Statistical Cost Research for THESL's New CIR Plan

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1. Introduction and Summary

Introduction

In proceeding EB-2023-0195, Toronto Hydro-Electric System Ltd. ("THESL" or "the Company") proposes to rebase its rates and establish a new Custom Incentive Rate-Setting ("CIR") framework that it calls CIR 2.0. The framework is a multiyear rate plan ("MRP") that would operate over the five years from 2025 to 2029. THESL notes challenging business conditions in advocating a forecasting approach to attrition relief mechanism design for operation, maintenance, and administrative ("OM&A") revenue as well as for capital revenue. Evidence supporting the proposal includes a report on statistical benchmarking 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 would cause 0.15% to be subtracted annually from the Company's proposed revenue requirement growth.

The benchmarking evidence merits careful scrutiny in this proceeding for reasons that include the following.

- Toronto Hydro is one of Ontario's largest power distributors.
- Utilities need to know that their cost performance will be independently evaluated in rebasings and that their benchmarking evidence will be carefully scrutinized.
- Clearspring reports markedly more favorable cost benchmarking results for THESL than it did in a similar study five years ago.

Evidence on industry cost efficiency trends is also useful. The Board has over the years shown a keen interest in reducing forecasted revenue requirements by an externally-based cost efficiency markdown. The Ontario Energy Board's ("OEB" or "Board") October 13, 2016 *Handbook for Utility Rate Applications* ("*Rate Handbook")* calls for a higher cost efficiency growth target than that used in generic price cap incentive rate-setting. However, the Board typically approves the same 0% cost efficiency growth target that applies to generic incentive rate-setting ("IR"). Efficiency growth targets have not been reconsidered in Ontario for many years.

CIR proceedings are opportunities for Ontario's regulatory community to reconsider how statistical cost research should be used in energy rate regulation. 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 Staff have constructively commented on statistical cost research methods in past IR proceedings.

Pacific Economics Group Research LLC ("PEG") is North America's leading consultancy on incentive ratemaking 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 rate framework parameters.

This is our report on this work. Following a brief summary of our findings, Section 2 provides an introduction to statistical cost research for THESL. Section 3 discusses cost benchmarking and THESL's productivity trends. Section 4 briefly discusses Clearspring's reliability benchmarking. Section 5 discusses methods for designing revenue cap indexes. New research by PEG on the productivity trends of U.S. power distributors is discussed in Section 6. X factor and stretch factor recommendations are provided in Section 7. Section 8 discusses a proposed upgrade to the inflation factor formula. The Appendix discusses additional details of our research.

Summary

Econometric Cost Benchmarking

Clearspring developed an econometric model of total power distributor cost using operating data from 78 U.S. electric utilities, mostly over the 2007-2021 period.[1] This model was used to benchmark the total cost of base rate inputs which THESL incurred over the historical 2005-2022[2] period, as well as the Company's forecasted/proposed cost over the 2023-2029 period. During the Technical Conference[3], Clearspring indicated they did not update the econometric model with Toronto Hydro's 2023 actual data filed April 2, 2024[4] and did not investigate whether such an update was likely to be material.

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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).

[2] Clearspring used THESL's historical data combined with forecasted input prices for 2022.

[3] Technical Conference Day 5, April 12, 2024. Clearspring's statements can be found on page 74 of the transcript.

[4] EB-2023-0195: THESL_2025-2029 Rate Application_Evidence Update_20240402

Clearspring reported THESL's total cost performance to have been exceptionally good in the early years of its sample period but to have steadily declined over time. The Company's forecasted/proposed total cost is about 23% below Clearspring's benchmarks on average during the years of the proposed CIR plan (2025-2029). THESL's total cost efficiency is expected to decline by an average of 0.4% each year. Using guidelines established by the OEB for Price Cap IR stretch factors,[5] 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 distributor cost benchmarking study in this proceeding. Here are some of our larger concerns.

- Clearspring's modified congested urban variable is overly sensitive to observations for a handful of urban utilities. The variable has other flaws that reduce its suitability, one of which is Clearspring's choice to use a 2012-2022 average growth in the number of Toronto skyscrapers to forecast a 7.1% annual growth rate in the congested urban area. Alternative and sensible treatments of the urban congestion challenge also receive strong statistical support but yield far less favorable benchmarking results for THESL.
- The area variable should not be translogged, and Clearspring's reported service territory area value for THESL changed markedly with no supporting documentation provided.
- The substation and substation capacity data used in the study were extensively flawed.
- 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. OM&A cost benchmarking is especially useful in this proceeding, where THESL claims that it can no longer operate under an indexed attrition relief mechanism for OM&A revenue.

PEG developed an alternative econometric total distributor cost benchmarking model the development of which relied chiefly on Clearspring's data. We found that THESL's total distributor cost was about 17% above our model's benchmark on average during the three most recent years for which

[5] These guidelines are discussed further in Section 5.

historical cost data were available for the Company (2020-2022). THESL's projected/proposed total cost is about 31% above our benchmarks on average during the five years of the proposed CIR plan.

PEG also developed models to evaluate THESL's projected/proposed OM&A and capital costs. THESL's OM&A cost was found to be about 18% above our benchmarks on average during the three most recent historical years. The Company's forecasted/proposed OM&A cost is about 29% above our model's prediction on average during the five years of the proposed new IR plan.

THESL's distributor capital cost was found to be about 25% above our benchmarks on average during the three most recent historical years. The Company's forecasted/proposed capital cost is about 38% above our model's prediction on average during the five years of the proposed new CIR plan.

THESL Productivity Growth

We calculated the productivity growth of THESL using Company cost data obtained from Clearspring. Over the ten years ending in 2022, the Company's total factor productivity averaged a 2.87% annual decline while its OM&A productivity averaged a slight 0.07% annual decline and its capital productivity averaged a 3.67% annual decline. Based on the Company's proposed revenue requirement, over the five years of the proposed new CIR plan THESL's total factor productivity would average a 2.58% annual decline while its OM&A productivity would average a 1.02% decline and its capital productivity would average a 2.97% decline.

Econometric Reliability Benchmarking

Distribution reliability is an increasingly important consideration in the energy transition, and econometric benchmarking is a promising informational tool for all parties. Clearspring developed econometric benchmarking models of SAIFI (Sustained Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index). The parameters of these models were estimated using data from Form EIA 861 for a sample of 80 U.S. electric utilities over the 2013-2021 sample period. We believe that econometric benchmarking of reliability is constructive but Mr. Fenrick's models are minimally-changed from those presented in THESL evidence five years ago. Clearspring reports THESL's SAIFI to be 98.8% above the benchmark and its CAIDI to be 104.1% below the benchmark for the 2020-2022 period.

Productivity Trends of U.S. Power Distributors

We estimated the productivity trends of U.S. power distributors using U.S. operating data that PEG has gathered for a lengthy sample period. Data for 87 U.S. power distributors were used for the study. We were able to incorporate data for 2022, which is a year beyond what was used in Clearspring's study. Over the 15-year period that ends in 2022, the even-weighted average of the TFP growth of sampled distributors was 0.08% while OM&A productivity growth averaged 0.61% annually. Capital productivity averaged a 0.14% annual decline. During these same years the cost-weighted average TFP growth of the distributors was 0.39% while OM&A productivity averaged 1.01% growth.

Over the ten-year period ending in 2022, total factor productivity averaged a 0.13% annual decline while OM&A productivity averaged 0.38% annual growth. During these same years, the cost-weighted average of TFP growth was 0.10% while that for OM&A productivity was 0.75%.

Recommended Base Cost Efficiency Trend

The OEB has not authorized a new study of Ontario productivity trends in more than a decade. The latest U.S. evidence suggests that a small base cost efficiency growth factor of 0.10% is reasonable for both the OM&A and capital revenue of THESL.

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 0.6% to Toronto Hydro. We consider it reasonable for a large distributor such as Toronto Hydro to submit an alternative model in the context of CIR and to base it on U.S. rather than Ontario data. Using our econometric total cost model in this proceeding, THESL's average cost over the five years of the new CIR would exceed the benchmark by 31% on average. We therefore find no reason to choose a value other than the 0.60% indicated by the default method and our new research.

2. Statistical Research on Power Distributor Cost

In North American IR, statistical cost research is often used to benchmark utility cost and determine the X factor terms in ARM escalation formulas. In this section we consider the nature of a power distributor's business and the pros and cons of the two primary sources of data on distributor operations.

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 from the transmission system to the premises of end users. The voltage of the power must be reduced from the rate at which it is received from the transmitter to the rate at which most end users consume it. Voltage is reduced by transformers at substations and there is a further reduction at line transformers located near customer premises. Distributors sometimes own and operate 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 the final voltage drop, and meters. Most distributors are responsible for customer accounts, send bills and receive payment, and provide some information services. Additionally, administrative and general costs are incurred jointly in the provision of distribution and other services that the utility provides.

U.S. and Ontario Distribution Data

In statistical benchmarking and productivity research supporting an IR proceeding for Toronto Hydro, a choice must be made of whether to use operating data from other Ontario utilities, the United States, or both. Use of *either* Ontario *or* U.S. data makes some sense. Both data sets are idiosyncratic and, if U.S. data are used, it is cost effective to get some consistent data from THESL but not from other Ontario utilities. If Ontario data are used, on the other hand, it is costly to make the requisite data adjustments for any U.S. utilities. In this section we discuss the pros and cons of using each data set.

U.S. Data

Overview

Most American businesses and households receive their power distributor services from an investor-owned utility ("IOU") such as National Grid in 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. Costs attributable to distribution and customer services that distributors provide are itemized on this form. 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 electric utilities in the US. It gathers other useful operating data, including data on the reliability of service and the use of automated metering infrastructure.

Major Advantages

U.S. data have major advantages in the power distributor cost and productivity research that are needed in this proceeding.

- Most power distributors in the United States perform similar tasks to those in Ontario.
- Many years of standardized data on the operations of numerous distributors facing varied business conditions has facilitated good productivity and econometric cost studies.
- 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. As discussed in Appendix A.1, this bolsters the accuracy of capital cost and quantity calculations.
- 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 in the Ontario sample and more similar to the size of Toronto Hydro. Over 60% of Ontario distributors serve fewer customers than all but three U.S. distributors in PEG's U.S. sample. Many companies in the U.S. sample serve large downtown areas.

- Handy Whitman indexes are available on regional trends in the costs of electric distribution and general plant construction.[6]
- OM&A expenses are broken down into labor and material and service expenses.

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

Other Advantages

- Data on pension and benefit expenses are itemized for easy removal if desired. This matters since it is often desirable to exclude these expenses from a benchmarking study.

Major Disadvantages

There are, however, some major disadvantages to using U.S. data in statistical cost research for a Toronto Hydro CIR.

- U.S. cost data are denominated in U.S. dollars and it is difficult to accurately convert these to Canadian dollars in a manner that is relevant for cost research.[7]
- Data on distribution line length are not readily available for a large number of IOUs over many years. We believe that line length data are preferable to the available service territory area data as a measure of system extensiveness.
- The available peak demand data are not ideal in that they are not expressly designed for power distribution. However, a sensible correction is possible.

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

[7] Market based currency exchange rate conversions are not preferred for cost research. They can be volatile and subject to changes in monetary policy and the prices of natural resources. Along with Clearspring, PEG uses purchasing power parities which measure the cost of purchasing a fixed basket of goods in each country using local currency.

Other Disadvantages

- The involvement of American IOUs in transmission (and sometimes also generation) raises the issue of how to allocate general costs. While reported general costs are modest, they are difficult to accurately allocate between the services that U.S. electric utilities provide.
- Expenses for conservation and demand management ("CDM") are typically reported as customer service and information ("CS&I") expenses 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 costs tend to be small.
- Some American IOUs provide gas as well as electric service. However, costs of gas service can be excluded from cost calculations and it is easy to devise an "adjustor" variable to account for economies of scope that might result from providing both services.

