Statistical Cost Research for the Elexicon Energy CIR Plan

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1. Introduction and Summary

1.1. Introduction

In proceeding EB-2025-0312, Elexicon Energy, Inc. ("Elexicon," "the Company") proposes to establish a new Custom Incentive Rate-Setting ("CIR") framework. The proposed framework is a multi-year rate plan ("MRP") that would operate over the five years from 2027 to 2031. Elexicon notes challenging business conditions in advocating a novel formula for its attrition relief mechanism ("ARM"), which it calls a Custom Price Cap Index. Evidence supporting the proposal includes a report on statistical benchmarking and index research by Steve Fenrick of Clearspring Energy Advisors, Inc. ("Clearspring"). The Company proposes a 0% base productivity growth trend and a 0.15% stretch factor. This combination would cause 0.15% to be subtracted annually from the Company's proposed revenue requirement growth.

Statistical cost research evidence in this proceeding merits careful scrutiny for reasons that include the following:

- Utilities proposing to change their plan from Price Cap to Custom IR need to know that their proposals must be fully supported, and that rigorous independent evaluation of their proposed framework is likely. Controversial technical work should be identified and, where warranted, challenged to avoid undesirable precedents for the Company and other Ontario utilities in the future. Witnesses for the Ontario Energy Board ("OEB") Staff have constructively commented on statistical cost research methods in past IR proceedings.
- CIR proceedings are opportunities for Ontario's regulatory community to reconsider how statistical cost research should be used in energy rate regulation.

Evidence on industry cost efficiency trends is also timely. The OEB has over the years shown a keen interest in reducing forecasted revenue requirements by an externally-based cost efficiency markdown. The OEB's October 13, 2016 *Handbook for Utility Rate Applications* ("*Rate Handbook")* calls for a higher cost efficiency growth target for CIR than that used in generic price cap incentive rate-setting. However, panels typically approve the same 0% cost efficiency growth target that applies to 4th generation incentive rate-setting ("4th GIRM").

Pacific Economics Group Research LLC (“PEG”) is a leading North American consultancy on IR and the benchmarking and price and productivity trend research that supports it. In addition to Ontario, we have provided research and testimony in these areas in numerous other North American jurisdictions. OEB Staff retained PEG to appraise and comment on Clearspring’s benchmarking evidence and the Company’s proposed CIR framework parameters.

This report covers our empirical work. Following a brief summary of our findings, Section 2 provides an introduction to statistical cost research for utility ratemaking. Please note that subsection 2.1 includes several new theoretical results of interest in the CIR context. Section 3 discusses the business of power distributors and appraises possible sources of benchmarking data. Clearspring’s benchmarking evidence is critiqued in Section 4. Data used in PEG’s research for OEB Staff in this proceeding are discussed in Section 5. PEG’s econometric modelling and benchmarking research are detailed in Section 6. New research by PEG on the productivity trends of Ontario power distributors is discussed in Section 7. X factor and stretch factor recommendations are provided in Section 8. The Appendix discusses additional details of our research. A companion document that we will call the Framework Report discusses other aspects of Elexicon’s proposed CIR framework. The opinions expressed in both reports are those of the author.

1.2. Summary

Econometric Cost Benchmarking

Clearspring developed an econometric model of total power distributor cost using operating data from 82 U.S. electric utilities, mostly over the 2000-2023 period.[1] This model was used to benchmark the total cost of base rate inputs that Elexicon incurred over the historical 2019-2024 period, as well as the Company’s pre-filed evidence forecasted/proposed cost over the 2025-2031 period that the Company submits in its prefiled evidence.

Clearspring reported Elexicon’s total cost performance to have been exceptionally good in the historical years of its sample period but to decline substantially in each year of its proposed CIR plan. The Company’s initial submission of forecasted/proposed total cost is 13.9% below Clearspring’s

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[1] Clearspring used a partial sample for a few utilities and dropped individual years for other utilities with unusable data (e.g., a negative account balance in one year).

benchmarks on average during the years of the proposed CIR plan (2027-2031). Clearspring forecasts that Elexicon's total cost efficiency will decline by an average of 4.4% each year of the term. Clearspring explains that Elexicon's plan to add a new substation in 2031 is directly responsible for the 700 basis point decline in the final year of the plan. While that is the largest single-year decline in the forecast period, there is also a 601 basis point decline forecasted for 2027. Using guidelines established by the OEB for Price Cap IR stretch factors,[2] Clearspring recommends a stretch factor of 0.15%.

While PEG and Clearspring agree on many methodological issues, PEG disagrees with some of the methods used in Clearspring's cost benchmarking study in this proceeding. Here are some of our larger concerns.

- Clearspring's sample period and sample selection are suboptimal for benchmarking Elexicon. Elexicon is more unlike the U.S. sample than any previous distributor that has filed a statistical benchmarking study in a CIR proceeding. Only 8 of the 82 sampled U.S. distributors have fewer customers than Elexicon, and only an additional 7 companies are larger but still in the same size ballpark. While econometric modeling does have the distinct advantage of not requiring a similar peer group, careful consideration must be given to benchmarking Elexicon against primarily much larger utilities rather than against peers who are more similar in size and have faced the same regulatory environment. Clearspring also exclude several U.S. companies that underwent mergers or amalgamations. The model parameters based on U.S. utility data back to the year 2000, in conjunction with using a single time trend variable for the entire 24 years, may not adequately measure or account for more recent trends, challenges, and technical change in the industry. Clearspring does not report testing any variables for a change in trends.
- We believe that it is strongly desirable to go beyond econometric total cost benchmarking in Custom IR proceedings by benchmarking OM&A and capital costs as well. Capital cost benchmarking may shed light on other sources of deterioration in total cost performance throughout the CIR period and better model the impact of capex proposals. OM&A cost benchmarking is especially useful in this proceeding, where Elexicon claims the previously-

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[2] These guidelines are discussed further in Section 2.2.

> set funding levels are insufficient due to inadequate inflation escalation and substantial changes in customer and capacity growth, reactive replacements and deterioration of assets, and staffing issues which were all unanticipated at the time of the merger. Despite this, Elexicon first presented OM&A expenses lower than they would be allowed under their proposed OM&A mechanism. Their evidence update nearly doubles their forecasted OM&A expenses during the CIR period.

PEG developed an alternative econometric total distributor cost benchmarking model the development of which relied chiefly on PEG data. Our sample for model development included 89 U.S. distributors and 3 Alberta distributors. We found that Elexicon's total distributor cost performance was about 28.8% below our model's benchmark on average during the three most recent years for which historical cost data were available for the Company (2022-2024). Elexicon's projected/proposed total cost is about 14% below our benchmarks on average during the five years of the proposed CIR plan.

PEG also developed models to evaluate Elexicon's OM&A and capital costs. The Company's OM&A cost was found to be about 28.9% below our benchmarks on average during the three most recent historical years. The Company's forecasted/proposed OM&A cost averaged about 9.1% above our model's prediction on average during the five years of the proposed new IR plan. An abrupt decline in OM&A cost efficiency is apparent in 2027, the first year of the proposed new plan. n subject to indexing the poor efficiency is sustained in later years of the plan. There is a reasonable suspicion of deferred OM&A spending during the prior plan.

Elexicon's capital cost was found to be about 26.4% below our benchmarks on average during the three most recent historical years. The Company's forecasted/proposed capital cost is about 28.6% below our model's prediction on average during the five years of the proposed new CIR plan. A good capital cost score is consistent with the Company's claimed need for supplemental capital revenue.

Productivity Trends

To shed new light on the appropriate productivity factor for Elexicon we calculated trends in the OM&A, capital, and total factor productivity ("TFP") of 53 Ontario electricity distributors. The full sample period for this study was the twenty-one growth rate years from 2004 to 2024.

The relevance of results for the full sample period is compromised by data problems. Most notably, capital productivity dipped materially in 2013 due to advanced metering infrastructure ("AMI") deferral account clearances in 2012 while OM&A productivity dipped in 2011 and 2012 due to the transition of many distributors to a new accounting system. Results may also be sensitive to the unavoidable inclusion of pension and benefit expenses in the costs of sampled distributors.

The eleven years of distributor operation that began in 2014 and ended in 2024 have fewer data problems[3] and coincide with the implementation of the Renewed Regulatory Framework. During these years, we found using simple (arithmetic) averages that the TFP trends of Ontario distributors averaged 0.15% annual growth while their OM&A productivity averaged 0.25% growth and their capital productivity averaged a slight 0.04% growth. Using cost-weighted averages, which are more sensitive to results for the larger distributors that serve most customers, we found that the TFP growth of all Ontario distributors averaged 0.49% annual growth while their OM&A productivity averaged 1.40% annual growth and their capital productivity averaged a 0.26% annual decline.

Brisk OM&A productivity growth raises the question of whether I-X indexing where X is based on the total factor productivity of the industry is just and reasonable in an application to the OM&A revenue of distributors proposing CIR plans that provide almost full compensation for the claimed inadequacy of I-X to fund their capital revenue requirements.

Larger distributors averaged a TFP decline in the 2014-2024 period despite more rapid OM&A productivity growth than the Ontario norm because this was offset by a material capital productivity decline. This decline of large distributors may reflect in part their greater use of supplemental capital revenue mechanisms that have entailed capital expenditure ("capex") forecasts and, in many cases, the clawback of capital cost underspends.

PEG counsels against postponing the issue of new productivity factors to a later proceeding. Positive productivity growth targets are now warranted, and customers would benefit at a time of real affordability concerns. Clearspring is quite capable of reviewing new Ontario productivity research in this proceeding.

Evidence from various sources suggests that a 0% productivity factor is no longer reasonable for Ontario power distributors. Should the Panel choose to apply the same productivity factor to the OM&A

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[3] The most relevant small remaining problems are the lack of company-specific data on OM&A labour expenses beginning in 2023 and the inconsistent reporting of distribution line lengths.

and capital revenue of Elexicon, PEG recommends that it be set at **0.15%.** Should the panel alternatively decide on separate productivity factors for OM&A and capital revenue, PEG recommends **0.25%** for OM&A revenue and **0.04%** for capital revenue.

Stretch Factors

We discuss stretch factors at some length in the report, detailing our latest thinking and recent precedents. Default stretch factors assigned by the OEB to 4th GIRM distributors are calculated each year based upon a cost benchmarking model of Ontario power distributors. The results of this model assign a stretch factor of 0.3% to Elexicon for the 2026 rate year. Elexicon's forecasted/proposed cost for 2027-2031 using the Price Cap IR PEG Forecast Model were about 2.15% above our model's predictions on average. This contrasts with the 0.15% stretch factor that is supported by our updated model based on their average total cost benchmarking score of about 14.0% below predicted cost.

2. Statistical Research for ARM Design

In this Section we discuss pertinent principles and statistical methods for the design of attrition relief mechanisms ("ARMs"). We begin by reviewing basic indexing concepts. We next discuss the use of indexing research in revenue cap index design and other important methodological issues. We then discuss some potential contributions of econometric research to X factor calibration.

2.1. Principles and Statistical 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*").

$$\text{Cost} = \text{Input Prices} \times \text{Inputs}. \qquad [1]$$

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, labour, and miscellaneous materials and services are the major classes of inputs that are typically addressed by the base rates of 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.[4]

$$\text{growth Cost} = \text{growth Input Prices} + \text{growth Inputs}. \qquad [2]$$

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

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

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

This greatly simplifies measurement of some input quantity trends.

Productivity Indexes

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

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

Indexes of this kind are used to measure the efficiency with which firms convert production inputs into the goods and services that they provide. 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.[5]

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

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 called *total* factor productivity indexes even though they rarely address all inputs that a company uses. Some indexes measure productivity in the use of a single class of inputs (e.g., labour or capital.) These indexes are sometimes called *partial* factor productivity indexes.

Output Indexes

Depending on its design, an output metric can compare the output levels of utilities in a given year, measure output trends, or do both. If output is multidimensional in character, its trend (or level) can be measured by a multidimensional output index. Each output dimension that is itemized in such an

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

index is 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.*[6] 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 an output or in the value of any other business condition variable is commonly measured by its cost "elasticity."[7] 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.[8] A productivity trend index calculated using a cost-based output index ("$Outputs^C$") will be denoted as $Productivity^C$.

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

Output research can alternatively be intended to study the impact of output growth on *revenue*. In that event, the output index should be constructed from one or more scale variables that measure the impact of output growth on *revenue*. In utility parlance, billing determinants are the appropriate scale variables. The weight for each billing determinant that is separately specified should reflect its share of revenue. A productivity trend index calculated using a revenue-weighted output index ("$Outputs^R$") may be denoted $Productivity^R$. Then

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

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[6] 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*.

[7] The cost elasticity of output *i* is the effect on cost of 1% growth in that output.

[8] 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.[9] 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 growth. 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 operations. For example, larger utilities may be less able than smaller utilities to achieve incremental scale economies from the same rate of output growth. At some level of output, the potential for incremental scale economies may be exhausted.

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 distributor is suburban forestation. As forestation increases, productivity growth will tend to 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 refurbish or replace aging plant. If a utility requires unusually high replacement capital expenditures, its cost growth surges

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[9] The seminal paper on this topic is Denny, Fuss and Waverman, *Ibid.*

and productivity growth can slow and even turn negative. 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 can slacken and productivity growth can accelerate after a period of unusually high capex.

All of the business conditions so far discussed affect productivity growth whether it is measured with a cost- or revenue-focused output index. An additional business condition is germane when a revenue-weighted output index is used. Consider that

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

Thus, growth in $\textit{Productivity}^R$ depends on any tendency of billing determinants to grow faster or slower than the workload of the enterprise. The term in parentheses may be called an “output differential.”

Our analysis of productivity growth drivers 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 demand growth and an unusually high number of assets needing replacement can experience productivity declines despite normal cost management.

Use of Index Research in ARM Design

Revenue Cap Indexes

Cost theory and index logic support the design of ARMs for multi-year rate plans. Consider first the following basic result of cost theory:

$$\textit{growth Cost} = \textit{growth Input Prices} - \textit{growth Productivity}^C + \textit{growth Outputs}^C.\text{[10]} \qquad [8]$$

The growth in the cost of a company is the difference between the growth in its input price and $\textit{Productivity}^C$ indexes plus the growth in a consistent cost-based output index.

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[10] See Denny, Fuss, and Waverman, o*p. cit.*

This result provides the basis for a revenue cap index of general form:

$$\mathit{Revenue}_t = \mathit{Revenue}_{t-1} \cdot [1 + \mathit{growth\ Input\ Prices} - (\overline{\mathit{Productivity}^C} + S)$$

$$+ \mathit{growth\ Scale}^C_{\mathit{Utility}} + Y_t + Z_t] \qquad [9a]$$

where:

$\mathit{Scale}^{\mathit{Utility}}$ = growth in the output of the utility using a cost-based output metric

$\overline{\mathit{Productivity}^C}$ = productivity factor [9b]

S = stretch factor

Here the productivity factor ("$\overline{\mathit{Productivity}^C}$") reflects a base growth target for $\mathit{Productivity}^C$ that is typically the average trend in the $\mathit{Productivity}^C$ 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.

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.[11] It then follows that

$$\begin{aligned} \mathit{growth\ Cost} &= \mathit{growth\ Input\ Prices} + \mathit{growth\ Outputs}^C \\ &\quad - (\mathit{growth\ Outputs}^C - \mathit{growth\ Input\ Quantities}) \\ &= \mathit{growth\ Input\ Prices} - \mathit{growth\ Productivity}^C + \mathit{growth\ Outputs}^C \end{aligned}$$

This derivation affords revenue cap index designers more flexibility.

Price Cap Indexes

As for price cap indexes, the revenue growth of an enterprise can be shown to be the sum of the growth in appropriately designed price and $\mathit{Outputs}^R$ indexes.

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

Rearranging terms it follows that

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

$$\textit{growth Prices} = \textit{growth Revenue} - \textit{growth Outputs}^{R}.$$

Assume now that cost growth equals revenue growth. Then

$$\textit{growth Prices} = \textit{growth Cost} - \textit{growth Outputs}^{R}.$$

Recalling the result in [2] it follows that

$$\begin{aligned}\textit{growth Prices} &= (\textit{growth Input Prices} + \textit{growth Input Quantities}) - \textit{growth Outputs}^{R}\\ &= \textit{growth Input Prices} - (\textit{growth Outputs}^{R} - \textit{growth Input Quantities})\\ &= \textit{growth Input Prices} - \textit{growth Productivity}^{R} \qquad [11]\end{aligned}$$

This result provides the basis for a price cap index of general form:

$$\textit{Prices}_t = \textit{Prices}_{t-1} \cdot [1 + \textit{growth Input Prices} - (\overline{Productivity^{R}} + S) + Y_t + Z_t]. \qquad [12]$$

The productivity factor is typically the average trend in the *Productivity*^{R} indexes of a sample of utilities.

Revenue Cap to Price Cap Conversion

Recollecting as well the result in [7], note also that

$$\textit{growth Prices} = \textit{growth Input Prices} - \textit{growth Productivity}^{C} + (\textit{growth Outputs}^{R} - \textit{growth Outputs}^{C})$$

This result provides the basis for a price cap index of general form:

$$\textit{Prices}_t = \textit{Prices}_{t-1} \cdot [1 + \textit{growth Input Prices} - (\overline{Productivity^{C}} + S + OD) + Y_t + Z_t] \qquad [13a]$$

where:

$$OD = \textit{Output Differential} = \textit{trend Outputs}^{R} - \textit{trend Outputs}^{C} \qquad [13b]$$

In this formulation, a productivity index calculated using a *cost*-based output index provides the basis for the productivity factor in a *price* cap index because there is an adjustment in the formula for any tendency of billing determinants to grow more or less rapidly than workload.

