bound of the ESM.

Table 4. How Productivity Growth of Central Maine Power Compared to That of Other U.S. Electric Utilities: 1980–2014*

Year	CMP			U.S. Average		
	MFP	PFP O&M	PFP Capital	MFP	PFP O&M	PFP Capital
1980	-0.17%	-2.17%	1.08%	-0.49%	-4.19%	1.24%
1981	0.45%	-3.00%	1.47%	0.17%	-2.42%	1.25%
1982	0.08%	-1.43%	1.84%	0.87%	-1.20%	1.53%
1983	0.42%	-2.22%	1.82%	0.51%	-0.38%	0.98%
1984	1.63%	1.28%	1.80%	1.27%	-0.22%	1.79%
1985	0.75%	-1.94%	1.94%	0.95%	-0.21%	1.37%
1986	2.08%	0.89%	2.57%	0.91%	0.88%	0.97%
1987	0.59%	-1.10%	1.28%	0.44%	-0.12%	0.68%
1988	-0.49%	-1.43%	-0.03%	0.57%	1.55%	0.24%
1989	-0.83%	-0.12%	-1.25%	0.26%	0.00%	0.23%
1990	-0.97%	0.24%	-1.79%	0.18%	0.64%	-0.05%
1991	-0.43%	1.04%	-1.39%	-0.03%	0.58%	-0.32%
1992	1.32%	2.51%	0.64%	0.48%	1.61%	0.10%
1993	-0.24%	-2.55%	1.04%	0.45%	1.19%	0.12%
1994	2.10%	2.87%	1.66%	0.94%	2.44%	0.29%
1995	1.80%	0.98%	2.30%	0.94%	3.58%	-0.04%
1996	1.67%	1.75%	1.62%	0.11%	0.67%	-0.13%
1997	1.08%	-0.40%	2.00%	1.53%	4.68%	0.39%
1998	0.17%	-2.94%	2.14%	0.67%	0.73%	0.71%
1999	2.03%	1.98%	2.05%	1.08%	2.24%	0.52%
2000	0.97%	-2.17%	2.18%	0.89%	0.86%	0.73%
2001	0.83%	-0.69%	1.80%	1.20%	2.73%	0.61%
2002	1.23%	1.28%	1.19%	0.79%	2.73%	0.33%
2003	1.35%	-0.49%	2.83%	-0.03%	-1.50%	0.43%
2004	-0.35%	-3.96%	2.56%	0.41%	0.76%	0.22%
2005	1.85%	1.27%	2.32%	-0.07%	-0.25%	0.09%
2006	1.02%	-0.48%	2.62%	-0.52%	-1.07%	-0.21%
2007	1.16%	-0.21%	3.12%	-0.12%	0.00%	-0.02%
2008	-1.51%	-2.67%	1.27%	-0.99%	-2.06%	-0.09%
2009	2.23%	2.57%	1.34%	1.01%	2.73%	-0.46%
2010	-0.51%	-1.65%	1.00%	-0.27%	-0.47%	0.05%
2011	3.54%	6.17%	0.85%	0.50%	0.05%	0.50%
2012	0.56%	1.86%	-0.63%	1.29%	2.90%	0.58%
2013	-0.73%	-2.31%	0.76%	0.03%	0.40%	-0.05%
2014	-1.61%	-4.74%	1.47%	-0.03%	-1.41%	0.56%
Average Annual Growth Rates						
1980-2014	**0.66%**	**-0.34%**	**1.36%**	**0.45%**	**0.53%**	**0.43%**
1980-1995	**0.51%**	**-0.39%**	**0.94%**	**0.53%**	**0.23%**	**0.65%**
1996-2013	**0.92%**	**-0.06%**	**1.72%**	**0.42%**	**0.90%**	**0.23%**
2008-2014	**0.28%**	**-0.11%**	**0.86%**	**0.22%**	**0.30%**	**0.15%**

*CMP operated under multiyear rate plans in the years for which results are shaded.

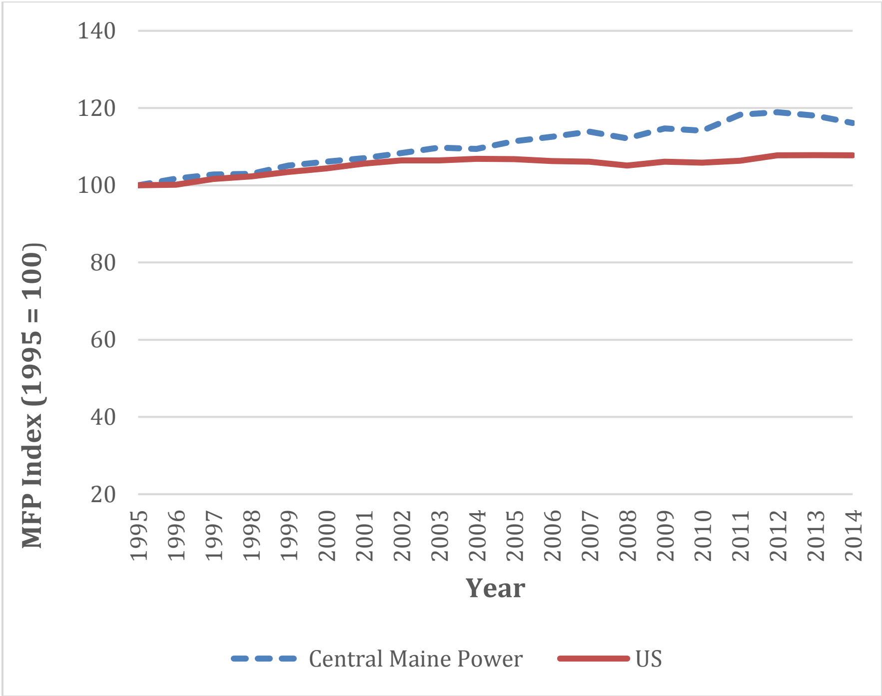

Figure 6. Comparison of Multifactor Productivity Trends of Central Maine Power and the U.S. Sample During Multiyear Rate Plan Periods. The MFP growth of CMP exceeded the industry norm during MRPs.

Marketing Flexibility

During its first rate plan, CMP entered into special contracts with 18 large customers. These contracts featured discounts from tariffed rates in exchange for a guarantee that customers would not attempt to shift their loads to competitors or self-generate during the contract term. In its 1999 10-K filing with the Securities Exchange Commission, CMP described the importance of pricing flexibility and its impacts on the company:

Central Maine believes that without offering the competitive pricing provided in the agreements, a number of these customers would be likely to install additional self-generation or take other steps to decrease their electricity purchases from Central Maine. The revenue loss from such a usage shift could have been substantial.[86]

Service Quality

During the second of CMP's three plans, the Energy and Utilities Committee of Maine's Legislature asked the Public Utilities Commission to investigate effects of the rate plans on service quality performance. This review ultimately resulted in a third-party report.[87] Results of this review were mixed. CMP generally met or exceeded service quality targets. However, performance was uneven. Feeders serving densely populated areas like Portland received greater attention, and these feeders had a greater effect on measured performance systemwide than feeders in rural areas. These performance differences may reflect the fact that reliability PIMs measured only systemwide performance and did not measure performance at a more granular level.

[86] Central Maine Power (1998), p. 81.
[87] Williams Consulting (2007).

Current Status

In 2013, near the conclusion of its third plan, CMP proposed a fourth-generation plan that would have significantly accelerated its revenue growth to help fund a forecasted capex surge.[88] Table 4 shows that CMP's capital productivity trend slowed after 2007. The case ended in a settlement that returned the company to a more traditional regulatory system.[89] A capital tracker for a new customer information system was approved, as was revenue decoupling. While service quality PIMs and the ESM no longer apply, pricing flexibility has continued. No rate case has subsequently been filed.

6.2 California

The California Public Utilities Commission (CPUC) has extensive experience with PBR. This includes the longest experience in North America with MRPs for retail energy utility services. The CPUC has jurisdiction over an energy utility industry that in North America is second in size only to that under the jurisdiction of the Federal Energy Regulatory Commission. Six investor-owned electric utilities (two of which are very large) are regulated, along with natural gas, telecommunications, water, railroad, rail transit and passenger transportation companies. This gives the CPUC strong incentives to contain regulatory costs. MRPs were also facilitated by the CPUC's routine use of forward test years. California's power market was restructured in the 1990s, but two of three large, jurisdictional electric utilities have continued to have sizable generation operations.

The CPUC has limited the frequency of general rate cases using rate case plans for decades. Rate cases were staggered to reduce the chance that the CPUC had to consider cases for multiple large utilities simultaneously. A two-year plan for Southern California Edison was approved in 1980. The standard lag between rate cases was increased to three years in 1984. Longer (e.g., four- or five-year) rate case cycles have since been approved on several occasions.

The CPUC has not always characterized its plans as PBR but did acknowledge the merits of PBR in a 1994 order:

We intend to replace cost-of-service regulation with performance-based regulation. Doing so neither changes the [regulatory] compact's tenets, nor threatens fulfillment of those tenets. We make this change for several reasons.

> First, prices for electric services in California are simply too high. The shift to performance-based regulation can provide considerably stronger incentives for efficient utility operations and investment, lower rates, and result in more reasonable, competitive prices for California's consumers. Performance-based regulation also promises to simplify regulation and reduce administrative burdens in the long term. Second, since the utilities' performance-based proposals currently before us leave both industry structure and the utility franchise fundamentally intact, consumers can expect service, safety and reliability to remain at their historically high levels. Third, the utilities' reform proposals are likely to provide an opportunity to earn that is at a minimum comparable to opportunities present in cost-of-service regulation. Finally, performance-based regulation can assist the utilities in developing the tools necessary to make the successful transition from an operating environment directed by government and focused on regulatory proceedings, to one in which consumers, the rules of competition, and market forces dictate. This is of critical importance in our view.[90]

[88] The Commission stated its opposition to a new plan with a hybrid ARM based on a capital cost forecast.
[89] Maine Public Utilities Commission (2014).
[90] California PUC (1994), pp. 34–35.

The CPUC also has been a national leader in revenue decoupling and PIMs for DSM. This makes California a good case study of the impact performance-based regulation can have on utility DSM as well as cost management. The evolution of MRP design in the state is of further interest given its long history and the diverse situations to which plans have applied.

Plan Design

Attrition Relief Mechanisms

Establishment of multiyear rate case cycles for California energy utilities raised issues of whether and how rates could be adjusted between rate cases. Utilities in the early 1980s were subject to cost pressures from inflation and capacity growth. The three largest utilities invested in nuclear power plants but were denied permission to fund their (often delayed) construction by charging for a return on construction work in progress. The CPUC encouraged large-scale purchases of power from non-utility generators. Revenue decoupling insulated utilities from risks of demand fluctuations but denied them extra revenue from growth in sales volumes, numbers of customers served, and other billing determinants.

Under these circumstances, the CPUC acknowledged that escalation of revenue is typically needed between rate cases.[91] ARMs were thus permitted,[92] and energy costs were addressed by trackers. The out-years of the rate case cycle came to be called *attrition years.* Various approaches to ARM design have been used over the years in California. Predetermined "stepped rate" increases were approved in 1980.[93] However, high inflation encouraged use of inflation measures in ARMs, and many subsequent California ARMs have provided some automatic inflation relief. A hybrid approach to ARM design has been used on many occasions. The broad outline of the first ARMs for Pacific Gas and Electric (PG&E), which started in 1981, is remarkably similar to that of hybrid ARMs that are still occasionally used today.[94]

- O&M expenses were escalated only for inflation. The CPUC implicitly acknowledged that growth in productivity and operating scale also drive cost escalation but assumed that their impact was offsetting.[95]

- Capex per customer was fixed in constant dollars at a five-year average of recent net plant additions, then escalated for inflation.

- Other components of capital cost, like depreciation and return on rate base, were forecasted using cost of service methods. Subsequent hybrid ARMs used in California have involved variations on this basic theme. For example, capex budgets have occasionally been fixed in real terms for several years at forward test year value, then escalated for construction cost inflation. Detailed indexes of utility O&M input price inflation have replaced indexes of

[91] The CPUC has nevertheless persistently maintained that attrition adjustments are not an entitlement even under revenue decoupling and has occasionally rejected their implementation. See, for example, the rejection of PG&E's 2002 attrition adjustment in D.03-03-034.
[92] The ARM was sometimes called an Attrition Relief Adjustment and has in recent years been called a post-test-year mechanism.
[93] California PUC D. 92497 (1980a) for Southern California Gas and California PUC D. 92549 (1980b) for Southern California Edison.
[94] Hybrid ARMs are frequently featured by utilities in their post-test year proposals.
[95] "Our labor and nonlabor costs adopted for test year 1982 will be escalated by appropriate inflation factors for labor and nonlabor expenses…. We will not adopt a growth factor but assume that any growth or increase in activity levels will be offset by increased productivity and efficiency." California PUC (1981) Cal. PUC LEXIS 1279; 7CPUC 2d 349.

macroeconomic price inflation in escalation of revenue requirements for O&M expenses. Some plans have permitted utilities to escalate their labor revenue to reflect wage growth in their union contracts.

Several utilities experimented with fully indexed ARMs between 1998 and 2007. For example, PG&E, Southern California Edison, and San Diego Gas & Electric all operated under indexed ARMs.[96] Southern California Gas, America's largest gas distributor, operated under a revenue-per-customer index with inflation and X factor terms. Larger utilities have in recent years most commonly operated under revenue caps with comprehensive stair step escalators. Cost trackers have provided supplemental revenue for advanced metering infrastructure and some reliability-related capex.

Revenue Decoupling

Revenue decoupling has often been used in conjunction with California multiyear rate plans to reduce utilities' incentives to boost retail sales. Revenue decoupling mechanisms called *supply adjustment mechanisms* were first instituted for gas distributors in the late 1970s at the conclusion of a generic proceeding.[97] By 1982, the CPUC approved revenue decoupling mechanisms (called *Electric Revenue Adjustment Mechanisms*) for the three largest California electric utilities. The appeal of decoupling for electric utilities came from several sources:

- Power conservation became a priority in the state in the 1970s, spurred by generation capacity concerns and high fuel prices.[98] The CPUC declared in 1976 that "Conservation is to rank at least equally with supply as a primary commitment and obligation of a public utility."[99] Utilities played a large role in administering DSM programs (and still do).

- Electric utilities had experimental rate designs such as inverted block rates that were intended to promote conservation but increased sensitivity of utility earnings to demand shifts.

- Utilities experienced substantial risk from other sources, including multiyear rate plans and the CPUC's unwillingness to grant funding for nuclear plant construction work in progress.

Despite a generally positive experience, use of decoupling for California electric utilities fell off in the mid 1990s due, in part, to rules governing the transition to retail competition. There was also some thought that DSM might be provided in the future by independent marketers. A return to decoupling was mandated in 2001 by state legislation motivated in part by the need to promote conservation and contain utility risk during the California power crisis.[100] The three largest electric utilities recommenced decoupling, which continues today.

[96] Indexed ARMs are still used for California energy utilities serving smaller state loads. For example, a 2007 decision in a PacifiCorp rate case approved a settlement that outlined an MRP featuring a price cap index and a three-year term. The index has escalated base rates to reflect growth in an annual forecast of CPI less a productivity adjustment of 0.5 percent. Supplemental revenue is permitted for the California portion of major plant addition costs exceeding $50 million. Parties later agreed to defer PacifiCorp's scheduled 2010 rate case for one year and adopted an identical MRP in the 2011 general rate case. The CPUC agreed to extend PacifiCorp's renewed MRP for several additional years, and the utility will not file a new rate case until 2019 at the earliest.
[97] CPUC Decision 88835, Case No. 10261, May 1978.
[98] Fossil fueled generators in California burned oil, gas or both.
[99] CPUC Decision 85559, March 1976, p. 489.
[100] See California Public Utilities Code (2001).

Demand-Side Management PIMs

California was also an early innovator in the area of DSM PIMs. The first experimental DSM PIMs were implemented in 1990. These measures did not survive deregulation of California's electricity market later in the decade.

In 2007, California reintroduced DSM PIMs for larger utilities through the Risk-Reward Incentive Mechanism. This mechanism featured a relatively complex shared savings approach to compensation. Each utility had targets for three metrics (if applicable): electricity savings, gas savings and peak demand reductions. Under the original incentive design, utilities could receive a reward of up to 12 percent of the dollar value of evaluated net benefits of eligible DSM programs if they performed strongly on all three metrics. Conversely, they would be penalized if they fell below 65 percent of the target for any one of the three metrics. Critically, utility financial outcomes would be based on evaluated (*ex post*), not predicted (*ex ante*), net benefits. That meant that utility outcomes were not known until program evaluations were completed. This choice extended the process and added complexity. However, the CPUC felt it important to reward or penalize how programs actually performed in order to properly align utility incentives and protect ratepayers from adverse outcomes.[101]

The Risk-Reward Incentive Mechanism was implemented for the first time at the end of the 2006–2008 utility program cycle. Disputes over net benefits soon developed, as the CPUC's evaluation consultants estimated program results that substantially differed from the utilities' estimates and implied very different financial outcomes, in part due to the sharp earnings cutoffs in the mechanism's reward structure.[102] Disputes stretched over several years and proved intractable enough that the CPUC modified the mechanism. It based net benefit calculations on parameters (for example, net-to-gross ratios) estimated before programs were implemented, as well as on actual program delivery outcomes.[103] It also lowered the incentive to a flat 7 percent of net benefits and eliminated the possibility of penalties. Savings used to calculate rewards were in between the utilities' and the CPUC's estimates. For programs from 2010 to 2012, the CPUC simplified these PIMs, establishing rewards conditioned primarily on utility spending (management fees) rather than evaluated program performance.

In 2013, the CPUC adopted the Energy Savings Performance Incentive.[104] Under this mechanism, performance awards for many programs were based on energy savings delivered, not net benefits. Energy savings were not discounted, unlike energy benefits in the earlier net benefits calculation. Thus, the revised mechanism provided greater relative rewards for deeper, longer-lived savings. The revised mechanism did not include a potential penalty and avoided sharp earnings cutoffs of the Risk-Reward Incentive Mechanism. Rewards under the Energy Savings Performance Incentive were expected to be lower, and the incentive also capped the maximum achievable reward at a lower level, compared to the Risk-Reward Incentive Mechanism, largely due to the absence of an earnings penalty.

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[101] See CPUC, 2007b, Interim Opinion on Phase 1 Issues: Shareholder Risk/Reward Incentive Mechanism for Energy Efficiency Programs, http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/73172.pdf.

[102] The reward/penalty function consisted of four tiers: a penalty if evaluated energy/capacity savings were less than 65 percent of a target; a dead band of no reward or penalty if savings were between 65 percent and 85 percent of a target; a 9 percent shared savings reward if savings were between 85 percent and 100 percent of a target; and a 12 percent shared savings reward if savings exceeded a target. Each transition between tiers created a sharp reward discontinuity. A small change in the evaluated savings could produce a big change in the reward. Further exacerbating these issues, a utility was paid based on the worst of the three outcomes. For example, if a utility fell below 65 percent of any of the three targets, it earned a penalty even if it performed strongly on the other two. In one case, a utility's estimated savings implied a $180 million reward; the evaluation consultants' estimates implied a $75 million penalty. See Chandrashekeran et al. (2015).

[103] This CPUC decision was controversial, with one commissioner objecting that the revised mechanism largely eliminated the actual performance incentives and ratepayer protections provided by the prior, *ex post*-based mechanism. See http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/128882.pdf.

[104] CPUC (2013).

The Energy Savings Performance Incentive calculates savings *ex post*, reintroducing one of the challenges under the previous incentive mechanism. Some parameters that are considered relatively certain were locked in *ex ante*; those deemed "sufficiently uncertain" by the CPUC required *ex post* measurement. In reintroducing *ex post* calculations, the CPUC emphasized the need to protect ratepayers from paying out rewards based on overly optimistic *ex ante* projections, arguing that this objective outweighed the utilities' desire for revenue certainty and justified potential disputes over *ex post* savings calculations. The Energy Savings Performance Incentive rewarded both codes and standards support programs and "non-resource" programs (those that cannot support an energy savings calculation — largely market transformation programs) using a management fee based on utility dollars spent. The Risk-Reward Incentive Mechanism had not rewarded these programs. Incentives distributed for 2013 and 2014, as well as some rewards for 2015, have prompted far fewer disputes over process and savings estimates.

The CPUC recently developed a pilot PIM program for DERs such as distributed generation and storage. The CPUC approved a management fee mechanism that would offer investor-owned electric utilities 4 percent of annual payments made to DER providers pretax as an incentive to use third-party DERs to cost-effectively displace or defer the need for capex for traditional distribution system investments that were previously planned and authorized.[105] Utilities are required to pursue at least one project and have the option to pursue three more.

The CPUC also authorized the utilities to keep any savings from capex underspends due to DER that had been previously approved until the next general rate case.[106] Estimated costs of the DER and administration of the solicitation are recoverable with interest up to a preapproved cap when rates are reset in the next rate case. Administrative costs above the cap will be reviewed for reasonableness in the next rate case.

In their procurement decisions, utilities are required to consider the net market value of potential DER pilot projects. The net market value calculation includes a broad range of factors, including capacity, energy, ancillary grid services, costs of grid integration, deferred distribution and transmission system costs, and the cost of the DER procurement contract. During the pilot, each of the three major electric utilities are allowed to use different methods for ensuring that DERs rewarded by the incentive are incremental to the utility's existing plans and efforts as governed by other Commission proceedings, in order to test the performance of each method.

Other MRP Provisions

Other characteristics of California electric utility regulation also merit note:

- The CPUC decided in Decision 89-01-040 to address target rates of return on capital of all energy utilities in a separate annual proceeding. This meant that revenue requirements generated by ARMs often have been subject to supplemental rate of return adjustments. Some of these adjustments have been formulaic.[107]

[105] California PUC (2016).
[106] This is not a change from current California regulatory practices, but was explicitly stated nonetheless.
[107] For example, San Diego Gas & Electric's Market Indexed Capital Adjustment Mechanism, approved in 1996, featured a trigger mechanism that updated the cost of capital if bond yields deviated from the benchmark by a specific amount. A similar mechanism was established in 2008 for all large California utilities.

- Cost allocation and rate design issues are commonly addressed in a second phase of a general rate case. In attrition years, utilities have additional opportunities to adjust cost allocations and rate designs in rate design "windows."[108]

- Use of capital cost trackers has been limited in California, due in part to the fact that hybrid and forecasted ARMs have been prevalent. Several plans have permitted separate treatment of discrete major plant additions such as those for power plants and AMI.

- The CPUC has experimented with incentivized trackers for generation fuel and purchased power expenses. For example, San Diego Gas and Electric had a PIM that assessed the effectiveness of its generation and dispatch costs through simulations of annual production costs using expected and actual data. PIMs also have been used for nuclear generation plant capacity factors where sharing of energy cost variances would occur if the capacity factor of a facility was above or below the dead band.

- The CPUC has approved MRPs for generating facilities, independent of other utility assets. For example, in the late 1980s, the CPUC approved an MRP for PG&E's Diablo Canyon nuclear plant where it was permitted to charge an escalating price per MWh for power produced. This charge initially compensated PG&E for capital costs as well as O&M expenses,[109] strengthening the company's incentive to keep the plan running. The Diablo Canyon rate plan expired in 2001.

- Earnings sharing mechanisms and PIMs for service quality have not been routinely featured in California MRPs. During the experimentation with index-based ARMs, earnings sharing mechanisms and service quality PIMs were more common. The CPUC has monitored service quality performance since at least the 1990s.