Ontario Data

Overview

There are currently around 55 power distributors in Ontario. These utilities like their U.S. counterparts provide a range of customer services that include metering, billing, conservation, and demand management. The largest distributor, Hydro One Networks, also does most power transmission in Ontario.

The primary source of data on the cost and operating scale of Ontario power distributors is the Regulatory Recordkeeping Requirements ("RRR") reports. The OEB has required each jurisdictional power distributor to file this report since 2002. A uniform system of accounts called the *Accounting Procedures Handbook* has been established for the RRR reports.

Major Advantages

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

- Two decades of standardized data are publicly and electronically available on operations of numerous Ontario power distributors. The sampled distributors vary greatly in operating scale and the degree of service territory urbanization. This provides the basis for econometric cost modelling that is useful in Ontario ratemaking. Consultants to Australia's energy utility regulator have used Ontario data in their econometric cost research.

- Cost data are denominated in Canadian dollars.
- Quality data are available for distributors on peak loads. The lengths of overhead distribution lines (in structure miles) and of all distribution lines (in circuit miles) are also available and the quality of these data have improved in recent years.

Other Advantages

- Data on pension and benefit and energy conservation expenses are itemized for easy removal if desired.

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 utilities until 1989. For some utilities (including THESL), these data are only available starting in 2002. The use of older Ontario plant value data also requires imputations. Data on gross plant additions, which are ideally used to calculate capital costs and quantities, are only available starting in 2013. For prior years, it is necessary to impute gross plant additions using data on changes in total gross plant value and an assumed retirement rate. Another problem in measuring Ontario capital costs is that itemized data on distribution and general plant are not readily available. Thus, reliance on Ontario data reduces the accuracy of capital cost benchmarking.
- Few, if any, Ontario companies face key business conditions highly similar to THESL's. For example, THESL is much larger and more urban than the sample norm. A few Ontario utilities have downtown areas but, in addition to being much smaller, several of these areas are in the suburbs of Toronto and systems are much younger.
- Many Ontario power distributors have transitioned in the last ten years to new Modified International Financial Reporting Standards ("MIFRS") that, among other things, reduce capitalization of OM&A expenses for many companies. This may have materially slowed the OM&A and total factor productivity trends of many distributors during these years.

- A breakdown of OM&A expenses into salary and wage and M&S expenses is not available. This reduces the accuracy of OM&A input quantity calculations.
- The OEB has not authorized a new power distributor econometric cost model or productivity study using Ontario data for more than a decade.

Other Disadvantages

- Some of the RRR data that distributors report have not been released to the public by the OEB.
- A custom index of power distribution construction costs is not available.
- A full itemization of OM&A expenses by function is not readily available prior to 2013.

Resolution

Given the many advantages of U.S. power distributor operating data, material problems with Ontario 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. data in our cost and productivity trend research for this project. Consultants in other Canadian IR proceedings have typically also followed this strategy. However, new and improved econometric benchmarking models based on Ontario data could also be useful in appraising THESL's efficiency.

3. Cost Benchmarking

Summary of Clearspring's Work

Clearspring used an econometric model to benchmark the total cost of THESL's base rate inputs over the 18-year historical period from 2005 to 2022.[8] The Company's projected/proposed costs were benchmarked for the 2023-2029 period that includes the five years of the new rate plan (2025-2029). Clearspring developed this model using data on power distributor operations of 78 investor-owned utilities in the United States using the sample period of the twenty-one years from 2000 to 2021.

The dependent variable in the model was real cost. Differences in the wage levels and construction costs that utilities in the sample faced were considered in the construction of the input price indexes. The model has three scale variables: the number of customers served, the service territory area, and a moving average of maximum monthly peak demand.[9]

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");
- the share of electric customers in the sum of gas and electric customers served;
- the share of distribution plant overhead x the share of service territory forested;
- the share of transmission lines with ratings above 50kV;
- the standard deviation of the elevation of the service territory;
- the number of distribution substations; and
- the total capacity (MVA) of distribution substations.

[8] Clearspring used Toronto Hydro's historical data combined with forecasted input prices for 2022.

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

The model also contains a (linear) trend variable.

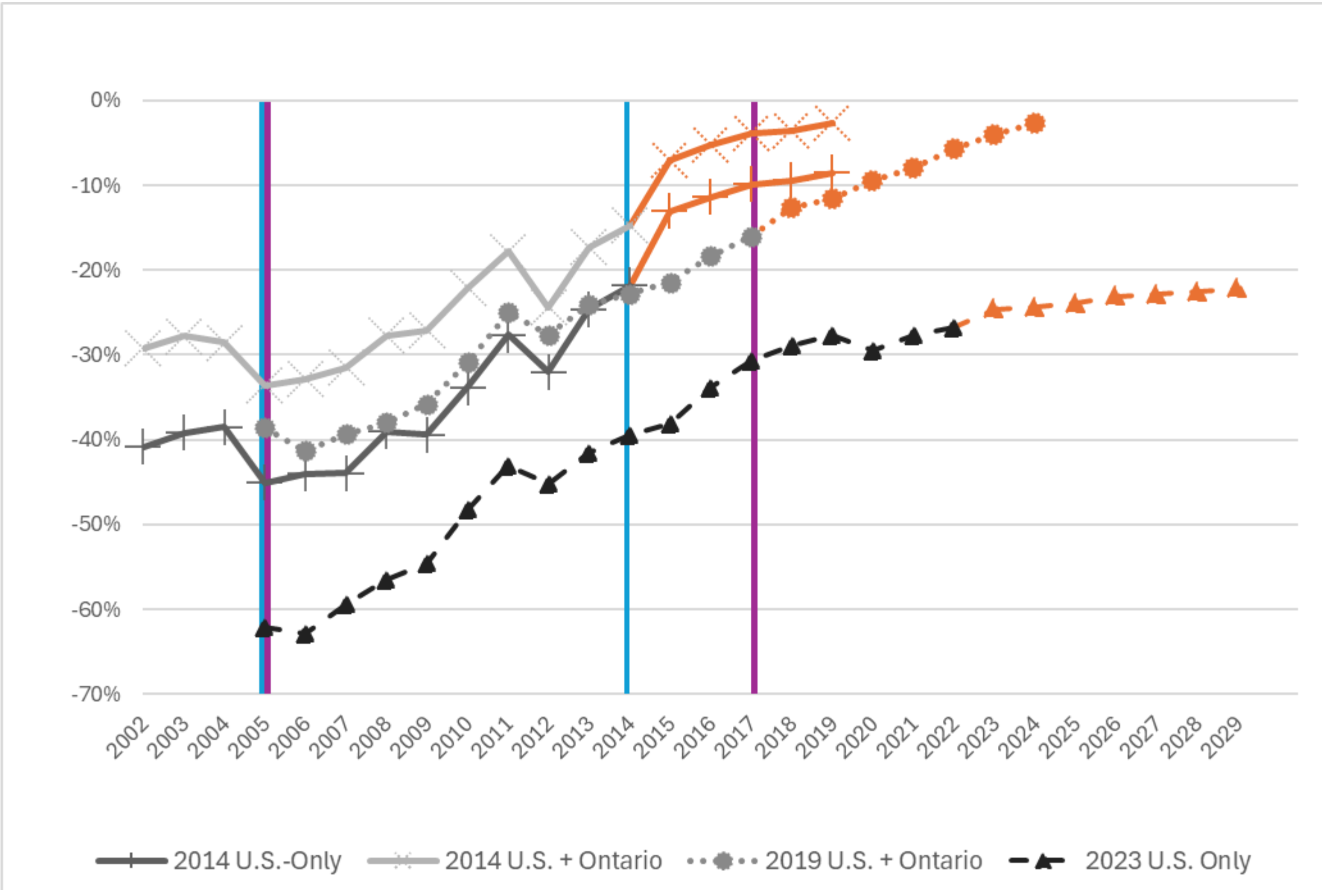
With respect to the form of Clearspring's distributor cost model, the model contains a full complement of quadratic and interaction terms (*Customers* x *Customers*, *Customers* x *Area*, and *Customers* x *Rolling Average Peak Demand*) for the three scale variables in addition to the corresponding first-order terms (*Customers*, *Area*, and *Rolling Average Peak Demand*). All parameter estimates for the variables in the model except for his distribution substation capacity variable are highly significant and those for the first order terms have plausible signs. The estimate of the trend variable parameter suggests that costs fell by about 0.5% annually over the sample period for reasons other than changes in the values of the included business condition variables.

Clearspring reported that THESL's total costs were well below the benchmarks yielded by its model. These results are much more favorable to THESL than the results of Mr. Fenrick's prior study for the Company. This is illustrated in Figure 1, which summarizes Mr. Fenrick's total cost benchmarking scores for THESL in this and two prior studies. The orange portions of each line are forecasted data; the non-orange portions of each line show markedly different performance scores for the same cost data.

THESL's forecasted/proposed costs over the five years of the proposed new CIR plan fall below the corresponding benchmarks by 22.9% on average. However, the Company's cost performance tended to steadily erode, with a nearly 40% decline in cost efficiency from 2005 to the end of the forecast period. From 2006 to 2023, THESL's measured cost efficiency declines an average of 2.1% annually. Deterioration in cost performance is expected to continue, but at a slower pace in the new plan. From 2025 to 2029, Clearspring reports that THESL's total cost efficiency is expected to average a 0.4% annual decline.

Figure 1

THESL-Commissioned Econometric Benchmarking Performance History



Note:

The lines correspond to the two overlapping historical sample periods for these studies (e.g., 2005-2014 for all studies and 2005-2017 for the 2019 and 2023 studies).

PEG Critique

At the outset of our critique we would first like to acknowledge that, since his prior study for THESL, Mr. Fenrick has changed his power distributor cost benchmarking methodology in several areas where we were critical of his approach in past Ontario proceedings.

- 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.
- Construction cost trends in Ontario are now computed as a weighted average of the trends in two asset price indexes.

- The construction cost was levelized in the correct year.
- The OM&A input price indexes now have company-specific weights.
- Pensions and benefit expenses were excluded from the data for THESL 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.
- Quadratic and interaction terms for business conditions other than scale variables have 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 small but nonetheless notable. We discuss our larger concerns first to facilitate the Panel's review.

Major Concerns

Congested Urban Variable

We acknowledge that challenges of urban congestion should be addressed by cost model variables in a benchmarking study for THESL. For example, in congested urban areas traffic affects the duration of distributor truck rolls, many work areas are brownfields, and specialized assets and designs are sometimes required for distribution facilities due to footprint and space availability.