Separate Ratemaking Treatments of OM&A and Capital

Index logic can also address situations where revenue escalation for some costs is not based on indexing. In Ontario, for example, many utilities that operate under rate or revenue cap indexes request and obtain supplemental revenue to fund their capex. The rationale is that the index formula cannot otherwise provide reasonable compensation for capex surges. Reasons that such surges might be needed include “lumpy” plant additions (e.g., new substations), a desire to install or replace costly advanced metering infrastructure for all customers, a surge in plant that needs replacement, or a tendency of the inflation factor to understate capital price inflation.

To qualify for these revenue supplements, Ontario utilities are expected to demonstrate that the required growth in their capital cost exceeds the capital revenue growth that is otherwise expected to be produced by their rate or revenue cap indexes. This has led to complicated hybrid ARM designs in which ratemaking treatments of OM&A and capital revenue are quite different. OM&A revenue is indexed while capital revenue escalation is based primarily on capital cost forecasts.[12] In these proceedings, it has commonly been assumed but rarely demonstrated that the rate or revenue cap indexes provide just and reasonable escalation of OM&A revenue.

The following further result of index logic is helpful for analyzing this situation. The growth in all inputs can be shown to be a cost-weighted average of the growth in OM&A and capital inputs. Formally

$$growth\ Inputs = sc_{OMA} \times growth\ Inputs^{OMA} + sc_{K} \times growth\ Inputs^{K}$$

where sc_{oma} and sc_{k} are the cost shares for OM&A capital respectively. It follows that

$$\begin{aligned} growth\ TFP &\\ &= growth\ Outputs - (sc_{OMA} \times \text{growth Inputs}^{\text{OMA}} + sc_{K} \times growth\ Inputs^{K}) \\ &= sc_{OMA} \times (growth\ Outputs - growth\ Inputs^{OMA}) + sc_{K} \times (growth\ Outputs - growth\ Inputs^{K}) \\ &= sc_{OMA} \times growth\ PFP^{OMA} + sc_{K} \times growth\ PFP^{K} \qquad [14] \end{aligned}$$

Total factor productivity growth is a cost-share weighted average of growth in the partial factor productivity (“PFP”) of OM&A and capital inputs.

This result can provide the basis for separate rate or revenue cap indexes for OM&A and capital revenue. Suppose, for example, that the OM&A productivity trend of the industry is materially more positive than the capital productivity of the industry and the utility asks for supplemental capital revenue. OM&A revenue can then be escalated by the formula

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[12] This reality is obscured by the common use of summary rate or revenue cap indexes that include “index runaround” terms such as the “Revenue Growth Factor” that Elexicon proposes in this proceeding.

$$Revenue_t^{OM\&A} = Revenue_{t-1}^{OM\&A} \cdot [1 + Input\ Prices - (\overline{PFP}^{OM\&A} + S) + growth\ Scale_{Utility} + Y_t^{OMA} + Z_t^{OMA}]. \quad [15a]$$

Here $\overline{PFP}^{OM\&A}$ is the trend in the OM&A productivity of a group of utilities.

The growth of capital revenue can then be determined by

$$Revenue_t^K = Revenue_{t-1}^K \cdot \left(1 + max\begin{Bmatrix}[Inflation - (\overline{PFP}^K + S) + growth\ Scale_{Utility}], \\ [growth\ CK^{Forecasted} - \overline{PFP}^K \text{ (if positive)} - S]\end{Bmatrix} + Y_t^k + Z_t^k\right) \quad [15b]$$

Here the utility can obtain supplemental capital revenue but it is a little harder to get because cost must grow more rapidly than an index that has a capital productivity trend that may be slow or negative. The maximization term determines whether capital revenue should be based on forecasted cost.

Consider now that there are several reasons why regulators may choose not to afford utilities all of the capital revenue growth that formula [15b] provides.

a) A materiality condition could discourage CIR applications when the need for supplemental capital revenue is small. This mechanism could have a dead zone, as do those in the OEB's incremental capital modules.

b) Slowing capital revenue growth could strengthen capital cost containment incentives and guard against the risk that information asymmetries prompt utilities to file bloated capital cost forecasts.

These concerns can be addressed by adding a supplemental capital stretch factor S_k to the formula. Then

$$Revenue_K^K = Revenue_t^K \cdot \left(1 + max\begin{Bmatrix}[Inflation - (\overline{PFP}^k + S) + growth\ Scale_{Utility}], \\ [growth\ CK^{Forecasted} - \overline{PFP}^{\,k} \text{(if positive)} - S - S_k]\end{Bmatrix} + Y_t^k + Z_t^k\right). \quad [15c]$$

The OEB has approved supplemental capital stretch factors for several CIR plans.

Alternatively, the difference between the growth of forecasted capital cost and full indexation can be shared mechanistically between the utility and its customers. The following formula provides a simple example of such a mechanism.

$$Revenue_t^K =$$

$$Revenue_{t-1}^K \cdot \left\{ \begin{matrix} 1 + Inflation - (\overline{PFP}^k + S) + \ growth\ Scale_{Utility} \\ +\alpha \cdot [growth\ CK^{Forecasted} - (Inflation - \ \overline{PFP}^k \ + growth\ Scale_{Utility})] \end{matrix} \right\}. \quad [15d]$$

Here α has a value between zero and 1. These formulas can be converted to price caps as discussed above.

Miscellaneous Cost Exclusions

If the multiyear rate plan provides for certain costs to be addressed by variance accounts, index logic similarly provides the rationale for excluding these costs from the productivity research. This principle is widely (if not unanimously) accepted, and certain costs that are frequently accorded variance account treatment in multi-year rate plans (e.g., costs of energy, CDM, and pensions and other benefits) are regularly excluded from the supportive productivity trend studies.

Inflation Factors

Suppose, now, that an I factor used in a rate or revenue cap index is an imperfect measure of input price inflation. In the United States this question has arisen because the gross domestic product price index ("GDPPI"), which measures the trends in the *output* prices of the economy, is often used as a proxy for utility *input* price trends.

Relation [8] can be restated as:

$$\begin{aligned} growth\ Cost &= growth\ Input\ Prices - growth\ Productivity^C + growth\ Outputs^C \ + (I - I) \\ &= I - [growth\ Productivity^C + (I - growth\ Input\ Prices)] + growth\ Outputs^C \qquad [17] \end{aligned}$$

Where *I* is the I factor. Relation [17c] shows that cost growth depends on the I factor, growth in operating scale and *Productivity*^{C}, and on the difference between *I* and utility input price inflation. This difference, which is found in parentheses, is sometimes called the "inflation differential."

The GDPPI is the U.S. government's featured index of inflation in the prices of the economy's final goods and services.[13] It can then be shown that the trend in the GDPPI equals the difference between the trends in the economy's input price and multifactor productivity ("MFP") indexes.

$$\text{growth GDPPI} = \text{growth Input Prices}^{\text{Economy}} - \text{growth MFP}^{\text{Economy}}. \qquad [18]$$

In some approved rate and revenue cap index formulas, the productivity factor has on these grounds been replaced by

$$[(\overline{Productivity}^{C} - \overline{MFP}^{Economy}) + (\overline{Input\ Prices}^{Economy} - \overline{Input\ Prices}^{Industry})]. \qquad [19]$$

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

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 see why, suppose that there was a province in which 80% of customers were served by distributor A and 20% were served by distributor B. Then the productivity trend of the provincial power distributor industry would depend a lot more on the productivity of A than on the productivity of B.
- 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 since the potential for realizing scale economies is more similar.

Arguments for even-weighted averages include the following.

- Size-weighted averages are sometimes unduly sensitive to results for a few large utilities.

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

- Even-weighted averages are more pertinent in X factor studies for medium or smaller-sized utilities.
- Econometric cost research places the same weight on all observations.

PEG typically uses size-weighted (even-weighted) averages in X factor studies applicable to larger (smaller) utilities.

2.2. Stretch Factors

Rationale

The X factor term of a rate or revenue cap index in Ontario is calibrated to reflect the industry productivity trend. The stretch factor term should then reflect an expectation of how the productivity growth of the utility that will be operating under IR (the "subject utility") should differ from the productivity trend of the peer group. This depends in part on how the performance incentives generated by IR --- 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 the subject utility also depends on the utility's operating efficiency at the start of the MRP. If a company is found to be inefficient, for example, it may take many years to fully rectify the problem. A stretch factor ensures customers the benefit of improving cost management whether or not it occurs and incentivizes better cost performance. If a company is already quite efficient, it has less potential to exceed the industry productivity trend.

Prior operation under MRPs with strong incentive power encourages improved efficiency. However, the productivity trend of the utility may 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, even after operating under multiple MRPs, exhaust its inefficiencies.

- 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 during these years.

- After multiple terms of MRPs, the subject utility will still be presented with a continuing stream 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 succession of asset cohorts approaching replacement age. Some utilities will be inclined to replace all assets that are old, while others will focus on asset condition and try to coax additional years of service out of older assets. Another salient issue is how the utility responds to new business conditions such as new technologies and the energy transition. An example here is that some utilities might use AMI to implement time-sensitive pricing that slows peak demand growth while others would stick with traditional rate designs despite having made a costly AMI investment.

- 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 athletes in the National Hockey League have strong incentives to perform well but their performances nonetheless vary widely. The income of less successful players reflects this reality.

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:

- A stretch factor linked to statistical benchmarking focused on costs incurred in the later years of an expiring rate plan and/or the proposed costs for a new plan can serve as an efficiency carryover mechanism. The current total cost benchmarking (“TCB”) program in Ontario, for example, can reward a utility for its efforts to lower future costs with a lower stretch factor.

- Utilities operating under MRPs sometimes slow cost growth in early plan years only to accelerate growth in later years in a way that can deny customers benefits. A stretch factor is one means of sharing with customers the benefits of cost savings that are achieved. The alternative of adding an earnings sharing mechanism to the plan entails weaker cost containment incentives.

- A stretch factor can also be warranted to address overcompensation concerns that result from supplemental capex funding but are difficult to measure accurately.

Role of Benchmarking

Our discussion of the various rationales for stretch factors suggests that statistical benchmarking can be quite germane in selecting them. This is typically accomplished by establishing a schedule that assigns utilities in a certain range of cost performance scores a particular stretch factor. These schedules typically lack a solid empirical foundation and should not be considered set in stone. For example, a schedule could reasonably make it possible for superior cost performers to receive accelerated revenue growth (i.e., some stretch factors could be negative). Consider also that having more benchmarking score/stretch factor categories gives distributors more hope that their efforts to contain cost can result in a better stretch factor.

Notable Stretch Factor Precedents

Ontario

The OEB is now in its fourth generation of IR for electricity distributors. IR is also used for gas distributors and electricity transmitters. In each generation, IR has featured MRPs with rate or revenue cap indexes. In both the third and fourth generation generic 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 mechanistically to benchmarking results. 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%.[14] Additionally, distributors are required to use the OEB's econometric model to benchmark their forward test year cost proposals in rate cases.[15]

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[14] 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.

[15] *Ibid*, pp. 19-20.

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%

Stretch factors determined by this schedule are not very sensitive to a change in cost performance. For example, a distributor could improve its performance from 24% above the model's prediction to 12% during a plan and still have the same stretch factor.

Larger Ontario electricity distributors, along with the largest power transmitter in the province, typically operate under an alternative approach to PBR called Custom incentive ratemaking ("CIR"). This approach also usually features MRPs with rate or revenue cap indexes that have formulas with X factors. CIR stretch factors are typically linked to custom econometric benchmarking studies that use multijurisdictional (specifically U.S. and Ontario) data. The current stretch factor of THESL is 0.6%, while that of Hydro Ottawa is 0.45% and that for electricity distributor services of Hydro One Networks Inc. ("HONI") is 0.45%.[16]

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

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[16] Ontario Energy Board (2024), Partial Decision and Order in EB-2023-0195, November 12, p. 10 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. A recently-approved settlement for Hydro Ottawa in EB-2024-0115 includes a 0.45% stretch factor.

(“BCUC”) approved stretch factors of 0.20% for FortisBC Energy Inc. and 0.10% for FortisBC.[17] 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**.[18] [Emphasis in original]

In their next MRP application, FortisBC and FortisBC Energy presented benchmarking studies of their performance. The companies argued that their performances in these studies were sufficient to justify zero stretch factors for their next generation PBR plans. While the BCUC did not approve an itemized stretch factor, they did believe that the companies’ performances were insufficient to justify a zero stretch factor.

> The Panel agrees that FEI and FBC’s performance on the benchmark metrics is superior to the median of their peer group on many of the metrics. The Panel disagrees that a stretch factor could not be applied because the Utilities have reached a productivity performance level that restricts their potential for further improvement.[19]

Benchmarking also informed the BCUC’s 2025 decision on stretch factors in the current generation of MRPs for FortisBC and FortisBC Energy. The companies presented unit cost benchmarking studies showing that FortisBC Energy was an average cost performer and FortisBC was a superior cost performer. The BCUC approved stretch factors of 0.27% for FortisBC Energy and 0.25% for FortisBC, rejecting the companies’ proposals for stretch factors of 0.1% and 0%, respectively. The

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[17] 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.

[18] 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).

[19] BCUC (2020), “FortisBC Energy Inc. and FortisBC Inc. Application for Approval of a Multi-Year Rate Plan for the Years 2020 through 2024 Decision and Orders G-165-20 and G-166-20,” p. 59.

BCUC rejected the companies' proposal for two reasons. First, the companies "continue to have further potential opportunities for productivity improvements and economies of scale beyond those reflected in the proposed stretch factors" and that neither company has "reached such a high productivity performance level as to preclude the potential for further improvement."[20] Second, that "[d]uring a period of heightened uncertainty driven by the energy transition and concerns about affordability, it is particularly important for utilities and incumbent upon them to continue to strive for increased productivity in all aspects of their operations."[21]

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 various benchmarking methods that include unit cost metrics and econometric modelling. Several utilities have voluntarily provided econometric benchmarking studies.

In its 2019 approval of an MRP for National Grid's Massachusetts electricity distributors, the DPU agreed to tie the stretch factor to performance in annual benchmarking studies. The magnitude of the stretch factor could change annually based on the company's performance in unit cost and productivity benchmarking studies compared to a national sample. The schedule of benchmarking results and stretch factors is provided in the figure below. Please note that stretch factors are suspended in the event of sluggish inflation.

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. 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.

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[20] BCUC (2025), "Decision and Orders G-69-25 and G-70-25", pp. 46-47.

[21] BCUC (2025), "Decision and Orders G-69-25 and G-70-25", p. 47.

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.

Nevertheless, stretch factors were frequently discussed in the Maine proceedings and benchmarking evidence was sometimes considered.

3. Statistical Research on Power Distributor Cost

In North American IR, statistical cost research is often used to benchmark utility cost and determine the productivity factors in ARM escalation formulas. In this section we consider the nature of a power distributor's business and the pros and cons of three salient sources of data on distributor operations that can be used in distributor cost research.

3.1. The Power Distributor Business

Reader understanding of the empirical research that is discussed in this report may be aided by a brief discussion of the general nature of a power distributor's business. Distributors deliver power to the premises of end users. Most of the power is received from the power transmission system but some may come from distributed energy resources ("DERs") such as solar generation or batteries. The voltage of the power must be reduced from the rate at which it is received from the transmitter to the rate at which most end users consume it. Voltage is reduced by transformers at substations and there is often a further reduction at line transformers located near customer premises. Some distributors own and operate higher-voltage substations and subtransmission lines and they typically own most low voltage power lines and services, the poles and underground conduits that carry them, line transformers that perform final voltage drops, and meters. Distribution facilities may be overhead or underground. Overhead facilities entail less capital cost but more OM&A cost. Most distributors manage the accounts of end users, send bills and receive payment, and provide information services. Additionally, administrative and general costs are incurred jointly in the provision of distribution and other services that the utility provides.

3.2. Sources of Distributor Operating Data

In statistical benchmarking and productivity research supporting the selection of X factors and revenue requirements for Ontario electricity distributors a choice must be made of whether to rely solely on operating data from these distributors or, additionally, to use data from other countries and Canadian jurisdictions. Adding data from other jurisdictions increases sample size, adds suitable peers for Ontario utilities, and increases the diversity of business conditions that are faced by sampled distributors. The accuracy of benchmarking models is aided to the extent that the subject utility is not an outlier, and a large and diverse sample aids econometric model development.

However, sacrifices must be made to preserve data standardization when data are drawn from other jurisdictions. Distributors in other jurisdictions may itemize costs differently or provide different services, and data may not be readily available for certain business condition variables. Many jurisdictions lack the many years of standardized data on the value of utility plant that are needed for the monetary approach to the calculation of capital costs and quantities.

Available data can sometimes control for some of these problems. For example, itemized data may facilitate the exclusion of certain costs, and "adjustor" variables may be easy to construct to control for certain differences. However, it can be impractical within a reasonable benchmarking budget to gather *new* data for other jurisdictions or even for all of Ontario's distributors given their large number.[22] It can make more sense to rely chiefly on data for other jurisdictions and then gather new data from a single subject utility.

In this project, PEG considered the inclusion of data from Ontario, Alberta, and the United States. We discuss in these sections the pros and cons of using data from these three sources.

Ontario Data

Overview

The OEB regulates more than 50 electricity distributors. In addition to distributing power, these utilities provide a wide range of customer services that include metering, billing, collection, and conservation and demand management ("CDM"). The largest distributor, HONI, also does most power transmission in Ontario. An extensive amount of standardized data are publicly available on the operations of Ontario electricity distributors.

Major Advantages of Ontario Data

Advantages of using Ontario data in cost and productivity research in this project include the following.