Outcomes

Cost Control

Table 5 and Figure 7 compare the distributor productivity trends of California's three largest electric utilities to the norm for our full U.S. electric utility sample. Over the full 1986–2014 period during which MRPs have been extensively used in California, the MFP growth of these utilities averaged a 0.14 percent annual *decline*, whereas the MFP of our full U.S. sample averaged 0.43 percent annual *growth.*[110] Thus, the MFP growth of the California utilities was 57 basis points *slower* on average. All three utilities had subpar trends. The capital productivity growth of California utilities has been especially slow. In the 1980–1985 period, before MRPs were widely used, MFP trends of these utilities and the full sample were similar.

[108] Any attrition relief adjustment that the ARM puts in motion is pooled with certain other revenue requirement adjustments and recovered in advice letter filings using the Phase II cost allocations, as amended by changes effected in the rate design windows.
[109] In 1997, however, the plan was revised so that the mechanism recovered only the incremental costs of the plant (costs of O&M and new plant additions). The ongoing recovery of sunk costs was achieved through a separate transition charge.
[110] The MFP growth trends of California utilities were fairly similar to those for the full sample during the six-year 1980 to 1985 period before MRPs became common.

These unflattering results may reflect special California operating challenges. However, the results may also reflect ineffective plan design. We have noted that California ARMs have often based a utility's budget for plant additions on its own historical additions, and passed through the escalation of a utility's union wages.

Table 5. How the Power Distributor Productivity Growth of Larger California Utilities Compared to That of Other U.S. Electric Utilities: 1980–2014*

	California Average			U.S. Sample Average		
	MFP	**O&M PFP**	**Capital PFP**	**MFP**	**O&M PFP**	**Capital PFP**
1980	-0.10%	-2.39%	0.96%	-0.49%	-4.19%	1.24%
1981	0.65%	-0.85%	1.22%	0.17%	-2.42%	1.25%
1982	-0.54%	-3.92%	0.78%	0.87%	-1.20%	1.53%
1983	-0.20%	-3.46%	0.99%	0.51%	-0.38%	0.98%
1984	1.43%	-0.20%	2.00%	1.27%	-0.22%	1.79%
1985	1.27%	-1.44%	1.78%	0.95%	-0.21%	1.37%
1986	0.96%	2.23%	0.61%	0.91%	0.88%	0.97%
1987	0.58%	2.56%	0.02%	0.44%	-0.12%	0.68%
1988	1.86%	10.04%	-0.35%	0.57%	1.55%	0.24%
1989	0.80%	3.51%	-0.04%	0.26%	0.00%	0.23%
1990	0.35%	3.49%	-0.71%	0.18%	0.64%	-0.05%
1991	-1.13%	-0.85%	-1.18%	-0.03%	0.58%	-0.32%
1992	-0.71%	0.98%	-1.26%	0.48%	1.61%	0.10%
1993	-1.45%	-1.66%	-1.38%	0.45%	1.19%	0.12%
1994	0.01%	3.17%	-0.93%	0.94%	2.44%	0.29%
1995	0.27%	0.02%	0.32%	0.94%	3.58%	-0.04%
1996	1.43%	3.26%	0.89%	0.11%	0.67%	-0.13%
1997	0.41%	-1.07%	0.87%	1.53%	4.68%	0.39%
1998	-0.24%	-1.81%	0.32%	0.67%	0.73%	0.71%
1999	-0.53%	1.21%	-1.08%	1.08%	2.24%	0.52%
2000	-0.32%	1.19%	-0.92%	0.89%	0.86%	0.73%
2001	1.63%	1.41%	1.76%	1.20%	2.73%	0.61%
2002	-1.21%	-3.73%	-0.45%	0.79%	2.73%	0.33%
2003	-1.21%	-3.63%	-0.29%	-0.03%	-1.50%	0.43%
2004	-0.14%	0.34%	-0.31%	0.41%	0.76%	0.22%
2005	-0.90%	-2.64%	-0.12%	-0.07%	-0.25%	0.09%
2006	-1.36%	-3.95%	-0.06%	-0.52%	-1.07%	-0.21%
2007	-0.57%	-0.56%	-0.58%	-0.12%	0.00%	-0.02%
2008	-1.44%	-2.17%	-0.80%	-0.99%	-2.06%	-0.09%
2009	0.83%	2.22%	-0.56%	1.01%	2.73%	-0.46%
2010	-1.15%	-0.58%	-1.47%	-0.27%	-0.47%	0.05%
2011	-1.94%	-1.12%	-2.29%	0.50%	0.05%	0.50%
2012	-0.39%	0.82%	-0.91%	1.29%	2.90%	0.58%
2013	1.33%	3.94%	0.23%	0.03%	0.40%	-0.05%
2014	0.04%	3.81%	-1.28%	-0.03%	-1.41%	0.56%
Average Annual Growth Rates						
1980-2014	**-0.05%**	**0.23%**	**-0.12%**	**0.45%**	**0.53%**	**0.43%**
1980-1985	**0.42%**	**-2.04%**	**1.29%**	**0.55%**	**-1.44%**	**1.36%**
1986-2014	**-0.14%**	**0.70%**	**-0.41%**	**0.43%**	**0.93%**	**0.24%**
2008-2014	**-0.39%**	**0.99%**	**-1.01%**	**0.22%**	**0.30%**	**0.15%**

*Shading indicates years when MRPs were in effect.

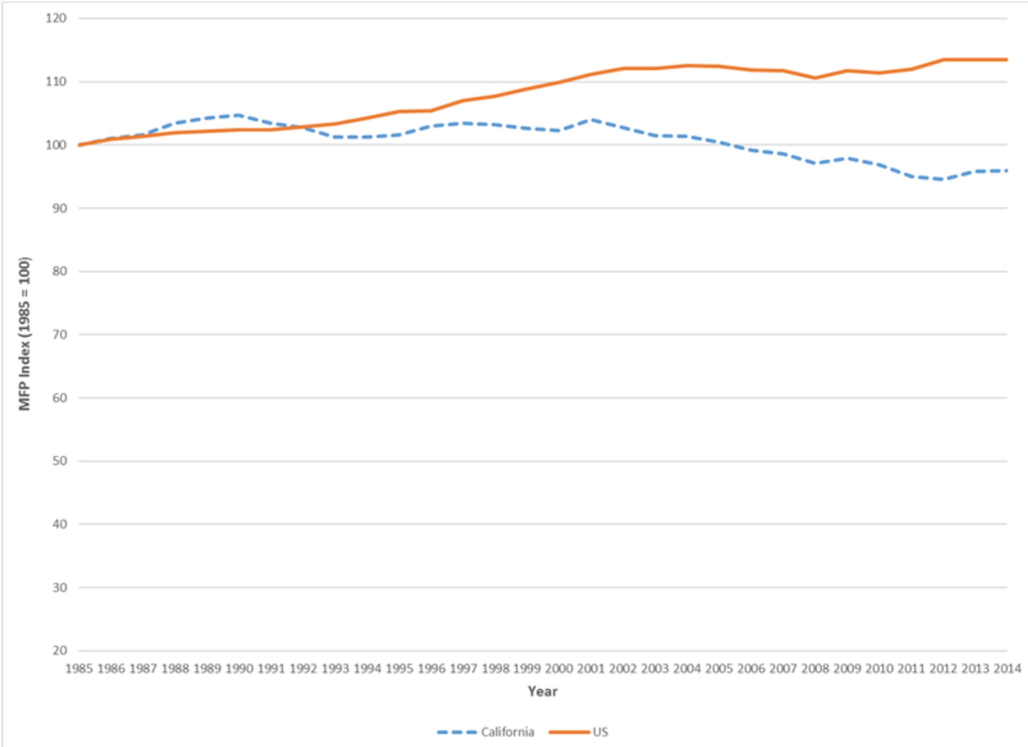

Figure 7. Comparison of Multifactor Productivity Trends of California Distributors and the U.S. Sample during Multiyear Rate Plan Periods. MFP growth of California utilities has fallen short of industry norms under MRPs.

DSM Programs

California electric utilities have typically operated large DSM programs, traditionally ranked near the top of most surveys. Since 1996, the American Council for an Energy-Efficient Economy (ACEEE) has issued annual scorecards evaluating state efforts and achievements in energy efficiency.[111] These surveys include estimates of DSM spending (or budgets) as a percentage of utility revenue. In the eight years for which data were available since 2006, California has averaged a 5.5 ranking out of 51 U.S. jurisdictions (with 1 the highest possible ranking).

Rate Designs

California has also been a national leader in use of rate designs that encourage DSM. For example, inclining block rate designs intended to encourage conservation have been mandated for residential customers since 1976.[112] Until recently, California investor-owned utilities (IOUs) had a very steep inclining block rate structure for these customers, consisting of four tiers ranging from $0.13/kWh for the lowest tier of usage to $0.42/kWh for the highest tier.[113] In a 2015 decision,[114] the CPUC reduced the number of tiers to two (plus a third tier for very high energy users) and specified that the second tier's price should be 25 percent higher than the first. The result is that the lowest tiers now face a higher price

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[111] Berg et al. (2016).
[112] California Public Utilities Code, section 739.
[113] St. John (2015).
[114] CPUC (2015b).

than before, while the higher tiers face a lower one — in other words, a flatter rate structure. This reduces what was formerly a very significant incentive for efficiency and distributed generation deployment for customers using large amounts of electricity. On the other hand, it raises this incentive for customers with lower usage.

Time of use rates are currently optional for residential customers. The CPUC has ordered the IOUs to transition most residential customers to default time of use pricing in 2019.[115] Most commercial and industrial IOU customers in California already face seasonally differentiated default time of use prices, which were introduced in 2014. While these customers can opt into non-time-differentiated rates, few have done so.

Service Quality

California's regulatory system for service quality is more reactive than proactive and has featured several investigations to assess utilities' service quality performance. An early investigation focused on whether PG&E had adequately responded to severe storms in 1995. In its decision, the CPUC ordered standardized service quality and reliability reporting requirements to be developed. Southern California Edison and Sempra had service quality PIMs in rate plans with index-based ARMs during the late 1990s and early 2000s.

Edison's service quality PIMs included one for customer satisfaction, as measured by a survey. In 2003 a whistleblower brought to the utility's attention that fraud had occurred in the customer satisfaction surveys. The company investigated the claims, confirmed that there had been misconduct, expanded the investigation to include the other PIMs, and notified the CPUC.

The Commission opened its own investigation on the matter. It found that Southern California Edison had provided false and misleading data in support of its performance claims on the customer satisfaction survey and health and safety PIMs. The Commission's decision required a refund of rewards that Edison had obtained through false reporting, made the utility forego recovery of additional rewards through these PIMs, and fined the utility an additional sum. The Commission was particularly concerned that the utility had gamed an incentive mechanism, stating that:

> Incentive mechanisms, such as the [PIMs], require a great deal of trust between the Commission and the utility's entire management. In turn, the utility's management must communicate through its practices, rules, and corporate culture that the data submitted to the Commission that impacts the incentive mechanisms must be completely accurate and timely. Increasingly, this Commission is turning to incentive mechanisms in order to align the interests of ratepayers and shareholders and to achieve desirable policy outcomes in the most cost effective and least burdensome manner. If the Commission is to continue to rely on and potentially create new incentive mechanisms, we must be able to trust the utilities to be accurate, timely, and completely honest about their reporting, and further, we must be vigilant against abuse and appropriately penalize violations in order to safeguard the integrity of incentive mechanisms going forward for all utilities.[116]

[115] Ibid.
[116] CPUC (2008), p. 102–103.

6.3 New York

New York has also had a long history with MRPs for energy utilities. Plans have been widely used there since the mid-1990s. Experience with MRPs has spanned some years when electric utilities were still vertically integrated, and more than 15 years after industry restructuring was completed. DSM programs are provided primarily by a state agency, the New York State Energy Research and Development Authority, but utilities also have some programs. MRPs are usually outcomes of negotiated settlements in regulatory proceedings.

The inclination of New York's Public Service Commission and Department of Public Service (DPS) to adopt MRPs has several root causes. Regulatory cost savings can be sizable, since New York's economy is large and there are six investor-owned electric utilities (and even more investor-owned gas utilities) to regulate.[117] MRPs also have been facilitated by New York's long-standing use of forward test years in rate cases. One of the earliest MRPs, for Orange & Rockland Utilities, was motivated in part by concerns about performance incentives. The Commission stated in approving the plan:

> Economic regulation, like most acts of market intervention, can have unintended and undesirable consequences. In the case of a regulated monopoly, the consequence most frequently watched for and least easily avoided is operating inefficiency within the firm, resulting from the "cost plus" nature of price controls. In theory, the [MRP] should encourage greater operating efficiency, because the period of regulatory lag during which the company would be allowed to retain savings from productivity gains would be longer.[118]

Reducing regulatory cost has also been cited in the Commission's support of MRPs. For example, in a 2008 rate case decision for Consolidated Edison, the Commission discussed the drawbacks of annual rate cases.

> We generally prefer multi-year rate plans in instances where the terms are broadly seen to be better than those that might result from a litigated one-year rate case. In addition, we note that this proceeding includes many of the same, or similar, issues and major cost drivers as did the Company's last one-year electric rate case. These circumstances raise a significant concern that the public benefit might not be optimized if the upcoming Consolidated Edison electric rate filing — the third in three years — ultimately boils down to consideration of the same, or similar, issues on which parties largely just replicate arguments we have already carefully reviewed and either accepted or rejected. We also question how well the public interest may be served by the demands on time and resources of the Company, DPS Staff, and other parties in the face of continual annual rate proceedings.[119]

The relatively poor performance of several New York utilities after a series of storms including Superstorm Sandy led the governor to issue an order establishing a commission, called the Moreland Commission on Utility Storm Preparation and Response (Moreland Commission), to investigate and review the storm preparedness of New York's electric utilities, the adequacy of regulatory oversight, and the jurisdiction, responsibility, and mission of New York's energy agency and authority functions.[120] The findings of the Moreland Commission encouraged the governor to push for a reassessment of electric utility regulation more generally. We discuss some Moreland Commission findings further below.

[117] A seventh investor-owned electric utility, Long Island Lighting, was transferred to the state-owned Long Island Power Authority during the 1990s.
[118] New York Public Service Commission (1990).
[119] New York Public Service Commission (2009), p. 282.
[120] Moreland Commission (2013a).

In 2014 New York's Public Service Commission initiated a generic proceeding to consider how the regulatory system of power distributors and their marketplace roles should evolve in an era of rapid change in distribution, metering, and DER costs and technologies.[121] This came to be called the "REV" proceeding after a Department of Public Service Staff report entitled *Reforming the Energy Vision*.

Track One of the proceeding considered appropriate roles of power distributors going forward. Utilities are envisioned as distributed system platform providers that accommodate customer-side DERs and energy service companies and may offer new services that use smart grid technologies. Utilities are now required to file Distribution System Integration Plans that among other things, consider the use of DERs to avoid capex. The first filings were made last summer.[122] Track Two of the proceeding has addressed miscellaneous ratemaking issues such as rate designs and MRP design. We discuss the outcomes further below.

Plan Designs

New York rate plans have featured forecasted ARMs.[123] Since decoupling has been common, most ARMs have effectively been revenue caps.[124] A "one-way" net plant reconciliation ("claw back") mechanism has been added to MRPs in recent years which returns to customers benefits of capex underspends.[125] Plans typically have a term of only three years. In the early 1990s and since 2007, plans also typically have included revenue decoupling and PIMs for utility DSM. Where New York utilities do not have an approved MRP but have revenue decoupling, they often have filed frequent rate cases. MRPs also typically have featured asymmetrical ESMs that share only surplus earnings.

Service quality PIMs are common in New York and are sometimes extensive. There are PIMs for customer service as well as reliability. In addition to these PIMs, service quality standards for SAIDI and CAIDI have been in place since 1991 which, if breached, require a corrective action plan to be filed with the Commission. Consolidated Edison's most recent plan had separate PIMs for its radial and network systems. This plan also featured PIMs for performance following major events (e.g., outages) and a wide variety of asset management activities.

New York plans during the late 1990s and early 2000s were somewhat different from plans that were approved in the early 1990s and after 2007. These plans did not feature revenue decoupling or DSM PIMs, but retained ESMs and service quality PIMs. Several plans featured rate freezes often tied to restructuring plans or merger approvals. A plan for Niagara Mohawk had a 10-year term.

The Commission issued an order on Track Two of its REV proceeding in 2016, including the design of its regulatory system.[126] Among the specific issues addressed are the following:

- The net plant reconciliation mechanism will be reformed to enable utilities to profit from DERs that displace previously approved capital projects. Because this will often be achieved through increased operating expenses, rather than capital expenses, the existing mechanism would require utilities to forfeit approved capital earnings. This creates a disincentive for utilities to adopt lower cost DER alternatives. To address this, the Commission will permit utilities to retain earnings on previously approved, traditional utility capital projects included

[121] New York Public Service Commission (2014a).
[122] Walton (2016a).
[123] Indexed ARMs have, however, been proposed by utilities on several occasions.
[124] From the late 1990s to mid-2000s, revenue decoupling was not featured in New York regulation. These plans were price caps where base rates were specified for each year of the plan.
[125] An underspend occurs if utility capex is less than the budget which the ARM provides.
[126] New York Public Service Commission (2016a).

in base revenue, even if these projects do not materialize, until rates are reset in the next rate case. To qualify for this treatment, a utility must demonstrate that DSM or other types of DERs displaced the capital project. The Commission expressed interest in considering further modifications to the claw back mechanism in the future, such as sharing any realized savings between the utility and customers over a longer time horizon.

- As utilities transition to a platform provider role, the Commission expects a growing share of their income to be Platform Service Revenues,[127] new revenues arising from the operation or facilitation of distribution-level markets.

- *Earnings Adjustment Mechanisms* are New York's term for performance incentive mechanisms. They are to focus on outcomes, rather than on utility inputs or the attainment of specific program targets, and are not restricted to items under the utility's direct control. The Commission expects these adjustment mechanisms to be most important in the near term, serving as a "bridge" to the time when markets provide utilities with a sizable share of revenue in the form of platform services revenues.

  To avoid encouraging utilities to grow rate base, the Commission stated that Earnings Adjustment Mechanisms should not take the form of basis-point adjustments to earnings (though they may be designed in reference to basis-point changes and fixed in dollar amounts before the mechanisms take effect). Mechanisms also generally should avoid estimated counterfactuals in order to reduce controversy and cost. In addition, they should be financially meaningful, encourage strategic, portfolio-level approaches beyond narrow programs, and generally be structured on a multiyear basis.

  Though specific metrics and associated Earnings Adjustment Mechanisms will be worked out in future proceedings, the Commission provided requirements and guidance in several areas:

  - *System Efficiency*. The Commission will require utilities to propose system efficiency Earnings Adjustment Mechanisms that address both peak reduction and load factor. Initial proposals should include only the possibility of positive adjustments.

  - *Energy Efficiency*. Pending recommendations from the Clean Energy Advisory Council based on State Energy Plan and Clean Energy Standard goals, energy efficiency Earnings Adjustment Mechanisms will be redesigned. One focal point will be systemwide electric usage intensity (e.g., measured as kWh per capita, kWh per customer or kWh per unit of GDP).

  - *Interconnection.* An Earnings Adjustment Mechanism will address interconnection of distributed generation and storage projects over 50 kW. It will include a threshold tied to meeting timeliness requirements, and a positive adjustment based on evaluations by interconnection customers of application quality and applicant satisfaction. Negative adjustments may also be considered in individual utility proceedings. The Track Two order required the utilities to develop an Earnings Adjustment Mechanism for distributed generation connection timeliness, customer satisfaction with distributed generation interconnection processes and audits of failed distributed generation interconnection applications.

[127] One potential problem with Platform Service Revenues is that margins from them are netted off of the revenue requirement in each rate case. Another is that competitors will endeavor to limit the role of utilities in the provision of new services. MRPs can help utilities retain margins from these new revenues for several years.

- *Customer Engagement.* The Commission declined to implement an Earnings Adjustment Mechanism related to general customer engagement. However, the Commission will consider proposals in this area. For example, Earnings Adjustment Mechanisms could reward utilities for increased customer participation in time-varying rates or adoption of ground-source heat pumps and electric vehicles.

- *Scorecards.* The Commission plans to use scorecard metrics to track utility progress, which could serve as the basis for Earnings Adjustment Mechanisms in the future.

- Utilities may also earn new revenues from displacing traditional infrastructure projects with non-wires alternatives (NWAs) in other ways. The Brooklyn Queens Demand Management program of Consolidated Edison (Con Ed) is the best-known example.[128] Approved by the Commission in 2014, its goal is to use DERs to delay or offset the need for traditional infrastructure upgrades in a portion of the Brooklyn and Queens boroughs.[129] In the absence of this program, upgrades needed by 2017 would have an estimated cost of approximately $1 billion and included a new area substation, a new switching station at an existing station, and new subtransmission feeders.[130]

  To overcome the disincentive for Con Ed to pursue NWA projects, the Commission adopted the following performance incentives contingent on satisfactory performance on the company's existing reliability PIMs:[131]

  1. Con Ed is permitted to earn its authorized overall rate of return (as approved in its most recent electric rate case) on all deferred Brooklyn-Queens program costs up to a cap. These amounts would be recovered over a 10-year period.

  2. The utility can earn up to an additional 100 basis points (incremental to its authorized rate of return on equity) on program costs contingent on performance.

  An NWA incentive mechanism was approved in 2016 which gives Central Hudson Gas and Electric a 30 percent share of savings associated with delaying investments in traditional power plant structures and reductions in wholesale capacity requirements. Program costs will be amortized and recovered over the subsequent five-year period.[132]

- The Commission declined to extend the terms of MRPs from three to five years in recognition of the need for a high level of regulatory oversight during the early REV transitional period. However, the Commission stated that longer plans had significant potential to achieve long-term benefits and declined to preclude parties from pursuing longer plans if desired.

Consolidated Edison was the first utility to have its rate case litigated after the Track Two decision was issued. This placed the company in the position of being the first to implement several REV features.[133] A separate decision on the same day as the rate case decision approved an incentive mechanism that allowed

[128] For further discussion, see Walton (2016b).
[129] New York Public Service Commission (2014b).
[130] Concurrently with the BQDM program, Con Ed is undertaking about 17 MW of traditional infrastructure investments.
[131] The utility proposed an additional shareholder incentive in its application. This proposal was a shared savings mechanism, under which the utility would have retained a 50 percent share of the annual net savings realized by customers. The Commission rejected this proposal, however, believing that the other two incentive mechanisms were sufficient.
[132] New York Public Service Commission (2016b).
[133] In the case of New York State Electric & Gas and Rochester Gas & Electric, Earnings Adjustment Mechanisms are being developed as a compliance filing to the rate case.

Con Ed to receive 30 percent of the net benefits of NWA projects, except on the Brooklyn Queens Demand Management program.[134] Costs of NWA projects will be recovered over a 10-year period. The net plant reconciliation mechanism was revised to allow Con Ed to use the revenue requirements that would otherwise be refunded to customers as a result of capex underspends from successful DER deployments to offset the revenue requirements of any related non-wires alternative project first.

Earnings adjustment mechanisms and metrics were approved to encourage superior Consolidated Edison performance in several areas.