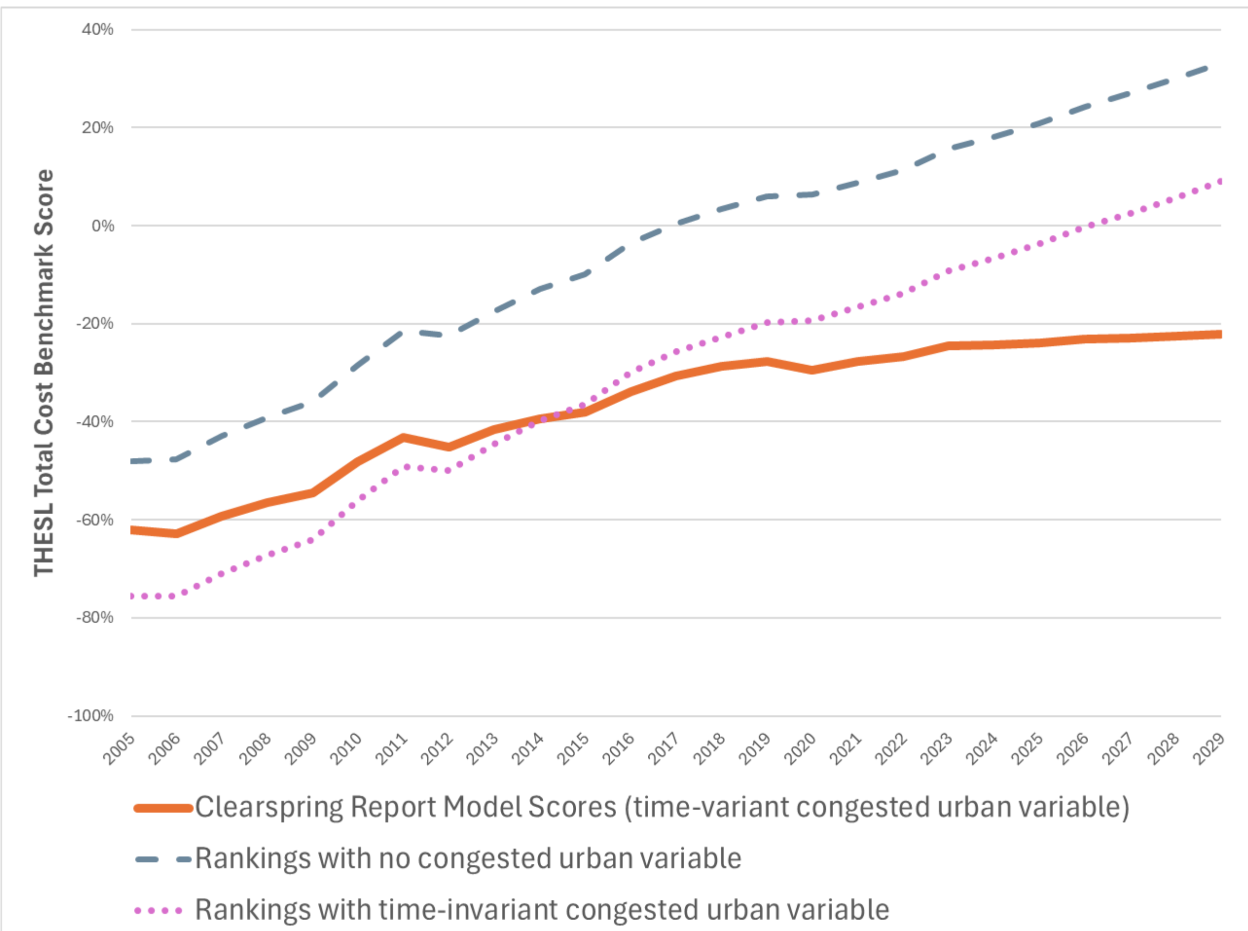
In prior testimony for THESL, Mr. Fenrick developed a congested urban variable measured as the share of the service territory area in which the height of buildings is typically seven stories or higher. This variable did not have time-variant values. For this proceeding, Mr. Fenrick made this variable time-variant by adjusting the original value for the annual growth in the number of skyscrapers exceeding 100 meters.

The new variable has a large positive coefficient in Clearspring's model. THESL's deteriorating cost performance trends are consistent in the previous models; the modified congested urban variable essentially shifts the entire cost score line downward. The effects of the modified congested urban variable vs. the non-time-variant version vs. altogether exclusion, shown in Figure 2 below, clearly matter substantially to THESL's benchmarking scores.

The models used in Figure 2 are identical except for a single change in each. The solid orange line shows THESL's cost benchmark scores from Clearspring's report model (which Clearspring correctly ranked out-of-sample) and is the base for the comparison. The light blue dashed line shows THESL's cost performance if the modified congested urban variable is excluded entirely from the model. THESL is ranked out-of-sample ("OOS") in accord with best practice. The difference between the two lines is entirely due to Clearspring's single variable. The 2029 end point moves from 22.2% below the cost benchmark to 33% over it. The magenta dotted line shows THESL's results, calculated out-of-sample, using Clearspring's time-invariant congested urban variable (the version they used in EB-2018-0165). Adding time variation in the congested urban variable noticeably flattens out THESL's cost performance decline.

Figure 2

Effect of Changes to Congested Urban Variable on THESL Benchmark Score



In addition to quantifying the model's sensitivity to the variable, it is fair to ask *why* the variable has such dramatic effects on THESL's cost performance benchmarks. One problem is the calculation of congested urban area. Econometric parameter estimates are more accurate to the extent that they are based on varied values of the data. Unlike in unit cost benchmarking, a variety of information is valuable as well as more information from similar utilities.

Using data from the full spectrum of urban tall building construction would enhance the model's ability to filter out noise from the data and arrive at a truer estimate of the typical cost impact of congestion.[10]

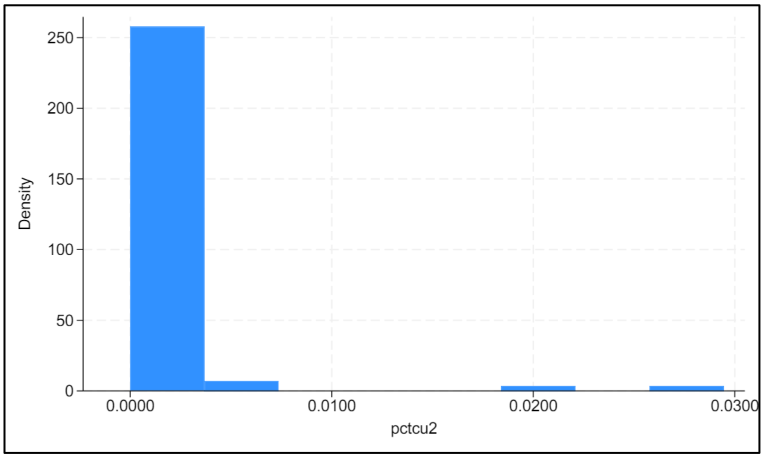
Skyscrapers below 100m in height were not used to escalate the congested urban area even though 100m is not consistent with a seven-story building height. Another problem is the wholesale exclusion of tall building/skyscraper growth data for utilities which did not make the cut as having congested urban areas in 2016-17. Data from cities which experienced density and tall urban building growth in the past 5-7 years could help move the variable in the direction of refinement. Note also that the original CU variable calculations missed sizable business districts in some smaller cities such as Clayton, Missouri and Bellevue, Washington.

Using the congested urban mapping data in a *percentage* format is another big concern. There are so few values other than 0 or near-0 that this variable tends to function more like a dummy variable for just two utilities with extreme values. THESL, along with Consolidated Edison, has congested urban variable values an order of magnitude larger than for any other utility in the sample. As a result they receive a very large cost performance benefit from a variable distorted by its makeup and construction. Figure 3 below is a histogram of the values for the modified congested urban area, "pctcu2."

[10] The well-researched fact that wider variety is preferable to a peer group in econometric modeling is, unfortunately, counterintuitive.

Figure 3

Distribution of Sample Values for Modified Congested Urban Variable



Contrast the percent congested urban variable density shown in Figure 4a with that of the sensible alternative specifications shown in Figures 4b and 4c. Multiplying the percent form by each company's total service territory area allows us to create variables for Total Area Congested Urban and Total Area NOT Congested Urban. These variables contain the same information as the percent version of the variable, but they capture substantially more variation.

Figure 4a (revised)

Distribution of Sample Values for Clearspring Percent Congested Urban Variable

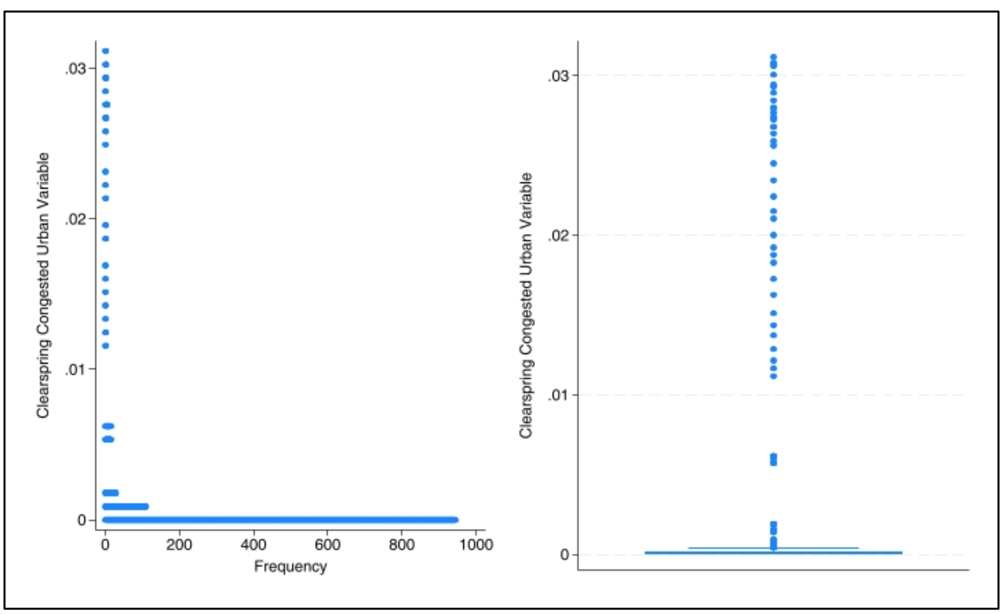


Figure 4b (revised)

PEG Total Area Congested Urban Variable

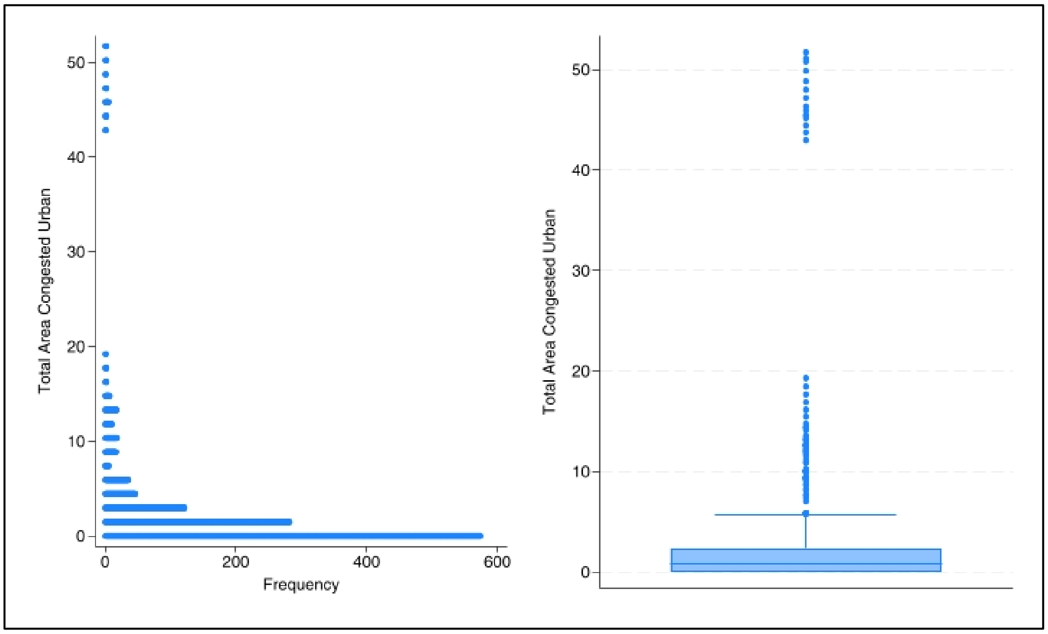
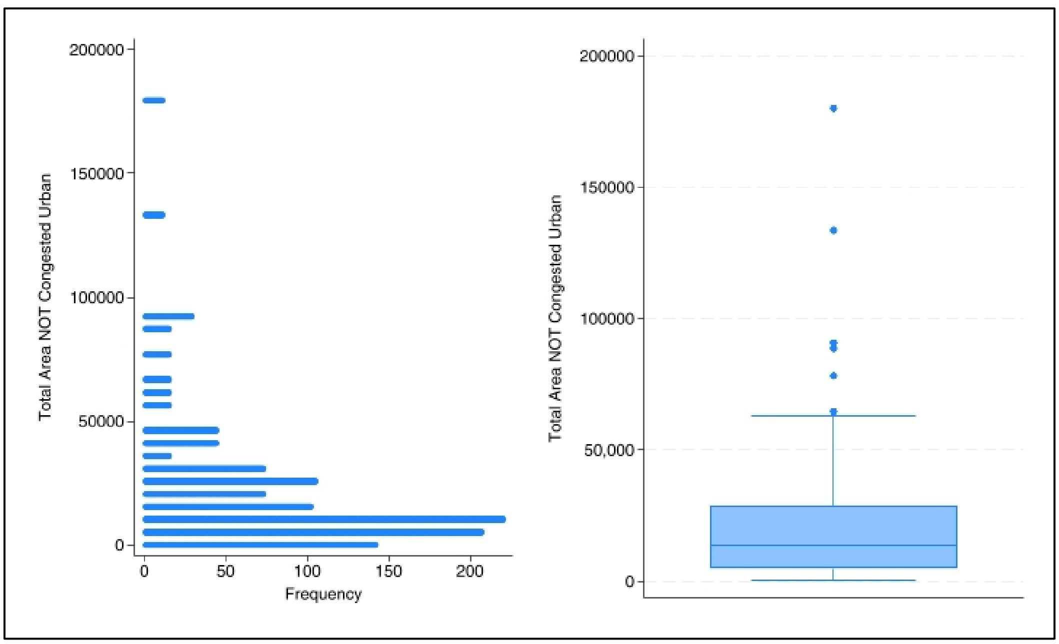