- Two decades of standardized data are publicly and electronically available on operations of dozens of distributors. The sampled distributors vary greatly in operating scale and some

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[22] We noted in Section 2.2 above that in several Custom IR proceedings, Ontario utilities have filed benchmarking studies based on econometric models that were estimated entirely with U.S. data. However, it is relatively easy for one utility to make the data adjustments needed to make their data consistent with U.S. data.

other business conditions. These circumstances aid development of good econometric cost models. Benchmarking consultants to the Australia Energy Regulator have for several years used Ontario data in their econometric cost benchmarking research.

- The business conditions facing Elexicon are not that different from the norms of the Ontario distributor industry.
- Cost data are denominated in Canadian dollars.
- Good data are available for important drivers of the cost of electricity distributors that include their peak loads, the length of their distribution lines, and the age of their assets.
- The distributors provide a similar array of services.
- Itemization of cost data facilitates the removal of some costs (e.g., CDM and bad debt expenses) that may complicate benchmarking.

Major Disadvantages

Major disadvantages of Ontario data include the following.

- Data that can be used to calculate capital costs and quantities are not available for most distributors until 1989. For a few utilities, these data are not available until 2002. Data on the gross plant additions that are preferred for standardized calculation of capital costs and quantities are only available starting in 2013. For prior years, it is necessary to impute gross plant additions using data on each distributor's gross plant value and an assumed retirement rate.

  These problems reduce the accuracy of capital cost and quantity estimates, especially in the early years following 2013. However, these problems will gradually be mitigated as additional years of data accumulate.

- Some Ontario utilities face unusual business conditions. For example, Toronto Hydro Electric System Limited ("THESL") serves a sizable area of high urban congestion while HONI and Algoma Power serve large rural areas that are heavily forested. The data for each of these companies should not be used to estimate the parameters of cost models that benchmark them. Thus, and by way of example, the most urban utilities in the sample whose data can influence the parameters of urbanization variables in THESL's benchmarking model are Hydro Ottawa, Alectra, and ENWIN Utilities Limited ("ENWIN"). This problem reduces the accuracy of Ontario econometric models when benchmarking some distributors. This has led to the submission of custom benchmarking studies based on U.S. data in rebasing proceedings for many of these distributors.

- PEG has not completed an econometric study of Ontario power distributor cost in more than a decade.
- Pension and benefit expenses are frequently excluded from statistical benchmarking studies of utility cost. Reasons include their sensitivity to volatile financial market conditions and their dependence on a distributor's financial commitments to retired workers. Since most Ontario distributors have not itemized their pensions and other benefit expenses, removal of these costs from a benchmarking study for all of these distributors is impractical. In Canada, an additional problem with including pension and benefit expenses in cost research is the lack of federal government labour price indexes that address these expenses as well as salaries and wages. Itemization of pension and other benefit expenses in annual cost reports merits consideration in Ontario going forward.
- Indexes of power distribution construction costs have not been available for Canada or its provinces for many years. This is unfortunate in an era when inflation in the unit cost of distribution system construction has been volatile. In this study, the use of utility construction cost indexes from the United States has as a consequence been explored.

Other Disadvantages

- Many Ontario electricity distributors have transitioned to Modified International Financial Reporting Standards ("MIFRS") that, among other things, reduce capitalization of their OM&A expenses. This materially slowed the OM&A and total factor productivity trends of many distributors during the transition. However, this transition was largely complete by 2013, and the problem can be mitigated by focusing on the years since this occurred.
- A few Ontario distributors ("LDCs") use U.S. Generally Accepted Accounting Principles ("GAAP") accounting. This generally entails more capitalization of OM&A expenses.

- Many Ontario distributors are transitioning to OM&A inputs such as cloud computing and non-wire alternatives (“NWAs”) to growth-related capex. The complication of NWAs can be mitigated by excluding CDM expenses from the analysis.
- Itemized data on the values of distribution and general plant are not readily available.
- Some Ontario distributors own and operate high voltage facilities (e.g., transmission substations and subtransmission lines) while others do not. However, many costs of high voltage operations have been itemized, permitting their removal from cost studies.

Alberta Data

Overview

The Alberta Utilities Commission (“AUC”) has regulated the four largest electricity distributors in the province using generic multi-year rate plans since 2013.[23] In addition to distributing power, these companies own, operate, and read meters and manage metering data. However, due to the approach to the restructuring of retail power markets pursued in Alberta, many billing and collection services are provided by other entities that also sell power to end users. The Alberta distributors also typically do not provide extensive conservation services or operate facilities with voltage exceeding 25 kV.

EUB Directive 014 has required Alberta electricity distributors to file extensive operating data each year beginning in 2005. The requisite data for benchmark year calculations of capital cost and quantity are available for 2004. A uniform system of accounts for electricity distributors was issued in 2006 in Alberta Energy and Utility Board Bulletin 2006-25. Rule 005 of the AUC has required annual reports on distributor operations since 2008.[24] 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.

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[23] ENMAX operated under MRPs prior to 2013.

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

Major Advantages of Alberta Data

- Substantially standardized data on distributor operations are available for four utilities since 2013.
- ENMAX and EPCOR are useful peers for Ontario's urban utilities. All distributors have itemized their total pension and benefit expenses and OM&A salaries and wages for at least some years of the sample period.[25]
- There are no complications due to currency difference in benchmarking research.

Major Disadvantages

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

- The non-performance of certain customer services makes Alberta data useless for benchmarking the cost that Ontario distributors incur to provide these services.
- Data needed to calculate consistent capital cost and quantity indexes using monetary methods are available only since 2004. As in Ontario, this limits the accuracy of capital cost data, especially in the early years for which data are available. However, the accuracy of Alberta data on gross plant additions and OM&A expenses are not affected by this problem.
- Some of the quality data available on Ontario business conditions are unavailable for Alberta. Distribution line length and system age are notable examples.
- ATCO Electric serves a rural service territory in northern Alberta and is an outlier in benchmarking studies that include its data.

Other Disadvantages

- There are some inconsistencies, between the four distributors and over time for individual distributors, in the itemization of OM&A expenses.

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[25] ATCO Electric stopped itemizing pension and benefit expenses during the sample period.

- Distributors are required to make contributions to some power transmission projects (e.g., at point of delivery locations) and usually capitalize these outlays. However, these data are itemized and can be removed.
- We understand that contributions of retail customers in aid of construction (“CIAC”) are unusually large in Alberta.
- Alberta distributors do not report on an integrated (e.g., transmission and distribution) basis. This makes the allocation of common costs between services opaque.

U.S. Data

Overview

Most American businesses and households receive their electricity distributor services from an investor-owned utility (“IOU”) such as National Grid, which owns several U.S. utilities including one that serves large areas of upstate New York. 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.

The U.S. government has gathered detailed data for decades on the operations of all “major” IOUs that distribute power. The primary source of these data is Federal Energy Regulatory Commission (“FERC”) Form 1. FERC Form 1 data are also available on peak loads, the number of customers served, and some important characteristics of distribution networks (e.g., the capacity of distribution substations). A Uniform System of Accounts encourages data standardization. Form EIA-861 is a census of all U.S. electric utilities. It gathers other useful operating data, including data on the reliability of service, the prevalence of automated metering infrastructure (“AMI”), and DERs.

Major Advantages of U.S. Data

U.S. data have notable advantages in the multijurisdictional benchmarking of Elexicon.

- Many years of standardized data are available on the operations of numerous U.S. distributors facing varied business conditions. This facilitates econometric model estimation.
- The cost data are highly itemized, making it easy to calculate costs of distribution and customer services that distributors provide and to remove some kinds of data that are

inconvenient for a benchmarking study. For example, we can remove costs of pension and other benefit expenses.

- 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 bolsters the accuracy of capital cost and quantity calculations using monetary methods.
- Most U.S. electricity distributors perform similar tasks to those in Ontario. For example, U.S. distributors typically provide billing and collecting services.
- Data on the value of distribution and general plant are itemized.
- Handy Whitman indexes have been available for many years on regional trends in the costs of power distribution and general plant construction.[26] These indexes are also relevant in the measurement of Canadian construction cost trends.
- Several Ontario utilities have few peers in the province and this, together with the U.S. data advantages just described, has led to numerous statistical benchmarking studies of Ontario utility cost by PEG and utility consultants using models estimated with U.S. data. This reduces the incremental cost of undertaking a study using U.S. data for Elexicon Energy.
- PEG is responding to a benchmarking study by Clearspring that used U.S. data.
- Data are available for numerous distributors that, like Elexicon, serve suburban areas of large metro areas. These distributors include those serving suburbs of New York City, Chicago, Miami, Washington DC, Atlanta, Philadelphia, San Francisco, and Detroit. Some distributors operate in states like California, Massachusetts, and New York that are in the North American vanguard of the energy transition.

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[26] Custom indexes can also be purchased (albeit at substantial cost) on trends in prices that electricity distributors face for materials and services.

Other Advantages

OM&A expenses are broken down, for each distributor and over time, into labour and material and service expenses. This aids development of good OM&A input price indexes.

Major Disadvantages of U.S. Data

There are, however, some major disadvantages to including U.S. data in a statistical benchmarking study of Ontario electricity distributor cost.

- U.S. cost data are denominated in U.S. dollars, making it harder to accurately compare prices of electricity distributor inputs in the U.S. and Canada.
- An econometric cost benchmark tends to be more reliable to the extent that the subject utility faces business conditions near the sample mean. In this regard, it is notable that the average size of companies in the U.S. IOU sample is much larger than that of Elexicon.
- The available peak demand data in the U.S. are not expressly designed for power distribution. A correction is possible that is sensible but probably not highly accurate.[27]
- Standardized data on distribution line length are not readily available for a large number of IOUs over many years. Data are available on service territory *area* but we consider this to be an inferior measure of system extensiveness.
- Some other good business condition variables available for Ontario distributors are not available for U.S. distributors. These include data on the age of distribution facilities.

Other Disadvantages

- We noted above that investor-owned electricity distributors in the U.S. typically also provide transmission services, and many also provide generation services. However, distributor cost data are itemized, administrative and general costs are a small part of total cost, and methods are available to allocate a portion of these costs to distributor services. These methods are straightforward if not highly accurate.

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[27] This correction is discussed in Section 5.3.

- U.S. IOUs provide gas as well as electric service and this tends to lower the cost of electric service. However, costs of gas service can be excluded from cost calculations and it is straightforward to devise an “adjustor” variable to account for economies of scope that might result when a distributor provides both services.
- CDM expenses are typically reported as customer service and information (“CS&I”) expenses in the U.S. but are not clearly itemized for easy removal. It is then necessary to exclude the entirety of CS&I expenses from cost and productivity studies. Fortunately, apart from CDM expenses, CS&I tends to account for only a small share of distributor costs.

Resolution

Given the many advantages of U.S. and Alberta power distributor operating data, material problems with Ontario data, the low incremental cost of a study using U.S. data, Clearspring’s decision to use U.S. data in their benchmarking, and the limited budget for this project, we decided to prioritize the use of U.S. and Alberta data in developing our benchmarking models for Elexicon Energy.

4. Clearspring's Benchmarking Evidence

4.1. Summary of Clearspring's Evidence

Clearspring used an econometric model to benchmark the total historical cost of Elexicon' base rate inputs over the 6-year period from 2019 to 2024. The Company's projected/proposed costs were benchmarked for the 2025-2031 period that includes the five years of the proposed new rate plan (2027-2031). Clearspring developed this model using data on power distributor operations of 82 investor-owned utilities in the United States. The sample period for most companies in the sample was the twenty-four years from 2000 to 2023. Data for some years were excluded for some companies due to wildfire-related costs or reporting consistency issues.

The dependent variable in Clearspring's model was real total cost --- the ratio of nominal total cost to a total factor input price index. 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 service territory area, and a rolling average of maximum monthly peak demand.[28]

Clearspring's model also contains the following variables that measure other drivers of power distributor cost:

- the estimated share of the service territory area that has urban congestion;
- the share of customers with advanced metering infrastructure ("AMI");
- a measure of the extent of system overheading x the share of service territory forested;
- a measure of potential scope economies defined as the share of electric customers in the sum of gas and electric customers served;
- another measure of potential scope economies defined as the share of distribution OM&A expenses in the sum of generation, transmission, and distribution OM&A expenses.

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[28] By way of comparison, the scale variables in the OEB's 2013 Total Cost Benchmarking model are the number of customers served, the ratcheted peak demand, and the total volume.

- A “distribution work” variable defined a share of transmission lines with ratings at or above 50kV; and
- the standard deviation of the elevation of the service territory.

The model also contains a (linear) trend variable.

With respect to the mathematical form of Clearspring’s model, it has a double log form except that it also contains a full complement of quadratic and interaction terms (e.g., *Customers* x *Customers*, *Customers* x *Area*, and *Customers* x *Rolling Average Peak Demand*) for the three scale variables in addition to the corresponding first-order terms (*Customers*, *Area*, and *Rolling Average Peak Demand*). This “translog” treatment of the scale variables affords the model the flexibility to capture nonlinearities in the relationship of cost to operating scale.

All parameter estimates for the first order terms in the model are highly significant and have plausible signs. The quadratic and interaction terms for the scale variables are also highly significant, suggesting that the relationship of cost to operating scale is nonlinear. The estimate of the trend variable parameter suggests that real total cost tended to fall by about 0.33% annually over the sample period for reasons other than changes in the values of the included business condition variables.

Elexicon’s total costs were well below the benchmarks yielded by Clearspring’s model during all twenty historical years and were 29.9% below the model’s prediction on average during the three most recent historical years (2022-2024). The Company’s forecasted/proposed costs over the five years of the proposed new CIR plan are below the corresponding benchmarks by 13.9% on average during the five years of the proposed rate plan. However, the Company’s total cost efficiency is expected to average a 4.5% annual decline during the plan with the sharpest declines occurring in the first and final years of the plan.

4.2. PEG Critique

At the outset of our critique we would like to acknowledge that Clearspring is right to base its stretch factor recommendation on an econometric benchmarking study

We also acknowledge that in his recent studies for Ontario utilities, Mr. Fenrick has changed his power distributor cost benchmarking methodology in several areas where we were critical of his approach in past proceedings. Here are some examples.

- The initial or benchmark year for the calculation of capital costs and quantities for sampled U.S. utilities is now 1947 whereas it was previously 1988.
- OM&A input price indexes that are used to calculate input quantity trends now have company-specific weights.
- Pension and benefit expenses were excluded from the data for Elexicon and all of the U.S. utilities.
- An economies of scope variable based on operation and maintenance expenses is now used instead of one based on plant values.
- The use of quadratic and interaction terms for business conditions other than scale variables has been reduced.

We nonetheless disagree with some of the methods Clearspring used in this study. Our concerns range from major ones to concerns that are notable but need not concern the panel presiding over this proceeding.

Major Concerns

Area Variable

Clearspring's total service territory area variable has two major problems. One is that Clearspring opted to give this variable full translog treatment as a scale variable. This adds three second-order scale variables to the cost model. Choosing this variable specification produced negative output cost elasticities with respect to numerous companies in the sample. In response to interrogatory 1-Staff-9 b), Clearspring said that:

> Out of the 5,709 [custom output elasticity] possibilities there are 655 negatives for area, 356 negatives for customers, and 279 negatives for peak demand.

Another problem is that the variable is not time variant whereas the actual area served does grow with the length of distribution lines. The estimated elasticity of cost with respect to area is far smaller than the elasticities with respect to customers and peak load.

PEG believes it is preferable to account for the service territory area in the model without using it as a scale variable complete with second-order terms. It makes sense then to treat area as a "network" variable and not accord it translog treatment.

Treatment of Area

Clearspring's model contains numerous quadratic and interaction terms because it designates three variables as scale variables. We believe that area should not be treated as a scale variable for reasons that we discuss further below.

Treatment of Capital Cost

Clearspring's model overstates the importance of capital cost by valuing it in replacement dollars and then ignoring how the net cost of ownership would be reduced by capital gains.

Distribution Work Variable

PEG acknowledges the desirability of a variable to measure the extent of high voltage work that a distributor performs since this can be costly and varies between distributors. However, the variable that Clearspring uses is too problematic for inclusion. The idea is that the greater is the share of high voltage lines in the total transmission lines that a transmission and distribution utility reports the more likely it is that the utility classifies subtransmission work as distribution. This reasoning is difficult to explain and understand. Moreover, there are many reasons why an unusually high share of a utility's transmission work may be high voltage that have little or nothing to do with the extent of its subtransmission work. We also found that this variable was, counterintuitively, statistically significant in our *OM&A* cost model but not in our *capital* cost model. Note finally that it is difficult to set credible values for this variable for Elexicon or for Alberta power distributors that we may wish to add to our sample.

Congested Urban ("CU") Variable

Challenges of urban congestion should be addressed by distribution cost models. In congested urban areas traffic affects the duration of distributor truck rolls, and costly assets and designs are sometimes required for distribution facilities due to footprint and space availability.

In testimony for THESL in 2018, Mr. Fenrick developed a congested urban variable measured as the share of the service territory area in which the height of buildings is typically seven stories or higher. This variable did not have time-variant values. In his next testimony for THESL, Mr. Fenrick made this variable time-variant by adjusting the original value for the annual growth in the number of skyscrapers exceeding 100 meters. The new variable has a positive and highly significant parameter estimate in Clearspring's model.

We have several concerns about this variable. One is that CU values weren't calculated for all companies in the sample. In response to 1-Staff-15 b), Clearspring explains that

> constructing the congested urban variable involved a large effort which required meticulous mapping of city blocks and streets. For this reason, only cities with populations above 200,000 at the time of the investigation were examined.

This likely excludes several smaller cities with congested urban areas (e.g., Atlantic City, NJ; Bellevue, WA; and Hartford, CT).

A second concern is that the parameter estimate is quite sensitive to the inclusion in the sample of one company, Consolidated Edison of New York, that has an unusually high CU value. In THESL CIR proceedings, PEG presented evidence that the estimated parameter on the modified variable changed substantially if the model was estimated without them. In response to 1-Staff-10 a), Clearspring said:

> it would be helpful, if it were possible, to add more utilities similar to Consolidated Edison to the sample. However, that is not currently feasible.