- In the area of energy efficiency and demand response, two metrics are relied on to assess Con Ed's performance. The first encourages Con Ed to increase its incremental gigawatt-hour (GWh) savings from energy efficiency programs. The second metric encourages Con Ed to improve its demand response effectiveness as measured by incremental system peak megawatt (MW) reductions from energy efficiency programs.

- With respect to deployment of incremental DERs, a metric encourages incremental use of DERs from solar energy, combined heat and power, battery storage, demand response and beneficial electrification, such as thermal storage, heat pumps and electric vehicle charging.

- Measurement of customer load factors is intended to encourage Con Ed to improve those of poor load factor customers. This metric is customer-specific and compares the customer's average load to their peak. Due to the need to conduct further research on this metric, no targets or incentives were assigned to this metric for the first year.

- Metrics also measure Con Ed's weather-normalized average use adjusted for incremental beneficial usage. One measures residential use per customer; another measures commercial use per employed person in Con Ed's service territory.

- Separate metrics are used to assess Con Ed's performance on distributed generation interconnection timeliness, customer satisfaction with distributed generation interconnections, and independent audits of failed distributed generation interconnection applications. Development of specific targets was deferred beyond the rate case, so that no Earnings Adjustment Mechanism will apply for the first rate year.

All of the proposed Earnings Adjustment Mechanisms will be reviewed each year for potential revisions. The incentives increase for each Earnings Adjustment Mechanism during the term of the MRP, with the maximum reward exceeding $50 million in year three of the plan.

[134] New York Public Service Commission (2017).

Outcomes

Utility Cost

Table 6 and Figure 8 compare the power distributor productivity trends of New York electric utilities to the averages for our full U.S. electric utility sample. From 1980–1993, before MRPs became commonplace, the MFP growth of New York power distributors averaged 0.98 percent annually. This was 51 basis points above the average for sampled power distributors nationally. Over the 1994–2014 period during which MRPs have been prevalent, the MFP trend of the New York utilities averaged 0.54 percent annually, whereas the average for our full national sample was a similar 0.45 percent. Capital productivity growth was more rapid in New York but O&M productivity growth was slower. Evidence that MRPs have improved cost performance is therefore not strong. This is not surprising since New York's approach to MRP design is conservative, with short rate case cycles.

Table 6. How the Power Distributor MFP Growth of New York Utilities Compared to That of Other U.S. Electric Utilities: 1980–2014*

	New York Average			U.S. Sample Average		
	MFP	**O&M PFP**	**Capital PFP**	**MFP**	**O&M PFP**	**Capital PFP**
1980	0.78%	-1.47%	1.42%	-0.49%	-4.19%	1.24%
1981	1.57%	1.73%	1.42%	0.17%	-2.42%	1.25%
1982	-0.28%	-4.42%	1.63%	0.87%	-1.20%	1.53%
1983	1.75%	1.82%	1.65%	0.51%	-0.38%	0.98%
1984	2.28%	1.81%	2.37%	1.27%	-0.22%	1.79%
1985	1.74%	-0.19%	2.39%	0.95%	-0.21%	1.37%
1986	1.89%	2.03%	1.82%	0.91%	0.88%	0.97%
1987	0.84%	-1.83%	1.78%	0.44%	-0.12%	0.68%
1988	1.94%	2.09%	1.87%	0.57%	1.55%	0.24%
1989	1.29%	1.73%	0.98%	0.26%	0.00%	0.23%
1990	0.01%	-1.19%	0.56%	0.18%	0.64%	-0.05%
1991	-1.65%	-4.97%	-0.12%	-0.03%	0.58%	-0.32%
1992	1.38%	4.27%	0.18%	0.48%	1.61%	0.10%
1993	0.16%	-0.35%	0.35%	0.45%	1.19%	0.12%
1994	1.67%	4.18%	0.61%	0.94%	2.44%	0.29%
1995	0.65%	0.12%	0.82%	0.94%	3.58%	-0.04%
1996	0.29%	-0.54%	0.59%	0.11%	0.67%	-0.13%
1997	0.16%	-1.63%	0.96%	1.53%	4.68%	0.39%
1998	-0.29%	-5.04%	1.70%	0.67%	0.73%	0.71%
1999	1.70%	1.78%	1.45%	1.08%	2.24%	0.52%
2000	0.60%	1.22%	0.18%	0.89%	0.86%	0.73%
2001	2.23%	2.96%	1.91%	1.20%	2.73%	0.61%
2002	-0.33%	-5.18%	1.18%	0.79%	2.73%	0.33%
2003	1.51%	1.37%	1.66%	-0.03%	-1.50%	0.43%
2004	0.90%	3.65%	-0.53%	0.41%	0.76%	0.22%
2005	-1.50%	-1.35%	-1.46%	-0.07%	-0.25%	0.09%
2006	-1.08%	-2.58%	-0.01%	-0.52%	-1.07%	-0.21%
2007	2.10%	3.91%	0.47%	-0.12%	0.00%	-0.02%
2008	-0.16%	-0.54%	0.58%	-0.99%	-2.06%	-0.09%
2009	2.26%	3.65%	0.32%	1.01%	2.73%	-0.46%
2010	-1.32%	-3.61%	0.90%	-0.27%	-0.47%	0.05%
2011	3.79%	7.39%	0.72%	0.50%	0.05%	0.50%
2012	1.19%	0.67%	0.53%	1.29%	2.90%	0.58%
2013	-2.93%	-6.18%	-0.14%	0.03%	0.40%	-0.05%
2014	-0.09%	-1.02%	0.51%	-0.03%	-1.41%	0.56%
Average Annual Growth Rates						
1980-2014	**0.72%**	**0.12%**	**0.89%**	**0.45%**	**0.53%**	**0.43%**
1980-1993	**0.98%**	**0.08%**	**1.31%**	**0.47%**	**-0.16%**	**0.72%**
1994-2014	**0.54%**	**0.15%**	**0.62%**	**0.45%**	**0.99%**	**0.24%**
2008-2014	**0.39%**	**0.05%**	**0.49%**	**0.22%**	**0.30%**	**0.15%**

*Shading indicates years when MRPs for a majority of New York's electric utilities were in effect.

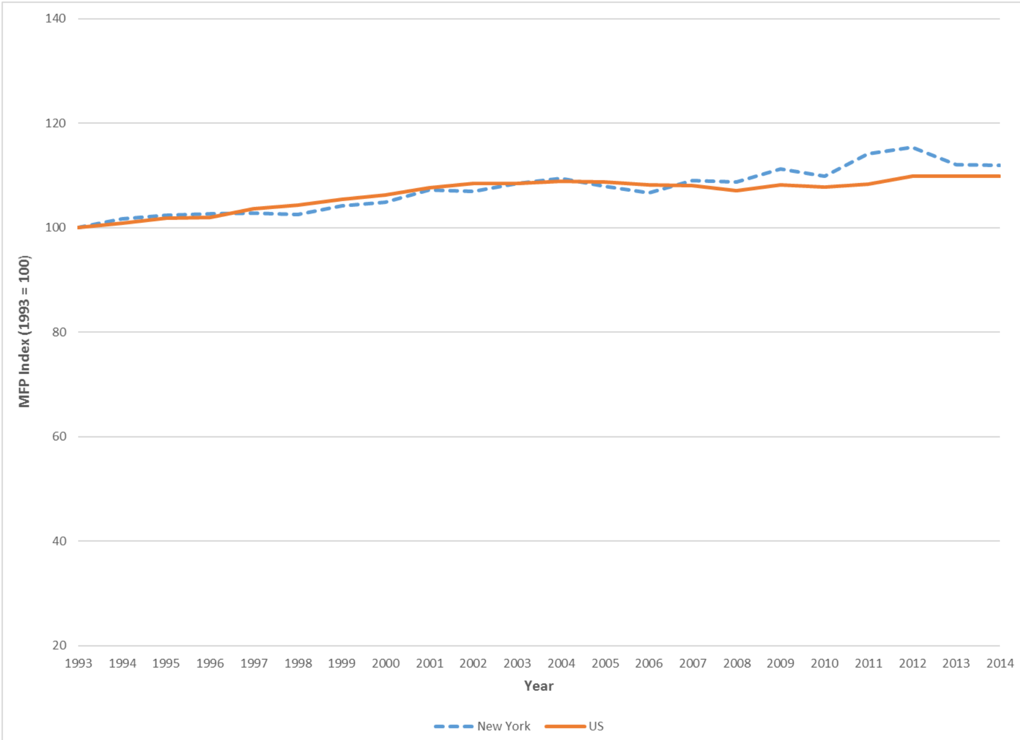

Figure 8. Comparison of Multifactor Productivity Trends of New York Distributors and the U.S. Sample During Multiyear Rate Plan Periods. The MFP trend of New York distributors has modestly exceeded industry norm under MRPs.

Rate Designs

In recent years New York utilities have had some of the highest residential customer charges in the United States. AMI is not pervasive.[135] The Commission recently directed utilities to develop strategies to increase opt-in of mass market (i.e., residential and small commercial) customers to time-of-use rates.[136] Utilities are to develop promotional and customer engagement tools with reference to best practices in states where participation in opt-in time-varying pricing programs is higher.

Utilities also will offer Smart Home Rates as demonstration projects. These rates will combine granular time-varying rates with location and time-based compensation for DERs, in a way that is managed automatically to optimize value for both the customer and system. Smart Home rates are intended to allow a customer to be compensated for multiple services (e.g., load shifting, peak reduction, voltage regulation).

In the longer term, the Commission supports time-sensitive rates for both commodity and delivery services. It has directed its staff to propose a study of the potential bill impacts of a range of mass-market rate reforms, including time-of-use and demand charges. The Commission identifies Smart Home Rates as “the model for a rate design that should become the widely-adopted norm as markets mature.”[137]

[135] At least one utility, Consolidated Edison, is beginning a large-scale deployment of AMI.
[136] New York Public Service Commission (2016a).
[137] New York Public Service Commission (2016a), p. 135.

Service Quality

New York's customer service and reliability PIMs generally have been successful. Over the past five years, New York utilities have generally had stable outage frequency and duration (with major storms excluded). In a 2016 staff report analyzing the customer service PIMs, staff concluded:

> With one exception…the electric and gas utilities' performance on measures of customer service quality in 2015 was satisfactory. The [customer service PIMs] currently in place at the utilities in New York State establish strong standards for performance and put significant amounts of shareholder earnings at risk for nonperformance. Overall, these mechanisms have been effective in encouraging companies to make customer service a corporate priority and providing criteria for ensuring that the quality of customer service remains at satisfactory levels.[138]

In spite of these successes there have been some concerns about the utilities' reliability performance. For example, Consolidated Edison was the subject of a 2006–2007 investigation about reliability due in part to complaints by the legislature. Superstorm Sandy had impacts that were particularly severe, leading the Moreland Commission to conclude in its final report that the utilities had not done enough to effectively respond to severe storms.[139]

6.4 MidAmerican Energy

MidAmerican Energy is a VIEU based in Des Moines that provides electric service in most of Iowa and portions of two adjacent states. The company operated under a sequence of MRPs without intervening rate cases for more than a decade through a series of settlements approved by the Iowa Utilities Board. The settlements had many common features, including rate freezes that extended to charges for energy procured.

Plan Designs

MidAmerican's first MRP began with a 1997 general rate case settlement that featured a three-and-a-half-year rate case stayout.[140] Residential rates were reduced in two steps at the outset. Rates for commercial and industrial customers were not directly reduced. Instead, amounts allocated for these reductions were to be used to fund negotiated contracts with customers or unbundled pricing retail access pilots. The energy adjustment clause was eliminated, exposing the company to fluctuations in prices of energy commodities but permitting it to benefit if high prices in bulk power markets bolstered margins from sales in these markets. A capital cost tracker was included in the plan to address costs of plant additions at the Cooper Nuclear Station. An earnings sharing mechanism (ESM) refunded a share of any earnings surpluses to customers.[141] An off-ramp was included to allow rate cases in the event that earnings were excessively low or high. Iowa law required utilities to offer DSM programs. Costs of these programs were tracked, but no DSM PIMs were approved. Service quality monitoring was instituted in the early 2000s through a change to the state's administrative code.

This plan also allowed MidAmerican to utilize additional marketing flexibility through waivers of existing flexible pricing rules. The company could provide discounts based on the cost to serve individual customers without being required to offer the same discount to all competing customers. The pricing floor

[138] New York State Department of Public Service (2016), pp. 13–14.
[139] Moreland Commission (2013b).
[140] Iowa Utilities Board (1997).
[141] The term revenue sharing is often used instead of earnings sharing in Iowa.

was set at the short-run marginal cost of serving that customer. Contracts in excess of five years were permitted.

Subsequently, approved settlements made small changes to the framework but continued the rate case stayout.[142] The customers' share from the earnings sharing mechanism was redirected into a source of funding for new plants. The capital tracker for Cooper plant additions expired.

Through separate legislation, Iowa electric utilities, including MidAmerican, gained unusual certainty with regard to future ratemaking treatment of generating plant additions. Instead of cost trackers, this certainty has been in the form of ratemaking principles to be applied to new facilities when they are added to the utility's rate base. These principles may include a prudence decision up to a cost cap, the allocation of plant costs to Iowa ratepayers, allowed ROE for the life of the plant, and plant service life.

Throughout the 1997–2013 period, MidAmerican's tariffed base rates did not increase. For residential customers, they decreased by $15 million. The company was nevertheless able to handle effects of several severe weather events and environmental compliance while building a coal-fired generating unit, a gas-fired combined cycle plant, and more than 1,800 MW of wind generation. These assets were added to the utility's rate base years after they entered service, which allowed them to be added at less than their gross plant value due to depreciation. The customer share of earnings yielded by the ESM-funded accelerated depreciation of the coal-fired Walter Scott, Jr. Energy Center Unit 4 exceeded $300 million.[143]

Surplus earnings were aided by bulk power market sales margins. In 2003 testimony, a MidAmerican witness stated:

> In Iowa rate cases prior to the adoption of revenue sharing in 1997, the appropriate treatment of wholesale margins was a contested issue. Since the adoption of revenue sharing, these margins have been shared with retail customers. In fact, since revenues from Iowa retail operations have consistently produced returns below 12% [the threshold for revenue sharing], the revenue sharing mechanism has essentially been a mechanism for sharing these wholesale margins with retail customers.[144]

Declines in bulk power market prices after 2007 helped trigger an off-ramp that resulted in a cost tracker being added to the plan. Other stresses identified by the company in requesting a tracker included environmental, coal and coal transportation costs. The company filed a full rate case in 2013, resulting in a new MRP that phased in a $135 million base rate increase over three years. This MRP also reinstituted an energy adjustment clause. Variances from test year revenue levels resulting from sales for resale continue to be shared solely through the ESM.

Outcomes

Cost Performance

The infrequency of rate cases and the unlikely ability of poorly managed distributor costs to trigger rate cases gave MidAmerican incentive to contain distributor costs that approached those in competitive markets. Table 7 and Figure 9 compare the power distributor productivity growth of MidAmerican to averages for our full U.S. electric utility sample. From 1980 to 1995, before the start of MRPs,

[142] Iowa Utilities Board (2001; 2003).
[143] Fehrman (2012), p. 3.
[144] Gale (2003), pp. 24–25.

MidAmerican's power distributor MFP growth fell by 1.37 percent annually. This was 190 basis points below the MFP growth trend of sampled power distributors nationally. Over the 17-year period over which MidAmerican Energy operated without a rate case (1997–2013), the MFP of its power distributor services averaged 1.16 percent annual growth. That compares to the 0.42 percent trend for our full sample of U.S. power distributors during the same period. The MFP growth differential therefore averaged 74 basis points in the years of the MRPs. The capital productivity growth of MidAmerican was especially rapid.

Service Quality

In 2015, staff of the Iowa Utilities Board performed a review of reliability performance of the state's two large investor-owned electric utilities. It found that between 2002 and 2014, reliability metrics for both companies were stable. This report also showed that MidAmerican's budgeted transmission and distribution expenses had risen between 2002 and 2005, plateaued until 2008, and fell off for 2009, 2010 and 2011, coinciding with dropping bulk power prices.

DSM Programs

In the eight years for which data were available since 2006, Iowa has averaged a 10.25 average ranking (out of 50) in ACEEE's scorecard on the percent of electric revenues devoted to energy efficiency spending.

Table 7. How the Power Distributor MFP Growth of MidAmerican Energy Compared to That of Other U.S. Electric Utilities: 1980–2014*

Year	MidAmerican Energy			U.S. Sample Average		
	MFP	O&M PFP	Capital PFP	MFP	O&M PFP	Capital PFP
1980	-1.93%	-4.26%	-0.78%	-0.49%	-4.19%	1.24%
1981	-2.73%	-5.09%	-1.58%	0.17%	-2.42%	1.25%
1982	-0.58%	3.85%	-2.54%	0.87%	-1.20%	1.53%
1983	1.20%	0.45%	1.46%	0.51%	-0.38%	0.98%
1984	1.89%	1.51%	2.00%	1.27%	-0.22%	1.79%
1985	-0.91%	2.81%	-1.80%	0.95%	-0.21%	1.37%
1986	-0.31%	-2.19%	0.11%	0.91%	0.88%	0.97%
1987	-3.56%	-4.46%	-3.35%	0.44%	-0.12%	0.68%
1988	-1.58%	-1.40%	-1.63%	0.57%	1.55%	0.24%
1989	-2.83%	-5.80%	-1.94%	0.26%	0.00%	0.23%
1990	-1.73%	-1.63%	-1.76%	0.18%	0.64%	-0.05%
1991	-1.82%	0.89%	-2.71%	-0.03%	0.58%	-0.32%
1992	-2.57%	1.99%	-3.92%	0.48%	1.61%	0.10%
1993	-0.02%	2.36%	-0.70%	0.45%	1.19%	0.12%
1994	-0.03%	1.26%	-0.40%	0.94%	2.44%	0.29%
1995	-4.42%	2.64%	-6.55%	0.94%	3.58%	-0.04%
1996	-0.19%	2.55%	-0.99%	0.11%	0.67%	-0.13%
1997	-0.06%	-3.21%	0.84%	1.53%	4.68%	0.39%
1998	-0.44%	-6.77%	1.45%	0.67%	0.73%	0.71%
1999	1.20%	3.47%	0.54%	1.08%	2.24%	0.52%
2000	1.97%	-1.61%	3.04%	0.89%	0.86%	0.73%
2001	-0.02%	-3.98%	1.30%	1.20%	2.73%	0.61%
2002	1.15%	3.17%	0.43%	0.79%	2.73%	0.33%
2003	0.48%	-1.19%	1.10%	-0.03%	-1.50%	0.43%
2004	1.15%	-1.15%	2.13%	0.41%	0.76%	0.22%
2005	0.58%	-0.01%	0.88%	-0.07%	-0.25%	0.09%
2006	1.27%	2.15%	0.72%	-0.52%	-1.07%	-0.21%
2007	-0.42%	-3.61%	2.59%	-0.12%	0.00%	-0.02%
2008	0.85%	1.50%	-0.27%	-0.99%	-2.06%	-0.09%
2009	6.10%	9.84%	0.58%	1.01%	2.73%	-0.46%
2010	2.00%	1.35%	2.48%	-0.27%	-0.47%	0.05%
2011	1.99%	3.30%	1.21%	0.50%	0.05%	0.50%
2012	2.54%	3.77%	1.87%	1.29%	2.90%	0.58%
2013	0.75%	-2.73%	2.42%	0.03%	0.40%	-0.05%
2014	2.32%	1.20%	2.85%	-0.03%	-1.41%	0.56%
Average Annual Growth Rates						
1980-2014	**0.04%**	**0.03%**	**-0.03%**	**0.45%**	**0.53%**	**0.43%**
1980-1995	**-1.37%**	**-0.44%**	**-1.63%**	**0.53%**	**0.23%**	**0.65%**
1997-2013	**1.16%**	**0.38%**	**1.24%**	**0.42%**	**0.90%**	**0.23%**
2008-2014	**2.37%**	**2.61%**	**1.59%**	**0.22%**	**0.30%**	**0.15%**

*Shading indicates years when MRPs were in effect.

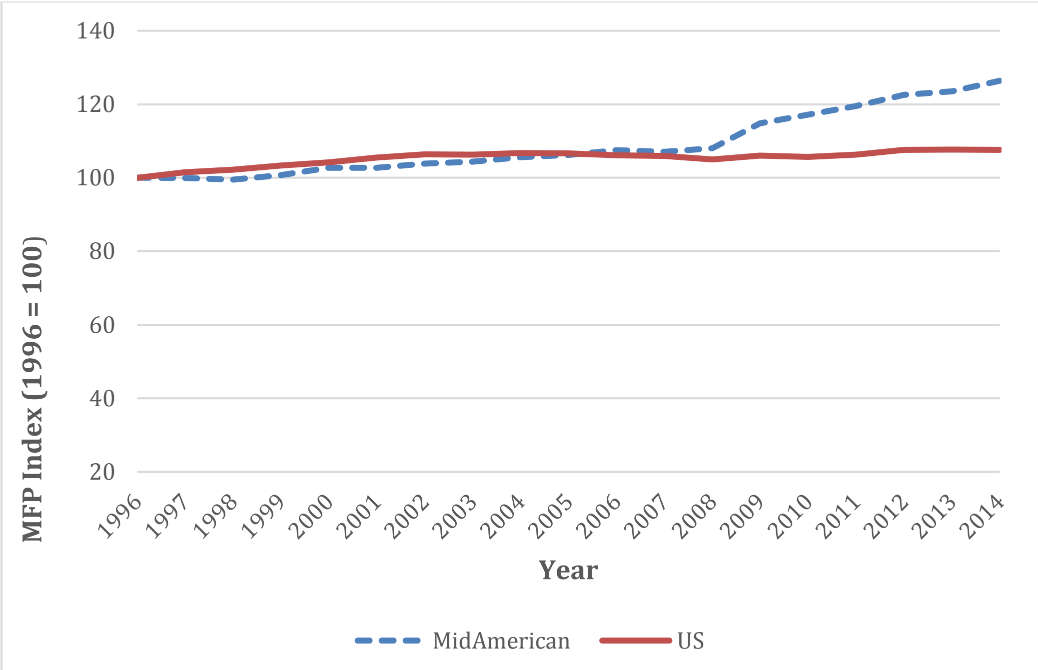

Figure 9. Comparison of Multifactor Productivity Trends of MidAmerican Energy and the U.S. Sample During Multiyear Rate Plan Periods. The MFP trend of MidAmerican exceeded the industry norm under its MRPs.

6.5 Other U.S. Electric Utilities With Extended Rate Stayouts

We noted above that many U.S. electric utilities have avoided general rate cases for lengthy periods. These utilities have been able to operate without rate cases for various reasons. In some cases, utility costs were likely to grow slowly due, for example, to recent completion of one or more large generating stations. Some utilities were able to slow cost growth with mergers or acquisitions. Others may have started their stayout periods with favorable initial rates due to high allowed rates of return. Some operated under an MRP for part of the period or a rate freeze during transition to retail power market competition and were not required to file a rate case upon their conclusion.

Table 8 identifies U.S. electric utilities in our sample that have experienced rate stayouts exceeding 12 years since 1980. About half of these utilities were vertically integrated throughout the sample period. Others started as VIEUs but restructured during the period.

We calculated productivity trends of these utilities as power distributors during the years of their rate stayouts and compared these trends to average annual productivity growth rates of our full U.S. sample during the same years. Table 8 presents results. We found that multifactor productivity growth of utilities during extended rate stayouts exceeded that of the full U.S. sample during the same period by 29 basis points on average. Operation and maintenance and capital productivity growth were both superior. During other years of the full 1980–2014 sample period, MFP growth of these utilities exceeded MFP growth of the full U.S. sample by less than a basis point on average. This evidence suggests that extended rate stayouts lowered distributor costs.