Figure 4c

PEG Total Area Not Congested Urban Variable



Another concern is that while the skyscraper data used are historical through 2022, Clearspring projects the skyscraper growth forward through 2029 using Toronto's brisk 7.1% 2012-2022 average annual growth rate in the number of skyscrapers. This is a major methodological assumption on Clearspring's part with material implications for the Company's forecasted cost performance. The tall building database Clearspring uses includes building data with expected completion dates through 2027. While it seems quite reasonable to believe that additional buildings will be planned and constructed during that time since Toronto's population is expected to continue, some support for assuming the same growth rate in skyscraper construction within THESL's service territory would be desirable. Clearspring's building database reports 1.19% growth in the number of skyscrapers in 2023, and 2.92% growth scheduled for 2024 completion.

Table 1 and Figure 5 below illustrate how various reasonable changes to Clearspring's skyscraper growth assumption affect THESL's forecasted cost performance scores. As a baseline for comparison, Figure 5 includes both the results from Clearspring's report model ("Clearspring Report Methodology") and from that same model with only what PEG considered the necessary minimum corrections for apparent errors ("Clearspring Methodology with all corrections made"). For the "corrections" model, PEG did not make changes to Clearspring's model specification and used Clearspring's preferred assumption for the percent congested urban variable so the effect of the skyscraper growth assumption can be isolated.[11]

[11] The corrected errors consist of the following four changes:

1. Using the correct value for Toronto Hydro's service territory area;
2. adding the information for the missed company in the percent electric customers variable;
3. excluding forecasted values from the meanscaling procedure; and
4. removal of the fundamentally flawed substation and mva variables entirely.

The details of these problems in Clearspring's report model are discussed immediately below Table 1 and Figure 5.

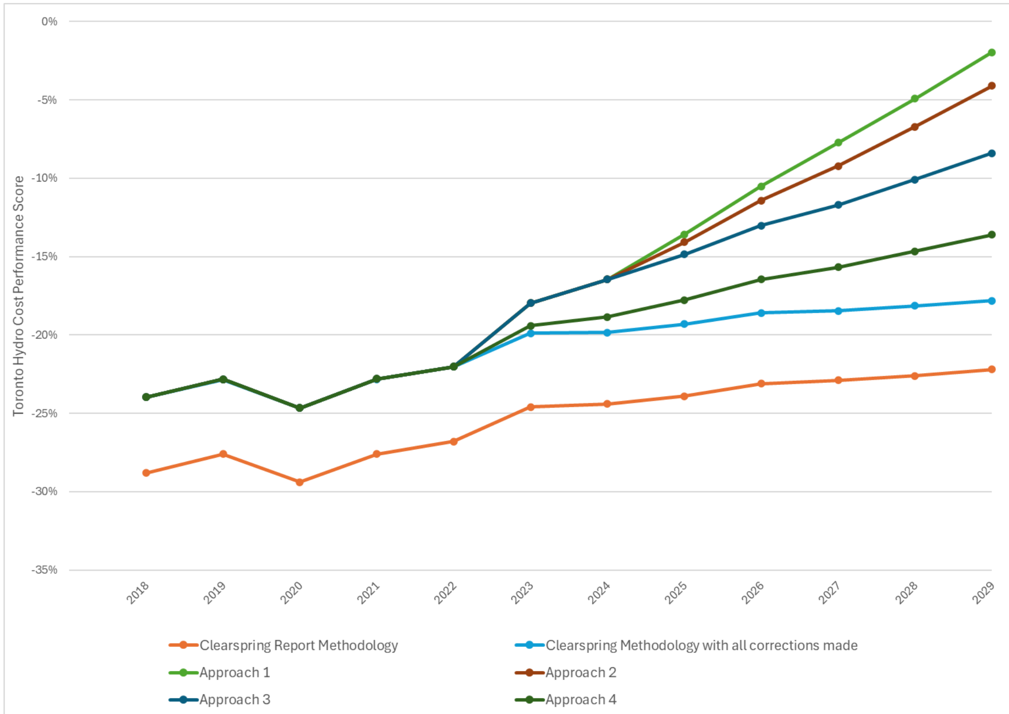
Table 1

Alternative Congested Urban Variable Forecast Approaches

	Clearspring Database	Clearspring Methodology	PEG Alternative Approaches			
			Approach 1	Approach 2	Approach 3	Approach 4
Year	Percentage change in actual skyscraper completions from Clearspring database	Forecast Toronto skyscraper additions from 2023-2029 using average growth rate from 2012-2022	Scheduled completion numbers from 2023-2027, then forecast 2028-2029 using the 2023-2027 average.	Scheduled completion numbers for 2023-2024, then forecast 2025-2029 using the 2023-2024 average.	Scheduled completion numbers for 2023-2024, then forecast 2025-2029 using the five-year 2020-2024 average.	Forecast 2023-2029 using the five-year 2018-2022 average.
2018	3.91%					
2019	6.31%					
2020	7.95%					
2021	3.59%					
2022	6.51%					
2023	1.19%	*7.08%*	1.19%	1.19%	1.19%	*5.65%*
2024	2.92%	*7.08%*	*2.92%*	2.92%	2.92%	*5.65%*
2025	0.57%	*7.08%*	*0.57%*	*2.06%*	*4.43%*	*5.65%*
2026	0.86%	*7.08%*	*0.86%*	*2.06%*	*4.43%*	*5.65%*
2027	0.28%	*7.08%*	*0.28%*	*2.06%*	*4.43%*	*5.65%*
2028	-	*7.08%*	*1.17%*	*2.06%*	*4.43%*	*5.65%*
2029	-	*7.08%*	*1.17%*	*2.06%*	*4.43%*	*5.65%*

Figure 5 (revised)

Clearspring Congested Urban Variable Sensitivity to Assumptions



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.[12] This adds three second-order scale variables to the cost model and results in output elasticities that vary by company. Choosing this variable specification produced negative output cost elasticities with respect to 33% of the sample (546 of the 1,668 observations). 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. The estimated elasticity of cost with respect to area is far smaller than the elasticities with respect to customers and peak load. It makes sense then to treat area as a "network" variable and not accord it translog treatment. The second problem is that Clearspring assigned an incorrect service territory area value to THESL that roughly doubled its actual area.

[12] PEG acknowledges that this treatment was used in the joint report of PEG and Clearspring in the recent Hydro One proceeding.

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 THESL proposes to abandon indexing of its OM&A revenue and notes its respectable OM&A cost performance in some of its benchmarking evidence as part of the rationale. 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.

Substation Data

Clearspring's data on the number of substations and substation capacity (MVa) data were not sufficiently cleaned and vetted. The double-counting and under-counting problems are widespread enough to treat the statistical results for these variables with major skepticism.

Tables 2 and 3 below give an overview of the type and severity of the immediately-apparent problems. Table 2 shows all percentage changes in excess of 10% in a single year[13] in either variable for 6 sampled companies in Clearspring's dataset. It can be seen that the swings in the data usually do not follow a pattern, do not correspond across the two variables from the same source, and cannot be classified as data blips which quickly resolve. Table 3 summarizes the extent of the problems within Clearspring's entire sample dataset. When asked to comment on these issues with the substation data, Clearspring declared that fixing the problems was not a feasible or worthwhile[14] endeavor.

[13] For context, Toronto Hydro's substations decline by 19% over the sample period, and the largest percentage change in a single year is less than 4%. The next largest value is just under 3%, and the rest are substantially lower.

[14] EB-2023-0195 Technical Conference Schedule JT5.34.

Table 2

Overview of Data Swings for Six Companies in Clearspring's Dataset

Changes in Variable Values >10% in a Single Year											
Madison Gas and Electric		Alabama Power		Cleco Power		Kentucky Power		Niagara Mohawk Power		Northern States Power - WI	
Number of Substations											
Year	Percentage Change	Year	Percentage Change	Year	Percentage Change	Year	Percentage Change	Year	Percentage Change	Year	Percentage Change
2001	155.06%	2001	56.65%	2003	78.50%	2004	-13.26%	2006	90.33%	2012	92.61%
		2004	75.14%	2008	19.34%	2005	-75.82%	2011	-12.76%		
		2005	-58.17%	2013	-34.68%	2011	-12.12%	2012	-10.01%		
		2010	81.98%			2012	14.32%	2014	27.31%		
		2012	-88.53%			2015	64.87%				
						2019	-26.56%				
						2020	-56.83%				
						2021	56.71%				
Total Capacity of Substations (MVA)											
Year	Percentage Change	Year	Percentage Change	Year	Percentage Change	Year	Percentage Change	Year	Percentage Change	Year	Percentage Change
2001	120.07%	2001	45.21%			2001	-24.97%	2001	20.79%	2012	-15.76%
		2005	14.24%			2002	15.16%	2006	-30.84%		
		2009	19.60%			2015	-224.51%	2011	-80.51%		
		2010	-15.70%			2019	-42.12%	2014	61.09%		
								2018	21.38%		
								2021	76.51%		

Table 3

Extent of Implausible Values in Clearspring's Variable

Percentage Change in a Single Year	Percent of Companies Affected[1]	
	Substation Variable	Capacity (MVA) Variable
75%	7.69%	7.69%
50%	14.10%	19.23%
25%	33.33%	51.28%
10%	69.23%	82.05%

[1]Percentage of the 78 companies Clearspring used in its substation and capacity econometric calculations. 66 of those companies have sample data through 2021.

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 THESL and other utilities, which steer clear of these problems will have more credibility.

- Clearspring's percent of plant overhead variable is in fact measuring 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).
- 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 stated[15] that they believe the construction makes "intuitive sense", but testing shows that using the logged form of both variables results in a *negative* and significant coefficient, which is why THESL's cost performance worsens to -20.9% from that single change.
- Clearspring does not mean-scale any of the business condition variables. While this does not affect the model predictions, doing so would better facilitate interpretation of the model estimates.
- 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).

Business Conditions Facing THESL

The external cost drivers faced by THESL should be considered when benchmarking their cost. The Company is headquartered in Toronto, a high-cost urban area with a densely-settled core that has

[15] EB-2023-0195 Technical Conference Schedule JT5.36

recently experienced a boom in the construction of high-rise condominiums. All customers now have AMI but the Company purposes to replace this infrastructure in the next few years.

Table 4 compares THESL's cost and external business conditions to the sample mean values in 2021. The following results are notable.