Lesser concerns include the fact that the skyscraper data are for the entire service territory of the company and not just for the designated CU area, as discussed in Clearspring's response to 1-Staff-15 h).

Sample

Clearspring's sample excludes Alberta data. It also excludes a number of U.S. power distributors for which data are available. Several of the excluded American distributors were involved in mergers and acquisitions during the sample period. Clearspring explained this by saying that:

> Recent mergers are excluded due to the extensive effort necessary to "reconstruct" the new utility for all the model variables.[29]

Clearspring also uses an unusually long sample period, justifying it by saying that they "did not see a rationale to deviate from our research methodology in recent applications where we used 2000 as the

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[29] 1-Staff-13, part c.

start year."[30] While this can sharpen model parameter estimates, the estimates pertain to a more dated era.

Lack of Granularity

Total cost benchmarking does not shed light on the sources of high and low costs that utilities incur. Knowledge of strengths and weaknesses in management of more granular categories such as OM&A expenses is useful to utilities and regulators alike. OM&A cost performance is an especially important issue in this proceeding where Elexicon advocates for a more OM&A-specific ratemaking treatment. The incremental cost of econometric OM&A cost benchmarking is modest when an econometric total cost benchmarking study is also undertaken because development of the two models involves many common variables and other shared costs. Clearspring conceded this in response to 1-Staff-7, part a.

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 Elexicon and other utilities, that steer clear of these problems will have more credibility.

- Clearspring uses the trends in both the Handy Whitman Power Distribution Construction Cost Index for the North Atlantic states and a Canadian capital stock deflator) to deflate Elexicon' gross plant additions. Recent research by PEG suggests that it is more accurate to just use the HWI. Clearspring appears to agree with us that the HWI is more appropriate, as discussed in their response to 1-Staff-14, saying that:

  > Clearspring's position has been for several past Custom IR applications that HWI is the most appropriate index to use for Ontario utility asset price inflation. We have continued our advocacy for the HWI.

  When asked to re-run the model using the HWI, Clearspring noted that the benchmarking results "are more stable year-over-year due to this change." Clearspring indicated that using the HWI would improve Elexicon's cost performance slightly during the CIR term.

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[30] 1-Staff-13, part a.

- Clearspring measures the extent of system overheading as the percent of total distribution plant value that is not identified as being underground (i.e., the numerator contains much more than the accounts identified as overhead assets). However, this places in the denominator of the variable assets that have not been itemized as being underground or overhead.

- Clearspring's overhead x forestation variable is constructed by interacting the logged form of percent forestation with the level (percent) form of overhead. This is needlessly confusing, and the variable does not work in the model when both terms receive the same treatment (e.g., both logged or both level).

- Clearspring assumes that the level of M&S prices is the same throughout the U.S. and throughout Canada. We believe that M&S prices will tend to be higher to the extent that local labour prices are higher.

- Clearspring does not mean-scale any of the business condition variables in its model. While this does not affect the model predictions, doing so would better facilitate interpretation of parameter estimates.

- Input price levels tend to differ between utilities in each year. Levelization of prices is typically undertaken once in a benchmarking study, and it makes sense to do this in a recent year of the sample period where benchmark accuracy is most valued. Clearspring levelizes its OM&A price index in 2010 and its capital price index in 2015. Clearspring explained that this was done in order "to remain consistent with the most recent Toronto Hydro benchmarking research (EB-2023-0195), the Hydro One joint conferral research (EB-2021-0110), and the current Elexicon benchmarking research (EB-2025-0252)" and that "it was not worth the effort to update those items."[31]

- There are no variables in Clearspring's model to capture the cost impact of energy transition challenges such as DERs on the customer side of the meter.

- Clearspring's capital cost does not include capital gains. It accordingly overstates the importance of capital cost performance.

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[31] 1-Staff-12, part b.

- Clearspring uses the OEB’s target ROE for all sampled utilities.
- Clearspring uses the Driscoll-Kraay standard error adjustment to their OLS model but does not use the “Fixed-b” adjustment version. This version was developed in 2008 specifically to improve the Driscoll-Kraay standard error calculations in samples with a generally low number of observations. While 1000+ observations may sound like a lot, Driscoll-Kraay was developed for enormous datasets (e.g., years of hourly financial data).
- Clearspring acknowledged that around 25 observations in its sample featured implausible administrative and general expense allocator values (e.g., negative values or values over 100%).[32]
- Clearspring’s economies of scope variable has 2 observations well in excess of 100%, giving rise to concerns about the calculation methodology.

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[32] 1-Staff-11, part a.

5. Data Used in PEG's Research

In this section of the report we discuss the data used in PEG's cost benchmarking and productivity research for this proceeding.

5.1. Ontario

Our research required data on Elexicon Energy for benchmarking and for all Ontario utilities for the productivity trend calculations.

Data Sources

The principal source of data we used on the operations of Ontario electricity distributors is their annual Reporting and Record Keeping Requirements ("RRR") reports to the OEB. Cost data are gathered chiefly under Section 2.1.7 of the OEB's Electricity RRR. These Trial Balance data are filed annually. The OEB has required each jurisdictional electricity distributor to file Trial Balance data since 2002. An *Accounting Procedures Handbook for Electricity Distributors* has been established that includes a Uniform System of Accounts and there are other instructions in the RRR filing system.

An important supplemental source of Ontario electricity distributor data is filed annually under Section 2.1.5 of the OEB's RRR. This source is sometimes called the PBR data. These include data on billed kWh and kW and other utility characteristics. There are also data on the value of gross plant additions that we used to compute capital cost in the Ontario productivity study. The data on the gross plant additions of Elexicon that we used in the benchmarking study were, however, obtained from Clearspring. Section 2.1.2 of the RRR has data on number of customers served which is an important scale variable.

Most of the Canadian price data used in this study were obtained from Statistics Canada. Data on electric utility construction cost *trends* were drawn from the *Handy Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates.

Sampled Distributors

To calculate Ontario productivity trends we used data from 53 Ontario electricity distributors that, together with any important predecessor companies, have filed RRR data for many years. These distributors are listed in Table 1 below.

Table 1

Ontario Distributors Included in the Productivity Trend Study

Alectra Utilities
Algoma Power
Atikokan Hydro
Bluewater Power Distribution
Burlington Hydro
Canadian Niagara Power
Centre Wellington Hydro
Cooperative Hydro Embrun
E.L.K. Energy
Elexicon Energy
Enova Power
Entegrus Powerlines
ENWIN Utilities
EPCOR Electricity Distribution Ontario
ERTH Power
Essex Powerlines
Festival Hydro
Fort Frances Power
GrandBridge Energy
Greater Sudbury Hydro
Grimsby Power
Halton Hills Hydro
Hearst Power Distribution
Hydro 2000
Hydro Hawkesbury
Hydro One Networks
Hydro Ottawa Limited
Innpower
Kingston Hydro
Lakefront Utilities
Lakeland Power Distribution
London Hydro
Milton Hydro Distribution
Newmarket-Tay Power Distribution
Niagara Peninsula Energy
Niagara-on-the-Lake Hydro
North Bay Hydro Distribution
Northern Ontario Wires
Oakville Hydro Electricity Distribution
Orangeville Hydro
Oshawa PUC Networks
Ottawa River Power
PUC Distribution
Renfrew Hydro
Rideau St. Lawrence Distribution
Sioux Lookout Hydro
Synergy North
Tillsonburg Hydro
Toronto Hydro-Electric System Limited
Wasaga Distribution
Welland Hydro-Electric System
Wellington North Power
Westario Power

Sample Period

Circumstances that merit consideration when choosing a sample period for distributor cost and productivity research based on Ontario data include the following:

- Standardized data on OM&A expenses of Ontario electricity distributors are not available for years before 2002.

- Many distributors changed their accounting standards in the 2011-2013 period.[33] This affected their capitalization of OM&A expenses and resulted for many distributors in a surge in these expenses and a drop in capex.
- During the 2006-2010 period Ontario electricity distributors deployed first-generation smart meters. This deployment affected OM&A expenses as well as capex. Costs of this transition were accorded deferral account treatment. The deferred OM&A expenses were chiefly cleared for recovery from ratepayers in the 2011-2013 period.
- Estimates of utility capital costs and quantities are ideally built up from many years of data on the value of gross plant additions. As we explain further below, calculation of capital costs and quantities could not begin before 1989 for some utilities and before 2002 for a few utilities.
- A full itemization of OM&A expenses by function is not readily available before 2013.
- OM&A salaries and wages were not itemized prior to 2015 or after 2022.
- The electricity distribution business in Ontario is changing rapidly, spurred by the energy transition and other sources of electricity demand growth. This argues for a shorter and more recent sample period and periodic updates of cost benchmarking and productivity studies.
- There is understandable interest in cost performance in the years since the Renewed Regulatory Framework was approved.

In view of these considerations, we calculate productivity trends using data for the longest sample period available. This is the growth rate years from 2004 to 2024. However, we feature results for the 2014-2024 period, which has eleven growth rate years.

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[33] Most of the changes were from Canadian GAAP accounting to MIFRS accounting.

Ontario Cost Data

The cost of Ontario electricity distributors that we considered in our cost modelling and productivity studies was the sum of applicable OM&A and capital costs. We discuss each kind of cost in turn.

OM&A Expenses

The OM&A expenses used in this research were drawn from RRR reports. In the Elexicon benchmarking study we included OM&A expenses for

- distribution less those for street lighting and signal systems (5060, 5165) and sentinel lights (5170, 5172);
- billing and collecting less those for bad debt (account 5335); and
- most administrative and general tasks.

We excluded expenses for power procurement.

There are a few differences in the scope of OM&A covered in our benchmarking and productivity studies. Pension and other benefit expenses were included in the Ontario productivity study but not the Elexicon benchmarking study. In the productivity study, community relations expenses other than energy conservation were included. In the benchmarking study, community relations expenses were excluded in their entirety. High voltage costs were included in both studies.

PEG's 2013 benchmarking and productivity studies featured several adjustments to address deferred smart meter cost. These were done either to adjust the timing of expenditures to reflect when they were incurred, or in the case of the productivity work, to exclude them entirely. For this project all such adjustments have been removed and smart meter costs are included at the time they are recognized in the RRR accounts. These costs were included in both the productivity and benchmarking studies.

Another complication is that some Ontario distributors are "embedded" in the distribution system of other distributors (chiefly HONI). The distributor relies upon services that would normally be included as part of distribution cost for other distributors but are included with power procurement. These costs are the low voltage services provided by HONI to distributors. To improve comparability among distributors, in the 2013 project, PEG added some itemized charges by HONI for low voltage services to these distributors to the reported costs of these distributors. This treatment was supported in 2013 by a working group of electricity distributors. We use the same cost adjustment for the Elexicon benchmarking but not for the Ontario productivity trend study.[34] The requisite billing data are obtained annually by OEB Staff from HONI as part of the TCB update process. The billing codes included in the low voltage charges in this study are the same as those used in the 2013 study.

Capital Costs

Monetary Approach In the benchmarking and productivity trend research alike we employed a monetary approach to capital cost, price, and quantity measurement that featured a geometric decay specification. The capital cost of each distributor was the product of a capital quantity index and a capital service price index. The capital quantity index was constructed using data on the deflated value of gross plant additions. Plant was valued in current dollars rather than the historical dollars used to set revenue requirements in rebasing proceedings. Capital cost included depreciation expenses and a return on net plant value. Taxes and franchise fees were excluded from our cost calculations.

Capital cost was calculated net of capital gains. This treatment modestly reduces the importance of capital cost containment in the total cost benchmarking. Further information on capital cost that includes the formulas we used in our calculations is provided in Section 9.1.

Benchmark Year Capital quantity indexes are customarily built up from the deflated value of plant (a rough estimate of the capital stock) in a certain “benchmark” year using perpetual inventory equations and data on gross plant additions. Since the deflation of plant value in the benchmark year can be quite inexact, accuracy is enhanced to the extent that the benchmark year is far in the past so that decay in the quantity of capital existing in that year reduces its importance relative to the quantity of newer capital that is better measured.

The plant value data needed for a benchmark year calculation are available from the RRR from 2002 onwards. In order to make possible an earlier capital benchmark year, OEB Staff provided PEG with plant value data from the Municipal Utility Databank (MUDBANK). MUDBANK is a dataset on

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[34] The productivity work is concerned with trends over time and not differences between distributors at a particular point in time. Therefore, this cost adjustment has much lower value in the productivity study relative to the benchmarking study.

operations of municipal utilities that was compiled by Ontario Hydro under the previous electric utility industry structure. MUDBANK data allowed PEG to use 1989 as the benchmark year in our capital cost research for most distributors. However, data limitations required us to use 2002 as the benchmark year for six distributors that include HONI.

Gross Plant Additions We noted in Section 3.2 above that gross plant additions are not readily available for Ontario distributors before 2013. From 2002 to 2012, we in most cases estimated each utility's gross plant additions using the annual differences in its reported accumulated gross plant value with a standard adjustment for retirements. For utilities with 1989 benchmark years, we were able to use this method in most years before 2002 as well but between 1997 and 2002 special imputations were required due to data gaps.[35]

In the calculation of Ontario gross plant additions we included CIAC for the productivity trend study but not for the Elexicon benchmarking study (e.g., for the Ontario research, we did not subtract CIAC from the value of these additions). Gross plant additions explicitly identified by distributors as high voltage assets were included in both the productivity trend study and the benchmarking study.

In our 2013 research, gross plant additions for smart meters were excluded from the productivity trend study. Smart meter gross plant additions were included in the Elexicon benchmarking and Ontario productivity studies. This tended to slow calculated productivity growth in the 2004-2013 period when smart meters were first acquired.

For the 2002-2031 period we used gross plant additions data from the Clearspring working papers for Elexicon. For the years prior to 2002 we used values from the 2013 4th GIRN productivity research. After 2013, data for the gross plant additions of all Ontario distributors in the productivity study were drawn from the RRR.

Operating Scale

Two scale variables were used in the benchmarking and productivity trend research: peak demand and the number of customers served. Ratcheted peak demand and a moving average of recent annual peak demands were both considered. We ratcheted the peak load data by using in each year the

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[35] Additional details of these calculations can be found in Kaufmann et al (2013), pp. 26-27.

highest value that the distributor had attained since 2002. The ratcheted approach was chosen for our modelling work for reasons that included the following.

- Distribution cost depends on the maximum peak that may occur with reasonable probability (e.g., the peak that might occur on an unusually hot and humid summer weekday when the economy is briskly growing). The moving average peak demand will tend to understate this.
- Even if this likely maximum peak trends downwards for a few years, most infrastructure established to serve the higher demand expectation of prior years will continue to be owned, operated, and maintained.
- The energy transition and brisk economic growth in the Toronto area are forecasted to make the near future a period in which a rolling average of past peak demand is likely to be especially off the mark. Not coincidentally in our view, Clearspring used its forecasted *actual* peak demand and not a *rolling average* of past demand to construct its proposed growth factor scale index.
- It is complicated to gauge the estimated cost impact of the two peak demand variables because there are three variables in the model related to peak demand: peak demand, peak demand squared, and peak demand x customers. Econometric total cost models with ratcheted peak demand had lower root mean squared errors and higher adjusted R Squared statistics than those with rolling average peak demand.

Canadian Input Prices

Prices distributors pay for inputs are another important driver of their costs. These prices change from year to year and differ between distributors in a given year. Differences in the prices faced by distributors in a given year (e.g., the difference between labour prices in Toronto and Edmonton) matter when benchmarking the level of costs in that year but not in the calculation of productivity *trends*. We used separate but related input price indexes in our benchmarking and Ontario productivity trend research. The productivity trend research used input price trend indexes that are similar to the trend components of the input price indexes we used for benchmarking.

The input price indexes we developed for Elexicon and the sampled Alberta distributors have similar designs. We accordingly discuss the input price indexes for all of these distributors in this section.

OM&A Prices

The OM&A inputs of energy distributors encompass labour, materials, and services. Our research requires indexes of the prices of these inputs.

Labour Labour prices were constructed for Elexicon and the sampled Alberta distributors using a multistep process. For 2021 (a census year in Canada) we calculated an index of labour price levels with values for each distributor. These indexes are based on itemized data that are published by Statistics Canada on median wages, salaries and commissions for utility sector workers by city.[36] Each Canadian distributor was assigned a single relevant city for which these data were available. The labour price was then expressed as the ratio of the value of this variable for the designated city to the value for all of Ontario.

For other years of the sample period, labour price index values were calculated for each sampled distributor by adjusting the 2021 level backwards and forwards for inflation in the applicable provincial fixed weighted index of average hourly earnings ("FWI AHE"). We believe the FWI AHE to be a more reliable index of growth in wage rates than the average weekly earnings that we used in some past studies. Its advantage can be material during recessions such as that which Canada recently experienced due to the Covid pandemic.

Materials and Services Material and service ("M&S") prices paid by distributors are assumed to vary regionally due to the sizable share of services in M&S expenses, the sizable share of local labour expenses in the cost of services, and the tendency of wage rates to vary regionally. We assumed that 1/3 of distributor M&S expenses are for local labour. The M&S price index was on this basis 1/3 levelized in 2021 using the labour price index.

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[36] These data are found in Statistics Canada table 11-10-0073-01: Wages, salaries and commissions of tax filers aged 15 years and over by main industry sector and sex. The utility sector of Canada's economy includes gas, water, and sewage utilities as well as electric utilities. The table reports median wages, salaries and commissions for various industries including the utilities sector.

We used the gross domestic product implicit price index for final domestic demand (“GDPIPI^{FDD}”) for Ontario and Alberta to deflate M&S expenses of Elexicon and the Alberta distributors respectively. This is preferable to the more comprehensive GDPIPI because the latter is quite sensitive to the volatile prices of Canada’s sizable commodity (e.g., oil, gas, and metal) exports.