Table 8. Difference Between Company and U.S. Power Distributor MFP Trends During Extended Stayout Periods

Company	Stayout Period			Stayout Period MFP Trend			Stayout Period O&M PFP Trend			Stayout Period Capital PFP Trend		
	Start	End	Duration*	Company	US Sample	Difference	Company	US Sample	Difference	Company	US Sample	Difference
Baltimore Gas and Electric Company	1993	2010	18	0.30%	0.45%	-0.15%	1.42%	1.11%	0.31%	-0.02%	0.20%	-0.21%
Dayton Power and Light Company	1992	2014	23	0.49%	0.45%	0.04%	1.76%	1.02%	0.74%	0.07%	0.23%	-0.15%
Duke Energy Carolinas, LLC	1991	2007	17	0.65%	0.51%	0.14%	2.91%	1.29%	1.62%	-0.10%	0.22%	-0.32%
Duke Energy Progress, LLC	1988	2012	25	0.64%	0.45%	0.19%	2.42%	1.09%	1.32%	-0.10%	0.19%	-0.29%
Duquesne Light Company	1988	2006	19	1.04%	0.52%	0.53%	1.61%	1.27%	0.34%	0.96%	0.22%	0.74%
El Paso Electric Company	1995	2009	15	0.76%	0.46%	0.30%	2.58%	1.12%	1.46%	-0.82%	0.20%	-1.02%
Fitchburg Gas and Electric Light Company	1985	1999	15	-0.35%	0.63%	-0.98%	0.10%	1.36%	-1.27%	-0.30%	0.34%	-0.64%
Florida Power & Light Company	1984	2001	18	0.99%	0.71%	0.27%	2.78%	1.32%	1.46%	0.24%	0.46%	-0.22%
Indiana Michigan Power Company	1993	2007	15	0.41%	0.55%	-0.14%	1.41%	1.32%	0.09%	-0.09%	0.27%	-0.36%
Indianapolis Power & Light Company	1995	2014	20	0.97%	0.42%	0.55%	1.38%	0.91%	0.47%	0.85%	0.24%	0.62%
Kentucky Power Company	1991	2005	15	0.41%	0.62%	-0.22%	1.28%	1.54%	-0.25%	-0.06%	0.27%	-0.33%
Kentucky Utilities Company	1983	1999	17	0.61%	0.66%	-0.05%	0.37%	1.17%	-0.80%	0.62%	0.46%	0.16%
Kingsport Power Company	1992	2014	23	0.26%	0.45%	-0.19%	0.70%	1.02%	-0.32%	0.19%	0.23%	-0.04%
Massachusetts Electric Company	1995	2009	15	1.27%	0.46%	0.81%	1.93%	1.12%	0.81%	0.75%	0.20%	0.54%
Metropolitan Edison Company	1993	2006	14	1.61%	0.60%	1.01%	1.88%	1.41%	0.47%	1.51%	0.29%	1.22%
ALLETE (Minnesota Power)	1994	2008	15	1.50%	0.46%	1.04%	1.23%	1.10%	0.13%	1.61%	0.25%	1.35%
MDU Resources Group, Inc.	1987	2001	15	1.13%	0.65%	0.49%	1.07%	1.56%	-0.49%	1.15%	0.27%	0.88%
Niagara Mohawk Power Corporation	1995	2009	15	1.64%	0.46%	1.18%	3.03%	1.12%	1.91%	0.35%	0.20%	0.14%
Nstar Electric	1992	2005	14	0.15%	0.67%	-0.52%	0.92%	1.61%	-0.69%	-0.26%	0.31%	-0.57%
Ohio Edison Company	1990	2007	18	1.23%	0.49%	0.74%	1.24%	1.26%	-0.02%	1.19%	0.21%	0.99%
Ohio Power Company	1995	2011	17	0.46%	0.42%	0.04%	1.43%	0.96%	0.47%	0.13%	0.21%	-0.09%
Otter Tail Corporation	1993	2007	15	0.02%	0.55%	-0.53%	-0.36%	1.32%	-1.68%	0.40%	0.27%	0.14%
PECO Energy Company	1990	2010	21	0.91%	0.41%	0.50%	1.19%	1.09%	0.10%	0.74%	0.16%	0.58%
Pennsylvania Electric Company	1984	2006	23	0.82%	0.58%	0.23%	1.32%	1.07%	0.25%	0.64%	0.39%	0.24%
Pennsylvania Power Company	1988	2014	27	0.62%	0.42%	0.20%	1.31%	0.97%	0.33%	0.35%	0.20%	0.15%
Potomac Edison	1994	2010	17	1.71%	0.45%	1.27%	2.24%	1.11%	1.14%	1.48%	0.20%	1.28%
Tampa Electric Company	1993	2008	16	0.95%	0.46%	0.50%	1.67%	1.11%	0.56%	0.75%	0.25%	0.51%
Duke Energy Kentucky, Inc.	1992	2006	15	0.84%	0.59%	0.25%	2.99%	1.43%	1.56%	0.01%	0.28%	-0.27%
West Penn Power Company	1995	2014	20	1.29%	0.42%	0.86%	2.49%	0.91%	1.58%	0.84%	0.24%	0.60%
Averages												
Stayout Period Average				**0.80%**	**0.52%**	**0.29%**	**1.60%**	**1.20%**	**0.40%**	**0.45%**	**0.26%**	**0.19%**

* Period is inclusive of both endpoints. End dates in January and start dates in December were assigned values one year earlier and later respectively.

6.6 Statistical Tests of Productivity Impacts

The productivity growth rates of individual utilities are quite volatile from year to year. Differences between the annual productivity growth rates of utilities operating under MRPs and annual full sample growth rates may therefore not reflect the impact of the plans. A statistical technique called *hypothesis testing* can be used to infer whether a utility's productivity growth is impacted by an MRP or, if instead, the observed difference between the productivity trends of individual utilities operating under MRPs and the full sample is a coincidence caused by volatility. We conducted hypothesis tests, called *T-tests*, to evaluate whether the average productivity trend of a utility under an MRP or stay out was significantly greater than the productivity trend of the full sample during the same years.

The first T-test was applied to observations of the differences in the MFP trends between utilities operating under a stay out and the full sample during the stay out period. The null hypothesis was that the difference in productivity trends is equal to zero. The alternative hypothesis is that the difference is greater than zero or, on average, utilities operating under a stayout have higher productivity trends than the full U.S. sample during the stayout period. The sample (N=29) consists of the number of "stayout utilities" in Table 8. The mean difference in the productivity trend is .29 percent, and the standard deviation is .53 percent. The t-statistic for this sample is 2.914, which is greater than the 5 percent one-sided critical value of 1.701. Thus, we can reject the null hypothesis in favor of the alternative hypothesis that companies operating under a stayout have a higher productivity trend during the stayout period than the full sample.

A second T-test was applied to observations of the differences between the productivity trends of utilities operating under formal MRPs as well as stayouts and the trend for the full sample in the same years. The null and alternative hypothesizes were the same as in the first test. The sample (N=40) consists of the utilities in the first test plus the California and New York utilities that have operated under an MRP, MidAmerican Energy, and Central Maine Power. The mean difference in the productivity trend is .22 percent and the standard deviation is .61 percent. The t-statistic for this sample is 2.224, which is greater than the 5 percent one-sided critical value of 1.683. Thus, we can again reject the null hypothesis in favor of the alternative hypothesis. The average difference in the productivity trend of .22 percent is half of the productivity trend of the full sample over the 1980–2014 time period, suggesting that MRPs have an economically significant effect on utility operations.

6.7 PBR for Ontario Electric Utilities

The Ontario Energy Board has emerged in recent years as a top practitioner of PBR.[145] The event that drove innovation was the transfer of responsibility to the Board in the late 1990s to regulate more than 200 provincial power distributors. In addition to power distributors, the Board regulates large provincially owned transmission and generation companies and two large gas utilities.

Power distributors regulated by the Board are remarkably varied. Hydro One, which provides most transmission services in Ontario, also provides distribution services to many towns and unincorporated areas. In addition, large distributors serve Ottawa and Toronto. Most other distributors serve small towns, suburbs or rural areas of the province, and some have just a few hundred or thousand customers. Many of these distributors are municipally owned while the largest, Hydro One Networks, is provincially owned.

[145] PEG Research has advised the Board on PBR for many years, performing several productivity and benchmarking studies.

Despite long experience with cost of service regulation (for gas utilities), the Board opted to use MRPs in power distributor regulation.[146] The Board stated in a draft policy decision three reasons why use of PBR would be helpful in electric utility regulation:

1. With passage of [a bill restructuring the electricity industry], the Board will have the task of regulating a large number of diverse utilities in the province. Since PBR has the potential to provide an expedient mechanism for adjusting rates over time as circumstances change, it is expected to result in fewer rate reviews before the Board and, hence, a lesser regulatory burden.

2. PBR would allow the Board to establish minimum service quality and reliability standards and maintain compliance with these standards.

3. PBR can provide greater incentives for cost reduction and productivity gains compared to those available under traditional cost of service regulation while protecting the interests of consumers.[147]

The Board has since approved a sequence of multiyear rate plans. PBR is called *incentive regulation* (IR) and rate plans are called *incentive regulation mechanisms* (IRMs). The first plan (IRM1) began in 2001. The Board extended this plan to March 2005 to allow utilities additional time to "explore the incentives for improvements and savings provided by the current PBR regime." However, IRM1 was suspended well before its termination date as a result of price spikes in Ontario's new bulk power market. Bill 210, enacted in December 2002, froze existing rates until May 2006 unless approval was otherwise granted by the Minister of Energy.[148]

Rates were adjusted in May 2006 based on rate cases filed in 2005. Between 1999 and May 2006, distributors therefore operated without rate cases and received only one or two modest base rate increases. During this period, utilities had strong incentives to contain costs, and some utilities may have deferred some expenditures.

IRM2 used the May 2006 rates as a starting point. Roughly a third of all distributors were then scheduled for rate cases in each year of the 2008–2010 period. After these rate cases (called *rebasings*), distributors switched over to IRM3. Terms of these plans were initially fixed at three years plus a rebasing year. This was later extended, resulting in plans for some companies lasting five years. Extension was partly based on the Board's in-depth reexamination of its ratemaking practices, called "A Renewed Regulatory Framework for Electricity," which began in 2010. A fourth generation IRM and some optional alternative MRP approaches resulted from these deliberations.

Plan Design

Attrition Relief Mechanism

All four IRMs featured indexed price caps. Macroeconomic inflation measures have been used in some plans and industry-specific measures in others. X factors have commonly had two components: a productivity factor reflecting the MFP trend of a peer group and a stretch factor. The peer groups in first and fourth generation IRMs were broad samples of Ontario power distributors, whereas the peer group in the third generation IRM was a broad sample of U.S distributors.

[146] The Board has subsequently embraced MRPs for regulation of provincial gas distributors.
[147] Ontario Energy Board (1998), p. 3.
[148] Legislative Assembly of Ontario (2002).

Stretch factors in third and fourth generation IRMs have varied between utilities based on results of statistical benchmarking studies commissioned by the Board. The benchmarking study in the fourth generation PBR uses an econometric model of total cost and is updated annually. Details of this benchmarking methodology are discussed in Appendix B.3.

Capital Cost Trackers

Capital cost treatments have evolved over Ontario's four IRMs. Supplemental revenue for capex was not available in the first IRM. A separate Ontario policy led to the use of trackers to finance costs of AMI deployment. In the proceeding to approve IRM2, distributors requested supplemental revenue for capex. This request was rejected due to a lack of perceived need, but distributors claiming a need for high capex were permitted to file a rate case early. The Board expressed concerns about special treatments of capital in its decision:

> 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.[149]

During the proceeding that led to IRM3, a number of utilities again argued that an indexed price cap would not fund their special capex needs. The Board responded by adding to the plans an Incremental Capital Module that could provide distributors with supplemental capex funding. The Board described this as "reserved for…circumstances that are not captured as a Z-factor and where the distributor has no other options for meeting its capital requirements within the context of its financial capabilities underpinned by existing rates."[150] The eligibility criteria for supplemental capex funding subsequently evolved but have consistently required that the capex funded by an Incremental Capital Module not be recoverable in rates, be prudent and the distributors' most cost-effective option, and exceed a materiality threshold. An eligibility formula ensures that forecasted total capex exceeds funding expected from depreciation and higher revenue from price cap index escalation and growth in billing determinants by a certain percentage (currently 10 percent).

Distributors are required to report their actual capex annually. Variances between forecasted and actual capex are reviewed by the Board to determine whether they are material enough to warrant a true-up in a subsequent rate case. Cost overruns are reviewed for prudence, while material underspends result in refunds to ratepayers.

Around 15 of approximately 70 Ontario power distributors have received approval for revenue from Incremental Capital Modules. These modules are typically used to address costs of large capital projects. About two-thirds of applications filed under the program included transformer-related assets as the focal point of the funding request.[151]

In 2014 the Board made "Advanced" Capital Modules rather than Incremental Capital Modules the major source of supplemental capital revenue in IRMs. Utilities must apply in advance, at the time of their rate cases, for supplemental funding of projects that are detailed in five-year Distribution System Plans. Reviews of Advanced Capital Module requests thus coincide with a review of projects proposed in Distribution System Plans, allowing for greater regulatory efficiency. An Incremental Capital Module

[149] Ontario Energy Board (2006), p. 37.
[150] Ontario Energy Board (2008), p. 31.
[151] Ontario Energy Board (2014), p. 7.

remains available for projects not included in a Distribution System Plan, as well as for projects that are in the plan whose eligibility for supplemental funding could not be determined in the rate case, or projects that expand after the plan is presented.

Other Plan Provisions

Terms of incentive regulation mechanisms in Ontario have varied over the years but have typically been four or five years. Reliability PIMs have never been used in Ontario power distributor regulation. However, reliability metrics and targets have been used routinely since IRM1.

Demand-side management PIMs and LRAMs have been offered as an incentive for distributors' DSM programs. A third-party administrator also offers DSM programs.

An earnings sharing mechanism to address overearnings was established for IRM1 but was abandoned in later plans. Some Custom IR plans include such a mechanism where distributor underspending is a concern.

New Plan Options

The Renewed Regulatory Framework deliberations resulted in two additional options to address the diversity of Ontario distributors.

- Custom IR is designed for distributors expecting several years of high capex. ARMs are based on forecasts of O&M and capital cost. Forecasts should be informed by Board-sponsored productivity and benchmarking analyses. Distributors operating with a Custom IR plan do not have the option to request supplemental capital funding. Custom IR plans have recently been granted to several of the larger distributors.

- The Annual IR index is designed for distributors that do not expect to undertake large capital projects. This option features a price cap index with an inflation — X formula, but the X factor is fixed to reflect the high end of the stretch factor range in IRM4 for all plan years. Utilities that choose the Annual IR index cannot obtain supplemental capital funding. The term of a plan with an Annual IR index is not fixed. The availability to distributors of IRM4 and the Annual IR index is a good example of the use of menus in MRP design.

Scorecards

Part of the implementation of the Renewed Regulatory Framework has been the development of a performance scorecard for Ontario distributors. The scorecard includes data on a distributor's cost, earnings, customer service quality, reliability, DSM and safety performance.

Figure 10 provides an example of a scorecard which was posted on the website of the Board.[152] Cost performance is addressed by two unit cost metrics and the outcome of the econometric benchmarking study that the Board updates annually. Financial metrics include a comparison of the company's ROE to its regulated targets. There are also metrics for less traditional areas, such as peak load management and the quality of service to renewable generation customers.

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[152] Scorecard - Hydro Ottawa Limited (2015), http://www.ontarioenergyboard.ca/documents/scorecard/2014/Scorecard%20-%20Hydro%20Ottawa%20Limited.pdf.

Results are presented in a manner that informs the reader of the utility's performance. For example, a company's billing accuracy is presented along with the target. The trend in performance is indicated for several metrics.

Outcomes

Cost Performance

Table 9 and Figure 11 present productivity trends of Ontario power distributors over the 2003–2011 period. This sample period excludes early years of operation under MRPs in Ontario, including the years of the rate freeze. Some distributors in the sample period we consider may have been catching up on their capex after years of deferrals.

Our results differ from those relied upon by the Board to set X factors in IRM4 because we have changed the output index to rely solely on customers, in order to make results more comparable to those from our U.S. productivity research for Berkeley Lab.[153] We have removed

2012 from our calculations due to concerns about cost data for that year.[154] Note also that the sample excludes Ontario's two largest distributors, Hydro One and Toronto Hydro Electric.

The table shows that Ontario distributors' multifactor productivity grew on average by 0.45 percent annually from 2003 to 2011. This exceeded the U.S. trend of -0.01 percent for these years by 4 basis points. O&M productivity averaged 0.76 percent annually while capital productivity growth averaged 0.26 percent annually. The year-by-year results show that O&M, capital and multifactor productivity grew most rapidly during the 2003–2005 period, the last years of the rate freeze. MFP growth then slowed and was negative in two years.

[153] The original results can be found in Kaufmann, Hovde, Kalfayan, and Rebane (2013). Our results were updated using the working papers:
http://www.ontarioenergyboard.ca/oeb/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Renewed%20Regulatory%20Framework/Measuring%20Performance%20of%20Electricity%20Distributors.
[154] While data for 2012 are available, use of these data is problematic for several reasons. For example, Ontario distributors were in the process of changing accounting systems from Canadian Generally Accepted Accounting Principles to the International Financial Reporting Standards, likely making data less comparable.

Scorecard - Hydro Ottawa Limited

9/28/2015

Performance Outcomes	Performance Categories	Measures		2010	2011	2012	2013	2014	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	100.00%	100.00%	100.00%	100.00%	⇒	90.00%	
		Scheduled Appointments Met On Time		100.00%	97.30%	97.40%	97.40%	98.30%	⇓	90.00%	
		Telephone Calls Answered On Time		82.10%	82.90%	82.50%	82.20%	80.30%	⇓	65.00%	
	Customer Satisfaction	First Contact Resolution					85.2%	84.1%			
		Billing Accuracy					99.6%	99.61%	⇒	98.00%	
		Customer Satisfaction Survey Results					90%	83%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public awareness [measure to be determined]									
		Level of Compliance with Ontario Regulation 22/04		NI	NI	C	C	C	⇑		C
		Serious Electrical Incident Index	Number of General Public Incidents	1	0	1	0	1	⇒		0
			Rate per 10, 100, 1000 km of line	0.186	0.000	0.178	0.000	0.182	⇒		0.076
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted		1.05	2.44	1.31	1.64	1.59	⇑		at least within 1.05 - 2.44
		Average Number of Times that Power to a Customer is Interrupted		0.77	1.40	1.13	1.36	0.86	⇑		at least within 0.77 - 1.40
	Asset Management	Distribution System Plan Implementation Progress					105%	94%			
	Cost Control	Efficiency Assessment				3	3	3			
		Total Cost per Customer [1]		$536	$529	$569	$579	$623			
		Total Cost per Km of Line [1]		$29,776	$28,793	$31,107	$33,222	$36,169			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Annual Peak Demand Savings (Percent of target achieved) [2]			14.13%	28.85%	45.57%	70.53%	●		85.26MW
		Net Cumulative Energy Savings (Percent of target achieved)			37.74%	65.64%	88.69%	110.71%	●		374.73GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	100.00%	100.00%	100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time					100.00%	100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.45	1.43	1.18	1.07	0.86			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.22	1.32	1.37	1.64	1.65			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)		8.57%	9.42%	9.42%	9.42%			
			Achieved		7.86%	9.41%	7.80%	8.06%			

Notes:
1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.
2. The Conservation & Demand Management net annual peak demand savings include any persisting peak demand savings from the previous years.

Legend: ⇑ up ⇓ down ⇒ flat ● target met ● target not met

Figure 10. Sample Ontario Performance Metrics Scorecard.

Table 9. Productivity Trends of Ontario Power Distributors: 2003–2011

	Output		**Inputs**						**Productivities**					
	Total Customers[1]		**Capital[1]**		**O&M[1]**		**Multifactor[2]**		**Capital**		**O&M**		**Multifactor**	
Year	**Level**	**Growth**	**Level**	**Growth**	**Level**	**Growth**	**Level**	**Growth**	**Level**	**Growth**	**Level**	**Growth**	**Level**	**Growth**
		[A]		[B]		[C]		[D]		[E = A-B]		[F = A-C]		[G = A-D]
2002	2,528,664		100		100		100.00		100.00		100.00		100.00	
2003	2,590,817	2.43%	101	1.01%	102	1.77%	101.30	1.29%	101.43	1.42%	100.66	0.66%	101.14	1.13%
2004	2,647,118	2.15%	103	1.66%	100	-1.51%	101.79	0.48%	101.92	0.49%	104.41	3.66%	102.84	1.67%
2005	2,703,821	2.12%	104	1.65%	99	-1.14%	102.42	0.61%	102.40	0.47%	107.87	3.26%	104.40	1.51%
2006	2,748,114	1.62%	105	0.80%	101	1.50%	103.51	1.06%	103.25	0.82%	108.01	0.12%	104.99	0.56%
2007	2,781,589	1.21%	108	2.44%	105	3.82%	106.62	2.96%	101.99	-1.23%	105.22	-2.61%	103.17	-1.75%
2008	2,823,654	1.50%	109	1.16%	106	1.67%	108.08	1.36%	102.34	0.34%	105.04	-0.17%	103.28	0.15%
2009	2,849,054	0.90%	109	0.19%	107	0.44%	108.39	0.29%	103.07	0.70%	105.52	0.45%	103.95	0.61%
2010	2,885,251	1.26%	111	1.80%	104	-2.39%	108.61	0.20%	102.52	-0.54%	109.45	3.65%	105.08	1.06%
2011	2,919,186	1.17%	113	1.30%	108	3.28%	110.87	2.06%	102.38	-0.13%	107.16	-2.11%	104.12	-0.89%
Average Annual Growth Rates:														
2003-2011		**1.60%**		**1.33%**		**0.83%**		**1.15%**		**0.26%**		**0.76%**		**0.45%**

Notes:

[1] Data are from PEG Working Papers: Part II - TFP and BM database calculation, filed with PEG's report "Empirical Research in Support of Incentive Rate-Setting: Final Report to the Ontario Energy Board" on November 21, 2013 (and updated on January 24, 2014).

[2] This is a Törnqvist index using the total cost shares of capital and OM&A as weights.