- THESL's total cost was 1.17 times the sample mean. The input prices that the Company faced were 1.15 (Clearspring's number) times the mean. Thus, the Company's real total cost was 1.17/1.15 = 1.02 times the mean.
- The Company's customer count was meanwhile 0.77 times the mean while its rolling average ratcheted peak demand was 0.89 times the mean, and the Company's percent of distribution lines underground was 1.98 times the mean.
- Combining all of this information, THESL's total factor distributor productivity level in 2021 was 0.82 times the mean. Its OM&A productivity level was 1.07 times the mean while its capital productivity level was 0.70 times the mean.

The TFP level result is clearly unfavorable to the Company. For THESL to be deemed a good distribution cost manager, it would therefore have to face other cost drivers that are markedly less favorable than the sample norms on balance. The table indicates that several business conditions were more challenging.

- The Company's service territory area in the urban core was 6.07 times the mean.
- The share of customers with AMI was 1.55 times the mean.
- The share of electric customers in the sum of gas and electric customers was 1.16 times the mean. The Company does not provide gas services.
- The construction standards index for the Company – a proxy for weather conditions - is 1.69 times the mean.
- The Company is much less diversified into power generation and transmission than other utilities.

Table 4

How the Model Variables for THESL Compare to the Sample Mean (2021)

	THESL	Sample	THESL/Sample
Cost	**$ 868,809**	**$ 740,899**	**117.3%**
O&M	$ 214,179	$ 208,481	102.7%
Capital	$ 654,630	$ 532,418	123.0%
Scale			**83.6%**
Customers	785,667	1,022,406	76.8%
Peak 10 year average	4,497	5,062	88.8%
Peak	4,386	5,053	86.8%
1000 x Peak / Customer	5.58	4.94	113.0%
Area	630	20,655	3.1%
Input Price	**1.53**	**1.33**	**115.4%**
O&M	1.625	1.289	126.0%
Capital	12.125	11.106	109.2%
Productivity			**81.7%**
O&M			106.9%
Capital			69.9%
Business Conditions			
Percent Electric	1.000	0.860	116.2%
O&M Scope	1.000	0.507	197.2%
Distribution Work	0.00%	8.55%	0.0%
Area Congested Urban	13.6	2.2	607.1%
Area Not Congested Urban	616	20,653	3.0%
YN / Area	1,247	49	2519.4%
AMI	100%	65%	154.8%
Construction Standards Index	53%	31%	168.7%
Overhead Line Plant	26%	63%	41.9%
Underground Line Plant	74%	37%	197.5%
Forestation	18%	59%	30.8%

On the other hand,

- The Company's service territory area outside of the urban core was a tiny 0.03 times the mean.
- The share of distribution assets overhead was 0.42 times the mean.
- Forestation in the Company's service territory was 0.31 times the mean.

PEG's Alternative Cost Benchmarking Research

Relying chiefly on Clearspring's data, we developed an alternative econometric model of the total cost of power distributor base rate inputs. We also developed econometric models of distributor OM&A and capital cost. The incremental cost of benchmarking OM&A and capital cost is modest as the variables meriting consideration are largely the same as in those total cost research and there are other shared costs. This is a low-cost activity that can help drive performance improvements.

Differences from Clearspring's Methodology

The following methods that we used in model development differed from Clearspring's.

- We did not treat service territory area as a scale variable warranting translog treatment. This eliminates three second-order translog terms.
- We mean-scaled all variables.
- We did not use Clearspring's modified percent congested urban variable as provided. We instead took the more reasonable approach of multiplying Clearspring's modified variable by the service territory area to obtain the area congested urban rather than the percent of area. We also calculated the total service territory area not congested urban and added this variable to the model. This treatment is analogous to having separate variables for residential and other customers in a cost model. This approach uses fewer degrees of freedom than Clearspring's approach of using translog area terms along with a percent congested urban area variable, and better accounts for the challenges of serving urban areas, non-urban areas, and serving both across the entire sample.
- We begin our sample period in 2007 to adjust for the disadvantage of using the longer time period in an OLS model. OLS pools all of the time series data as though they occurred in one

time period. The trend variable parameter estimate with the shorter sample has a lower value than that of the longer sample, suggesting the more recent industry cost trends may be masked by including the older data. An estimate of this parameter that is based on the most recent 15 years of data is more relevant in determining the base cost efficiency growth factor.

- We replaced the overhead x forestation variable with standalone forestation. The variable works just as well if not better than the interaction version, and has a straightforward interpretation.
- We added a distribution construction standards index variable developed by Power Systems Engineering to the OM&A cost model. This variable measures the minimum requirements for strength of distribution structures, which vary by geographic region and their respective extreme weather conditions.
- We corrected some implausible values in Clearspring's scope variable.
- We replaced Clearspring's variable measuring the share of total distribution plant outside of the two accounts related to underground line. We instead use the share of overhead line of the total underground + overhead line accounts.
- We use the "Fixed-b" standard error correction to Driscoll-Kraay, developed in 2008, to improve upon Clearspring's OLS estimation method.[16,17]
- We removed the substation and substation capacity variables, sidestepping the task of fixing the problematic data.
- We benchmarked the OM&A and capital cost of THESL as well as its total cost.

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

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

Econometric Results

Results of our econometric cost research are reported in Tables 5-7. In each model, the dependent variable was *real* cost --- the ratio of nominal cost to the corresponding input price index. This specification enforces a key result of cost theory.[18]

Each table reports econometric estimates of model parameters and their associated asymptotic t-statistics and p-values. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero can be rejected at a high level of confidence. These significance tests were used in model development. In all three models, all of the parameter estimates for the first-order terms of the business condition variables were statistically significant 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 5. Here are some salient results.

- The parameter estimates for the number of customers and the 10-year rolling average of ratcheted peak demand are highly significant and positive. The parameter estimates for the quadratic and interaction terms associated with these three scale variables were also highly significant. The relationship of cost to the three scale variables was therefore significantly nonlinear.
- Total cost was also higher the higher was the area of the service territory that was congested and urban and the area that wasn't, the share of service territory area that was forested, AMI penetration, the value of the distribution work variable, the share of electric plus any gas customers that were electric, and the share of distributor operations and maintenance expense in transmission, distributor, and generation operations and maintenance expense.
- The estimate of the trend variable parameter suggests that there was a 0.22% annual decline over the fifteen-year sample period in total cost for reasons other than changes in the values of the included business condition variables.

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

Table 5 (revised)

PEG's Econometric Model of Total Power Distributor Cost

VARIABLE KEY

N = Number of Customers
D = 10-Year Rolling Avg of Distribution Peak
N*N = Number of Customers squared
D*D = Distribution Peak squared
N*D = Number of Customers times Distribution Peak
AREACU = Area Congested Urban
AREAOTHER = Area Not Congested Urban
PCTELEC = % Electric Customers
PCTAMI = Percent AMI
PCTODXG = Percent Distribution O&M of Transmission, Distribution, and Generation O&M
FOR = Percent Forestation in Service Territory
DXWORK = % Distribution Lines Over 50 kV
TREND = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.423***	54.697	0.000
D	0.532***	59.797	0.000
N*N	0.696***	6.049	0.000
D*D	1.131***	10.239	0.000
N*D	-0.898***	-7.818	0.000
AREACU	0.0215***	26.445	0.000
AREAOTHER	0.0428***	23.185	0.000
PCTELEC	0.0792***	5.371	0.000
PCTAMI	0.0127***	3.389	0.001
PCTODXG	0.0899***	11.052	0.000
FOR	0.0475***	32.749	0.000
DXWORK	0.179***	8.476	0.000
TREND	-0.0022	-1.577	0.115
CONSTANT	13.11***	1005.514	0.000

Adjusted R^2	0.972
Sample Period	2007-2021
Number of Observations	1,143

Pacific Economics Group Research, LLC

The adjusted R^2 for the model was 0.972. This suggests that the model had a high explanatory power.

Capital Cost

Details of PEG's distributor capital cost research are presented in Table 6. Here are some key findings.

- The parameter estimates for the number of customers and rolling average peak demand were both highly significant and positive. All three parameter estimates for the extra 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 area served that was congested and urban and the area that wasn't, AMI penetration, the value of the distribution work, and the ratio of electric customers to the sum of gas and electric customers.

  The estimate of the trend variable parameter indicates that there was a slight 0.07% annual decline in capital cost for reasons other than changes in the values of the model's business condition variables.
- The 0.969 value of the adjusted R^2 for the model was very similar to that for the total cost model.

Table 6 (revised)

PEG's Econometric Model of Distributor Capital Cost

VARIABLE KEY

N = Number of Customers
D = 10-Year Rolling Avg of Distribution Peak
N*N = Number of Customers squared
D*D = Distribution Peak squared
N*D = Number of Customers times Distribution Peak
AREACU = Area Congested Urban
AREAOTHER = Area Not Congested Urban
PCTOHL = % of Line Plant Overhead
PCTELEC = % Electric Customers
PCTAMI = %AMI
DXWORK = % Distribution Lines Over 50 kV
TREND = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.474***	50.258	0.000
D	0.522***	71.918	0.000
N*N	0.360***	5.528	0.000
D*D	0.688***	13.044	0.000
N*D	-0.512***	-8.790	0.000
AREACU	0.0234***	7.492	0.000
AREAOTHER	0.0288***	14.500	0.000
PCTOHL	-0.045	-1.585	0.113
PCTELEC	0.0965***	5.157	0.000
PCTAMI	0.0237***	17.641	0.000
DXWORK	0.126***	5.455	0.000
TREND	-0.000699	-0.560	0.576
CONSTANT	10.59***	572.752	0.000

Adjusted R^2	0.969
Sample Period	2007-2021
Number of Observations	1,143

OM&A Expenses

Results of PEG's econometric distribution OM&A research are presented in Table 7. Please note the following.

- The parameter estimates for the number of customers and rolling average peak demand were both significant and positive. Notice that the number of customers had a considerably greater impact on OM&A cost than in the total cost model. This makes sense since OM&A expenses include many customer-driven expenses like those for metering, billing, and collection. Peak demand had a much smaller cost elasticity.
- The parameter estimates of both area variables were positive.
- The parameter estimates for the three second-order terms associated with the two included scale variables were all highly significant. This suggests that the relationship of cost to these scale variables was significantly nonlinear.
- OM&A cost was higher the greater was the percent of the service territory that was forested, the higher was distribution line overheading, the value of the distribution construction standards index, and the value of the distribution work variable.
- The trend variable parameter estimate indicates that OM&A cost growth was slowed by 0.71% annually for reasons other than changes in the values of included business condition variables.
- Table 7 also reports a 0.885 adjusted R^2 statistic for the OM&A model. This is modestly below that for the total cost and capital cost models. Evidently, distributor OM&A proved somewhat more difficult to accurately model than distributor capital cost or total cost.

Table 7 (revised)

PEG's Econometric Model of Distributor OM&A Expenses

VARIABLE KEY

N = Number of Customers
D = 10-Year Rolling Avg of Distribution Peak
N*N = Number of Customers squared
D*D = Distribution Peak squared
N*D = Number of Customers times Distribution Peak
AREACU = Area Congested Urban
AREAOTHER = Area Not Congested Urban
PCTOHL = % of Line Plant Overhead
DXCSI = Distribution Construction Standards Index
FOR = Percent Forestation in Service Territory
DXWORK = % Distribution Lines Over 50 kV
TREND = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.549***	21.171	0.000
D	0.376***	17.069	0.000
N*N	1.163**	3.163	0.002
D*D	1.627***	4.815	0.000
N*D	-1.368***	-3.888	0.000
AREACU	0.0318***	5.933	0.000
AREAOTHER	0.0452***	8.712	0.000
PCTOHL	0.431***	6.342	0.000
DXCSI	0.450***	13.341	0.000
FOR	0.0738***	15.778	0.000
DXWORK	0.155**	2.994	0.003
TREND	-0.00706***	-4.613	0.000
CONSTANT	11.99***	659.437	0.000

Adjusted R^2	0.885
Sample Period	2007-2021
Number of Observations	1,143

Pacific Economics Group Research, LLC

Econometric Benchmarking Results

We benchmarked the OM&A, capital, and total distributor cost of THESL in each year of the historical 2007-2022 period as well as in the 2023-2029 period for which the Company has provided proposals/projections. All benchmarks were based on our econometric model parameter estimates and values for the business condition variables which are appropriate for the Company in each historical and future year.