Summary OM&A Price Indexes Summary OM&A input price indexes played an important role in our research. We calculated these indexes using as price subindexes our chosen labour and M&S price indexes. As suggested by our discussion of input price index design in Section 2.1, the weights for these subindexes should be cost shares that reflect a company-specific and time-variant breakdown of OM&A expenses into those for labour and M&S expenses. The requisite data for such weights were available for Alberta. For the years 2015 to 2022, company-specific and time-variant data were used on the share of salaries and wages in OM&A expenses. These results were stretched to apply to other years where they were needed.

Capital Prices

The monetary approach to the calculation of capital cost that we used required us to calculate capital (service) price indexes. We constructed these indexes from capital asset prices and data on the rates of return to capital investment.

A multistep process was used to construct the capital asset prices. We first calculated an index of construction cost *levels* which varied between the service territories of sampled distributors 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.[37] RSMeans index values are available for multiple Ontario and Alberta cities. We assigned one such city to ENMAX, EPCOR, and Elexicon and multiple cities to Fortis Alberta due to its sprawling service territory.

To obtain levelized asset price index values for other years, we trended the 2019 values for Canadian distributors backwards and forwards using Handy Whitman Indexes of electric utility construction cost for total distribution plant. For the Ontario distributors we used the HWI for the North

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

Atlantic region of the United States, while for Alberta distributors we used the analogous index for the Plateau region of the U.S.

In our 2013 Ontario TCB benchmarking and subsequent updates, the rate of return (r_t) has been computed as the weighted average cost of capital ("WACC") of Ontario distributors. This has been appropriate since the rate of return is intended to reflect a distributor's opportunity cost of capital, not its actual returns. The WACC is calculated by the OEB and reflects its approved values for long-term debt rates, short-term debt rates, and return on equity. We continue to use these time variant WACCs in this study. For Alberta, PEG calculated the distributors' WACC based on AUC-approved capital structures and returns on equity along with the costs of debt and preferred equity that the distributors report in their Rule 005 filings.

Total Factor Input Price Indexes

Total factor input price indexes were required for the econometric total cost benchmarking. For this purpose we calculated the total factor input price level in 2021 and then escalated it backwards and forwards using total factor input price trend indexes. The summary total factor input price trend indexes that we used in the econometric total cost research were constructed for each distributor by combining the growth rates of the capital and summary OM&A price trend indexes using company-specific, time-varying cost share weights.

Mergers and Amalgamations

Our calculations have been adjusted for amalgamations that have taken place since the 2013 study. The historical cost performance of the combined entity was calculated from the historical results of the predecessor distributors that amalgamated or were acquired. In each of these cases the companies have consolidated reporting and are benchmarked as single entities under the new company names.

5.2. Ex Ontario Data

Data Sources

United States

The primary source of data on the cost of U.S. electricity distributors that we used in our benchmarking was FERC Form 1. FERC Form 1 data were for many years published by the U.S. Energy

Information Administration ("EIA").[38] More recently, these data have been available in raw form electronically from the FERC. They are also available (for a sizable fee) in more processed forms from commercial vendors. Customer data were generally drawn[39] from Form EIA-861 (the *Annual Electric Power Industry Report*). We also relied on Form EIA-861 for data on AMI and DERs. The data from FERC Form 1 and Form EIA 861 that we used in this study were obtained directly from government agencies and processed by PEG.

Data on U.S. labour prices were obtained from the Bureau of Labour Statistics ("BLS") of the U.S. Department of Labour. The gross domestic product price index ("GDPPI") that we used as the proxy for an M&S price trend index 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 cities were obtained from RSMeans. Data on electric utility construction cost *trends* were drawn from the *Handy Whitman Index of Public Utility Construction Costs*. Data on forestation in North America were obtained from the Commission for Environmental Cooperation's geographical information system ("GIS") maps of North American landcover as of 2020. These landcover maps are a product of the its collaborative North American Land Change Monitoring System initiative.

Alberta

Data on the costs of Alberta utilities were drawn chiefly from their Rule 005 filings and rebasing applications. Data on Alberta input prices were obtained from Statistics Canada and were discussed in Section 5.1 above.

Sample Period for Econometric Model Development

The sample period for the development of the cost benchmarking models was the 15-year period from 2009 to 2023. We believe that this period strikes the right balance between the need for data relevance and the need for a large sample to sharpen parameter estimates.

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

[39] Occasionally, the EIA 861 customer data had isolated implausible values. In such cases, we drew the customer number from the FERC Form 1 or another credible source such as the company's 10-K filing.

Sampled Ex Ontario Companies

United States

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 in the years since then. To be included in this study, the data also were required to be of good quality and plausible.

Table 2 lists all of the sampled utilities in the cost modelling that have service territories outside Ontario. Data for 89 U.S. distributors were included. Most broad regions of the U.S. are well represented.[40]

Alberta Utilities

We included data for three of Alberta's four largest electricity distributors: ENMAX, EPCOR, and FortisAlberta. Since data from Alberta utilities have rarely been used in Ontario cost benchmarking studies we provide here some information about these utilities.

ENMAX ENMAX Power Corporation ("ENMAX") is an electric transmission and distribution utility based in Calgary. It distributes power to most of Calgary's metropolitan area, which in 2025 had a population of about 1.7 million. This is similar to the population of the Ottawa-Gatineau metro area. However, as the center of Canada's sizable 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 underground. ENMAX began full-scale deployment of AMI in 2023 which was largely completed by the end of 2025.

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, retailer, and miscellaneous other energy and customer care 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.

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

Table 2

Ex-Ontario Utilities Sampled in the Benchmarking Research

Alberta

- ENMAX
- EPCOR
- FortisAlberta

United States

- Alabama Power
- ALLETE (Minnesota Power)
- Ameren Missouri
- Appalachian Power
- Arizona Public Service
- Atlantic City Electric
- Avista
- Baltimore Gas and Electric
- Central Hudson Gas & Electric
- Cleco Power
- Cleveland Electric Illuminating
- Commonwealth Edison
- Connecticut Light & Power
- Consolidated Edison Company of New York
- Consumers Energy
- Dayton Power & Light (now AES Ohio)
- Delmarva Power & Light
- Dominion Energy South Carolina
- 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
- Evergy Kansas Central
- Evergy Kansas South
- Evergy Metro
- Fitchburg Gas & Electric Light
- Florida Power & Light
- Georgia Power
- Green Mountain Power
- Idaho Power
- Indiana Michigan Power
- Indianapolis Power & Light
- Jersey Central Power & Light
- Kentucky Power
- Kentucky Utilities
- Kingsport Power
- Louisville Gas & Electric
- Madison Gas & Electric
- MDU Resources Group
- Metropolitan Edison Company
- MidAmerican Energy
- Mississippi Power
- Monongahela Power
- Narragansett Electric
- Nevada Power
- New York State Electric & Gas
- Niagara Mohawk Power
- Northern Indiana Public Service
- Northern States Power - MN
- NSTAR
- Ohio Power
- Oklahoma Gas & Electric
- Orange & Rockland Utilities
- Pacific Gas & Electric
- PacifiCorp
- PECO Energy
- Pennsylvania Power Company
- Portland General Electric
- Potomac Electric Power
- PPL Electric Utilities
- Public Service Company of Colorado
- Public Service Company of New Hampshire
- Public Service Company of Oklahoma
- Public Service Electric & Gas
- Puget Sound Energy
- Rochester Gas & Electric
- San Diego Gas & Electric
- Southern California Edison
- Southern Indiana Gas & Electric
- Southwestern Electric Power
- Southwestern Public Service
- Tampa Electric
- Toledo Edison
- Tucson Electric Power
- United Illuminating
- Upper Peninsula Power
- Virginia Electric & Power
- West Penn Power Company
- Wisconsin Electric Power
- Wisconsin Power & Light
- Wisconsin Public Service

EPCOR 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 2025 the Edmonton metropolitan area had a population of about 1.6 million. About 420,000 customers were served in 2021. With a predominantly urban service territory, a high percentage of EDTI's distribution facilities are underground. EDTI has completed a buildout of AMI to its electric customers.

EDTI also provides power transmission service, and affiliates provide power retailing and water, and wastewater treatment services in Edmonton. This creates opportunities to realize scope economies. Other affiliates of EDTI provide electricity distributor and gas distributor services in Ontario. Water utility services have also been provided in other Alberta communities and in British Columbia, Saskatchewan, Arizona, New Mexico, and Texas.

FortisAlberta FortisAlberta ("Fortis") is an investor-owned electric utility based in Calgary. It distributes power to some cities near Calgary and Edmonton and to numerous small cities, 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 (which include a swath of the Rocky Mountains) 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 rural electrification areas ("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.[41] This limits opportunities to realize scope economies. However, its corporate parent Fortis Inc. owns energy

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

utilities in other Canadian provinces (e.g., FortisBC Energy, formerly known as Terasen Gas) and in the United States, Central America, and the Caribbean.

Conclusions

We believe that the expanded data set forms a good base for rigorous research on the cost performance of Elexicon. The sample is large and varied enough to permit development of credible econometric cost models with numerous statistically significant business condition variables.

5.3. Variables Used in PEG's Benchmarking Model

Cost Data

United States

The cost of U.S. electricity distributors that we included in our total cost benchmarking was the sum of applicable capital and OM&A costs. OM&A expenses that we included comprised applicable distribution expenses and a sensible share of reported administrative and general expenses. We excluded costs that the U.S. utilities reported for power production, procurement, transmission, uncollectible accounts, street lighting, CS&I, and any gas utility services that they provided. The entirety of CS&I expenses was excluded because in the U.S. these expenses contain large conservation expenses that are not consistently itemized for easy removal. Pension and other benefit expenses were also excluded.

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.

We added to each U.S. utility's cost of distributor services a share of its administrative and general expenses equal to the share of included distributor OM&A in the OM&A cost of its generation, transmission, and distributor services. Since many general costs are tied to the management of labour, in calculating OM&A for this purpose we excluded some OM&A costs from these calculations which are large relative to their labour cost component. Examples of these excluded expenses are those for purchased energy and uncollectible bills.

We employed a monetary approach to capital cost, price, and quantity measurement. In addition to costs of *distribution* plant ownership, we included a sensible share of the costs of *general* plant ownership. We used the same share that we applied to administrative and general expenses. The available gross plant addition data for U.S. distributors are reported net of CIAC.[42]

Alberta

The cost of Alberta electricity distributors considered in our econometric total cost modelling was the sum of applicable capital and OM&A expenses. These costs include each utility's allocation to power distribution of the general costs of providing diverse services.

The OM&A 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 data included the normal expenses incurred by the distributors with the exception of their taxes and franchise fees.

The Alberta distributor capital costs we considered were those for distribution plant and all reported general plant. CIAC, construction work in progress, and contributions to transmission were excluded from gross plant additions.[43,44]

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[42] The term CIAC here is meant to be synonymous with contributed capital from customers.

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

[44] Please note that in a data request response to PEG in the recent Alberta PBR3 proceeding (27388), the ATCO companies indicated that Alberta distributors tended to have high CIAC relative to distributors in other jurisdictions. The ATCO companies cited evidence filed in a 2011 generic cost of capital proceeding.

U.S. Input Prices

OM&A Prices

Labour Our benchmarking requires indexes of U.S. labour and M&S input prices. For the year 2019 we calculated indexes of labour price levels for 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 level 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. The index numbers were calculated relative to the U.S. average.

To arrive at U.S. labour price levels that are comparable to the Canadian prices described in Section 5.1 above, these index numbers must be adjusted to reflect the difference between Canadian and U.S. dollars. To calculate comparable wage rate index values for U.S. distributors in 2019, we relied on average annual earnings data for the utilities sectors of the United States (as computed by BLS) and Ontario (as computed by Statistics Canada).[45] The ratio of the U.S. value to the Ontario value was used to adjust the U.S. wage index level. Because the U.S. work was done for 2019 and the Canadian work was done for 2021, an adjustment for the two intervening years was also made.

For other years of the sample period, values of each company's labour price index were calculated by adjusting these levels for changes in labour price trend indexes. For the U.S. utilities PEG used for this purpose regionalized indexes of trends in BLS Employment Cost Indexes ("ECIs") for *salary and wage* rates in the utilities sector of the U.S. economy.

Materials and Services Prices that U.S. utilities pay for M&S inputs are often assumed in statistical cost research to rise over time at the rate of the 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 consumer products, business equipment, and exports. However, recent research by PEG suggests that the GDPPI tends to materially understate the M&S price inflation of U.S. utilities.

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[45] The same Ontario data source that we used to calculate relative Ontario labour price levels was used for these calculations. The same data source was used for Alberta and therefore is already comparable to Ontario.

In the benchmarking work, the levels of utility M&S input prices were assumed to differ in 2019 by 1/3 of the difference between distributors in their corresponding labour prices. We used our labour price index to effect this adjustment.

Summary OM&A Price Indexes We used the labour and M&S price indexes to construct summary OM&A price trend indexes.[46] Growth in the summary index for each utility was a cost-weighted average of the growth of the two subindexes. The cost shares in our indexes for U.S. distributors were company-specific and time-variant. The average share of labour in the total applicable OM&A expenses that resulted from these calculations was 39% for the sampled U.S. distributors over the 2014-2023 period.

A price "patch" is required between input prices in the United States and Canada. Canadian data are expressed in Canadian Dollars and the U.S. data in U.S. Dollars. The foregoing discussion explained how this is done for labour prices. For M&S prices a similar method was used with the Purchasing Power Parity between the U.S. and Canada being used in place of the labour price ratio. The OM&A price patch entails a cost-weighted average of the two price comparisons. The capital price indexes do not need to be patched because the RSMeans indexes used in their calculation already reflect currency differences.

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 once again used to construct the requisite capital asset prices. We first calculated an index of construction cost levels which varied between the service territories of U.S. sampled distributors in 2019 in proportion to the relative cost of local construction as measured by total heavy construction city cost indexes published by RSMeans. RSMeans index values are available for multiple cities in the service territories of most sampled U.S. distributors. For these distributors, we typically computed a weighted average of these values using as weights the approximate populations of the pertinent cities.[47]

To obtain levelized asset price index values for other years, we trended the values for 2019 backwards and forwards using asset price trend indexes. As asset price trend indexes for the

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[46] The formulas for our input price indexes are discussed further in Section 9.

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

distribution plant of U.S. distributors we used the applicable regional HWIs for Total Distribution Plant. As asset price trend indexes for general plant we used the gross domestic product price index.

For the rates of return of U.S. utilities we calculated 50/50 averages of rates of return for debt and equity. 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.[48]

Summary Multifactor Input Price Indexes

Summary multifactor input price indexes were required for the total cost modelling. We once again established the multifactor input price level for a certain year and then escalated it backwards and forwards using a multifactor input price trend index with company-specific, time-varying cost share weights.

Scale Variables

Two scale variables were used in our benchmarking model: the number of customers served and ratcheted peak demand. The parameters of the first-order terms of both of these variables should have positive signs in all three cost models. We added quadratic and interaction terms for these variables to bolster the flexibility of the model to reflect complicated cost-output relationships.

Alberta peak demand data were drawn from information request responses in the PBR3 proceeding.[49] 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 the peak power *demand* of vertically-integrated electric utilities from their retail and requirements sales for resale (e.g., muni and cooperative) customers. It expressly excluded the peak-

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[48] 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 *EEI Rate Case Summary* quarterly reports.

[49] Two distributors provided their peak load data measured in megavolt amperes. We used the AESO's official minimum power factor obligation of 0.9 to convert these data into megawatts.

period demand of non-requirements sales for resale customers. We adjusted these data to make them more applicable to electricity distributors.[50]

Line length data analogous to those available for Ontario distributors are unfortunately unavailable for U.S. or Alberta distributors. Service territory area has sometimes been used as a proxy for the geographical extensiveness of the system. In past transnational benchmarking studies that we have undertaken for OEB Staff we used area estimates for U.S. utilities made by Power Systems Engineering ("PSE"), a Madison-based engineering consultancy, in research and testimony for Ontario utilities. For this study, we updated those territory maps to account for mergers and changes in territory which have occurred since the database was created. We then recalculated all service areas and matched the territories to North American Environmental Atlas GIS maps of categorized landcover and subtracted the water area. We used this updated estimate of square kilometer of service territory land area in the multijurisdictional model. For Alberta, we used area estimates provided by the three distributors in their information request responses in the PBR3 proceeding.

We did not use area as a stand-alone output variable for several reasons. One is that its estimated total cost elasticity is much smaller than those for customers and peak demand. A second is that the variable is not time-variant, whereas the true area served will grow slowly over time. A third is that treating area as an output variable would add three second-order terms to the model. This reduces the precision of all parameter estimates. We instead use this variable to create a customer density variable (customers/area) for the year 2023. We add a quadratic term to the log linear term because the relationship of cost to density may be highly nonlinear. Non-linearity is quite possible because very low and very high density are both known to pose cost challenges.

Other Business Condition Variables

Data on the vegetation challenges in the spans between power poles are not available for the U.S. or Alberta distributors, as they are for the Ontario distributors. It is possible to construct estimates of general forestation in the service territories of distributors, but these data have several limitations.

- They are not estimates of vegetation where distribution lines actually run.

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[50] We multiplied the highest reported monthly peak load for the year by the ratio of total retail volume to total retail and requirements sales for resale volume.

- It is difficult to accurately measure vegetation along the streets of towns and cities where most distributors make most of their deliveries. A sensible alternative is to measure the *general* forestation in *non-urban* areas that distributors serve.

We have developed for this project a measure of general forestation in non-urban areas using the same North American Environmental Atlas landcover GIS maps as in the service territory land area calculations. Six of the nineteen classes of landcover defined in these maps are forest types. We summed the forested areas within each distributor's territory and divided it by distributor's total land area (ex-water).