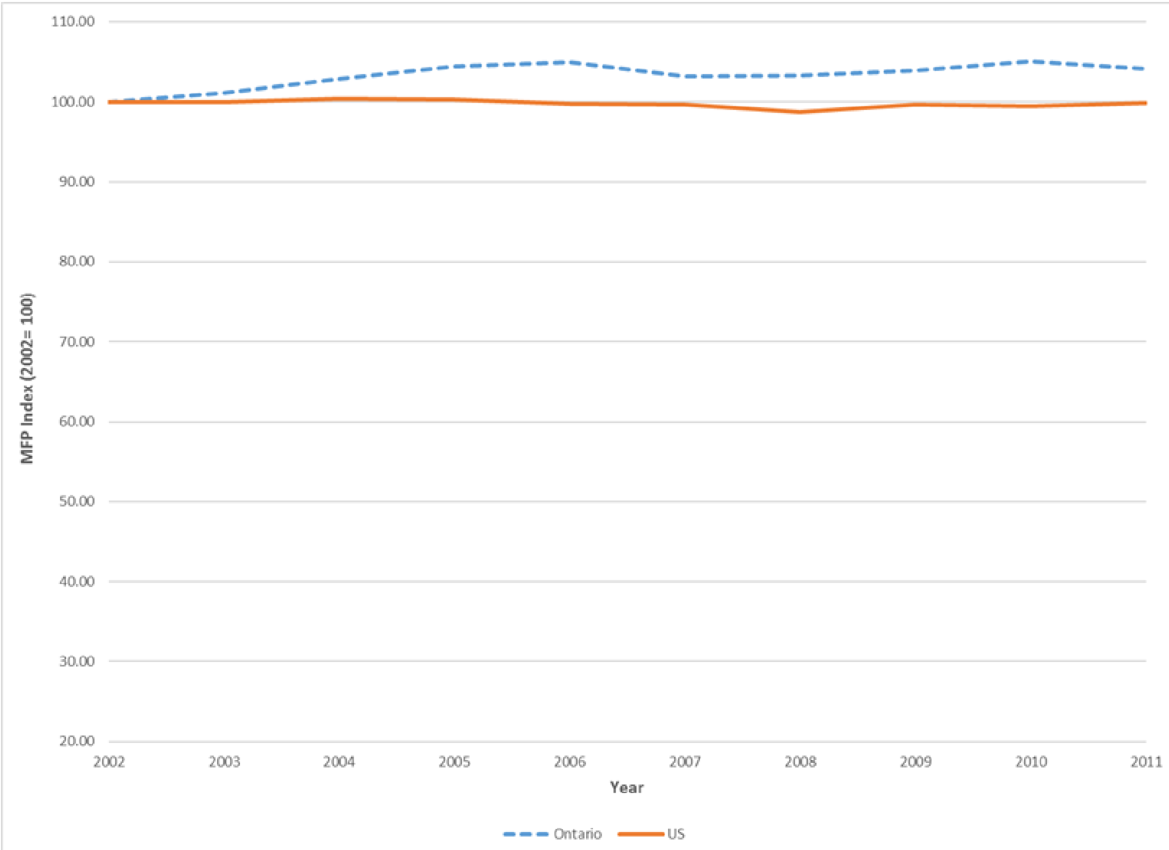

Figure 11. Comparison of Multifactor Productivity Trends of Ontario Distributors and the U.S. Sample During Multiyear Rate Plan Periods. The MFP trend of Ontario distributors exceeded the industry norm under MRPs.

Consolidation

Since the late 1990s, Ontario's power distribution industry has consolidated from more than 200 distributors that existed prior to PBR to about 70 distributors. Hydro One Networks has purchased more than 80 distributors. The Ontario government has noted on several occasions that the industry could become more efficient with greater distributor consolidation. Consolidation may have spurred productivity growth.

Service Quality

Effects of the Ontario MRPs on utility service quality are unclear, potentially a result of data the Board has been gathering. Reported reliability metrics do not exclude major events, leading to potentially large year-to-year variations in performance due to weather events beyond distributors' control. In addition, the period of operation under MRPs (2005–2012) has witnessed the rollout of AMI and SCADA systems. These deployments are often linked to a worsening of measured reliability because more outages are detected by automatic reporting systems.

Some observers have suggested that Ontario distributors had high levels of service quality at the beginning of the MRPs, even to the point of arguing that some utilities had engaged in "gold-plating" their systems. These observers find that during the 2000s, which encompassed IRM1, a rate freeze, and IRM2, reliability suffered.

> [R]eliability has declined continuously from 2000 to 2008; degradation has become progressively worse. Results in the middle years [during the rate freeze] (2003-2005) are significantly worse than the earlier [IRM1] years (2000-2002), and results in the last years (2006-2008) [in which rates were reset and IRM2 was in effect] significantly worse than the middle.[155]

A 2010 Board staff report presented more mixed results:

> The [customer] surveys indicate that the majority of consumers are generally satisfied with current levels of system reliability, with 89% of residential consumers and 92% of business consumers reporting that they are "somewhat satisfied" or "very satisfied" with the reliability of electricity supply. However, over 75% of respondents in both groups indicated that, despite being generally satisfied, they still believe it is important for distributors to continue to work to reduce the number of outages…. There was a strong consensus amongst many participants that the Board should focus on ensuring that system reliability levels are maintained. These participants believe that the current regime is adequate for the purposes of ensuring continued sustainability and reliability…. Ratepayer groups that supported the development of a new reliability regime were in the minority. Some ratepayer representatives suggested that reliability has declined almost continually over the last 8 years.[156]

6.8 Power Distribution MRPs in Great Britain[157]

The power distribution industry of Great Britain also has a history very different from that of the United States. Until 1990, British electric utilities were not investor-owned. In the intervening years, these utilities have been privatized and restructured into separate generation, transmission and distribution operations. End users are billed by retailers, not distributors. This arrangement reduces the role of distributors in provision of DSM programs. Regulatory requirements of British utilities are codified in their licenses, rather than tariffs, administrative codes or laws.

There are currently 14 power distributors, eight gas distributors, three electric transmitters and one gas transmitter in Britain. The sizable task of regulating these utilities has been assigned to the Office of Gas and Electricity Markets (Ofgem). Ofgem also regulates gas and electric commodity markets.

[155] Cronin and Motluk (2011).
[156] Ontario Energy Board (2010), p. 7–10.
[157] A 2016 Berkeley Lab report (Lowry and Woolf) discussed the British system of energy utility regulation. This section provides additional history and plan design details and discusses notable outcomes.

Since privatization, British energy utilities have operated under a sequence of MRPs called *price controls*. The British approach to price controls has its roots in a 1983 document by British economist Stephen Littlechild, which relied on five criteria to evaluate regulatory options:[158]

- protect against monopoly power
- encourage efficiency and innovation
- minimize regulatory cost
- promote competition
- maximize proceeds from privatization

Traditional cost of service regulation was rejected by policymakers after scoring poorly on four of the five criteria. The one criteria where cost of service regulation performed well was protecting against monopoly power.

Littlechild proposed to regulate rate growth with an index using an inflation – X formula. Regulators have refined various features of the plans over the years in their periodic price control reviews. To date there have been five completed generations of price controls, with the sixth price control beginning in 2015. Ofgem undertook a substantial review of its regulatory practices beginning in 2008. The revised regulatory system that resulted from these deliberations is called *RIIO* (Revenues = Incentives + Innovation + Outputs).

Plan Design

Plan Term

British MRPs have traditionally had five-year terms. With the adoption of RIIO, the term of plans was extended to eight years. This strengthens performance incentives but has complicated the task of developing and reviewing plans.

Attrition Relief Mechanism

Price controls for power distributors in Britain originally featured price caps but now feature revenue caps. Caps of both kinds have been escalated by hybrid methods. Allowed revenue trajectories are established based on multiyear total cost forecasts. Principal components are forecasts of the value of the current capital stock and of capital spending, depreciation, the return on capital, and O&M spending. Because of the focus on component costs, the British approach to ARM design is sometimes called the *building block* method.

Britain's Retail Price Index (RPI) has been used as the inflation measure of the revenue cap indexes. Given forecasts of total cost, billing determinants and inflation, past plans have selected combinations of initial rates and an X factor such that forecasted revenue equals forecasted cost. The revenue cap escalator in RIIO has an implicit X factor of zero.

Use of forecasts to establish allowed revenue led to concerns by Ofgem and its predecessor, the Office of Electricity Regulation, about utility exaggerations of capex requirements. For example, underspends occurred in a period when utilities had forecasted high capex due to an "echo effect" when facilities installed in a past capex surge approached the end of their service lives. In its 1994–1995 price control review, the regulator accepted the need for a high level of replacement capex, noting that facilities from a

[158] Littlechild (1983). Littlechild subsequently served as director general of the electricity regulator.

prior capex surge were approaching retirement age. The regulator nonetheless reduced individual company total capex proposals by as much as 25 percent because not all of the capex was deemed necessary.

In its next price control review, the agency compared distributors' actual capex during the expiring price control to the budgets that had been approved. Figure 12 shows that actual capex was lower than the regulator's approved levels. The regulator came to the conclusion that the "echo effect" was less pronounced than it had expected.[159]

The regulator suspected that some utilities had misrepresented their capex needs. This experience encouraged the regulator to consider some implications of extensive capex underspends in developing a new price control.[160] Ofgem began by reassessing its policy on underspending:

> Ofgem would expect such companies to retain the benefit of their under-spend. Given that, to a significant extent, the nature and timing of capital expenditure (particularly non-load related expenditure) is discretionary, measures need to be introduced to ensure that companies are only rewarded for genuine efficiency not timing benefits obtained through manipulation of the periodic regulatory process.
>
> In this context, it is particularly important to ensure that companies do not have a perverse incentive to 'achieve' periodic delays in capital expenditure, such that they regularly under-spend Ofgem's forecasts, thereby gaining a financial benefit, and then claim a higher allowance for the subsequent period in respect of the capital expenditure which has not been undertaken.… Further where [distributors] underspend in one period and then forecast an increase in expenditure in the next, this will be carefully scrutinized.[161]

The regulator further stated that:

> The unavoidable information asymmetry between regulator and regulated companies is a major issue especially since, under the present regime, regulated companies have an incentive to overstate required expenditures when discussing future price controls with the regulator.[162]

[159] Offer (1999), p. 46.
[160] During the course of the proceeding, Offer merged with the British gas regulator Ofgas to become Ofgem.
[161] Ofgem (1999), p. 41.
[162] Ofgem (1999), p. 7.

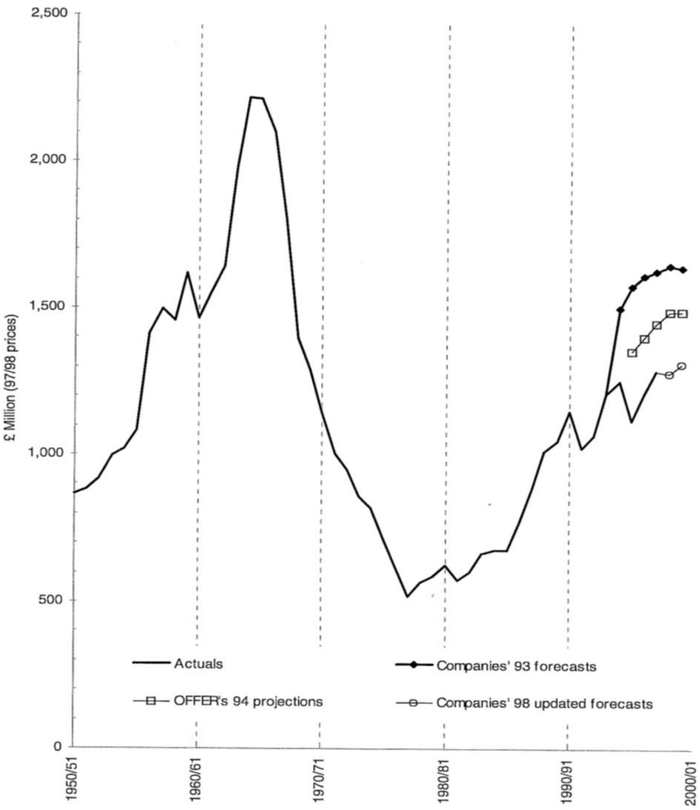

Figure 12. Distribution Business Capital Expenditures (1997/98 Prices). A capex surge during the period 1993–2000 was due to an "echo effect" from a past capex surge that was lower than forecasted.[163]

Ofgem penalized three distributors in its final decision which had provided exaggerated forecasts of capex and operating expenditures (opex). Nevertheless, it became apparent that forecasting overstatements had continued. Ofgem found that capex was being underspent by utilities under the first three years of the new price control.[164] Many power distributors were also providing forecasts describing a need for capex that was more than 20 percent greater than previous forecasts.[165]

Due in part to such experiences, Ofgem has over the years commissioned numerous statistical benchmarking and engineering studies to develop its own independent view of required cost growth. In 2004, Ofgem added to rate plans an Information Quality Incentive (IQI) to encourage more accurate capex forecasts. This complicated PIM, an example of an incentive-compatible menu, is discussed further in Appendix A.3.

Distributors that have well-justified business plans at an early stage of the RIIO proceeding can be "fast-tracked." Fast-tracking allows the distributor to receive approval of its business plans as much as a year earlier than would otherwise be the case and avoid more intense scrutiny of its business plan. This enables the distributor a greater opportunity to focus on executing its business plan during the run-up to the new MRP.

Another innovative feature of RIIO is its focus on total expenditures (totex) to level the playing field between capex and opex. Ofgem has explained the rationale for a totex focus:

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[163] Offer (1999), p. 45.
[164] Ofgem (2004a).
[165] Ofgem (2004b).

> The incentives to manage different types of costs under the price control are not equal. These imbalances may distort the decisions that [distributors] need to make between capex and opex solutions and create boundary issues. This is not in customers' interests as it may lead to [distributors] seeking to outperform the settlement by favoring capex over opex (or vice versa). This may lead to inefficient network development and higher charges for customers in the short or long term….
>
> These rules create two undesirable effects:
>
> - Incentives are distorted toward adopting capex rather than opex solutions. This means that [distributors] are not incentivized to minimize total lifetime costs as they are sometimes better off by adopting a capex solution rather than a cheaper opex solution due to the way that the different expenditures are treated.
>
> - Boundary issues are created. There is an incentive to record expenditure in the areas with the highest rates of capitalization even if the expenditure was not technically in that area. This requires significant policing of the cost reporting of [distributors].[166]

To address these problems, Ofgem decided to equalize the incentives between opex and capex for most cost categories.[167] Instead of traditional expensing and capitalization rules, Ofgem fixed the amount of total expenditures that could be capitalized at 85 percent. Newly capitalized costs would be recovered over a 45-year period, while existing rate base costs would be recovered over a 20-year period. The remaining 15 percent would be expensed.

Performance Metric System

RIIO features complicated performance metric systems that include several PIMs. Metrics in this system are called *outputs.* The performance incentive mechanisms in RIIO place a sizable share of distributor revenue at risk, prompting some commentators to call RIIO a "results-based" approach to regulation. However, the unusually large sensitivity of earnings to performance mechanisms in RIIO is due mainly to the Information Quality Incentive.

With respect to service quality, Ofgem adopted guaranteed reliability standards early on, later adding guaranteed standards of performance for connections. One example of a guaranteed standard is that distributors are required to restore service within 12 hours in normal weather conditions. Distributors must make predetermined payments directly to customers each time a minimum performance standard is not met. Ofgem also developed a reliability PIM called the *Interruptions Incentive Scheme* that addresses distributors' outage frequency and duration performance.

Ofgem has expanded its customer satisfaction PIM over the years into a Broad Measure of Customer Satisfaction. This encompasses the number of complaints that a distributor has and an assessment of customer satisfaction with distributors' responsiveness with regard to outages, connections and general inquiries. Ofgem has also experimented with PIMs to encourage reductions in line losses.

Distributors are required to report annually on numerous additional metrics. These have expanded over the years from cost and revenue reporting to include measures that are not commonly reported in the United States, including the health of assets, substation utilization levels and air emissions. Business

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[166] Ofgem (2010), p. 107.

[167] Costs that were not provided this treatment include many types of administrative and general expenses, pensions and several costs that receive supplemental funding, discussed later in this section.

Carbon Footprint metrics include distributors' annual electricity losses in addition to their direct carbon emissions.

Ofgem reviews distributors' annual reports on these metrics and issues its own report summarizing distributors' performance. Reports feature a scorecard with "traffic lighting," using red to indicate poor performance, green to indicate good performance, and yellow to indicate performance in between.

RIIO also changed asset health metrics into a risk index. The risk index is a composite measure of asset health and criticality indexes, reflecting risks of asset failures for a distributor. The asset health index measures the likelihood of an asset failure, while the criticality index measures the impact of a potential asset failure. The risk index has become the basis for a PIM with a possible penalty or reward of 2.5 percent of avoided or incurred costs.

RIIO has also increased use of discretionary financial incentives. A stakeholder engagement incentive encourages distributors to engage with customers and incorporate their input in decisions and to identify vulnerable customers and take efforts to ensure their energy needs are met. An incentive for connections engagement assesses a distributor's effort in formulating and pursuing strategies for providing and improving connection services to large customers, as well as a distributor's use of information learned from these customers to improve these services. A load index measures substation loading on a distributor's primary network.

Revenue Decoupling

While being described as a "price control," Ofgem today uses revenue caps. A "correction factor" refunds or charges customers for variances between actual and allowed revenue. In past plans, sales volume and customer growth increased the company's allowed and actual revenue to some extent.[168] However, this linkage was eventually eliminated, resulting in revenue decoupling that continues through RIIO today.

Cost Trackers

British MRPs often feature mechanisms similar to cost trackers for various costs that are difficult to control. For example, most pension costs have been tracked. Trackers also have been put in place for an assortment of special projects including load reinforcement, high value projects and rail electrification. Supplemental revenue can only be requested at one or two prespecified periods during the rate plan. Another variant on cost trackers is supplemental allowances that distributors can access for specific projects. These allowances have been developed for various purposes, including improvement in the reliability of service to "worst served customers," workforce renewal, distributor innovation efforts, and to encourage distributors to begin making changes toward a low carbon future.

Outcomes

From 2008–2010, as part of the RPI-X@20 process to modernize its regulatory system, Ofgem undertook an extensive review of effects of its price controls. Reviews are also held at the end of each price control. In these reviews, Ofgem indicated that many MRP features had functioned well. For example, in 2009 the regulator stated:

> We have found that allowed revenue have declined since RPI-X regulation was introduced and we expect network charges to have followed a similar trend. Improvements in operating

[168] The percentage of revenue growth tied to the growth in revenue drivers, including customer and sales growth, was determined for each rate plan.

> efficiency and stability in the allowed cost of capital have facilitated these declines. Capital investment has been increasing and the reliability of the supply to customers has improved. These have all been driven at least partly by the regulatory framework…
>
> Our analysis reveals changes in recent years, however. Allowed revenue has stabilized or increased, reflecting increased investment. Operating efficiency improvements are expected to continue, but the scale may be limited compared to the period since RPI-X regulation...
>
> We have also found evidence that the regulated networks have generally managed to beat the regulatory settlement. Whilst this in itself is not necessarily cause for concern, there are questions about the extent to which companies are able to outperform and whether those companies earning the highest returns are indeed those that perform best for consumers.[169]

Cost Performance

Studies of multifactor productivity trends of British power distributors like those we have undertaken for North American distributors have been hampered by poor data. In particular, a consistent time series dataset is not available for many years, as the definitions of costs have changed over time.[170]

Ofgem commissioned a study of historic and expected productivity trends of British power distributors and the U.K. economy.[171] The study found that from program year 1991–1992 to program year 2001–2002, the British distributors averaged annual MFP growth of 4.3 percent. The opex productivity trend was 7.9 percent while the capital productivity trend was 1.2 percent. These MFP results were substantially higher than those of the U.K. economy as a whole and U.S. power distributors for similar time periods. However, the MFP measurement methodology was different.

In its RPI-X@20 review, Ofgem found that during the course of the price controls, real controllable operating costs per unit of energy distributed declined by 3.1 percent per year.[172] This decline exceeded the targets set by Ofgem in the price control reviews. In addition, distributors often underspent their capex budgets.

A major focus of Ofgem reviews of distributors' performance is comparisons of actual and allowed spending. The regulator found that 12 of 14 distributors had underspent their allowance. Ofgem attributed this outcome to several factors: improvements in efficiency, with unit costs for asset replacement work falling significantly; falling input prices; and a drop in reinforcement, connection and high value projects due to economic conditions. However, distributors had not delivered on their commitments in some areas, such as flood risk reduction programs.[173]

Reliability

The RPI-X@20 review assessed the reliability performance of power distributors under price controls. It found that the frequency and duration of outages had declined about 30 percent between 1990 and 2008. These trends continued, with a further 20 percent reduction in outage frequency and 30 percent reduction in outage duration between program year 2009–2010 and program year 2014–2015.[174]

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[169] Ofgem (2009a), p. 26.
[170] Ofgem (2009e).
[171] Information comparable to what we have gathered on the MFP trends of U.S. power distributors is unavailable.
[172] Real controllable operating costs were defined as operating costs less depreciation and "atypical" items.
[173] Ofgem (2015), p. 22.
[174] Ofgem (2015), p. 45.

RIIO

In February 2017, Ofgem released its first annual report on experience under RIIO.[175] The regulator reported that 12 of 14 distributors were spending less than they were allowed.[176] After the first year, distributors expected to underspend their allowances by 3 percent for the entire term of RIIO.

The report also noted that distributors had managed to over-earn by about 300 basis points on average. Ofgem believed that ROE performance was "predominantly driven by all [distributors] performing well against the Interruptions Incentive Scheme."[177] All distributors earned rewards under the scheme.

Distributors also had strong performances in several other areas:

- All distributors decreased their business carbon footprint and sulfur hexafluoride leaks during the first year of RIIO.

- Distributors also significantly improved their times to quote new connections. The industry average for the first year of RIIO was 46 percent to 49 percent lower than the target.[178]

- No distributors were penalized under the Incentives on Connections Engagement, as Ofgem was pleased with quality and detail of distributors' submissions.

All distributors received awards from the Broad Measure of Customer Service, and only one distributor was penalized as a result of poor customer satisfaction survey score.

[175] Ofgem (2017).
[176] On average, the distributors spent 9 percent less than their allowance for the first year of RIIO. These areas of underspending were partly offset by increased spending on inspections, repairing faults on the networks, and service quality.
[177] Ofgem (2017), p. 13.
[178] Ofgem (2017), p. 33.

7.0 Conclusions

The electric utility industry has played a key role over the years in the high performance of the U.S. economy. The industry was largely built under the cost of service approach to utility regulation. This regulatory system sets base rates in general rate cases at levels that compensate utilities for the costs they incur for capital, labor and materials. The scope of trackers that expedite recovery of utility costs has expanded in some jurisdictions to encompass costs of capital and other base rate inputs, as well as energy.

We have shown in this report that the efficacy of cost of service regulation (COSR) varies with business conditions. When conditions favor utilities, as often was the case in the years when COSR became an American tradition, rate cases are infrequent, performance incentives are strong, and regulatory cost is restrained. When business conditions are unfavorable, utilities file frequent rate cases or seek tracker treatment for more costs, or do both. As a consequence, performance incentives are weaker and regulatory cost is higher.

Multiyear rate plans are a salient alternative to COSR for electric utilities. Extensive experience has accumulated with these plans. Regulators have typically approved MRPs on the grounds that they strengthen performance incentives while reducing regulatory cost. Plans have had diverse provisions, and extensive experimentation has occurred.

MRPs can improve the efficiency of regulation. With less time spent on general rate cases, costs of regulation can be reduced, or resources can be redeployed to other useful activities like rate design and distribution system planning. In principle, MRPs that do not impair utility performance or harm customers could be adopted solely on the basis of better regulatory efficiency.

It is difficult to assess the impacts of MRPs and rate case frequency on utility cost performance. Costs of utilities are, after all, influenced by many other business conditions (e.g., severe storms and system age) as well as by their regulatory system. This report reviewed impacts of regulation on utility cost performance using two analytical tools: numerical incentive power analysis and empirical research on utility productivity trends.