Table 8 and Figure 6 report results of this benchmarking work. For each cost considered, the tables show results for each year and highlight the average results for the last three historical years and the seven years of forecasted costs, the last five of which cover the period of the proposed new Custom IR plan. Recollecting the recent benchmark years for estimating THESL's capital cost, we shade results for the early years as being less accurate for total cost and capital cost.

Total Cost

The results of our distribution *total* cost benchmarking show that THESL's total distributor cost was initially well below the model's predictions, but cost performance deteriorated from 2007 to 2022. Total cost efficiency will continue to deteriorate during the Company's current CIR plan. On average, projected/proposed total cost during the new plan will exceed the benchmarks by about 31% during the 2025-2029 term of the CIR plan.

Capital Cost

The results of our distribution *capital* cost benchmarking show that THESL's capital cost efficiency was below model predictions at the outset but has trended downward since 2007. Efficiency is expected to continue deteriorating in the next CIR plan. On average, projected/proposed capital cost during the new plan will be about 38% above our benchmarks for the 2025-2029 period.

Table 8 (revised)

Year-by-Year Distributor Cost Benchmarking Results

Year	Total Cost Benchmark Score	Capital Cost Benchmark Score	OM&A Cost Benchmark Score
	[Actual - Predicted Cost]		
2007	-26.85%	-20.82%	-11.58%
2008	-23.56%	-16.99%	-10.25%
2009	-21.21%	-15.87%	-5.17%
2010	-14.21%	-12.23%	10.00%
2011	-7.85%	-5.58%	15.37%
2012	-8.99%	-5.67%	11.22%
2013	-4.26%	-2.04%	17.50%
2014	-0.78%	3.16%	15.78%
2015	1.67%	7.24%	11.01%
2016	6.95%	13.90%	10.86%
2017	10.69%	18.40%	11.30%
2018	12.65%	19.46%	15.78%
2019	14.67%	21.13%	18.74%
2020	14.95%	22.65%	15.37%
2021	17.52%	24.48%	19.97%
2022	19.41%	27.47%	18.01%
2023	*22.89%*	*30.14%*	*23.31%*
2024	*24.52%*	*31.24%*	*26.12%*
2025	*26.62%*	*33.14%*	*28.23%*
2026	*28.92%*	*35.54%*	*29.41%*
2027	*30.82%*	*37.94%*	*28.91%*
2028	*32.92%*	*40.18%*	*29.67%*
2029	*35.18%*	*42.86%*	*29.69%*
Averages			
2020-2022	**17.30%**	**24.87%**	**17.78%**
Forecast Period 2023-2029	***28.84%***	***35.86%***	***27.90%***
CIR Period 2025-2029	***30.89%***	***37.93%***	***29.18%***

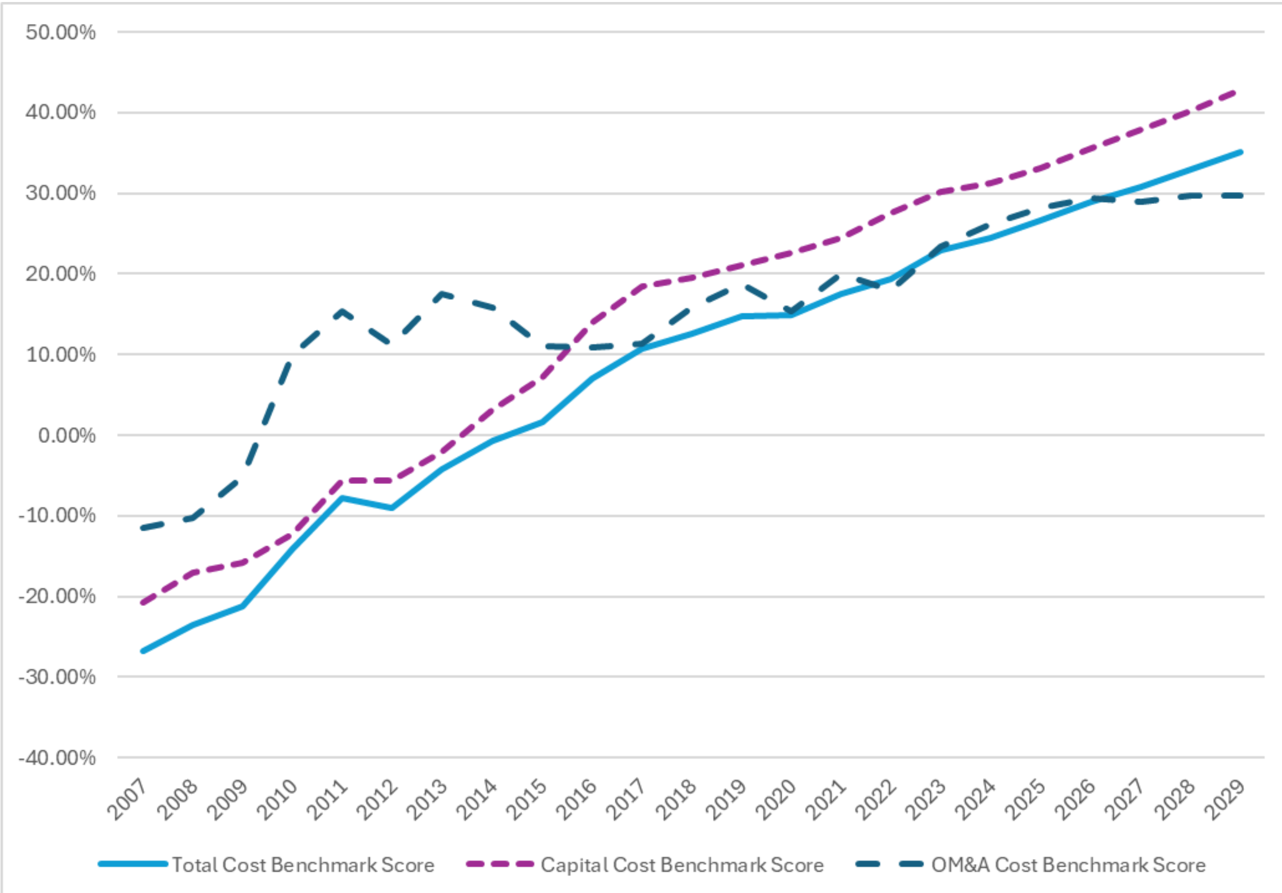
Notes

Shading indicates years for which capital and total cost benchmarking results are deemed to be especially sensitive to the recent capital benchmark year.

Italics indicate years for which THESL has projected its costs.

Figure 6 (revised)

Cost Benchmarking Results Using PEG's Models



OM&A Expenses

Our distribution OM&A benchmarking results show that THESL's distribution OM&A efficiency was only modestly below average in 2007 but trended bumpily downward over the 2012-2022 period. Increased deterioration is expected to occur during the expiring CIR and into the new plan. OM&A efficiency will be markedly worse in 2023 and 2024, and then decline more gradually from 2025-2029. On average, projected/proposed OM&A during the new plan will be about 29% above the benchmarks during the 2025-2029 Custom IR term.

THESL Productivity Trends

The sample period for our research on the productivity trends of THESL was the 24 years from 2006 to 2029. The data used in these calculations were provided by Clearspring with the exception of the OM&A input prices.

The growth in productivity was measured as the difference between the growth in an output quantity index and growth in an input quantity index. PEG constructed the output quantity index as an elasticity-weighted average of the growth in number of customers and the growth in a 10-year moving average of distribution peak demand. This output specification is appropriate for cost efficiency measurement. The cost elasticity weights we used were taken from PEG's econometric work and represent the estimated relative impact of customer numbers and peak demand on the cost of sampled utilities.

PEG constructed an alternative OM&A input price index for THESL. For the labor price, instead of the average hourly earnings data that Clearspring used, we used the fixed weighted index of average hourly earnings for Ontario industrial businesses. For material and service prices, we retained the Gross Domestic Product – Implicit Price Index ("GDP-IPI") for final domestic demand that Clearspring used for their M&S trend calculations.

We also account for the substantial amount of outsourcing done by Toronto Hydro. Outsourced services are generally labor-intensive. We assume that 75% of Toronto Hydro's M&S expenses are outsourced services. We assign the labor price index to half of this 75% with the remaining 25% being assigned to the GDP-IPI FDD. In response to a data request, Toronto Hydro stated that 47% of total OM&A was outsourced services.[19] The 75% figure is the approximate proportion of M&S that is outsourced using the 47% and the proportion of OM&A that is not company labor according to the Clearspring work.

Tables 9a, 9b, and Figure 7 provide results of our productivity growth calculations for THESL. In appraising these results, remember that they are not net of the cost efficiency trend of the industry, as is the case in an econometric benchmarking model. Recollecting that the benchmark year for THESL's

[19] 4-AMPCO-82

Table 9a (revised)

Toronto Hydro Productivity Growth (2006-2029)

Year	Total Factor	OM&A	Capital
2006	-1.1%	0.9%	-1.9%
2007	-6.0%	-11.5%	-3.7%
2008	-3.7%	1.1%	-5.5%
2009	-2.4%	-2.8%	-2.1%
2010	-7.1%	-14.9%	-4.0%
2011	-6.2%	-3.7%	-7.1%
2012	1.3%	5.5%	-0.2%
2013	-4.5%	-5.9%	-3.8%
2014	-3.7%	2.2%	-5.8%
2015	-2.4%	4.0%	-4.3%
2016	-5.5%	-0.1%	-7.1%
2017	-3.6%	0.4%	-4.7%
2018	-1.9%	-3.8%	-1.2%
2019	-2.1%	-1.8%	-2.1%
2020	-0.5%	4.7%	-2.1%
2021	-2.5%	-3.3%	-2.0%
2022	-2.1%	3.0%	-3.5%
2023	*-3.8%*	*-5.4%*	*-3.2%*
2024	*-2.0%*	*-3.0%*	*-1.6%*
2025	*-2.5%*	*-2.3%*	*-2.5%*
2026	*-2.7%*	*-1.4%*	*-3.0%*
2027	*-2.3%*	*0.2%*	*-3.0%*
2028	*-2.6%*	*-1.1%*	*-2.9%*
2029	*-2.8%*	*-0.4%*	*-3.4%*

Average Annual Growth Rates			
Full sample Period	**-3.17%**	**-1.53%**	**-3.61%**
Last 15 Years (2008-2022)	**-3.12%**	**-1.03%**	**-3.71%**
Last 10 Years (2013-2022)	**-2.87%**	**-0.07%**	**-3.67%**
Last 5 Years (2018-2022)	**-1.81%**	**-0.25%**	**-2.19%**
2025-2029	***-2.58%***	***-1.02%***	***-2.97%***

Notes

Shading indicates years for which capital and total cost benchmarking results are deemed to be especially sensitive to the recent capital benchmark year.

Italics indicate years for which THESL has projected its costs.