We use the forestation variable as an interaction term with the percent of plant overhead. Overheading is calculated from FERC Form 1 Electric Plant in Service at End of Year accounts as the ratio of the sum Overhead Conductors and Devices and Poles and Fixtures to the sum of Underground Conductors and Devices, Underground Conductors and Devices, Overhead Conductors, and Devices and Poles and Fixtures. We expect the vegetation challenges to be more important to the extent that the company has assets overhead, and that this is likely to increase both capital and OM&A due to higher ongoing maintenance needs and susceptibility to early replacement or reinforcement. We expect this interaction variable to have a positive parameter in a OM&A cost model and an indeterminate, but most likely positive parameter, in the capital and total cost models. Since percent overhead, as the inverse of percent underground, tends to have a negative relationship with capital cost, the effects on capital cost may cancel and the variable may be insignificant when combined with the percent forestation.

We use the percent of plant underground, the inverse of overheading, as a standalone variable in the OM&A cost model. We expect this variable to have a negative parameter in this model due to the long-term maintenance savings associated with undergrounding.

As a measure of cost challenges posed by urban congestion we used the number of buildings in the service territory with a height that equals or exceeds 100 meters. These data, which are available for Alberta, Ontario, and the U.S., are time-variant and were purchased from the Council on Tall Buildings and Urban Habitat. We noted above that in recent benchmarking research and testimony for

THESL, Steven Fenrick used these data to calculate an adjustment to an urban congestion variable.[51] This variable used as a standalone measure should be highly correlated with the size of any congested urban area that a company serves. We accordingly expect the parameter for this variable to have a positive sign in the total cost and capital cost models. The sign is less clear in the OM&A cost model because undergrounding per se reduces labour requirements. In contrast to an Ontario sample, the many distributors in our multijurisdictional sample that serve urban cores facilitate the estimate of a reasonable parameter estimate for this variable.

Since some of the sampled U.S. electricity distributors (e.g., Pacific Gas and Electric) may realize scope economies from the joint provision of gas and electricity services, the share of electric customers in the sum of the numbers of gas and electric customers served by U.S. distributors was added to the model. Data on the number of gas customers served by a distributor are drawn from Form EIA 176. All Alberta distributors and Elexicon are assumed to have values of 1 for this variable. We expect this variable to have a positive parameter in all three cost models.

AMI is used by many electricity distributors today and its use is often mandated. Elexicon has a full AMI buildout, but some U.S. and Alberta distributors do not. AMI is more costly than conventional meters and creates new data management tasks for distributors. However, it can also potentially produce some distribution cost savings. The share of customers with AMI, sourced from the EIA 861, therefore is expected to have a parameter estimate of uncertain sign in the total cost and OM&A models and a positive sign in the capital cost model.

We calculated a DER penetration variable which is the ratio of DER generation capacity to a 3-year rolling average of maximum peak load. The source of these data for the United States is the Form EIA 861 survey's sections on Net Metering and Non-Net Metering Distributed Generation. We obtained analogous data from the Alberta transmission system operator for the Alberta distributors. The expected sign of this variable is indeterminate in all three cost models.

Customer growth is another important business condition faced by distributors. We calculated this variable as the percentage change in total customers from the beginning of the sample period in

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[51] Fenrick, Steve, "Econometric Benchmarking Study of Toronto Hydro's Total Cost and Reliability Metrics," EB-2023-0195, Exhibit 1B, Tab 3, Schedule 3, Appendix A, October 31, 2023.

2009 to the end of the sample in 2023. New customers inherently require some additional capital costs, which at first are undepreciated. New customers may also add stress to their area of the grid if it is already near capacity. The distributor's customer and billing management systems should be able to accommodate customer growth at minimal incremental cost, and the new customers should need less maintenance in the first several years with new equipment and recently assessed local assets. We expect this variable to have a positive parameter estimate in the capital cost model, and an indeterminate but likely negative estimate in the OM&A model. The sign in a total cost model is indeterminate since it depends on the strength of the respective capital and OM&A cost effects.

6. PEG’s Alternative Cost Benchmarking Research

Relying chiefly on our own data, PEG developed alternative econometric models of the total cost, OM&A, and capital costs of electricity distributors.

6.1. Differences from Clearspring’s Methodology

Here are some salient differences from Clearspring’s benchmarking methodology.

- We provide separate cost benchmarking models for OM&A, capital, and total cost.
- Data from Alberta distributors were used in our sample as well as data from U.S. distributors.
- There are appreciably more U.S. companies in our sample (89 vs. 82 companies).
- We begin our sample period in 2009 instead of 2000 to adjust for the disadvantage of using the longer time period in the cost model. The regression pools all of the time series data as though they occurred in one time period. An estimate of the trend variable parameter based on the most recent 15 years of data is more relevant in determining the Productivity Factor.
- We use ratcheted rather than average peak demand as a scale variable. We explained above that ratcheted peak is more relevant to the emerging cost pressure of brisk demand growth.
- We did not treat service territory area as a scale variable warranting translog treatment. This eliminates three second-order translog terms (although we add one quadratic term for the density variable).
- We use a different asset price index (now just the Handy Whitman Power Distribution Construction Cost Index for the North Atlantic states instead of an average of this HWI and a Canadian capital stock deflator) to deflate Elexicon’s gross plant additions.
- We use an alternative, fully time-variant urban congestion variable (number of skyscrapers) that has a positive value for Elexicon starting in 2025.
- PEG’s input price index for materials and services is quarter-levelized while Clearspring’s is not. Our approach permits M&S prices to be higher where labour prices are higher.

- We use 2019 data to link US prices to Canadian prices for US companies whereas Clearspring used 2015 for its capital price index and 2010 for its OM&A price index. This makes the benchmarking of costs in recent years more accurate.
- We use a more accurate measure of the extent of system overheading, specifically the share of all assets that are itemized as being overhead or underground that are overhead.
- We have new forestation and service territory area variables.
- Our new models include a distributed generation variable that addresses an important cost of the energy transition.
- We mean-scaled all variables.
- We included a capital gains term in the capital service price index.
- We used different ROE values for the U.S. and Canada.
- We use the “Fixed-b” standard error correction to Driscoll-Kraay, developed in 2008, to improve upon the standard error calculations that Clearspring used.[52,53]

6.2. Econometric Modelling Results

Results of our econometric cost research are reported in Tables 3-5. As in Clearspring’s work, the dependent variable in each model was *real* cost --- the ratio of nominal cost to the corresponding input price index. This specification enforces a key result of cost theory.[54]

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-

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[52] Paper available at: https://www.princeton.edu/~erp/erp%20seminar%20pdfs/papersspring09/hansen.pdf

[53] Code available from Tim Vogelsang, a professor at Michigan State University, on his academic website: https://sites.google.com/view/tim-vogelsang-msu/code

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

order terms of the business condition variables were statistically significant at a high level of confidence and plausible as to sign and magnitude.

Econometric results for PEG's distributor total cost model are presented in Table 3. Here are some salient results.

- The parameter estimates for the number of customers and the ratcheted peak demand are highly significant and positive. The 0.593 elasticity of cost with respect to customers is considerably higher than the 0.398 elasticity with respect to peak demand. The parameter estimates for the quadratic and interaction terms associated with these scale variables were also highly significant. The relationship of cost to these scale variables was therefore significantly nonlinear.
- Total cost was found to be higher the greater was customer density, the number of skyscrapers, the share of service territory area that was forested x the share of assets overhead, AMI penetration, the importance of DERs, the share of electric plus any gas customers that were electric, and the pace of customer growth. Total cost tended to be higher the greater was customer density, and the quadratic term was positive and highly significant, suggesting that the relationship of cost to density was nonlinear.
- The estimate of the trend variable parameter suggests that there was about a 0.54% annual decline in real total cost over the 15-year sample period for reasons other than changes in the values of the included business condition variables.
- The 0.971 adjusted R^2 statistic suggests that the model has a high degree of explanatory power. However, these statistics tend to have high values in models of this kind.

Table 3

PEG's Econometric Model of Total Power Distributor Cost

VARIABLE KEY

YN = Number of Customers
YP = Ratcheted Max Distribution Peak
YN*YN = Number of Customers squared
YP*YP = Distribution Peak squared
YN*YP = Customers * Peak
(YN/YA) = Density
(YN/YA)*(YN/YA) = Density squared
%ELEC = % Electric Customers of Total Gas & Electric
%OHP*%FOR = %OH Line Plant * % Forested Land
%AMI = % Customers with AMI
SKY = # of Skyscrapers (100m+) in Service Territory
DGCAP = Renewable Distributed Gen as % of Total MW Capa
YNgr15 = Customer Growth over the 15-year Sample Period
TREND = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YN	0.593***	21.690	0.000
YP	0.398***	15.645	0.000
YN*YN	1.316***	9.599	0.000
YP*YP	1.488***	11.397	0.000
YN*YP	-1.417***	-10.600	0.000
(YN/YA)	0.0119**	2.516	0.012
(YN/YA)*(YN/YA)	0.0353***	10.737	0.000
%ELEC	0.0314***	3.134	0.002
%OHP*%FOR	0.0606***	23.991	0.000
%AMI	0.0211***	5.699	0.000
SKY	0.00556***	8.190	0.000
DGCAP	0.0209***	7.821	0.000
YNgr15	0.0357***	3.961	0.000
TREND	-0.00544***	-5.980	0.000
CONSTANT	20.05***	1443.831	0.000

Adjusted R^2	0.971
Sample Period	2009-2023
Number of Observations	1,357

Capital Cost

Details of PEG's distributor capital cost research are presented in Table 4. Here are some key findings.

- The parameter estimates for the number of customers and ratcheted peak demand were both highly significant and positive. Relative to the total cost model, the elasticity of cost with respect to peak demand was materially higher and the elasticity with respect to customers was lower. 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 greater was the number of skyscrapers, the pace of customer growth, AMI penetration, the share of service territory area that was forested x the share of assets overhead, the importance of DERs, and the ratio of electric customers to the sum of gas and electric customers.
- Capital cost was lower the greater was customer density and once again the quadratic term was positive and significant. The estimate of the trend variable parameter indicates that there was about a 0.15% annual decline in capital cost for reasons other than changes in the values of the model's business condition variables.
- The distribution work variable surprisingly was statistically insignificant in the capital cost model. This calls into question the merit of including the variable in any of the models.
- The 0.974 value of the adjusted R^2 for the model was slightly higher than that for the total cost model.

Table 4

PEG's Econometric Model of Distributor Capital Cost

VARIABLE KEY

YN= Number of Customers
YP= Ratcheted Max Distribution Peak
YN*YN= Number of Customers squared
YP*YP= Distribution Peak squared
YN*YP= Customers * Peak
(YN/YA)= Density
(YN/YA)*(YN/YA)= Density squared
%ELEC= % Electric Customers of Total Gas & Electric
%OHP*%FOR= %OH Line Plant * % Forested Land
%AMI= % Customers with AMI
SKY= # of Skyscrapers (100m+) in Service Territory
DGCAP= Renewable Distributed Gen as % of Total MW Capacit
YNgr15= Customer Growth over the 15-year Sample Period
TREND= Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YN	0.511***	26.310	0.000
YP	0.500***	28.241	0.000
YN*YN	1.091***	19.760	0.000
YP*YP	1.230***	18.704	0.000
YN*YP	-1.171***	-19.256	0.000
(YN/YA)	-0.0105***	-3.475	0.001
(YN/YA)*(YN/YA)	0.0211***	5.684	0.000
%ELEC	0.0724***	7.325	0.000
%OHP*%FOR	0.0478***	66.909	0.000
%AMI	0.0323***	14.967	0.000
SKY	0.00891***	26.478	0.000
DGCAP	0.00851*	2.449	0.014
YNgr15	0.115***	17.265	0.000
TREND	-0.0015	-1.580	0.114
CONSTANT	17.56***	3124.303	0.000

Adjusted R^2	0.974
Sample Period	2009-2023
Number of Observations	1,357

OM&A Expenses

Results of PEG's econometric distribution OM&A research are presented in Table 5. Please note the following.

- The parameter estimates for the number of customers and ratcheted peak demand were both significant and positive. Notice that the number of customers had a greater estimated impact on OM&A cost while peak demand had less impact than in the total and capital cost models. This makes sense since OM&A expenses include many customer-driven expenses like those for metering, meter reading, billing, and collection.
- The parameter estimates for the linear and quadratic terms associated with the scale variables were all highly significant. This again suggests that the relationship of cost to these scale variables was significantly nonlinear.
- OM&A cost was also higher the greater the percent of the service territory that was forested x the share of assets overhead and the importance of DERs.
- OM&A cost was increased by customer density and the quadratic density variable was positive and highly significant, once again suggesting a nonlinear relationship between cost and density.
- OM&A cost was reduced by customer growth and the extent of system undergrounding.
- The trend variable parameter estimate indicates that OM&A cost growth was slowed by about 1.3% annually for reasons other than changes in the values of included business condition variables during the 15-year sample period.
- Table 5 also reports a 0.907 adjusted R^2 statistic for the OM&A model. This is well below the corresponding statistic for the total cost and capital cost models. Evidently, distributor OM&A cost proved more difficult to accurately model than distributor capital cost or total cost.

Table 5

PEG's Econometric Model of Distributor OM&A Expenses

VARIABLE KEY

YN = Number of Customers
YP = Ratcheted Max Distribution Peak
YN*YN = Number of Customers squared
YP*YP = Distribution Peak squared
YN*YP = Customers * Peak
(YN/YA) = Density
(YN/YA)*(YN/YA) = Density squared
%OHP*%FOR = %OH Line Plant * % Forested Land
%UGP = % of Line Plant UG
DGCAP = Renewable Distributed Gen as % of Total MW Capacity
YNgr15 = Customer Growth over the 15-year sample period
TREND = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YN	0.745***	15.758	0.000
YP	0.238***	5.304	0.000
YN*YN	1.547***	5.031	0.000
YP*YP	1.716***	5.900	0.000
YN*YP	-1.643***	-5.485	0.000
(YN/YA)	0.0802***	6.909	0.000
(YN/YA)*(YN/YA)	0.0655***	13.716	0.000
%OHP*%FOR	0.0644***	18.368	0.000
%UGP	-0.143***	-4.873	0.000
DGCAP	0.0354***	16.053	0.000
YNgr15	-0.0545***	-4.093	0.000
TREND	-0.0126***	-16.475	0.000
CONSTANT	19.56***	322.359	0.000

Adjusted R^2	0.907
Sample Period	2009-2023
Number of Observations	1,357

Pacific Economics Group Research, LLC

6.3. Elexicon Utilities Background

Elexicon Utilities was established in 2019. Due to the 10-year merger deferred rebasing period, the Company has never undergone a cost of service rebasing. Its predecessor companies last rebased in 2014 (Veridian Connections) and 2011 (Whitby Hydro). Its proposed cost of service rebasing is in 2027 rather than the expected 2029.

Elexicon has a non-contiguous service territory consisting of 10 municipalities scattered across southeast Ontario. The territory includes remote areas and island communities near Gravenhurst and a swath of Toronto’s eastern suburbs. Company headquarters are in Ajax, a town in the regional municipality of Durham bordering Lake Ontario. In addition to Ajax, Elexicon serves several other communities in the regional municipality of Durham including Pickering, Whitby, and the urban areas of the municipality of Clarington. The Company serves less than 5% of all electricity distribution customers in Ontario.

Durham has grown briskly in recent years through both increased urban density and suburban subdivisions. The Durham region has attracted many new industries and offices and is home to one of Ontario's newest universities, Ontario Tech University. All customers now have AMI, but a replacement with AMI 2.0 is expected to begin deployment in 2028 and continue throughout the rest of the new rate plan. Elexicon is partially embedded in Hydro One Networks, which serves many of the areas between the Company’s territories. The Company reports outsized cost pressures particularly from numerous current and future transportation projects initiated by municipalities within its service territory. Under the OEB’s Price Cap IR benchmarking model, Elexicon has stated that its proposed spending revenue results in a stretch factor of 0.3% in each year

6.4. Business Conditions Facing Elexicon Energy

The external cost drivers faced by Elexicon should be considered when benchmarking their cost. Table 6 compares Elexicon’s cost and external business conditions to the sample mean values in 2023. The following results are notable.

Table 6

How the Model Variables for Elexicon Compare to the Sample Mean[1] (2023)

	Elexicon	Alberta Sample	U.S. Sample	Sample	Elexicon/Sample
Cost	**$ 108,011,701**	**$ 316,353,197**	**$ 673,682,823**	**$ 661,638,004**	**16.3%**
OM&A	$ 40,151,746	$ 98,310,333	$ 229,238,918	$ 224,825,595	17.9%
Capital	$ 67,859,955	$ 218,042,864	$ 444,443,905	$ 436,812,409	15.5%
Scale					**16.5%**
Customers	176,725	537,528	982,368	967,374	18.3%
Peak (2002 Ratchet)	751	2,510	5,514	5,413	13.9%
Peak	696	2,451	4,874	4,793	14.5%
1000 x Peak / Customer	3.94	4.56	4.96	4.95	79.5%
Input Price	**1.42**	**0.98**	**1.15**	**1.15**	**123.6%**
OM&A	1.20	1.09	0.91	0.91	130.9%
Capital	9.44	5.54	8.00	7.92	119.2%
Productivity					**123.8%**
OM&A					129.6%
Capital					120.2%
Business Conditions					
Percent Electric	100%	100%	87%	87%	114.8%
Area	698	60,527	23,411	24,662	2.8%
YN / Area	253	9	42	39	645.5%
AMI	100%	78%	71%	72%	139.8%
% Overhead Line Plant	56%	45%	63%	62%	90.3%
% Underground Line Plant	44%	55%	37%	38%	115.8%
% Forested Service Territory	34%	13%	33%	33%	103.7%
# Skyscrapers in Service Territory	0	53	26	27	0.0%
Renewable Distributed Gen as % Total Capacity	6%	1%	7%	7%	84.60%
Customer Growth over 15 years	16%	25%	9%	10%	163.1%

[1] Since the econometric model is an unbalanced panel, there are a few companies who are in the sample only in years prior to 2023; only companies who are in the model in 2023 are reflected in this table.