Both lines of research suggest that MRPs (and, more generally, infrequent rate cases) can materially improve utility cost performance. For example, multifactor productivity growth of the U.S. electric, gas and sanitary sector was found to be considerably slower relative to that of the economy in a period of frequent rate cases than it was in periods when rate cases were much less frequent. We also found that the MFP growth of investor-owned electric utilities that operated for many years without rate cases, due to MRPs or other circumstances, was significantly more rapid than the U.S. electric utility norm. Stronger incentives produced cost savings of 3 percent to 10 percent after 10 years.

Our incentive power research suggests that *modest* steps in the direction of MRPs from traditional regulation produce only modest improvements in utility cost performance. This is also consistent with our empirical research, which showed that the MFP growth of California and New York utilities, which typically operated under conservative MRPs, were similar to or worse than the U.S. electric utility norm on balance. More robust MRPs — such as those with five-year plans, no earnings sharing, efficiency carryover mechanisms, and avoidance of rate cases between plans — can potentially produce larger gains. Recent innovations in MRP design, such as advances in efficiency carryover mechanisms, can increase incentive power.

Our incentive power research and case studies have important implications. First, utility performance and regulatory cost should be on the radar screen of state utility regulators, consumer groups and utility managers. We have shown that key business

conditions facing utilities today are less favorable than in prior periods when COSR worked well. This can lead to increased rate case frequency and expanded use of cost trackers which weaken utility incentives for improved cost performance.

Notwithstanding potential benefits of MRPs, they have not been adopted for energy utilities in most U.S. jurisdictions.[179] Several reasons can be advanced.

- COSR is well established in the United States, and some commissions are accomplished practitioners. When challenges emerge to the continuation of COSR, quick fixes such as revenue decoupling to address problems related to declining average use and expanded use of cost trackers have been more appealing to many regulators than the more extensive changes required to implement MRPs. State regulators also have tended to resist sweeping change in the direction of cost-plus regulation such as formula rate plans.

- Continuing evolution of COSR will slow diffusion of MRPs. For example, capital cost trackers can be incentivized. Use of PIMs to encourage cost-effective use of DERs can be expanded.

- It can be difficult to design MRPs that generate strong utility performance incentives without undue risk and that share benefits of better performance fairly with customers.

- Some adverse conditions (e.g., need for high capex) which give rise to frequent rate cases and expansive cost trackers under COSR have proven challenging to accommodate under MRPs.

- MRPs invite strategic behavior and plan design controversies. The dollars at stake invite stakeholders to energetically defend their positions. In proceedings to approve plans with indexed ARMs, for example, controversy over X factors has been common.

- Transitional regulatory systems that limit risks of bad outcomes from MRPs through such means as earnings sharing mechanisms and relatively short plan terms often do not generate substantially greater performance improvements than traditional COSR.[180]

- Utilities in most states have not proposed MRPs. While this may reflect their perception of the regulatory climate in their jurisdictions, many utilities may believe that they will make more money (or make the same money more easily) from frequent rate cases and more expansive cost trackers than under an MRP.

- Many consumer advocates are unsure of their role in an MRP system of regulation. Under COSR, consumer advocates intervene in each general rate case to reduce the revenue requirement. The substantial long-term cost to customers of slow productivity growth due to COSR is less visible. The lost opportunity for consumer advocates to spend more time on other regulatory issues may also be underappreciated.

- A key advantage of MRPs is the ease with which they can address brisk inflation. However, inflation has been slow in recent years.

- The impetus for PBR in many countries has come more from regulators and other policymakers than it has from utilities. Regulatory commissions in U.S. states typically have a less daunting

[179] For another discussion of why MRPs are not more popular in the United States, see Costello (2016).

[180] These transitional plans may nonetheless be important stepping stones to more effective regulatory systems.

mandate than regulators in other countries, who often have national jurisdictions with numerous utilities. This reduces the appeal of streamlined regulation.

Notwithstanding these considerations, we believe that use of MRPs is likely to increase in electric utility regulation over time.

- Key business conditions that trigger general rate cases are more likely to deteriorate than to improve in coming years. For example, inflation is more likely to rebound than to slow further due, for example, to rising bond yields. Penetration of customer-side DERs is likely to increase.

- Use of MRPs is already growing in the regulation of vertically integrated U.S. electric utilities.

- Continuing innovation in the United States, Canada and other countries will produce better MRP approaches. For example, regulators are becoming more skilled at designing plans for utilities engaged in accelerated grid modernization. Incentive compatible menus and efficiency carryover mechanisms help to ensure customer benefits.

- A growing number of power distributors will complete accelerated modernization programs and enter a period of more routine capex requirements that pose fewer problems for MRP design.

The strengths and weaknesses of MRPs are not fully understood. Plan design continues to evolve to address outstanding challenges. Areas of recommended future research include impacts of MRPs (and reduced rate case frequency more generally) on service quality, operating risk, and levels of bills that customers pay.[181] Evidence gathered for this report suggests that MRPs did not impair reliability, but this evidence was anecdotal. Lack of data is a major barrier to more comprehensive research on reliability and bill impacts.

[181] In addition, more refined statistical tests of the impacts of MRPs can be devised.

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Appendix A. Further Discussion of Multiyear Rate Plan Designs

This appendix discusses some topics in incentive plan design in greater detail. We consider earnings sharing mechanisms (ESMs), Z factors, marketing flexibility and Ofgem's Information Quality Incentive.

A.1 Earnings Sharing Mechanisms

Earnings sharing mechanisms share earnings variances that arise when a utility's return on equity (ROE) deviates from a commission-approved target. Treatment of earnings variances may depend on their magnitude. For example, there are often dead bands in which the utility does not share smaller variances (e.g., less than 100 basis points from the ROE target) with customers. Beyond the dead band there may be one or more additional bands in which earnings are shared in different proportions between customers and the utility.[182] While some ESMs share both surplus and deficit earnings, others share only surplus earnings. This maintains an incentive for companies to become more efficient to avoid under-earning.

Whether or not to add an ESM is one of the more difficult decisions in multiyear rate plan (MRP) design. The offsetting pros and cons of ESMs may help to explain why they are only featured in about half of current U.S. and Canadian MRPs. On the plus side, an ESM can reduce risks that revenue will deviate substantially from cost. Unusually high or low earnings may be undesirable to the extent that they reflect windfall gains or losses, poor plan design, data manipulation, or strategic deferrals of expenditures. Reduced likelihood of extreme earnings outcomes can help parties agree to a plan and make it possible to extend the period between rate cases.

On the downside, ESMs weaken utility performance incentives. Permitting marketing flexibility can be complicated in the presence of an ESM because discounts available to some customers can affect earnings variances that are shared with all customers.[183] ESM filings can be a source of controversy. Customers may complain, for example, if the ROE never gets outside the dead band so that surplus earnings are shared. There is less need for an ESM if the plan features other risk mitigation measures such as inflation indexing, Z factors or revenue decoupling.

A.2 Z Factors

A Z factor adjusts revenue for miscellaneous hard-to-foresee events that impact utility earnings. Many MRPs have explicit eligibility requirements for Z factor events. Here is a typical list of requirements.

<u>Causation</u>: The costs must be clearly outside of the base upon which rates were derived.

<u>Materiality</u>: The costs must have a significant impact on utility finances. Materiality can be measured based on individual events, cumulative impacts of multiple events, or both.

[182] An ESM is therefore sometimes referred to as a "banded ROE."
[183] This problem can be contained by sharing only the utility's earnings surpluses.

Outside of Management Control: The cost must be attributable to events outside of management's ability to control.

Prudence: The cost must have been prudently incurred.

One of the primary rationales for Z factor adjustments is the need to adjust revenue for effects of changes in tax rates and other government policies on the utility's cost. Another rationale for Z factors is to adjust for effects of miscellaneous other external developments on utility costs which are not captured by inflation and X factors. Z factors can potentially reduce operating risk, without weakening performance incentives for the majority of costs. Z factors can thus reduce the possibility that an MRP needs to be reopened, while maintaining most benefits of MRPs.

A.3 Marketing Flexibility

Need for Flexibility

Regulators have long acknowledged the need to afford utilities some flexibility in fashioning rate and service offerings. A utility's need for marketing flexibility is greater to the extent that demand for its services is complex, changing and elastic (i.e., sensitive) with respect to the terms of services offered. When demand is elastic, rates that are too high produce more bypass of utility services.[184] Demand elasticity is greater when customers have alternative ways to meet their needs which are competitive with respect to cost and quality. Elasticity is also greater for products that are "discretionary" in the sense that they do not address a customer's most basic needs.

While "core" customers have fewer options and lower elasticities of demand for basic services, electric utilities have long relied on marketing flexibility to customize terms of service to large-volume customers. These customers play a larger role in the earnings of VIEUs than they do in the earnings of UDCs. One reason is that UDCs do not profit from sizable sums these customers pay for power supplies. Another is that some of these customers take service at transmission voltage and do not pay for many distribution-level costs. In addition, all types of utilities desire flexibility when marketing underutilized capacity in competitive markets (e.g., leasing land in transmission corridors).[185]

Interest among electric utilities in marketing flexibility is growing as demand for power services is becoming more complex, changeable and sensitive to terms of service that utilities offer. For example, advanced metering infrastructure, other smart grid technologies, distributed storage, and plug-in electric vehicles open the door to a variety of new utility services. Large-load customers have a growing interest in customized green power services to meet corporate goals. Distributed generation and storage pose a growing competitive challenge in some jurisdictions. However, for the foreseeable future regulators will likely control terms of service to distributed generation and storage customers carefully.

Marketing flexibility can also help utilities encourage customers to use their services in less costly ways. For example, AMI makes it more cost-effective to offer time-varying tariffs to

[184] Uneconomic bypass occurs when a customer would use a system more at a lower rate that still exceeds the cost of service. When uneconomic bypass is reduced, customers make more contributions to fixed costs that lower rates for other customers.
[185] Margins from "other revenues" benefit retail customers by, for example, reducing the retail revenue requirement in rate cases.

residential and small business customers. These tariffs can encourage reduced loads at times when the cost of electricity is especially high and slow the need for costly upgrades for substations and load-following generation capacity.

Flexibility Measures

Marketing flexibility runs the gamut from greater effort by regulators to approve new rates and services by traditional means to "light-handed" regulation and even decontrol of certain utility offerings.[186] Light-handed regulation typically takes the form of expedited approval of new or revised rate and service offerings. These offerings may be subject to further scrutiny at a later date, such as in the next rate case. Pricing floors are often established based on marginal or incremental cost of service to ensure that customers of new rates and services contribute to margin.

Regulators most commonly grant marketing flexibility for rate and service offerings with certain characteristics. Generally speaking, flexibility is encouraged where new offerings are likely to benefit target customers while also benefitting other customers — for example, by increasing contributions to margins so that contributions by other customers can be reduced. Optional offerings have often been accorded expedited treatment by regulators because targeted customers are protected by their recourse to service under standard tariffs, as well as offerings by potential third-party providers that compete with the utility.

Several kinds of offerings may be deemed optional, such as:

1. A discount from rates in a standard tariff, offered to particular customers — for example, due to relatively high elasticity of their demands for utility services
2. An optional tariff that is available to all qualifying customers, such as a time-sensitive rate for electric vehicle charging
3. Special (negotiated) customer-specific contracts for utility services
4. A new premium quality service for customers prepared to pay for better quality
5. A discretionary service such as lighting on a backyard power pole
6. Special service packages (which may include standard services as components), such as a rate for a bundle of services that includes premium quality service and electric vehicle charging

Why MRPs Facilitate Marketing Flexibility

MRPs facilitate marketing flexibility for several reasons. Less frequent general rate cases reduce the chore of deciding how to allocate the revenue requirement between a complex and changing mix of market offerings. Multiyear rate plans also reduce concerns about cross-subsidies between service classes because infrequent rate cases and other plan provisions, such as service baskets, insulate core customers from potentially adverse consequences of marketing flexibility.[187] To the

[186] Decontrol of utility rate and service offerings is typically limited to markets that are robustly competitive.
[187] Cost trackers create a "back door" to cross-subsidization unless discounting of tracked costs is prohibited.

extent that the utility's earnings losses from special terms of services for certain customers can't be recovered from other customers, regulators are more confident that discounts are prudent.

In addition to facilitating marketing flexibility, MRPs create a special need for flexibility since rate cases are less frequently available as occasions for redesigning rates. Special proceedings to redesign rates in a revenue-neutral way can occur during an MRP. Alternatively, utilities may be permitted (or required) to gradually change rate designs during a rate plan in accordance with commission-approved goals. For example, the commission could approve a phase-in of time-sensitive usage charges.

MRPs can also strengthen utility incentives to improve marketing because the utilities are able to keep resultant margins longer. For example, under MRPs utilities have greater motivation to discourage load patterns that are especially costly. Under price caps, utilities have more incentive to encourage large-load customers to expand their operations.

Marketing Flexibility Precedents

Electric utilities have long been granted flexibility by regulators in rates and services they offer to some of the markets they serve. For example, rates utilities charge for use of their assets in various competitive markets are frequently not addressed by state regulators. Examples include sales in bulk power markets and rental of surplus office space. Light-handed regulation is sometimes accorded to special contracts for large-load customers with price-elastic demands or an interest in customized green power services.[188] However, special contracts for utility services require specific approval in many jurisdictions.

Multiyear rate plans have been extensively used to regulate utilities in industries where market-responsive rates and services are a priority. The example of Central Maine Power is discussed in Section 6 in this report. However, MRPs have not to date played a large role in fostering electric utility marketing flexibility. One reason is that many MRPs to date have applied to utility distribution companies, which traditionally had less need for special pricing for large-load customers.

A.4 Britain's Information Quality Incentive

Britain's Information Quality Incentive (IQI) rewards distributors for making conservative cost forecasts and then performing better.[189] The IQI is essentially a menu consisting of cost forecast-allowed revenue combinations. It currently applies to most operation and maintenance (O&M) expenses and capex. Each utility is asked to give a cost forecast and is eventually given an allowed revenue amount based on this forecast. The IQI's input on allowed revenue is in two parts: *ex-ante* allowed revenue and an IQI adjustment factor. By announcing its cost forecast, the utility implicitly chooses both its *ex-ante* allowed revenue and an IQI adjustment factor formula.

The *ex-ante* allowed revenue is a weighted average of the regulator's and the utility's cost forecasts. The regulator's forecast receives 75 percent weight while the utility's forecast receives

[188] Duke Energy (2015).
[189] Ofgem states that distributors with "less well justified capex forecasts, as compared with the views of Ofgem's consultants would be permitted to spend above the amounts that they had justified to Ofgem but [these distributors] would receive relatively lower returns for underspending. In contrast, those [distributors] that had better justified their forecasts, and were in line with the views of the consultants, would be rewarded with a higher rate of return and a stronger incentive for efficiency." See Ofgem (2009b), p. 38.

25 percent weight. This treatment alone greatly reduces the payoff to the distributor from a high cost forecast. The substantial weight assigned to the regulator's forecast reflects the large investment it makes in engineering and consulting services to develop an independent review of future cost.

The IQI adjustment factor is composed of an incentive rate and an additional income factor. The incentive rate specifies sharing, between utilities and customers, of variances between the utility's actual expenditures and the allowed revenue for these expenditures it was granted *ex ante*. The utility's share of these variances increases as the difference between the utility's cost forecast and regulator's own forecast decreases. The additional income factor, also referred to as an upfront reward or penalty, provides an immediate incentive for the utility to provide a cost forecast that is at or below Ofgem's own forecast.

Together these provisions make the menu "incentive compatible." The utility is rewarded when its cost forecast is low and its actual cost is similar. The IQI discourages a strategy of proposing a high forecast and subsequently incurring low costs.

Figure A-1 shows the IQI menu developed for the 2010-2015 plan:[190]

- The first row is a ratio of the utility's cost forecast to the regulator's cost forecast. A ratio of less than 100 means the utility has presented a lower cost forecast than the regulator, while a ratio above 100 means the utility's cost forecast is higher than the regulator's.

- The second row is the utility's share of what it over- or underspends relative to the *ex-ante* allowed revenue. The utility's share of these variances increases when its cost forecast is low. This feature provides greater incentives for the utility to cut costs and provide a forecast that is not inflated.

- The third row is the *ex-ante* revenue the utility can collect, expressed as a percentage of the regulator's cost forecast. This is much closer to Ofgem's forecast than to the utility's.

- The fourth row is the additional *ex post* income the utility can collect, expressed as a percentage of the regulator's cost forecast. This is a reward for a low cost forecast.

Values in the second section of Figure A-1, labeled IQI Adjustment Factor, illustrate possibilities for additional revenue (expressed as a percentage of Ofgem's cost forecast) which the utility can collect once it reports actual expenditures for the price control period. The amount of additional revenue depends on how the company's forecast compares to Ofgem's forecast and to the company's ultimate expenditures. The revenue adjustment is more favorable to the utility to the extent that its expenditures are low relative to its own forecast and Ofgem's forecast. The highest reward is offered for spending less than a utility forecast that was low relative to Ofgem's forecast.

[190] There have not been any major changes to the IQI methodology since this matrix was established.

Utility's cost forecast (% of Ofgem's cost forecast)	95	100	105	110	115	120	125	130	135	140
Utility's share of under/over spending (incentive rate)	0.53	0.5	0.48	0.45	0.43	0.4	0.38	0.35	0.33	0.3
Ex-ante allowed revenue (% of Ofgem's cost forecast)	98.75	100	101.25	102.5	103.75	105	106.25	107.5	108.75	110
Ex-post additional income (% of Ofgem's cost forecast)	3.09	2.5	1.84	1.13	0.34	-0.5	-1.41	-2.38	-3.41	-4.5
Actual utility expenditure (% of Ofgem's cost forecast)	**IQI Adjustment Factor (% of Ofgem's cost forecast)**									
90	7.69	7.5	7.19	6.75	6.19	5.5	4.69	3.75	2.69	1.5
95	5.06	5	4.81	4.5	4.06	3.5	2.81	2	1.06	0
100	2.44	2.5	2.44	2.25	1.94	1.5	0.94	0.25	-0.56	-1.5
105	-0.19	0	0.06	0	-0.19	-0.5	-0.94	-1.5	-2.19	-3
110	-2.81	-2.5	-2.31	-2.25	-2.31	-2.5	-2.81	-3.25	-3.81	-4.5
115	-5.44	-5	-4.69	-4.5	-4.44	-4.5	-4.69	-5	-5.44	-6
120	-8.06	-7.5	-7.06	-6.75	-6.56	-6.5	-6.56	-6.75	-7.06	-7.5
125	-10.69	-10	-9.44	-9	-8.69	-8.5	-8.44	-8.5	-8.69	-9
130	-13.31	-12.5	-11.81	-11.25	-10.81	-10.5	-10.31	-10.25	-10.31	-10.5
135	-15.94	-15	-14.19	-13.5	-12.94	-12.5	-12.19	-12	-11.94	-12
140	-18.56	-17.5	-16.56	-15.75	-15.06	-14.5	-14.06	-13.75	-13.56	-13.5
145	-21.19	-20	-18.94	-18	-17.19	-16.5	-15.94	-15.5	-15.19	-15

Figure A-1. IQI Matrix for Ofgem's 5th Distribution Price Control Review.[191] IQI Matrix is an incentive compatible menu intended to encourage utilities to make low expenditure forecasts and then outperform them.

Suppose, by way of illustration, that a utility made a forecast that was just 5 percent above Ofgem's. Its *ex ante* allowed revenue would be only 1.25 percent above Ofgem's forecast, but it would be entitled to a fairly high 48 percent of surplus earnings and additional income equal to 1.84 percent of Ofgem's forecast. If its actual cost turned out to be the same as its forecast, it would garner an additional reward equal to 0.06 percent of Ofgem's forecast.

[191] Ofgem (2009c), p. 111. Presented here with some small changes to be more easily understood.

Appendix B. Details of the Technical Work

This appendix provides more technical details of two lines of research presented in this report. One is the numerical incentive power research. The other is the empirical research on power distributor productivity. We also discuss some statistical benchmarking concepts.

B.1 Incentive Power Research[192]

This section discusses incentive power research that PEG has conducted over the years on behalf of several utilities and regulatory commissions.[193] Implications of this research are summarized in Section 5 of this report.

Overview of Research

Our incentive power research considers how the performance of utilities differs under alternative regulatory systems that feature various performance-based regulation (PBR) features as well as systems that resemble traditional rate regulation. The research can be used to explore multiyear rate plan (MRP) design options such as earnings sharing mechanisms and alternative plan terms.

At the heart of our research is a mathematical optimization model of the cost management of a company subject to rate regulation. We consider a company facing business conditions like those of a large energy distributor. In the first year of the decision problem, we assume for our example calculations that total annual cost is around $500 million for a company of average efficiency. Capital accounts for a little more than half of total cost. The annual depreciation rate is a constant 5 percent, the weighted average cost of capital is 7 percent, and the income tax rate is 30 percent.

Some assumptions have been made in the model to simplify the analysis. There is no inflation or output growth that would cause cost to grow over time.[194] The utility's revenue will be the same year after year in the absence of a rate case.

The company has opportunities to reduce its cost through cost reduction initiatives. Two kinds of cost reduction projects are available. Projects of the first type lead to temporary (specifically, one-year) cost reductions. Projects of the second type involve a net cost increase in the first year in exchange for *sustained* reductions in future costs. Projects in this category vary in their payback periods. The payback periods we consider are one year, three years and five years. For projects of each kind, there are diminishing returns to additional cost reduction effort in a given year. In total, we consider eight kinds of cost reduction projects — four for O&M expenses and four for capex. In our simulations, the company is permitted to pass up each kind of project in a given year (so that there is zero effort) but cannot choose *negative* levels of effort which constitute deliberate waste. This is tantamount to assuming that deliberate waste is recognized by the regulator and disallowed.

The company can increase earnings by undertaking cost containment projects, but experiences employee distress and other *unaccountable* costs when pursuing such projects. These costs are assumed to occur in

[192] Further details of this research can be requested from the authors.
[193] Our research in this area was for several years spearheaded by Travis Johnson, a graduate of the Massachusetts Institute of Technology and Stanford Business School who is now a professor at the McCombs School of Business at the University of Texas.
[194] The comparatively low weighted-average cost of capital reflects these assumptions.

the first year of the initiative. We have assigned these unaccountable costs a value, in the reckonings of management as it crafts a business plan, that is about one quarter the size of the *accountable* upfront costs.

The company is assumed to choose the cost containment strategy that maximizes the net present value of earnings, less the unaccountable costs of performance improvement just discussed, given the regulatory system, income tax rate and available cost reduction opportunities. We are interested in examining how the company's cost management strategy differs under alternative regulatory systems.

Reference Regulatory Systems[195]

We have developed five "reference" regulatory systems that constitute useful comparators for MRPs:

One is "cost plus" regulation, in which a company's revenue is exactly equal to its cost every year. This has no real-world counterpart, since even traditional regulation requires at least a one-year rate case cycle and some incentive, once rates are set, to cut costs of base rate inputs. Another reference system is full externalization of the ratemaking process so that rates are no longer trued up periodically to the company's costs. Such an outcome would be obtained if the company were to embark on a permanent revenue cap regime.

The other three reference regimes approximate traditional regulation. In each, there is a predictable cycle of rate cases in which revenue is reset to the company's cost. We consider cycles of one, two and three years.

Multiyear Rate Plans

We considered various types of MRPs in our incentive power research. In most of these plans, there is no stretch factor shaving the revenue requirement mechanistically from year to year. The plans differ with respect to several kinds of provisions:

- *Plan term.* We consider terms of three, five, six and 10 years.