Table 9b (revised)

Details of Toronto Hydro's Productivity Growth

Year	Output Quantity Index*	Input Quantities		
		Total Factor	OM&A	Capital
2006	0.6%	1.7%	-0.4%	2.5%
2007	0.0%	6.0%	11.6%	3.8%
2008	-0.1%	3.6%	-1.1%	5.4%
2009	0.1%	2.5%	3.2%	2.3%
2010	0.7%	7.8%	15.8%	4.7%
2011	0.7%	7.0%	4.5%	7.9%
2012	0.6%	-0.7%	-4.7%	0.9%
2013	1.1%	5.6%	7.3%	4.9%
2014	0.3%	4.0%	-1.6%	6.2%
2015	0.1%	2.5%	-3.4%	4.6%
2016	-0.3%	5.2%	0.0%	6.9%
2017	-0.3%	3.3%	-0.4%	4.5%
2018	0.3%	2.2%	4.2%	1.5%
2019	-0.1%	2.0%	1.9%	2.0%
2020	-0.3%	0.3%	-4.9%	1.9%
2021	-0.3%	2.2%	3.3%	1.8%
2022	-0.4%	1.7%	-3.1%	3.1%
2023	*-0.6%*	*3.2%*	*5.1%*	*2.6%*
2024	*0.2%*	*2.2%*	*3.2%*	*1.9%*
2025	*0.0%*	*2.5%*	*2.4%*	*2.5%*
2026	*-0.3%*	*2.5%*	*1.4%*	*2.8%*
2027	*0.2%*	*2.5%*	*0.0%*	*3.2%*
2028	*-0.2%*	*2.4%*	*1.0%*	*2.7%*
2029	*0.1%*	*2.9%*	*0.6%*	*3.5%*
Average Annual Growth Rates[1]				
Full sample Period	**0.17%**	**3.33%**	**1.90%**	**3.82%**
Last 15 Years (2008-2022)	**0.14%**	**3.26%**	**1.41%**	**3.90%**
Last 10 Years (2013-2022)	**0.11%**	**2.65%**	**0.18%**	**3.51%**
Last 5 Years (2018-2022)	**-0.14%**	**1.98%**	**0.84%**	**2.34%**
2025-2029	***-0.02%***	***2.39%***	***1.61%***	***2.62%***

Notes

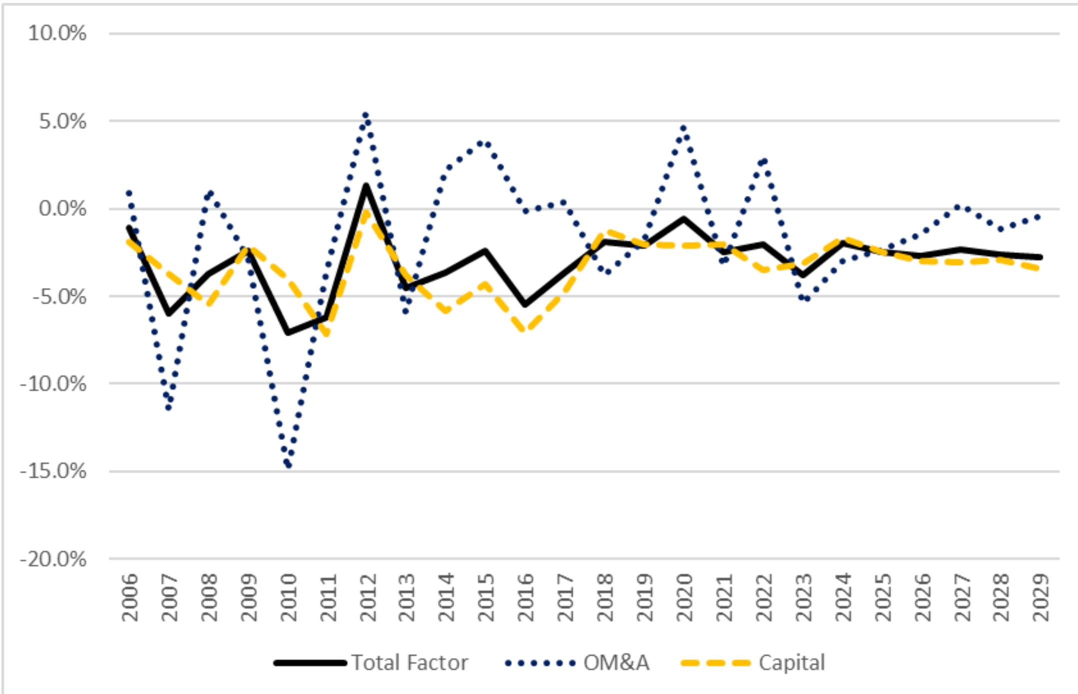
Shading indicates years for which capital and total cost benchmarking results are deemed to be especially sensitive to the recent capital benchmark year.

Italics indicate years for which THESL has projected its costs.

* The index presented is using weights for the total cost econometric model. Indexes were constructed specific to OM&A and capital using weights from the corresponding econometric work.

Figure 7 (revised)

Productivity Growth of THESL (2006-2029)



capital quantity calculations is 2002, please also note that the accuracy of the capital and total factor productivity growth calculations is particularly reduced in the years for which results are shaded.

For the ten historical years from 2013 to 2022, the Company's total factor productivity growth averaged a 2.87% annual decline. OM&A productivity growth averaged a slight 0.07% annual decline while capital productivity growth averaged a substantial 3.67% annual decline.

Over the five years of the proposed plan the Company's total factor productivity growth is forecasted to average a 2.58% annual decline. OM&A productivity growth would average a 1.02% decline while capital productivity would average a 2.97% decline. We retained the same forecasts for labor prices and M&S prices that Clearspring used where historical data were not available.

4. Econometric Reliability Benchmarking

PEG Critique

Clearspring also updated its previously-presented econometric reliability benchmarking models[20] for THESL's actual SAIFI and CAIDI values for 2005-2022 and its forecasted values for 2023-2029. The models are estimated using U.S. data from 2013-2021. Clearspring reports benchmarks for SAIFI and CAIDI, then multiplies the two values to obtain SAIDI benchmarks implied by the two models.

Clearspring reports outlying results for THESL in both the SAIFI and CAIDI models; substantially over the SAIFI benchmarks (implying poor service) and under the CAIDI benchmarks (implying good service). The combination of the two produces average results for THESL's SAIDI performance.

PEG has a number of concerns with Clearspring's methodology in their reliability models. Some of our larger concerns include the following.

- Other than the addition of data through 2021, Mr. Fenrick did not attempt to improve or refine the models from his 2019 models for THESL's CIR proposal. Clearspring has presented improved reliability models using the same dataset since then, so it is unclear why the model is mostly unchanged despite readily available improvements.
- Clearspring excluded plausible and complete reliability data for a number of companies and years based only on their total cost model exclusions. This is especially unfortunate because the U.S. reliability data are only available in a consistent format beginning in 2013, and having less data makes precise econometric modeling more difficult.
- The U.S. reliability data from the EIA include a variable indicating whether utility outages are recorded automatically. Clearspring states in 1B-Staff-75 part e) that they did not attempt to include this readily-available and relevant variable in its models.
- Similarly, in parts g) and a) of the same IR (1B-Staff-75), Clearspring indicates that even the most basic improvements, such as including an IEEE major event day definition variable in both models instead of just one, were not considered.

[20] EB-2018-0165

5. Revenue Cap Index Design

In this Section we discuss pertinent principles and statistical methods for the design of revenue cap indexes. 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.

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*").

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

These indexes can provide summary comparisons of the prices and quantities of the various inputs that a company uses. Depending on their design, these indexes can compare the *levels* of prices (and quantities) of different utilities in a given year, the *trends* in the prices (and quantities) of utilities over time, or *both.* Capital, labor, and miscellaneous materials and services are the major classes of inputs that are typically addressed by the base rates of electric utilities. These are capital-intensive businesses, so heavy weights are placed on the capital subindexes.

The growth rate of a company's cost can be shown to be the sum of the growth in (properly designed) input price and quantity indexes.[21]

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

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

growth Inputs = *growth Cost* – *growth Input Prices.* [3]

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

This greatly simplifies input quantity measurement.

Productivity Indexes

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

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

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.[22]

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

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

The scope of a productivity index depends on the array of inputs that are addressed by the input quantity index. A *multifactor* productivity index measures productivity in the use of multiple inputs. These are sometimes 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., labor 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 is

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

measured by a sub-index, and the summary index is a weighted average of the growth in the sub-indices.

In designing an output index, choices concerning sub-indices and weights should depend on the way the index is to be used. One possible objective of output research is to study the impact of output on *cost.*[23] In that event, the index should be constructed from one or more output variables that measure the "workload" that drives cost. If there is more than one output variable, the weights for these variables should reflect their relative cost impacts.

The sensitivity of cost to a small change in an output or in the value of any other business condition variable is commonly measured by its cost "elasticity."[24] Cost elasticities can be estimated econometrically using data on the costs of utilities and on outputs and other business conditions that drive these costs. Such estimates provide the basis for elasticity-weighted output indexes.[25] A productivity trend index calculated using a cost-based output index ("$Outputs^C$") will be denoted as $Productivity^C$.

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

Sources of Productivity Growth

Economists have studied the drivers of productivity growth using mathematical theory and empirical methods.[26] This research has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit firms to produce given output quantities with fewer inputs.

A second important source of productivity growth is output growth. In the short run, output growth can spur a company's productivity growth to the extent that it has excess capacity. In the longer

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[23] 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*.

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

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

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

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 an enterprise. For example, larger utilities may be less able than smaller utilities to achieve incremental scale economies from the same rate of output growth. 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 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.

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

Use of Indexing in Revenue Cap Index Design

Revenue Cap Indexes

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

$$growth\ Cost = growth\ Input\ Prices - growth\ Productivity^{C} + growth\ Outputs^{C}.\ [27] \qquad [7]$$

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

$$Revenue_t = Revenue_{t-1} \cdot [1 + growth\ Input\ Prices - (X + S) + growth\ Scale^{Utility}] + Y_t + Z_t \qquad [8a]$$

where:

$$X = \overline{Productivity^{C}}. \qquad [8b]$$

S = stretch factor

Here X, the productivity or X factor, reflects a base productivity growth target ("$\overline{Productivity^{C}}$") which is typically the average trend in the productivity indexes of a regional or national sample of utilities. A consistent cost-based output index is used in the supportive productivity research. A stretch factor (aka consumer dividend) is often added to the formula which slows revenue cap index growth in a manner that shares with customers the financial benefits of performance improvements which are expected under the multiyear rate plan.

An alternative basis for a revenue cap index can be found in index logic. Recall from [2] that growth in the cost of an enterprise is the sum of the growth in an appropriately-designed input price index and input quantity index.[28] It then follows that

$$\begin{aligned} growth\ Cost &= growth\ Input\ Prices + growth\ Outputs^{C} \\ &\quad - (growth\ Outputs^{C} - growth\ Input\ Quantities) \\ &= growth\ Input\ Prices - growth\ Productivity^{C} + growth\ Outputs^{C} \end{aligned} \qquad [9]$$

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

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

Simple vs. Size-Weighted Averages

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

- This is a better measure of the industry productivity trend. To 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.
- 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.

Scale Escalators

Formula [8a] raises the issue of the appropriate scale escalator for a revenue cap index. For gas and electric power distributors, the number of customers served is a sensible component of a revenue cap index scale escalator, for several reasons. The number of customers often has the highest or one of the highest estimated cost elasticities amongst the scale variables studied in econometric research on distributor cost. The number of customers clearly drives costs of connections, meters, and customer services and has a high positive correlation with peak load and delivery capacity. Consider also that a scale escalator that includes volumes or peak demand as output variables diminishes a utility's incentive to promote conservation demand management. This is an argument for excluding these system-use variables from a revenue cap index scale escalator.[29]

Revenue cap indexes do not always include explicit scale escalators. A revenue cap index of general form

$$growth\ Revenue^{Allowed} = growth\ GDPPI + growth\ Customers - (X + Stretch) \qquad [10a]$$

where

$$X = \overline{TFP}^{C}_{Industry}.$$

Is equivalent to the following:

$$growth\ Revenue^{Allowed} = growth\ GDPPI - (X + Stretch^{Augmented}) \qquad [10b]$$

where

$$X = \overline{TFP}^{C}_{Industry}$$

$$Stretch^{Augmented} = Expected\ growth\ Scale_{Utility} + Stretch. \qquad [10c]$$

It can be seen that if the plan does not otherwise compensate the utility for growth in its operating scale, the expected scale index growth of the utility is an implicit stretch factor. The value of this implicit stretch factor will be larger the more rapid is the utility's expected scale index growth.