- Elexicon's total cost was just 0.16 times the sample mean. The input prices that the Company faced were about 1.24 times the mean. Thus, the Company's real total cost was 0.15/1.24 = 0.12 times the mean.
- The Company's customer count was meanwhile about 0.18 times the mean while its ratcheted peak demand was about 0.14 times the mean.
- Combining all of this information, Elexicon's total factor distributor productivity level in 2023 was about 1.24 times the mean. Its OM&A productivity level was about 1.30 times the mean while its capital productivity level was about 1.20 times the mean.

The TFP level result is consistent with good performance by the Company. This TFP level result can be thought of as an evaluation of cost adjusted for relative scale of operations and input prices. The econometric benchmarking work will improve upon this evaluation by considering a wider variety of business conditions that affect cost.

Here are some additional business condition comparisons.

- The Company's customer growth over the most recent 15-year period was 1.63 times the mean.
- The Company had 0 times the sample mean number of skyscrapers in 2023.
- The Company had a much higher density than the mean, at about 6.46 times the mean.
- The Company's share of customers with AMI was about 1.40 times the mean.
- The share of electric customers in the sum of gas and electric customers was 1.15 times the mean. The Company does not provide gas services.
- Forestation in the Company's service territory was about 1.04 times the mean.
- The land area of the Company's service territory was a tiny 0.03 times the mean.
- The share of distribution assets overhead was 0.90 times the mean, and the share underground was 1.16 times the mean.
- Renewable DERs as a share of total capacity was about 0.85 times the mean.

6.5. Econometric Benchmarking Results

We benchmarked the OM&A, capital, and total distributor cost of Elexicon in each year of the historical 2017-2024 period as well as in the 2025-2031 period for which the Company has provided cost forecasts. 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 year.

Table 7 and Figure 1 report results of this benchmarking work. For each cost considered, the table shows results for each year and highlight the average results for the available historical years, the

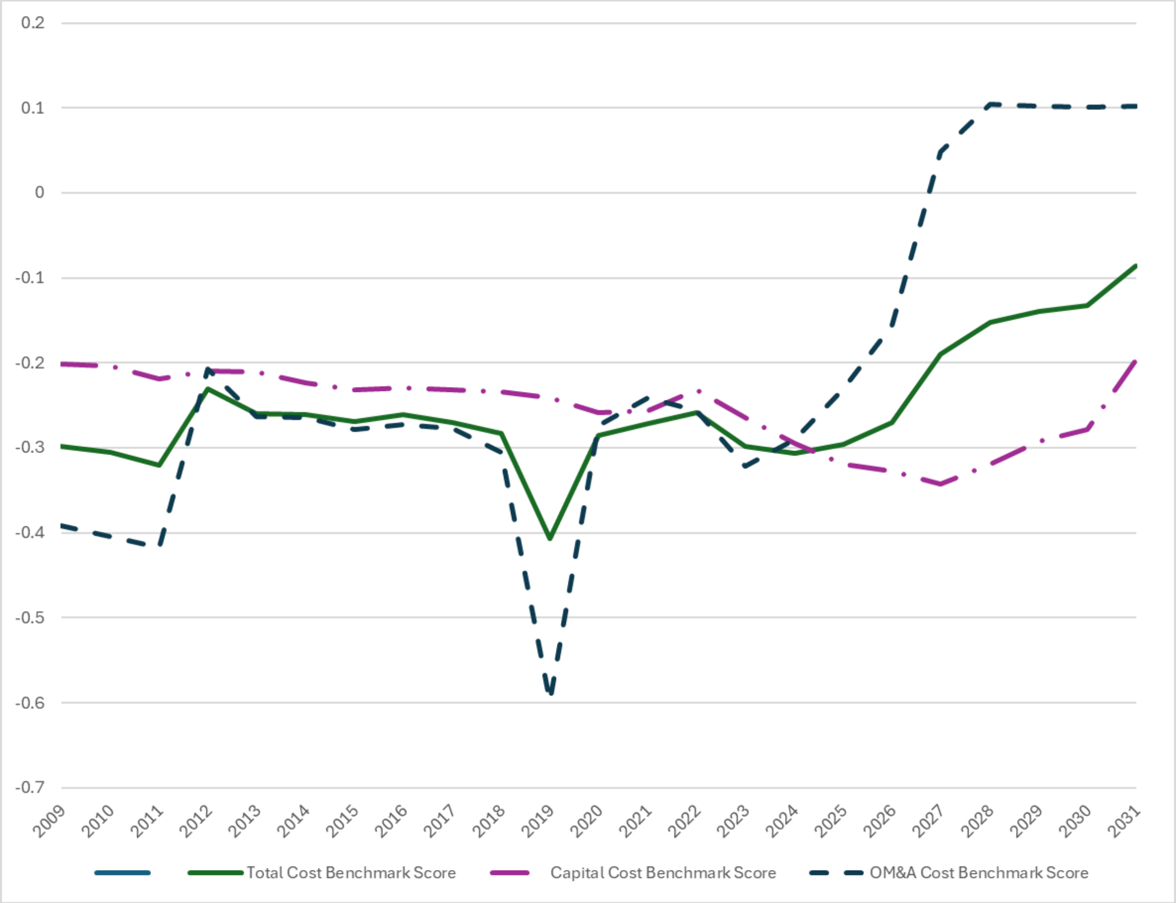
Table 7

Year-by-Year Distributor Cost Benchmarking Results

	[Actual - Predicted Cost]		
Year	**Total Cost Benchmark Score**	**Capital Cost Benchmark Score**	**OM&A Cost Benchmark Score**
2009	-29.83%	-20.09%	-39.11%
2010	-30.52%	-20.34%	-40.46%
2011	-32.02%	-21.88%	-41.70%
2012	-23.07%	-20.99%	-20.68%
2013	-26.00%	-21.13%	-26.32%
2014	-26.05%	-22.41%	-26.48%
2015	-26.94%	-23.14%	-27.86%
2016	-26.10%	-22.93%	-27.23%
2017	-27.00%	-23.19%	-27.69%
2018	-28.36%	-23.42%	-30.51%
2019	-40.68%	-24.07%	-59.87%
2020	-28.52%	-25.82%	-27.38%
2021	-27.14%	-25.62%	-24.16%
2022	-25.91%	-23.23%	-25.62%
2023	-29.83%	-26.42%	-32.13%
2024	-30.63%	-29.52%	-28.97%
2025	-29.61%	-31.90%	-23.06%
2026	-26.99%	-32.75%	-15.63%
2027	*-19.00%*	*-34.30%*	*4.81%*
2028	*-15.25%*	*-31.97%*	*10.38%*
2029	*-13.92%*	*-29.28%*	*10.16%*
2030	*-13.21%*	*-27.81%*	*10.04%*
2031	*-8.55%*	*-19.71%*	*10.18%*
Averages			
2009-2019	**-28.78%**	**-22.14%**	**-33.45%**
2020-2024	**-28.41%**	**-26.12%**	**-27.65%**
2022-2024	***-28.79%***	***-26.39%***	***-28.90%***
Forecast Period 2025-2031	***-18.07%***	***-29.67%***	***0.98%***
CIR Period 2027-2031	***-13.98%***	***-28.61%***	***9.12%***

Figure 1

Cost Benchmarking Results Using PEG's Models



last three historical years, and the seven forecasted years that include the five years of the proposed rate plan.

Total Cost

The results of our distribution *total* cost benchmarking show that Elexicon' total distributor cost was well below the model's prediction, averaging 29% below the prediction in the three years ending in 2024. Cost performance was fairly stable during the historical years considered. Total cost efficiency is forecasted to fall sharply in 2027 and to continue to erode in the last four years of the plan. On average, projected/proposed total cost during the new plan will be about 14% below our benchmarks during the 2027-2031 period.

Capital Cost

The results of our distribution *capital* cost benchmarking show that Elexicon' capital cost efficiency was also well below model predictions during the historical period considered, averaging about 26% below the predictions in the three years ending in 2024. Capital cost performance will improve through 2027 but then trend downward in the out years of the proposed plan. On average, projected/proposed capital cost during the new plan will be a remarkable 29% below our benchmarks during the 2027-2031 period.

OM&A Expenses

Our distribution OM&A benchmarking results show that Elexicon's OM&A cost efficiency was well below average during the historical period, averaging about 29% below the benchmark in the last three years. Performance is forecasted to trend downward from 2024 to 2026 and then to fall precipitously in 2027, the first year of the new plan. Performance will deteriorate further in 2028 before stabilizing at this level for the rest of the plan. There is a reasonable suspicion of deferred OM&A spending during the prior plan. PEG discussed the phenomenon of deferred spending at length in its recent Spending Pattern Analysis report for OEB Staff. On average, projected/proposed OM&A during the new plan will be about 9.1% above our benchmarks during the 2027-2031 CIR term.

7. Ontario Distributor Productivity Trends

The full sample period for our research on the productivity trends of Ontario electricity distributors was the 21 growth rate years from 2004 to 2024. PEG calculated the OM&A, capital, and total factor productivity growth of each sampled distributor. We then computed even-weighted (arithmetic) and cost-weighted averages of the results for individual distributors. This approach yields much more information than the approach that PEG used in the 2013 productivity study, which was to compute the productivity of an aggregated utility industry.

The growth (rate) of productivity was measured as the difference between the growth of a scale index and the growth of an input quantity index. Growth of the OM&A input quantity index was calculated as the difference between the growth of included OM&A expenses and the growth of an OM&A input price trend index. Growth of the total factor input quantity of each distributor was then calculated as a weighted average of the growth of its OM&A and capital quantity indexes using company-specific and time-variant cost share weights.

Growth of the scale index of each distributor was a weighted average of the growth in two scale subindexes. These subindexes were the number of customers served and ratcheted peak demand. The weight for each scale variable was its share of the sum of the estimated cost elasticities for these variables. The estimated cost elasticities were the estimated parameters of the first-order terms of the scale variables in the total cost model presented in Table 3. These elasticity estimates were 0.593 for customer numbers and 0.398 for ratcheted peak demand. The corresponding cost elasticity shares, which must necessarily sum to one, were 0.598 and 0.402 respectively.

Table 8a and Figures 2a and 2b provide summary results of our productivity growth calculations. We present average annual productivity growth rates using simple and cost-weighted averaging. Results for three years of unusually negative productivity growth are shaded for reader convenience.

Table 8a

Productivity Growth of Ontario Electricity Distributors 2004-2024

Year	**Simple Averages of Annual Productivity Growth Rates**			**Cost-Weighted Averages of Annual Productivity Growth Rates**		
	Total Factor	**OM&A**	**Capital**	**Total Factor**	**OM&A**	**Capital**
2004	1.64%	1.92%	0.97%	2.40%	3.90%	-0.30%
2005	-0.15%	1.03%	-0.51%	0.62%	0.88%	0.46%
2006	-1.13%	-2.02%	-0.85%	-1.21%	-3.33%	0.12%
2007	-1.12%	-1.61%	-0.41%	-3.52%	-8.18%	-0.29%
2008	-0.76%	-0.90%	-0.70%	0.56%	1.29%	0.03%
2009	-0.25%	0.25%	-0.48%	-0.87%	-1.80%	-0.22%
2010	0.67%	0.87%	0.68%	0.34%	-1.64%	1.72%
2011	-2.28%	-4.79%	-0.01%	-1.13%	-2.90%	0.19%
2012	-4.39%	-7.52%	0.12%	2.64%	1.44%	3.64%
2013	-1.20%	-1.04%	-1.83%	-2.83%	-4.29%	-1.50%
2014	1.39%	1.80%	0.35%	0.80%	0.05%	1.50%
2015	-0.14%	-0.05%	0.18%	3.71%	5.75%	1.91%
2016	-0.82%	-0.78%	-0.76%	-0.76%	0.56%	-1.89%
2017	-0.27%	0.31%	-0.54%	0.96%	3.57%	-1.32%
2018	0.41%	0.49%	-0.12%	-0.44%	0.19%	-0.98%
2019	0.67%	1.58%	-0.02%	0.57%	2.15%	-0.69%
2020	1.49%	2.59%	-0.11%	1.28%	3.84%	-0.73%
2021	0.55%	0.67%	0.34%	-0.07%	0.38%	-0.43%
2022	-1.09%	-1.93%	0.01%	-1.39%	-2.94%	-0.27%
2023	0.17%	-0.15%	0.63%	-0.54%	-1.36%	-0.03%
2024	-0.75%	-1.80%	0.46%	1.23%	3.24%	0.11%

Average Annual Growth Rates

2004-2024	**-0.35%**	**-0.53%**	**-0.12%**	**0.11%**	**0.04%**	**0.05%**
2004-2010	**-0.16%**	**-0.07%**	**-0.19%**	**-0.24%**	**-1.27%**	**0.22%**
2014-2024	**0.15%**	**0.25%**	**0.04%**	**0.49%**	**1.40%**	**-0.26%**

Figure 2a

Ontario Electricity Distributor Productivity Growth 2004-2024
Simple vs Cost-Weighted Averages of Annual TFP Growth Rates

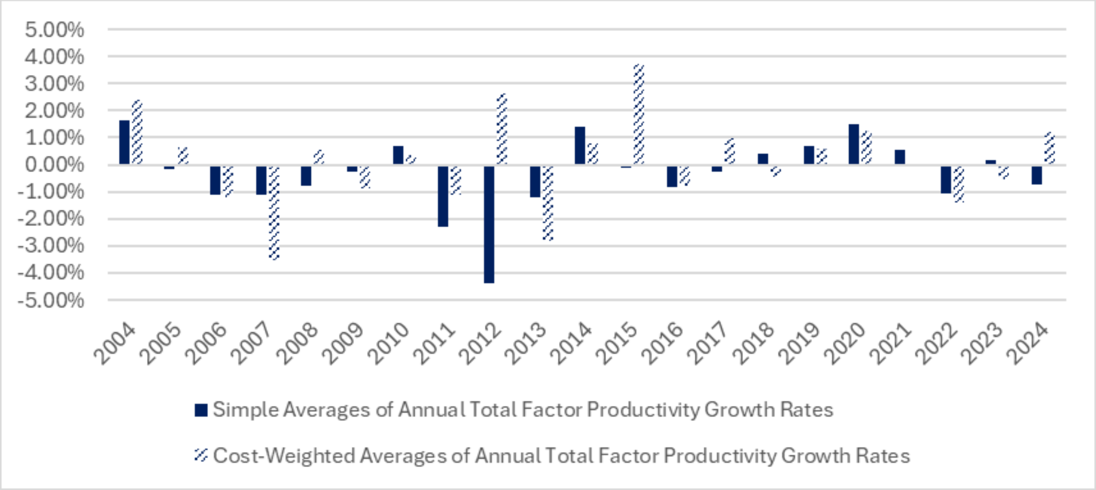
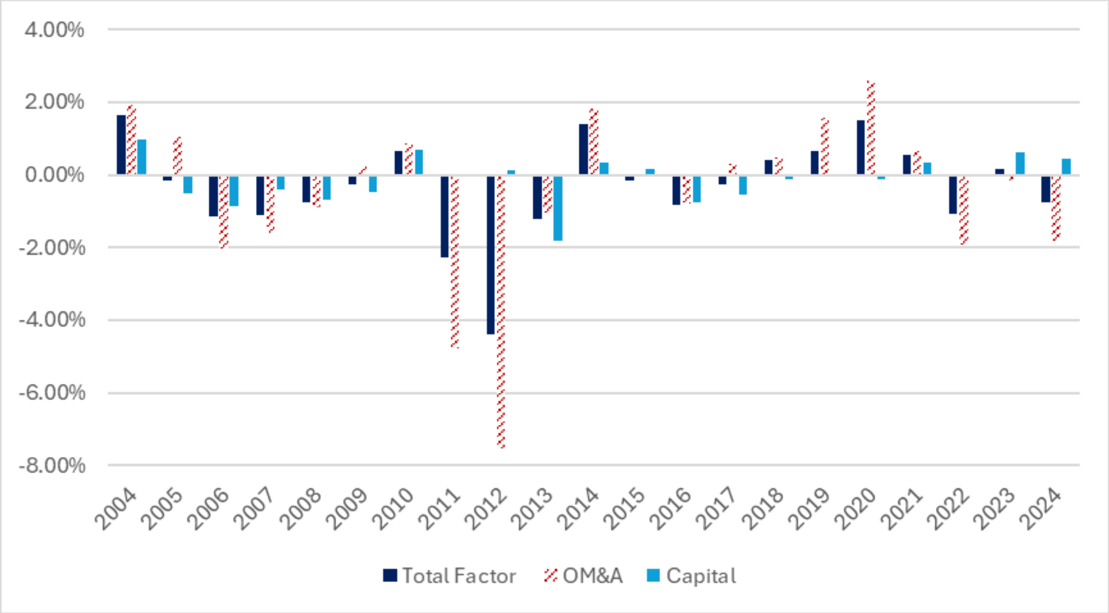


Figure 2b

Ontario Electricity Distributor Productivity Growth 2004-2024
Simple Averages of Detailed Annual Productivity Growth Rates



It can be seen that the TFP trend was negative in the early years of the full sample period using both kinds of averaging. The productivity results for these years reflect different calculation methods than those used in PEG's 2013 study. There are several reasons for this but the most important is that our earlier work adjusted the data to remove the estimated cost impact of the smart meter mandate. The concern was that this would produce a TFP growth target that was inappropriate going forward. Our new research includes these costs, albeit in years in which they cleared smart meter deferral accounts rather than in the years when they were incurred. The first sample year that was free of these clearances was 2014.