- *Impact of earnings sharing.* Plans considered also vary with respect to the earnings sharing specification. We consider earnings sharing mechanisms that have various company/customer allocations of earnings variances. Company shares considered are zero, 25 percent, 50 percent and 75 percent. None of the mechanisms considered have dead bands or multiple sharing bands, as these complicate calculations.

- *How rates change with rate case.* Our characterization of the rate case is important in modeling both traditional regulation and the MRP regimes. We assume in most model runs that rates in the initial year of the new regulatory cycle are, with one qualification, set to reflect the cost of service in the last year of the previous regulatory cycle.[196] The qualification is that any upfront *accountable* costs of initiatives for sustainable cost reductions that are undertaken in the historical reference year are amortized over the term of the plan.

- *Efficiency carryover mechanisms.* We also have considered the impact of some stylized efficiency carryover mechanisms. In one mechanism, the revenue requirement at the start of a new plan is based on a percentage (α%) of the cost in the last year of the previous plan and (1-

[195] The tables presented later in this appendix present results for these various scenarios.
[196] This is reasonable considering the lack of inflation and the stability of demand.

α)% on the revenue requirement in that year. This effectively permits the company to share (1-α)% any deviation between its cost and the revenue requirement. We consider alternative values of α, ranging from 90 percent to 50 percent.

In addition, we considered an efficiency carryover mechanism in which the revenue requirement in the first year of a new rate plan is adjusted for a percentage of the variance between an exogenous benchmark value of cost in the last plan year and the actual cost incurred. The revenue requirement for the first year of the new MRP is thus a weighted average of the benchmark and actual cost. The same result can be achieved by positing that the revenue requirement in year t is based 50/50 on the cost and the benchmark in year t-1.

- *Avoided rate case option.* We also have considered a menu approach to incenting long-term efficiency gains. It gives the company the option at the end of the plan to start the new plan without a rate case. The revenue requirement for the next plan is in this eventuality established on the basis of a predetermined formula. The formula we consider is a stretch factor reduction in the revenue requirement established in the preceding rate case.[197] The company can thus avoid a rate case if it agrees to a starting revenue requirement for the new plan that regulators believe offers value to customers.

Another decision that must be made in comparing alternative regulatory systems is what occurs at the conclusion of a plan. Our view is that the best way to compare the merits of alternative systems is to have them repeat themselves numerous times. For example, we examine the incentive impact of five-year plan terms by examining the cost containment strategy of a company faced with the prospect of a lengthy series of five-year plans.

Identifying the Optimal Strategy

Numerical analysis was used to predict the utility’s optimal strategy. Under this approach we considered, for each regulatory system and each kind of cost containment initiative, thousands of different possible responses by the company. We chose as the predicted strategy the one yielding the highest value for the utility’s objective function. An advantage of numerical analysis in this application is that it permits us to consider regulatory systems of considerable realism.

Research Results

Tables B-1 to B-3 present a summary of results from the incentive power model. For each of several regulatory systems the tables show the net present value of cost reductions from the operation of the system over many years. In the columns on the right-hand side of the tables, we report the average percentage reduction in the company’s total cost that results from the regulatory system. We report outcomes for the first and second plan and the long run. We discuss here only the long-run results.

Results are presented for 10 percent, 30 percent and 50 percent levels of initial operating inefficiency. We focus here on the 30 percent results since our benchmarking research over the years has suggested that this is a normal level of operating inefficiency. Table B-1 presents the 30 percent results. Tables B-2 and B-3 show that performance gains from more incentivized regulatory systems are generally larger for less efficient companies. Changes in productivity from the various PBR mechanisms are greatest in Table B-3 (companies starting with 50 percent inefficiency) and smallest in Table B-2 (companies starting with 10 percent inefficiency).

[197] In a world of input price and output growth, a more complex formula would be required.

Results for Reference Regulatory Systems

Table B-1 shows that no cost reduction initiatives are undertaken under cost plus regulation. This reflects the fact that there is no monetary reward for undertaking cost reduction initiatives, all of which involve unaccountable costs. At the other extreme, a complete externalization of future rates such as might occur if rate cases were never held again produces performance improvements relative to cost plus regulation that, over many years, accumulate to a net present value (NPV) of more than $2 billion. Average annual performance gains of 2.71 percent (or 271 basis points) are achievable in the long run.

As for the traditional regulatory systems, the system with a *three*-year cycle incents companies to achieve long-run savings with an NPV of about $900 million — a major improvement over cost plus regulation but less than half of the savings that are potentially available from efficiency initiatives. Average annual performance gains rise from zero to 0.90 percent. The fact that some cost savings occur under traditional regulation is not surprising inasmuch as the assumed three-year regulatory cycle permits some gains to be reaped from temporary cost reduction opportunities and from projects with one-year payback periods. A two-year rate case cycle produces only 0.66 percent annual performance gains.

Table B- 1 Results From the Incentive Power Model: 30% Initial Inefficiency

	Net Present Value ($m) of Cost Redutions	Relative Incentive Power	Average Annual Performance Gain*	
			First two rate cycles	Long run
Reference Regulatory Options				
Cost plus	0	**0%**	0.00%	0.00%
2 Year Cost of Service	657	**29%**	1.19%	0.66%
3 Year Cost of Service	899	**39%**	1.22%	0.90%
Full Rate Externalization	2299	**100%**	3.93%	2.71%
Impact of Plan Term				
Term = 3 years	899	**39%**	1.22%	0.90%
Term = 5 years	1318	**57%**	1.93%	1.41%
Term = 6 years	1428	**62%**	1.96%	1.58%
Term = 10 years	1664	**72%**	2.35%	2.23%
Impact of Earnings Sharing Mechanism				
5-year plans				
No Sharing	1318	**57%**	1.93%	1.41%
Company Share = 75%	1075	**47%**	1.29%	1.17%
Company Share = 50%	966	**42%**	1.14%	1.01%
Company Share = 25%	879	**38%**	1.03%	0.88%
Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)				
3-Year Plans, Extern				
Externalized Percentage = 0%	899	**39%**	1.93%	0.90%
Externalized Percentage = 10%	990	**43%**	1.29%	1.07%
Externalized Percentage = 25%	1336	**58%**	1.80%	1.66%
Externalized Percentage = 50%	1799	**78%**	3.41%	2.15%
5-Year Plans, Extern				
Externalized Percentage = 0%	1318	**57%**	1.93%	1.41%
Externalized Percentage = 10%	1469	**64%**	2.07%	1.55%
Externalized Percentage = 25%	1598	**70%**	2.30%	1.76%
Externalized Percentage = 50%	1989	**86%**	3.00%	2.27%
Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)				
3-Year Plans				
Externalized Percentage = 0%	899	**39%**	1.93%	0.90%
Externalized Percentage = 10%	1535	**67%**	2.26%	1.93%
Externalized Percentage = 25%	1824	**79%**	3.68%	2.29%
Externalized Percentage = 50%	2016	**88%**	3.84%	2.54%
5-Year Plans				
Externalized Percentage = 0%	1318	**57%**	1.93%	1.41%
Externalized Percentage = 10%	1621	**70%**	2.34%	1.80%
Externalized Percentage = 25%	1908	**83%**	3.08%	2.31%
Externalized Percentage = 50%	2109	**92%**	3.57%	2.56%
Rate Option Plans				
3-Year Plans				
No rate option	899	**39%**	1.93%	0.90%
Yearly rate reduction = 1%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 1.5%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2.5%	899	**39%**	1.93%	0.90%
5-Year Plans				
No rate option	1318	**57%**	1.93%	1.41%
Yearly rate reduction = 1%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 1.5%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2%	1318	**57%**	1.93%	1.41%
Yearly rate reduction = 2.5%	1318	**57%**	1.93%	1.41%

*** = measured by the average year-over-year percent decrease in costs**

Table B-2 Results From the Incentive Power Model: 10% Initial Inefficiency

	Net Present Value ($m) of Cost Redutions	Relative Incentive Power	Average Annual Performance Gain*	
			First two rate cycles	Long run
Reference Regulatory Options				
Cost plus	0	**0%**	0.00%	0.00%
2 Year Cost of Service	436	**29%**	1.08%	0.57%
3 Year Cost of Service	623	**42%**	1.02%	0.76%
Full Rate Externalization	1496	**100%**	2.64%	2.32%
Impact of Plan Term				
Term = 3 years	623	**42%**	1.02%	0.76%
Term = 5 years	811	**54%**	1.10%	1.15%
Term = 6 years	976	**65%**	1.19%	1.30%
Term = 10 years	1088	**73%**	1.48%	1.73%
Impact of Earnings Sharing Mechanism				
5-year plans				
No Sharing	811	**54%**	1.10%	1.15%
Company Share = 75%	723	**48%**	0.97%	0.97%
Company Share = 50%	653	**44%**	0.87%	0.84%
Company Share = 25%	602	**40%**	0.83%	0.73%
Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)				
3-Year Plans, Extern				
Externalized Percentage = 0%	623	**42%**	1.02%	0.76%
Externalized Percentage = 10%	672	**45%**	1.09%	0.87%
Externalized Percentage = 25%	887	**59%**	1.32%	1.36%
Externalized Percentage = 50%	1123	**75%**	1.87%	1.80%
5-Year Plans, Extern				
Externalized Percentage = 0%	811	**54%**	1.10%	1.15%
Externalized Percentage = 10%	932	**62%**	1.20%	1.27%
Externalized Percentage = 25%	1025	**69%**	1.36%	1.47%
Externalized Percentage = 50%	1239	**83%**	1.91%	1.90%
Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)				
3-Year Plans				
Externalized Percentage = 0%	623	**42%**	1.02%	0.76%
Externalized Percentage = 10%	1037	**69%**	1.65%	1.64%
Externalized Percentage = 25%	1182	**79%**	2.08%	1.94%
Externalized Percentage = 50%	1253	**84%**	2.48%	2.16%
5-Year Plans				
Externalized Percentage = 0%	811	**54%**	1.10%	1.15%
Externalized Percentage = 10%	1033	**69%**	1.42%	1.42%
Externalized Percentage = 25%	1229	**82%**	1.97%	1.83%
Externalized Percentage = 50%	1280	**86%**	2.41%	2.26%
Rate Option Plans				
3-Year Plans				
No rate option	623	**42%**	1.02%	0.76%
Yearly rate reduction = 1%	1496	**100%**	3.93%	2.71%
Yearly rate reduction = 1.5%	1496	**100%**	3.93%	2.71%
Yearly rate reduction = 2%	623	**42%**	1.02%	0.76%
Yearly rate reduction = 2.5%	623	**42%**	1.02%	0.76%
5-Year Plans				
No rate option	811	**54%**	1.10%	1.15%
Yearly rate reduction = 1%	1496	**100%**	2.64%	2.32%
Yearly rate reduction = 1.5%	811	**54%**	1.10%	1.15%
Yearly rate reduction = 2%	811	**54%**	1.10%	1.15%
Yearly rate reduction = 2.5%	811	**54%**	1.10%	1.15%

*** = measured by the average year-over-year percent decrease in costs**

Table B-3. Results From the Incentive Power Model: 50% Initial Inefficiency

	Net Present Value ($m) of Cost Redutions	**Relative Incentive Power**	**Average Annual Performance Gain***	
			First two rate cycles	Long run
Reference Regulatory Options				
Cost plus	0	**0%**	0.00%	0.00%
2 Year Cost of Service	905	**30%**	1.33%	0.75%
3 Year Cost of Service	1430	**47%**	2.36%	1.05%
Full Rate Externalization	3022	**100%**	4.75%	3.05%
Impact of Plan Term				
Term = 3 years	1430	**47%**	2.36%	1.05%
Term = 5 years	1778	**59%**	2.29%	1.65%
Term = 6 years	2143	**71%**	2.37%	1.82%
Term = 10 years	2520	**83%**	3.29%	2.42%
Impact of Earnings Sharing Mechanism				
5-year plans				
No Sharing	1778	**59%**	2.29%	1.65%
Company Share = 75%	1603	**53%**	2.06%	1.36%
Company Share = 50%	1520	**50%**	1.96%	1.22%
Company Share = 25%	1354	**45%**	1.75%	1.02%
Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)				
3-Year Plans, Extern				
Externalized Percentage = 0%	1430	**47%**	2.36%	1.05%
Externalized Percentage = 10%	1551	**51%**	2.48%	1.21%
Externalized Percentage = 25%	2017	**67%**	3.17%	1.90%
Externalized Percentage = 50%	2481	**82%**	4.08%	2.42%
5-Year Plans, Extern				
Externalized Percentage = 0%	1778	**59%**	2.29%	1.65%
Externalized Percentage = 10%	1979	**65%**	2.52%	1.81%
Externalized Percentage = 25%	2279	**75%**	2.75%	2.02%
Externalized Percentage = 50%	2666	**88%**	3.68%	2.60%
Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)				
3-Year Plans				
Externalized Percentage = 0%	1430	**47%**	2.36%	1.05%
Externalized Percentage = 10%	2202	**73%**	3.58%	2.20%
Externalized Percentage = 25%	2531	**84%**	4.30%	2.61%
Externalized Percentage = 50%	2793	**92%**	4.61%	2.84%
5-Year Plans				
Externalized Percentage = 0%	1778	**59%**	2.29%	1.65%
Externalized Percentage = 10%	2309	**76%**	2.81%	2.04%
Externalized Percentage = 25%	2558	**85%**	3.68%	2.54%
Externalized Percentage = 50%	2880	**95%**	4.35%	2.88%
Rate Option Plans				
3-Year Plans				
No rate option	1430	**47%**	2.36%	1.05%
Yearly rate reduction = 1%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 1.5%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2.5%	3022	**100%**	4.75%	3.05%
5-Year Plans				
No rate option	1778	**59%**	2.29%	1.65%
Yearly rate reduction = 1%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 1.5%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2.5%	1778	**59%**	2.29%	1.65%

*** = measured by the average year-over-year percent decrease in costs**

Impact of Plan Term

Consider now the effect of extending the plan term beyond the conventional three-year rate case cycle. Extending the term from three years to five years increases annual performance gains by about 51 basis points in the long run. Evidently, stronger performance incentives elicit better performance. Extending the term from three years to 10 years increases average annual performance gains by 133 basis points.

The benefits of a longer plan term are greater when rate cases would be more frequent under traditional regulation. For example, if rate cases would otherwise be held every two years, a five-year MRP with no earnings sharing produces 75 basis points of additional annual performance gains in the long run.

Impact of Earnings Sharing

The third panel of Table B-1 shows that the addition of earnings sharing mechanisms (ESMs) reduces cost savings compared to a plan of the same duration with no sharing mechanism. For example, a five-year plan in which the company keeps 75 percent of earnings variances produces only 27 basis points of additional performance gains annually in the long run compared to a three-year rate case cycle.

However, plans with an earnings sharing mechanism can deliver more cost savings than a pattern of frequent rate cases. For example, a five-year plan with 75/25 sharing produces 51 more basis points of annual performance gains than traditional regulation with a two-year cycle.

Impact of Efficiency Carryover Mechanism

Let's consider now the impact of the efficiency carryover mechanism that uses the predetermined revenue requirement from the previous plan as the benchmark. The fourth panel of Table B-1 shows that, in the context of a five-year rate plan, assigning the benchmark a weight of 25 percent produces 35 basis points of additional performance gains. Of greater interest perhaps is that it boosts the performance gains from a three-year plan by a substantial 76 basis points. Thus, this efficiency carryover mechanism can give a three-year plan considerable incentive power.

Let's turn now to the alternative efficiency carryover mechanism approach in which cost in the historical reference year is compared to a *fully external* benchmark such as that produced by an econometric model developed using industry data. Remarkably, the fifth panel of Table B-1 shows that assigning the benchmark a weight of only 25 percent more than doubles the cost savings produced by three-year plans. This suggests that a benchmark-based efficiency carryover mechanism has the potential to strengthen performance incentives rather dramatically. With a *five*-year rate case cycle, the effect of the same 25 percent externalization is still substantial, but more modest than in a three-year cycle. This is mainly due to the fact that more of the potential cost savings are achieved by the five-year term.

Impact of Rate Case Avoidance

Let's turn now to the impact of rate case avoidance. The sixth panel of Table B-1 shows that, in three-year plans with stretch factors of 1 percent, 1.5 percent and 2 percent, this approach produces the same dramatic cost efficiency savings that would result from full rate externalization. Evidently, the company judges that with a high level of cost containment effort it can get its costs permanently below the cost growth target and acts accordingly.

Conclusions

Our incentive power research for this report yields important results on the consequences of alternative regulatory systems. Most fundamentally, the results show that the frequency of rate cases can have a material impact on utility cost performance. Under COSR, performance will be considerably better when rate cases typically occur every three years than when they typically occur every two years. Thus, the favorability of business conditions affects operating performance.

Our research also shows that an MRP with a five-year rate case cycle can simulate the stronger incentives, especially when rate cases are more frequent than every three years. In addition, an MRP should have advantages when the alternative is pervasive cost trackers. Incentives are weakened under an ESM. We also show that adding innovative plan provisions on the frontier of PBR, such as efficiency carryover mechanisms and menus, can materially strengthen performance incentives. Many of the real-world plans reviewed in this report did not have these incentive power "turbochargers."

B.2 Utility Productivity Research

We presented results of our utility productivity research in Section 6 of this report. This section of Appendix B discusses productivity and revenue cap indexes, sources of productivity growth, and productivity trends of U.S. power distributors. We also provide mathematical details of the calculations.

Productivity Indexes

The Basic Idea

A productivity index is the ratio of an output quantity index (Outputs) to an input quantity index (Inputs):

$$Productivity = \frac{Outputs}{Inputs} \qquad [B1]$$

It is used to measure the efficiency with which firms convert production inputs into the goods and services that they provide. The growth trend of a productivity trend index can then be shown mathematically to be the *difference* between the trends in the output and input quantity indexes.

$$trend\ Productivity = trend\ Outputs - trend\ Inputs. \qquad [B2]$$

Productivity grows when the output index rises more rapidly (or falls less rapidly) than the input index. Productivity can be volatile but tends to grow over time. The volatility is typically due to fluctuations in output, the uneven timing of certain expenditures, or both. The volatility of productivity growth tends to be greater for individual companies than the average for a group of companies.

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

The output (quantity) index of a firm or industry summarizes trends in the scale of operation. Growth in each output dimension that is itemized is measured by a subindex. One possible objective of output research is to measure the impact of output growth on company *cost.* In that case, the sub-indexes should measure the dimensions of the "workload" that drive cost. If there is more than one pertinent scale variable, the weights for each variable should reflect the relative cost impacts of these drivers.[198] A productivity index calculated using a cost-based output index may fairly be described as a "cost efficiency index."

Sources of Productivity Growth

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

Economies of scale are a second source of productivity growth. These economies are available in the longer run if cost tends to grow more slowly than output. A company's potential to achieve incremental scale economies depends on the pace of its output growth. Incremental scale economies (and thus productivity growth) will typically be reduced when output growth slows.

A third important source of productivity growth is change in inefficiency. Inefficiency is the degree to which a company fails to operate at the maximum efficiency that technology allows. Productivity growth rises (falls) when inefficiency diminishes (increases). The lower the company's current efficiency level, the greater the potential for productivity growth from a change in inefficiency.

Another driver of productivity growth is changes in the miscellaneous external business conditions, other than input price inflation and output growth, which affect cost. A good example for an electric power distributor is the share of distribution lines that are undergrounded. An increase in the share of lines that are undergrounded will tend to slow multifactor productivity growth (because of the higher capital requirements) but accelerate O&M productivity growth (since there is less line maintenance).

Finally, consider that in the short to medium run a utility's productivity growth is driven by the position of the utility in the cycle of asset replacement. Productivity growth will be slower to the extent that the need for replacement capex is large relative to the existing stock of capital.

Revenue Cap Indexes

Index research provides the basis for revenue cap indexes. The following basic result of cost research is a useful starting point:

$$\textit{growth Cost} = \textit{growth Input Prices} - \textit{growth Productivity} + \textit{growth Outputs} \qquad \text{[B3]}$$

The cost trend is the difference between the trends in input price and productivity indexes plus the trend in operating scale as measured by a cost-based output index. This result provides the rationale for a revenue cap escalator of the following general form:

$$\textit{growth Revenue} = \textit{growth Input Prices} - X + \textit{growth Outputs} \qquad \text{[B4a]}$$

where

$$X = \overline{MFP} + \textit{Stretch}. \qquad \text{[B4b]}$$

[198] The sensitivity of cost to the change in a business condition variable is commonly measured by its cost "elasticity." Elasticities can be estimated econometrically using data on the operations of a group of utilities. A multiple category output index with elasticity weights is unnecessary if econometric research reveals that there is one dominant cost driver.

Here X, the "X factor," is calibrated to reflect a base MFP growth target ($\overline{MFP}$). A "stretch factor" is often added to the formula which slows revenue cap index growth in a manner that shares with customers the financial benefits of performance improvements expected during the MRP. Since the X factor often includes *Stretch,* it is sometimes said that the index research has the goal of "calibrating" (rather than solely determining) X.

For electric power distributors, the number of customers served is a useful scale variable for a revenue cap index. Relation [B3] can then be restated as:

$$\begin{aligned} &\textit{trend Cost} \\ &\quad = \textit{trend Input Prices} - (\textit{trend Customers} - \textit{trend Inputs}) + \textit{trend Customers} \\ &\quad = \textit{trend Input Prices} - \textit{trend } MFP^{N} + \textit{trend Customers} \end{aligned} \qquad \text{[B5a]}$$

where MFP^{N} is an MFP index that uses the number of customers to measure output.

Rearranging the terms of [B5a] we obtain:

$$\begin{aligned} &\textit{trend Cost} - \textit{trend Customers} \\ &= \textit{trend } (\textit{Cost/Customer}) = \textit{trend Input Prices} - \textit{trend } MFP^{N}. \end{aligned} \qquad \text{[B5b]}$$

This provides the basis for the following revenue per customer index formula:[199]

$$\textit{growth Revenue/Customer} = \textit{growth Input Prices} - X + Y + Z \qquad \text{[B6]}$$

where

$$X = \overline{MFP^{N}} + \textit{Stretch}.$$

Productivity Trends of U.S. Power Distributors

Data

The primary source of our cost and quantity data is FERC Form 1. Selected Form 1 data were for many years published by the U.S. Energy Information Administration (EIA).[200] More recently, the data have been available electronically in raw form from FERC and in more processed forms from commercial vendors. FERC Form 1 data used in this study were obtained directly from government agencies and processed by PEG Research. Customer data were drawn from FERC Form 1 in the early years of the sample period and from Form EIA-861 (the *Annual Electric Power Industry Report)* in later years.

Data were eligible for inclusion in the sample from all major investor-owned electric utilities in the United States that filed the Form 1 in 1964 (the benchmark year for our study, described further below)

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[199] This general formula for the design of revenue cap indexes is currently used in the PBR plans of ATCO Gas and AltaGas in Canada. The Régie de l'Energie in Québec has directed Gaz Métro to develop a plan featuring revenue per customer indexes. Revenue per customer indexes were previously used by Southern California Gas and Enbridge Gas Distribution, the largest gas distributors in the United States and Canada, respectively.

[200] This publication series had several titles over the years. A recent title is Financial Statistics of Major US Investor-Owned Electric Utilities.

and that, together with any important predecessor companies, have reported the necessary data continuously. To be included in the study the data also were required to be of good quality and plausible. One important quality criterion was that there were no major shifts in cost between the distribution and transmission plant. Data from 86 utilities met our standards and were used in our indexing work. We believe that these data are the best available for rigorous work on the productivity trends of U.S. power distributors.