Productivity trends in the early years of the sample period were also influenced in 2011 and 2012 by the transition to MIFRS accounting by many distributors. The MIFRS transition resulted in increased reported administrative and general expenses because a portion of these expenses were no longer eligible to be capitalized. As can be seen, the simple average OM&A productivity growth rates in 2011 and 2012 were quite negative. Results for a truncated sample period ending in 2010 provide another reference period that did not have these two negative productivity years.[55] Recollecting that the benchmark years for the calculation of capital quantity indexes are fairly recent in Ontario, please also note that the accuracy of the capital and total factor productivity growth calculations is lower in the early years of the sample period.

Some other changes in our methodology for calculating productivity growth in the early years include the following.

- The now-defunct Statistics Canada Electric Utility Cost Price Index was replaced with a Handy-Whitman construction cost index as a means of deflating gross plant additions.
- There are different scale index variables and weights and other methodological improvements.

Using simple averages of the results for individual utilities, a 0.15% positive TFP trend for 2014-2024 is also shown. This sample period is free of the aforementioned data problems and is also the

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[55] However, results for the period ending in 2010 don't reflect the cost impact of AMI.

period in which the RRF was in place. When compared to the period ending in 2010, there was a material TFP gain in the RRF period of 0.31% per annum.

Similar patterns in the results can be seen if industry productivity growth is calculated as a *cost*-weighted average of distributor-specific productivity growth. The cost-weighted averages are heavily influenced by results for the four largest Ontario distributors. The positive 2014-2024 TFP trend of 0.49% was materially greater than the 0.24% decline during the period ending in 2010.

Some insight into the sources of improved productivity performance is provided by examining the productivity trends in capital and OM&A inputs. Using simple (arithmetic) averages, the 2014-2024 period shows OM&A productivity growth averaging a 0.25% annual gain whereas the result in the 2004-2010 period was a slight 0.07% annual decline. Please note that in the simple averages the OM&A productivity growth decline in 2013, the year that provides the base for this trend calculation, is fairly normal. Capital productivity growth averaging a slight 0.04% annual increase in the RRF years was a greater than the 0.19% annual decline in the earlier years. The *cost*-weighted trends show a marked acceleration in OM&A productivity growth during the RRF years while capital productivity growth was materially more negative than in the period ending in 2010. This result is sensitive to results for a few companies.

While the result of accelerating productivity growth is encouraging, it is worthwhile to remember that the OM&A productivity trends could be influenced by the inclusion of pension and other benefit expenses in the cost data. Note also that OM&A productivity growth was much more volatile than capital productivity growth. The sharp declines in simple average OM&A productivity in 2011 and 2012 are likely attributable to the changes in accounting standards. An OM&A productivity surge in 2020 followed by an OM&A productivity decline in 2022 likely reflect the impact of the pandemic.

Table 8b shows the trends in the scale variables used to construct the scale indexes as well as the growth in capital and OM&A inputs used to construct the input quantity index. Growth in ratcheted peak demand was slower than the growth in the number of customers served.[56] This likely reflected Ontario's sizable CDM programs. Peak demand growth may well accelerate in the next five years.

It is also useful to examine productivity trend results by size of distributor which are presented in Table 8c.[57] There was a divergence in trends between larger and smaller distributors. For the RRF period from 2014-2024, the average annual TFP growth of small distributors was positive 0.20% whereas medium-sized distributors averaged 0.09% growth. Large distributors averaged a slight annual decline of 0.02%. Their capital productivity growth was much more negative than the sample norm, but their OM&A productivity growth was much more positive. These trends compare favorably to the earlier periods ending in 2010 for large and small distributors but not for medium-sized distributors due partly to the superior historical performance of these distributors in the earlier period. PEG cautions that because OM&A productivity growth is so volatile the average annual growth rate over the 2014-2024 period for a few large companies may not reflect their longer-term trend.

Our results suggest that the TFP growth of Ontario distributors has improved under the RRF. The more rapid growth in OM&A productivity than in capital productivity likely reflects in part the fact that indexing has played a larger role in the determination of OM&A revenue escalation than it has in the determination of capital revenue escalation. The more negative productivity growth patterns of large distributors likely reflect some combination of their greater need for capex and their greater reliance on incentive-weakening supplemental capital revenue mechanisms such as those approved under Custom IR. Higher capex may have facilitated greater OM&A productivity growth for this size group.

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[56] This means that an output quantity index constructed using elasticity weights from the OM&A cost model would grow more rapidly than one using weights from the total cost model, while an output quantity index constructed using elasticity weights from the capital cost model would grow more rapidly.

[57] These size categories are based on the share of the distributor's total cost to the total cost of all sampled distributors in 2023.

Table 8b

Details of Ontario Electricity Distributor Productivity Growth 2004-2023

Year	Simple Averages of Annual Growth Rates					
	Output Quantity Index	Scale Measures		Input Quantities		
		Customers	Ratcheted Peak	Total Factor	OM&A	Capital
2004	1.75%	3.77%	2.56%	0.64%	1.59%	0.92%
2005	1.38%	1.74%	1.52%	0.49%	2.03%	1.67%
2006	0.75%	1.27%	0.96%	2.98%	1.81%	2.09%
2007	1.45%	0.70%	1.15%	2.76%	1.56%	2.27%
2008	1.05%	0.41%	0.79%	1.69%	1.49%	1.55%
2009	0.71%	0.15%	0.49%	0.24%	0.96%	0.74%
2010	0.88%	0.53%	0.74%	-0.13%	0.05%	0.07%
2011	0.89%	0.65%	0.79%	5.58%	0.80%	3.08%
2012	0.77%	0.67%	0.73%	8.25%	0.61%	5.12%
2013	0.95%	0.52%	0.78%	1.82%	2.61%	1.98%
2014	0.91%	0.07%	0.57%	-1.23%	0.23%	-0.82%
2015	0.76%	0.09%	0.49%	0.54%	0.31%	0.63%
2016	0.99%	0.06%	0.62%	1.39%	1.37%	1.43%
2017	1.01%	0.00%	0.60%	0.30%	1.15%	0.87%
2018	1.01%	0.00%	0.60%	0.11%	0.73%	0.20%
2019	0.79%	0.20%	0.55%	-1.03%	0.57%	-0.12%
2020	0.96%	0.71%	0.86%	-1.73%	0.97%	-0.63%
2021	0.99%	0.11%	0.63%	-0.04%	0.29%	0.09%
2022	1.06%	0.13%	0.69%	2.62%	0.68%	1.77%
2023	1.26%	0.51%	0.96%	1.11%	0.33%	0.79%
2024	0.85%	0.38%	0.66%	2.46%	0.21%	1.41%
Average Annual Growth Rates[1]						
2004-2024	**1.01%**	**0.60%**	**0.85%**	**1.37%**	**0.97%**	**1.20%**
2004-2010	**1.14%**	**1.22%**	**1.17%**	**1.24%**	**1.36%**	**1.33%**
2014-2024	**0.96%**	**0.21%**	**0.66%**	**0.41%**	**0.62%**	**0.51%**

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

Table 8c

Ontario Productivity Growth by Distributor Size

	Average Productivity by Size of Distributor			
	2004-2010	2013-2024	2014-2024	2004-2024
TFP	-0.16%	0.04%	**0.15%**	-0.35%
Large (5% +)	-0.37%	-0.21%	**-0.02%**	-0.32%
Medium (0.5%-5%)	0.28%	-0.06%	**0.09%**	-0.20%
Small (under 0.5%)	-0.39%	0.12%	**0.20%**	-0.44%
OM&A	-0.07%	0.14%	**0.25%**	-0.53%
Large (5% +)	-1.29%	0.72%	**1.14%**	-0.40%
Medium (0.5%-5%)	1.27%	0.09%	**0.21%**	-0.07%
Small (under 0.5%)	-0.68%	0.10%	**0.16%**	-0.81%
Capital	-0.19%	-0.12%	**0.04%**	-0.12%
Large (5% +)	-0.18%	-0.90%	**-0.89%**	-0.43%
Medium (0.5%-5%)	-0.85%	-0.33%	**-0.12%**	-0.49%
Small (under 0.5%)	0.20%	0.11%	**0.25%**	0.13%

The 2014-2024 TFP and OM&A productivity trends offer interesting possibilities for OEB policy. While PEG's 2013 study did not support positive TFP growth expectations based on historical trends, the more recent history of Ontario electricity distributors under RRF does. The simple and cost-weighted average TFP trends were both positive. These results suggest that the presumption of zero productivity growth in Ontario is no longer valid.

The OM&A productivity trends detailed in Table 8a are also potentially useful results. As also discussed in our Framework Report, evidence in support of CIR proposals has typically assumed that I–X escalation formulas work satisfactorily for OM&A revenue but are under compensatory for capital revenue escalation, with distributors having the right to full compensation (apart from the stretch factor). The new results suggest that the I-X formulas may have overcompensated CIR distributors for growth in their OM&A expenses for many years. The OM&A productivity trend using size-weighted averages has been especially rapid but these are arguably over-sensitive to results for a few large distributors.

Other recent studies about power distributor cost efficiency trends reach broadly similar conclusions.

- In recent research and testimony for OEB Staff in a Toronto Hydro proceeding (EB-2023-0195), PEG addressed the recent productivity trends of a large sample of U.S. power distributors.[58] PEG reported that, over the last 15 years ending in 2022, the simple average of the TFP growth of these distributors was **0.08%** annually. OM&A productivity averaged **0.61%** annual growth while capital productivity averaged a **0.14%** annual decline. The cost weighted TFP growth for the same period averaged **0.39%** annually, with OM&A productivity averaging **1.01%** growth and capital productivity averaging **0.08%** average growth.

- Witnesses for energy distributors in British Columbia and Massachusetts have recently reported positive OM&A productivity growth for gas and electric power distribution. In 2024 testimony for the FortisBC utilities, former PEG senior advisor Larry Kaufmann reported that the OM&A productivity trend of the US gas distribution industry averaged 0.28% growth for the 15 years ending in 2022 and that the OM&A productivity trend for a national sample of US electric utilities averaged 0.20% growth for that same period.[59] In 2023 testimony on behalf of Massachusetts Electric and Nantucket Electric, Christensen Associates testified that the OM&A productivity trend of a northeast sample of US power distributors averaged 0.21% growth over the 2009-2022 period.[60]

- Clearspring's econometric total cost benchmarking model in this proceeding includes a -0.0033 value for the trend variable parameter. PEG's total cost benchmarking model includes a negative 0.00544 value for the trend variable parameter. These results are consistent with a positive TFP trend during the respective sample periods of the studies.

- The Australian Energy Regulator commissions annual studies that include productivity trend analyses of Australian power distributors. While the most recent TFP study shows a negative trend for the most recent 15-year period ending in 2024, the methodology for measuring the capital quantity trend is quite different there from that commonly used in North American IR

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[58] Lowry, Mark, N. (2024), "Statistical Cost Research for THESL's New CIR Plan, filed May 6, 2024 as Exhibit M3 in OEB Case EB-2023-0195, p. 69.

[59] Kaufmann, Lawrence, and Ralph Zarumba, "Report on Indexing Formula Components for FortisBC", March 2024.

[60] Meitzen, Mark E., and Nicholas A. Crowley, "Pre-Filed Direct Testimony of Mark E. Meitzen, Ph.D. and Nicholas A. Crowley, MS, as filed in Massachusetts D.P.U. 23-150 as Exhibit NG-MM-NC-1,

proceedings. The OM&A productivity trend of Australian power distributors averaged 0.15%.[61][62]

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[61] PEG calculation based on Cunningham, Michael, Joseph Hirschberg, and Alice Giovani, "Economic Benchmarking Results for the Australian Energy Regulator's 2025 DNSP Annual Benchmarking Report," Report Prepared for Australian Energy Regulator, November 13, 2025, p. 16.

[62] The Australian Energy Regulator conducts annual econometric benchmarking of its distributors through the firm Quantonomics. They add data from several distributors from New Zealand and Ontario to their estimation sample in order to facilitate increased accuracy of the estimated models' output parameters. While Quantonomics typically only reports the cost performance results for the Australian companies, in their November 2024 update they included parameters to estimate Opex productivity growth for the New Zealand and Ontario (as groups) separately.

The analysis was performed specifically to test the productivity trends of New Zealand and Ontario, but only so far as to test whether differing jurisdictional trends could affect accurate estimation of the Australian companies' trends. They did not further tailor the analysis to Ontario, so caution against precise interpretation is warranted.

8. X Factor and Stretch Factor Recommendations

8.1. Base Productivity Growth Trend

Evidence from various sources suggests that a 0% Productivity Factor is no longer reasonable for Ontario power distributors. Most relevantly, PEG's new Ontario power distributor productivity research has found that during the RRF years, during which Ontario data are less problematic than in earlier years, a simple (arithmetic) average of the TFP growth of Ontario electricity distributors was **0.15%** per annum while OM&A productivity averaged **0.25%** growth and capital productivity averaged a slight **0.04%** annual growth. Results from other recent studies are generally consistent with these findings.

PEG counsels against postponing the issue of new productivity factors to a later generic proceeding. Positive productivity growth targets are now warranted, and Elexicon's customers would benefit from their use in ARM design at a time of real affordability concerns. Clearspring is well-positioned to review new Ontario productivity research in this proceeding. It is likely that only the less controversial OM&A productivity trend would have an impact on the Company's revenue escalation.

Should the Panel choose to apply the same Productivity Factor to the OM&A and capital revenue of Elexicon, PEG recommends that it be set at 0.15%. Should the panel alternatively decide on separate Productivity Factors for OM&A and capital revenue, PEG recommends 0.25% for OM&A revenue and 0.04% for capital revenue. The simple-weighted results are more conservative and less sensitive to the productivity fluctuations of a few large utilities. PEG's calculation of the OM&A productivity trend is in line with those from recent studies from other jurisdictions.

8.2. Stretch Factor

We have provided evidence on the cost performance of Elexicon that is useful for setting stretch factors. The forecasted total cost of the Company in each year of the proposed CIR plan is on average about 14% below our econometric total cost benchmark. Based on these results we recommend a **0.15%** stretch factor for the Company.

9. Additional Information on Research Methods

9.1 Capital Specification

Monetary Approaches to Capital Cost and Quantity Measurement

The capital cost ("CK") specification is critical in research on distributor cost because the technology of distribution is capital intensive. The annual pro forma 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 capital price and quantity measurement 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

$$CK = WK \cdot XK.^{63} \qquad [A1]$$

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 cost 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.[64] Construction cost trend indexes specific to the electric utility industry have not been available in Canada for many years.

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[63] 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.

[64] If taxes are included in the study, capital prices are also a function of tax rates.

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.[65] Another issue is whether plant is valued in historic or replacement dollars. Here are brief descriptions of the 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 therefore sometimes 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. The trend in this capital service price is driven by trends in construction costs and the rate of return on capital.

2. Hyperbolic Decay Hyperbolic decay has in recent years been used in a few North American X factor and utility benchmarking studies. 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 sometimes computed net of capital gains. The capital price is a service price which reflects these assumptions.

3. 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

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[65] 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.

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 therefore sometimes computed net of capital gains. As with GD, it is common to use a capital service price that is consistent with the OHS assumption.

4. 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.[66] 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 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 additions 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

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[66] The OHS assumptions are more markedly different.

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.

Geometric Decay

For this proceeding we used a geometric decay specification in our U.S. power distributor productivity trend research. 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 the GDPPI 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*,

$$XK_{j,t} = (1-d)\cdot XK_{j,t-1} + \frac{VKA_{j,t}}{WKA_{j,t}}. \qquad \text{[A2]}$$

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 corresponding capital service price indexes used in our U.S. productivity research were smoothed versions of the formula:

$$WKS_{j,t}= d\cdot WKA_{j,t} + r_t\cdot WKA_{j,t-1} + (WKA_{j,t} - WKA_{j,t-1}). \qquad \text{[A3]}$$

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.[67]

9.2 Econometric Research Methods

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:

$$C_{h,t} = a_0 + a_1 \cdot L_{h,t} + a_2 \cdot D_{h,t}. \qquad [A4]$$

Here, for each company h in year t, $C_{h,t}$ is cost, $L_{h,t}$ is the length of distribution lines and $D_{h,t}$ is ratcheted peak demand. Here is an analogous cost model of *double log* form:

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln L_{h,t} + a_2 \cdot \ln D_{h,t}. \qquad [A5]$$

The double log model is so-called because the right- and left-hand side variables in the equation are all logged.[68] 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 [A5] 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.

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[67] The capital gains term is smoothed. A 15-year compound annual growth rate is calculated for the asset price. This is multiplied by the lagged asset price to calculate the change in the value of WKA shown in the formula.

[68] i.e., the variable is used in the equation in natural logarithmic form, as ln(X) instead of X.

Here is an analogous model of *translog* form:

$$\ln C_{h,t} = a_o + a_1 \cdot \ln L_{h,t} + a_2 \cdot \ln D_{h,t} + a_3 \cdot \ln L_{h,t} \cdot \ln L_{h,t} + a_4 \cdot \ln D_{h,t} \cdot \ln D_{h,t} + a_5 \cdot \ln L_{h,t} \cdot \ln D_{h,t} \quad [A6]$$

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 utility's distribution 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 in a cost model 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, along with a squared term for the density variable. This preserves degrees of freedom but permits the model to recognize some nonlinearities. All 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 calculated using fixed-b asymptotics. 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 Elexicon required that the data for the Company be dropped from the sample. The parameter estimates of the cost models reported in the tables above therefore differ (in most cases slightly) from those in the models used for benchmarking.

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