Table B-4 lists the companies from which data were drawn. Most broad regions of the United States are well-represented.[201]

Scope of Research

The total cost of power distributor services considered in the study was the sum of applicable O&M expenses and capital costs. Reported costs of any gas services provided by combined gas and electric utilities in the sample were excluded.[202] We also excluded expenses for purchased power and customer service and information. The featured results employed a geometric decay approach to capital cost measurement that is explained further below. Capital cost is the sum of depreciation expenses, a return on the value of net plant, taxes and capital gains.

We calculated indexes of growth in the O&M, capital, and multifactor productivity of each sampled utility in the provision of power distributor services. Simple arithmetic averages of those growth rates were then calculated for all sampled companies.

[201] Unfortunately, the requisite customer data are not available for most Texas distributors.
[202] Gas service costs of combined gas and electric utilities are itemized on FERC Form 1 for easy removal. We exclude customer service and information expenses because on FERC Form 1 these include DSM expenses.

Table B-4. Companies Included in Our Power Distributor Productivity Research

Alabama Power	MDU Resources Group
ALLETE (Minnesota Power)	Metropolitan Edison
Appalachian Power	MidAmerican Energy
Arizona Public Service	Mississippi Power
Atlantic City Electric	Monongahela Power
Avista	Narragansett Electric
Baltimore Gas and Electric	Nevada Power
Central Hudson Gas & Electric	New York State Electric & Gas
Central Maine Power	Niagara Mohawk Power
Cleco Power	Northern States Power - MN
Cleveland Electric Illuminating	Northwestern Public Service
Connecticut Light and Power	Nstar Electric
Consolidated Edison	Ohio Edison
Dayton Power and Light	Ohio Power
Delmarva Power & Light	Oklahoma Gas and Electric
Duke Energy Carolinas	Orange and Rockland Utilities
Duke Energy Florida	Otter Tail Power
Duke Energy Indiana	Pacific Gas and Electric
Duke Energy Kentucky	PacifiCorp
Duke Energy Ohio	PECO Energy
Duke Energy Progress	Pennsylvania Electric
Duquesne Light	Pennsylvania Power
El Paso Electric	Portland General Electric
Empire District Electric	Public Service Company of Colorado
Entergy Louisiana	Public Service Company of Oklahoma
Entergy Mississippi	Public Service Electric and Gas
Entergy New Orleans	Rochester Gas and Electric
Fitchburg Gas and Electric Light	San Diego Gas & Electric
Florida Power & Light	South Carolina Electric & Gas
Georgia Power	Southern California Edison
Green Mountain Power	Southern Indiana Gas and Electric
Gulf Power	Superior Water, Light and Power
Idaho Power	Tampa Electric
Indiana Michigan Power	Toledo Edison
Indianapolis Power & Light	Union Electric
Jersey Central Power & Light	United Illuminating
Kansas City Power & Light	Virginia Electric and Power
Kansas Gas and Electric	West Penn Power
Kentucky Power	Western Massachusetts Electric
Kentucky Utilities	Wheeling Power
Kingsport Power	Wisconsin Electric Power
Louisville Gas and Electric	Wisconsin Power and Light
Massachusetts Electric	Wisconsin Public Service

Number of Sampled Companies: 86

The major tasks in a power distributor's operation are the local delivery of power and the reduction of its voltage. Most power is delivered to end users at the voltage at which it is consumed. U.S. distributors also typically provide an array of customer services such as metering and billing.

Index Construction

Productivity growth was calculated for each sampled utility as the difference between the growth rates of output and input quantity trends. We used as a proxy for output growth the growth in the total number of retail customers served.

In calculating input quantity trends, we broke down the applicable cost into those for distribution plant, general plant, labor, and material and service (M&S) inputs. The cost of labor was defined for this purpose as O&M salaries and wages and pensions and other benefits. The cost of M&S inputs was defined as applicable O&M expenses net of these labor costs. The growth of the multifactor input quantity index is a weighted average of the growth in quantity subindexes for labor, materials and services, and power distribution plant.

Sample Period

The full sample period for which productivity results were calculated was 1980-2014.[203]

Index Results

Table B-5 summarizes our productivity research for the full sample. Over the full 1980-2014 sample period, the average annual growth rate in the MFP of all sampled U.S. power distributors was about 0.45 percent. Customer growth averaged 1.16 percent annually, whereas input growth averaged 0.70 percent. O&M productivity growth averaged 0.53 percent while capital productivity growth averaged 0.43 percent. O&M productivity growth was much more volatile than capital productivity growth.

[203] In other words, 1980 was the earliest year for growth rate calculations.

Table B-5. U.S. Power Distribution Productivity Trends

	Output	Inputs	PFP O&M	PFP Capital	MFP
1980	1.77%	2.26%	-4.19%	1.24%	-0.49%
1981	1.66%	1.49%	-2.42%	1.25%	0.17%
1982	1.63%	0.76%	-1.20%	1.53%	0.87%
1983	0.96%	0.45%	-0.38%	0.98%	0.51%
1984	1.60%	0.33%	-0.22%	1.79%	1.27%
1985	1.71%	0.76%	-0.21%	1.37%	0.95%
1986	1.70%	0.79%	0.88%	0.97%	0.91%
1987	1.77%	1.33%	-0.12%	0.68%	0.44%
1988	1.47%	0.90%	1.55%	0.24%	0.57%
1989	1.49%	1.23%	0.00%	0.23%	0.26%
1990	1.42%	1.25%	0.64%	-0.05%	0.18%
1991	1.17%	1.20%	0.58%	-0.32%	-0.03%
1992	1.12%	0.64%	1.61%	0.10%	0.48%
1993	1.41%	0.96%	1.19%	0.12%	0.45%
1994	1.39%	0.45%	2.44%	0.29%	0.94%
1995	1.40%	0.46%	3.58%	-0.04%	0.94%
1996	1.16%	1.05%	0.67%	-0.13%	0.11%
1997	1.37%	-0.16%	4.68%	0.39%	1.53%
1998	1.54%	0.87%	0.73%	0.71%	0.67%
1999	0.81%	-0.27%	2.24%	0.52%	1.08%
2000	1.37%	0.48%	0.86%	0.73%	0.89%
2001	1.59%	0.39%	2.73%	0.61%	1.20%
2002	1.17%	0.38%	2.73%	0.33%	0.79%
2003	1.14%	1.17%	-1.50%	0.43%	-0.03%
2004	1.06%	0.66%	0.76%	0.22%	0.41%
2005	1.07%	1.14%	-0.25%	0.09%	-0.07%
2006	0.51%	1.03%	-1.07%	-0.21%	-0.52%
2007	1.02%	1.14%	0.00%	-0.02%	-0.12%
2008	0.54%	1.53%	-2.06%	-0.09%	-0.99%
2009	0.26%	-0.75%	2.73%	-0.46%	1.01%
2010	0.45%	0.72%	-0.47%	0.05%	-0.27%
2011	0.28%	-0.22%	0.05%	0.50%	0.50%
2012	0.39%	-0.91%	2.90%	0.58%	1.29%
2013	0.44%	0.41%	0.40%	-0.05%	0.03%
2014	0.65%	0.68%	-1.41%	0.56%	-0.03%
Average Annual Growth Rates					
1980-2014	**1.16%**	**0.70%**	**0.53%**	**0.43%**	**0.45%**
1996-2014	**0.88%**	**0.49%**	**0.77%**	**0.25%**	**0.39%**
2008-2014	**0.43%**	**0.21%**	**0.30%**	**0.15%**	**0.22%**

Over the more recent 1996-2014 sample period, the average annual growth rate in the MFP of all sampled U.S. power distributors was similar, at 0.39 percent. Customer growth slowed modestly to average 0.88 percent annually, while input growth averaged 0.49 percent annually. O&M productivity growth accelerated to average 0.77 percent, while capital productivity growth slowed to average 0.25 percent.

Since 2007 the MFP growth of power distributors has slowed modestly, averaging 0.22 percent annually. This is mainly due to a slowdown in O&M productivity growth, which averaged 0.30 percent annually. Capital productivity growth slowed slightly to average 0.15 percent.

Table B-6 provides the annual growth rates in the MFP indexes for the individual utilities in our sample. We report results for the full sample period (1980-2014) and for the 1996-2014 and 2008-2014 sample periods.

Additional Details on Productivity Research

Input Quantity Indexes. The quantity subindex for labor is the ratio of salary and wage expenses to a regionalized salary and wage labor price index.[204] The quantity subindex for M&S inputs is the ratio of the expenses to the GDPPI. Details of the capital quantity index are provided below.

The summary quantity indexes for O&M, capital, and all inputs were of chain-weighted Törnqvist form.[205] This means that their annual growth rate was determined by the following general formula:

$$ln\left(\frac{Inputs_t}{Inputs_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1} \right) \cdot ln\left(\frac{X_{j,t}}{X_{j,t-1}} \right) \qquad [B7]$$

where in each year *t*,

$Inputs_t$ = Summary input quantity index

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

$sc_{j,t}$ = Share of input category *j* in the applicable cost

[204] The growth rate of the labor price index was calculated for most years as the growth rate of the national employment cost index (ECI) for the salaries and wages of the utility sector plus the difference between the growth rates of multi-sector ECIs for workers in the utility's service territory and in the nation as a whole.
[205] For seminal discussions of this index form, see Törnqvist (1936) and Theil (1965).

Table B-6. Power Distributor MFP Trends of Individual U.S. Electric Utilities

Distributor	Average Annual MFP Growth Rate 1980-2014	1996-2014	2008-2014
Alabama Power	-0.52%	-0.61%	-0.50%
ALLETE (Minnesota Power)	0.86%	1.32%	0.54%
Appalachian Power	0.12%	0.38%	-0.29%
Arizona Public Service	0.39%	0.88%	0.98%
Atlantic City Electric	0.37%	0.10%	-1.37%
Avista	0.41%	0.09%	-0.71%
Baltimore Gas and Electric	0.35%	-0.06%	-1.08%
Central Hudson Gas & Electric	0.81%	-0.04%	-0.45%
Central Maine Power	0.66%	0.79%	0.28%
Cleco Power	-0.14%	-0.35%	-0.42%
Cleveland Electric Illuminating	0.40%	0.49%	0.05%
Connecticut Light and Power	0.41%	-0.10%	0.03%
Consolidated Edison	0.06%	-0.45%	-0.44%
Dayton Power and Light	0.84%	0.35%	-0.93%
Delmarva Power & Light	0.60%	0.71%	-1.08%
Duke Energy Carolinas	-0.04%	1.09%	0.75%
Duke Energy Florida	0.64%	0.38%	1.00%
Duke Energy Indiana	0.58%	0.08%	-0.09%
Duke Energy Kentucky	0.35%	0.54%	-1.24%
Duke Energy Ohio	0.58%	0.81%	-0.87%
Duke Energy Progress	0.56%	0.65%	1.35%
Duquesne Light	0.64%	0.73%	0.04%
El Paso Electric	0.88%	0.45%	-0.17%
Empire District Electric	-0.09%	-0.26%	-0.65%
Entergy Louisiana	0.63%	0.71%	1.86%
Entergy Mississippi	-0.01%	-0.17%	0.40%
Entergy New Orleans	0.43%	-0.54%	4.37%
Fitchburg Gas and Electric Light	0.34%	0.22%	0.98%
Florida Power & Light	0.84%	0.66%	1.06%
Georgia Power	0.40%	1.11%	1.09%
Green Mountain Power	0.82%	0.52%	1.05%
Gulf Power	0.21%	0.28%	-0.39%
Idaho Power	1.29%	1.48%	1.23%
Indiana Michigan Power	0.30%	-0.02%	-0.46%
Indianapolis Power & Light	0.81%	1.17%	0.86%
Jersey Central Power & Light	0.68%	0.63%	0.84%
Kansas City Power & Light	1.01%	0.76%	0.37%
Kansas Gas and Electric	0.70%	0.57%	0.18%
Kentucky Power	-0.71%	-0.56%	-1.42%
Kentucky Utilities	0.18%	0.01%	-2.38%
Kingsport Power	0.46%	0.23%	-1.33%
Louisville Gas and Electric	0.33%	0.20%	-2.39%
Massachusetts Electric	0.96%	1.10%	0.72%
MDU Resources Group	0.61%	0.76%	1.01%
Metropolitan Edison	1.25%	1.42%	1.06%

Table B-6 (continued) Power Distributor MFP Trends of Individual U.S. Electric Utilities

Distributor	1980-2014	1996-2014	2008-2014
MidAmerican Energy	0.04%	1.22%	2.37%
Mississippi Power	-1.18%	-1.42%	0.65%
Monongahela Power	0.10%	0.57%	0.54%
Narragansett Electric	0.80%	0.57%	-0.03%
Nevada Power	0.99%	1.12%	1.67%
New York State Electric & Gas	1.02%	1.57%	1.51%
Niagara Mohawk Power	0.54%	0.81%	0.68%
Northern States Power - MN	0.73%	0.26%	1.06%
Northwestern Public Service	0.30%	0.68%	1.01%
Nstar Electric	0.40%	0.59%	1.14%
Ohio Edison	0.97%	1.34%	1.02%
Ohio Power	0.28%	0.45%	-0.20%
Oklahoma Gas and Electric	0.14%	-0.07%	-0.49%
Orange and Rockland Utilities	0.82%	0.32%	0.07%
Otter Tail Power	0.00%	0.04%	0.37%
Pacific Gas and Electric	0.24%	-0.04%	0.10%
PacifiCorp	0.08%	1.18%	2.26%
PECO Energy	0.91%	0.16%	-0.21%
Pennsylvania Electric	0.84%	0.94%	1.15%
Pennsylvania Power	0.60%	0.75%	0.51%
Portland General Electric	0.57%	-0.72%	0.10%
Public Service Company of Colorado	0.72%	0.01%	0.90%
Public Service Company of Oklahoma	0.00%	-0.43%	0.07%
Public Service Electric and Gas	0.80%	0.76%	0.49%
Rochester Gas and Electric	1.05%	0.64%	0.97%
San Diego Gas & Electric	-0.31%	-0.41%	0.21%
South Carolina Electric & Gas	0.16%	0.21%	0.02%
Southern California Edison	-0.08%	-0.45%	-1.47%
Southern Indiana Gas and Electric	0.29%	-0.03%	-1.19%
Superior Water, Light and Power	0.57%	0.31%	-0.40%
Tampa Electric	0.97%	0.80%	0.42%
Toledo Edison	1.07%	1.13%	0.94%
Union Electric	0.38%	0.25%	0.45%
United Illuminating	-0.72%	-1.51%	-5.50%
Virginia Electric and Power	0.65%	0.88%	0.64%
West Penn Power	0.83%	1.38%	1.73%
Western Massachusetts Electric	0.75%	1.01%	0.42%
Wheeling Power	0.11%	-0.19%	-1.06%
Wisconsin Electric Power	0.41%	0.11%	0.74%
Wisconsin Power and Light	-0.04%	-0.29%	-0.38%
Wisconsin Public Service	0.82%	0.57%	2.31%
Full Sample Averages	**0.45%**	**0.39%**	**0.22%**

The growth rate of each summary index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable total cost of each utility in the current and prior years served as weights.

Productivity Growth Rates and Trends. The annual growth rate in each company's productivity index is given by the formula:

$$ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right) = ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}}\right) - ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right) \quad [B8]$$

The long-run trend in each productivity index was calculated as its average annual growth rate over the full sample period.

Capital Cost Measurement. A service price approach is used to measure capital costs. This approach has a solid basis in economic theory and is widely used in scholarly empirical work. In the application of the general method used in this study, the cost of a given class of utility plant *j* in a given year *t* ($CK_{j,t}$) is the product of a capital service price index ($WKS_{j,t}$) and an index of the capital quantity at the end of the prior year ($XK_{j,\,t-1}$):

$$CK_{j,t} = WKS_{j,t} \bullet XK_{j,\,t-1} \quad [B9a]$$

It can then be shown mathematically that:

$$growth\ CK_{j,t} = growth\ WKS_{j,t} + growth\ XK_{j,\,t-1} \quad [B9b]$$

In constructing both indexes we used the geometric decay approach. We took 1964 as the benchmark year. The values for these indexes in the benchmark year are based on the net value of plant as reported in FERC Form 1. We estimated the benchmark year (inflation-adjusted) value of net distribution plant by dividing this book value by a triangularized weighted average of 37 values of an index of utility construction cost for a period ending in the benchmark year.[206] The construction cost index (WKA_t) was the applicable regional Handy-Whitman index of the cost of the relevant asset category.[207]

The following formula was used to compute subsequent values of each capital quantity index:

$$XK_{j,t} = (1-d)\cdot XK_{j,t-1} + \frac{VI_{j,t}}{WKA_{j,t}}. \quad [B10]$$

Here, the parameter *d* is the economic depreciation rate and VI_t is the value of gross additions to utility plant. The economic depreciation rate was set at 4.34 percent for distribution plant. It is based on a weighted average of economic depreciation rates for different types of distribution assets. The depreciation rate also reflects declining balance parameters that were 0.91 for structures and 1.65 for equipment.

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[206] A triangularized weighted average places a greater weight on more recent values of the construction cost index. This make sense intuitively since more recent plant additions are less depreciated and to that extent tend to have a bigger impact on net plant value.

[207] These data are reported in the Handy-Whitman Index of Public Utility Construction Costs, a publication of Whitman, Requardt and Associates.

Following is the full formula for the capital service price indexes for each asset category:

$$WKS_{j,t} = [CK_{j,t}^{Taxes} / XK_{j,t-1}] + d \cdot WKA_{j,t} + WKA_{j,t-1}\left[r_t - \frac{\left(WKA_{j,t} - WKA_{j,t-1}\right)}{WKA_{j,t-1}}\right]. \quad \text{[B11]}$$

The first term in the expression corresponds to the cost of taxes and utility franchise fees ($CK_{j,t}^{Taxes}$). The second term corresponds to the cost of depreciation. The third term corresponds to the real rate of return on capital. This term was smoothed to reduce capital cost volatility.

The calculation of [B11] requires an estimate of the rate of return on capital (r_t). We employed a weighted average of rates of return for debt and equity.[208] Prior to 1995, we relied on a 50/50 average of the average yield on AA utility bonds and ROE using data from Moody's.[209] For subsequent years, we relied on a 50/50 average of the embedded average interest rate on long-term debt as calculated from FERC Form 1 data and the average allowed rate of ROE approved in electric utility rate cases for each year as reported by the Edison Electric Institute.[210]

B.3 Statistical Benchmarking

Quantitative performance benchmarking commonly involves one or more gauges of activity. These are sometimes called *key performance indicators* (KPIs) or *metrics.* The values of these indicators for a utility are compared to benchmark values that reflect performance standards. Given information on the cost of a utility and a certain cost benchmark one might, for instance, measure its cost performance by taking the ratio of the two values:

$$Cost\ Performance = Cost^{Actual} / Cost^{Benchmark}.$$

Benchmarks are often developed using data on the operations of agents that are involved in the activity under study. Statistical methods are useful in the calculation of benchmarks and are sometimes used in performance appraisals. An approach to benchmarking that features statistical methods is called *statistical benchmarking.*

Econometric Benchmarking

Cost benchmarks should reflect the cost pressures a utility faces. The impact of external business conditions on the costs of utilities can be estimated using statistics. Consider, by way of example, the following simple model of power distributor cost. In a given year *t*, the cost of power distributor *h* ($C_{h,t}$) is a function of the number of customers it serves ($N_{h,t}$) and the market wage rate ($W_{h,t}$):

$$C_{h,t} = a_0 + a_1 N_{h,t} + a_2 W_{h,t} \quad \text{[B12]}$$

The parameters a_1 and a_2 determine the impact of the business conditions on cost.

[208] This calculation was made solely for the purpose of measuring productivity trends and does not prescribe appropriate rate of return levels for utilities.
[209] Moody's Public Utility Manual (1995).
[210] Edison Electric Institute.

A branch of statistics called *econometrics* has developed procedures for estimating the parameters of economic functions using historical data.[211] The parameters of a utility cost function can be estimated using historical data on the costs incurred by a group of utilities and the business conditions that they faced. Abundant, high quality data are available for this purpose from the federal government. The sample used in model estimation is typically a "panel" data set that pools time series data for several companies.

Tests can be constructed for the hypothesis that the parameter for a candidate cost driver equals zero. A variable is deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence.

A cost function fitted with econometric parameter estimates may be called an *econometric cost model.* We can use such a model to predict a company's cost given local values for cost driver variables. These predictions are econometric benchmarks. Cost performance can be measured by comparing a company's cost in year *t* to the cost projected for that year and company by the econometric model. There is no need to choose a peer group because the methodology uses the exact business conditions faced by the benchmarked company.

Suppose, for example, that we wish to benchmark the cost of a hypothetical utility called Eastern Edison. We might then predict the cost of Eastern Edison in period *t* using the following model constructed from [B12]:

$$\hat{C}_{Eastern,t} = \hat{a}_0 + \hat{a}_1 \cdot N_{Eastern,t} + \hat{a}_2 \cdot W_{Eastern,t} \ . \qquad [B13]$$

Here $\hat{C}_{Eastern,t}$ denotes the predicted cost of the company, $N_{Eastern,t}$ is the number of customers it served, and $W_{Eastern,t}$ measures the wage rate in its region. The $\hat{a}_0$, $\hat{a}_1$, and $\hat{a}_2$ terms are parameter estimates. Performance might then be measured using a formula such as

$$Performance = C_{Eastern,t} / \hat{C}_{Eastern,t} \ .$$

Table B-7 provides details of the econometric model of total power distributor cost that is used to set stretch factors in the IRM4 multiyear rate plan in Ontario. There is one input price variable (a capital price index), three scale variables (the number of customers, the retail delivery volume, and peak demand), two additional business conditions (average line length and a system age variable), and a trend variable. Note that the number of customers is the scale variable with the highest parameter estimate and t statistic. This model has a translogarithmic functional form so that, in addition to the "first order terms" representing the basic business condition variables, there are interaction and quadratic terms for the price and output variables. Model parameters were estimated using Ontario data

[211] The estimation of model parameters is sometimes called regression.

Table B-7. Econometric Cost Model for Ontario[212]

VARIABLE KEY

Input Price:	WK = Capital Price Index
Outputs:	N = Number of Customers
	C = System Capacity Peak Demand
	D = Retail Deliveries
Other Business Conditions:	L = Average Line Length (km)
	NG = % of 2012 Customers added in the last 10 years
	Trend = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
WK*	0.6271	85.5530
N*	0.4444	8.0730
C*	0.1612	3.2140
D*	0.1047	3.4010
WKxWK*	0.1253	4.5320
NxN	-0.3776	-1.6160
CxC	0.1904	0.9340
DxD*	0.1646	2.1660
WKxN*	0.0536	3.4540
WKxC	0.0100	0.7200
WKxD	-0.0001	-0.0100
NxC	0.1415	0.7040
NxD	0.0674	0.6790
CxD*	-0.1990	-2.3070
L*	0.2853	13.9090
NG*	0.0165	2.4110
Trend*	0.0171	12.5700
Constant*	12.815	683.362
System Rbar-Squared	0.983	
Sample Period	2002-2012	
Number of Observations	802	

***Variable is significant at 95% confidence level**

[212] Kaufmann, Hovde, Kalfayan, and Rebane (2013), p. 58.

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