Dealing with Cost Exclusions

It is important to note that relation [9] applies to *subsets* of cost as well as to total cost. Thus, a revenue cap index designed to escalate only OM&A revenue can reasonably take the form

$$Revenue_t^{OM\&A} = Revenue_{t-1}^{OM\&A} \cdot [1 + Inflation - (X + S) + growth\ Scale^{OM\&A}] + Y_t^{OM\&A} + Z_t^{OM\&A} \qquad [11]$$

where

$$X = \overline{Productivity}^{OM\&A}.$$

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[29] In choosing a scale escalator for a North American power distributor, it is also pertinent that standardized data on miles of distribution line, another important distribution cost driver, are not readily available for most U.S. power distributors. This bolsters the arguments for using the number of customers as the sole scale variable in an RCI for a U.S. power distributor.

Here X is the trend in the productivity of a group of utilities in the management of OM&A inputs. The scale escalator involves one or more output variables that drive OM&A cost.

If the multiyear rate plan provides for certain costs to be addressed by variance accounts, relation [9] similarly provides the rationale for excluding these costs from the X factor research. This principle is widely (if not unanimously) accepted, and certain costs that are frequently accorded variance account treatment in multiyear rate plans (e.g., costs of energy, CDM, and pension programs) are frequently excluded from the supportive X factor studies.

This reasoning is important when considering how to combine a revenue cap index with multiyear rate plan provisions that furnish extra funding for capex. Many multiyear rate plans with indexed rate or revenue caps have had provisions for supplemental capital revenue. The rationale is that the index formula cannot by itself provide reasonable compensation for capex surges. Reasons that such surges might be needed include "lumpy" plant additions, a desire to install costly "smart grid" equipment, a surge in plant that has reached replacement age, or a surge in demand. Provisions for funding capex surges often involve variance accounts that effectively exempt capital revenue or a portion thereof from indexing. In Ontario, for example, a "C factor" is sometimes added to a revenue (or price) cap index formula that helps capital revenue grow at a rate that is close to that of forecasted capital cost.

Inflation

Suppose, now, that a macroeconomic price index is used as the inflation measure in the revenue cap index formula. In the United States the gross domestic product price index ("GDPPI") has frequently been used this way.

If a macroeconomic inflation index, such as the GDPPI, is used as the inflation measure in a revenue cap index, Relation [7] can be restated as:

$$\begin{aligned} \textit{growth Cost} &= \textit{growth Input Prices} - \textit{growth Productivity}^{C} + \textit{growth Outputs}^{C} \\ &\quad + \textit{growth GDPPI} - \textit{growth GDPPI} \\ &= \textit{growth GDPPI} - [\textit{growth Productivity}^{C} + (\textit{growth GDPPI - growth Input Prices})]. \\ &\quad + \textit{growth Outputs}^{C}. \qquad [12] \end{aligned}$$

Relation [12] shows that cost growth depends on GDPPI inflation, growth in operating scale and productivity, and on the difference between GDPPI and utility input price inflation (which 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.[30] 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 indexes.

$$\textit{growth GDPPI} = \textit{growth Input Prices}^{Economy} - \textit{growth MFP}^{Economy}. \quad [13]$$

The formula for the X factor can then be restated as:

$$X = [(\overline{Productivity}^{C} - \overline{MFP}^{Economy}) + (\overline{Input\ Prices}^{Economy} - \overline{Input\ Prices}^{Industry})]. \quad [14]$$

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

Relation [14] has been the basis for the design of several approved X factors in multiyear rate plans in the United States.[31] Since the multifactor productivity growth of the U.S. economy has tended to be brisk, it has contributed to the approval of substantially negative X factors in several American *MRPs* for energy distributors. MFP growth has historically been considerably slower in Canada's economy, and macroeconomic price indexes are less frequently the sole inflation measures used in revenue cap indexes.

Contributions from Econometric Analysis

Economic theory reveals that the cost of an enterprise is a function of input prices, operating scale ("*Outputs*", which may be multidimensional), and miscellaneous other external business condition variables ("*Other Variables*"). This relationship may be expressed in general terms as

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

[31] This approach has, for example, been approved in Massachusetts on several occasions. See, for example, D.P.U. 96-50, D.T.E. 03-40, D.T.E. 05-27, D.P.U. 17-05, and D.P.U. 18-150.

$$Cost = f(Input\ Prices, Outputs, Other\ Variables, Time). \quad [15]$$

We can measure the impacts of business conditions on utility cost by positing a specific form for the cost function and then estimating model parameters using econometric methods and historical data on utility operations. Here is a simple example of an econometric cost model with two output variables.

$$\ln Cost^{Real} = \hat{\beta}_0 + \hat{\beta}_1 \times \ln Output_1 + \hat{\beta}_2 \times \ln Output_2$$
$$+ \hat{\beta}_3 \times \ln Other_1 + \hat{\beta}_4 \times \ln Other_2 + \hat{\beta}_T \times Trend \quad [16]$$

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

Econometric cost research has several uses in the determination of X factors. In the case of our illustrative model, econometric estimates of output variable parameters can be used to construct an output quantity index with the following formula:

$$growth\ Outputs^C = [\hat{\beta}_1 / (\hat{\beta}_1 + \hat{\beta}_2)] \times growth\ Output_1 +$$
$$[\hat{\beta}_2 / (\hat{\beta}_1 + \hat{\beta}_2)] \times growth\ Output_2. \quad [17]$$

This formula states that output index growth is an elasticity-weighted average of the growth in the two output variables. An index of this kind can be used in productivity trend research. It can also serve as the scale escalator of a revenue cap index formula. If the formula lacks such an escalator, the expected growth in the output index during the term of the MRP can provide the basis for an X factor adjustment.

Denny, Fuss, and Waverman provided the additional useful result that, for a cost model like [16], growth in a company's productivity can be decomposed as follows.

$$growth\ Productivity = [1 - (\hat{\beta}_1 + \hat{\beta}_2)] \times growth\ Outputs^C$$
$$- (\hat{\beta}_3 \times growth\ Other_1 + \hat{\beta}_3 \times growth\ Other_2) - \hat{\beta}_T. \quad [18]$$

The first term in [18] is the incremental scale economies that are realized due to output growth. These economies are greater the smaller is the sum of the cost elasticities with respect to output ($\hat{\beta}_1 + \hat{\beta}_2$) and the greater is output index growth. Relation [18] also shows that if growth in the value of a business condition variable like $Other_1$ raises cost it also slows productivity growth. If the trend variable parameter estimate has a negative (positive) value it would to that extent raise (lower) productivity growth. Formulas like [17] and [18] can be generalized to models with other business condition variables and a larger or smaller number of scale variables.

Econometric cost research and an equation like [18] can be used to identify productivity growth drivers and estimate their impact. Given forecasts of the change in output and other business conditions, an equation like [18] can also provide the basis for productivity growth projections that are specific to the business conditions of a utility that will be operating under incentive ratemaking.

In an application to Canadian telecommunications Denny, Fuss, and Waverman, *op. cit*., were the first to use econometric research and a formula like [18] to decompose productivity growth. In work for the Ontario Energy Board, PEG used this method in an Ontario gas performance-based ratemaking ("PBR") proceeding to project the TFP trends of two large gas utilities and published a paper on the work in the *Review of Network Economics.*[32] These projections were useful because the productivity drivers facing Enbridge Gas Distribution (e.g., rapid customer growth in Toronto and Ottawa) were very different from those facing gas utilities in adjacent American states.

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

A simpler use of econometrics is to calibrate the cost efficiency growth target using the values of $(1 - \hat{\beta}_1) \cdot$ *growth Output* - $\hat{\beta}_T$ or just $\hat{\beta}_T$. Both approaches would ignore the productivity impact of

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

changes in the model's other business conditions while the second would additionally ignore incremental scale economies as a source of cost efficiency growth. These approaches are simpler than a full econometric productivity growth projection and have the added rationale that any tendency of productivity growth to be slower than the industry trend has been addressed by not using a fully-indexed ARM. This general approach to choosing an efficiency growth target for utilities was favored by California Public Service Commission staff in several proceedings.[33]

Stretch Factors

The stretch factor term of an indexed ARM formula has several rationales. Since the OEB has not reconsidered the stretch factor issue for many years, this section traces PEG's current thinking on this issue.

Rationale

The stretch factor term of a rate or revenue cap index should reflect an expectation of how the productivity growth of the utility that will be operating under IR (the "subject utility") will 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 cost efficiency research sample.

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

- The extent of inefficiencies that can be immediately addressed at the start of IR varies between utilities. It is harder to eliminate all of them in one or two plans the larger was the initial inefficiency.

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

- 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. CIR as recently practiced has not generated strong incentives for capex containment. Even if an MRP has no earnings sharing, 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 in these years.

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

- Utility plant that is excessively costly may nonetheless not merit replacement for many years.
- Even after multiple terms of PBR, the subject utility will still be presented with a continuing sequence of new cost management challenges and its response to these challenges will be influenced by its incentives and improved business sense as an operator under IR. One salient issue is how the utility handles the steady succession of new asset cohorts approaching replacement age.[34] Another salient issue is how the utility responds to new industry developments such as new technologies. An example here is the opportunity to use AMI to implement time-sensitive distribution rates that could slow the need for additional distribution capacity.

Consider also that strong incentives don't guarantee good performance. Companies in unregulated markets, for instance, experience continually strong incentives to contain cost but nonetheless have varied efficiency levels. Many businesses in these markets fail every year.

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

Analogously, all players in the National Hockey League have strong incentives to perform well but their performances nonetheless vary widely.

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

- Utilities operating under MRPs are incented to defer certain costs until the next rebasing. A stretch factor is one means of sharing the benefits of these deferrals to customers.
- A stretch factor can also be warranted to address overcompensation concerns that result from supplemental cost funding but are difficult to measure accurately.
- Stretch factors linked to benchmarking studies can strengthen cost containment incentives. We discuss this option further in the next section.

Role of Benchmarking

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

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

Notable Stretch Factor Precedents

Ontario In Ontario's 4th GIRM, the stretch factors in price cap index formulas vary between utilities and over time with the outcome of annual benchmarking exercises that use the Board's own econometric total cost model. Each distributor's stretch factor depends on its average econometric benchmarking score over the three most recent years. As detailed in Figure 8 below, the best cost performers get a stretch factor of zero while the worst get a stretch factor of 0.60%.[35]

Figure 8

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%

CIR stretch factors are typically linked to custom econometric benchmarking studies that use transnational (specifically U.S. and Ontario) data. The current stretch factor of Toronto Hydro is 0.6%, while that of Hydro Ottawa is 0.45% and that for power distributor services of Hydro One is 0.45%.[36]

Massachusetts The Massachusetts Department of Public Utilities ("DPU") first considered statistical benchmarking studies to set the stretch factor of an energy utility (Boston Gas) in the 1990s and has resumed their consideration since they resumed using MRPs with indexed and hybrid ARMs several years ago. These studies have used a mix of benchmarking methods that include unit cost metrics and econometric modelling.

In its approval of the current MRP for National Grid's Massachusetts power distributors, the DPU tied the stretch factor in the revenue cap index formula to the Company's performance in annual benchmarking studies. The schedule of benchmarking results and stretch factors, which are called "consumer dividends," is provided in the figure below.

[35] 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.

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

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.

6. U.S. Power Distributor Productivity Trends

Data Sources Used in the U.S. Productivity Study

The primary source of data on the operations of U.S. power distributors which we used in our U.S. productivity research is FERC Form 1. FERC Form 1 data were for many years published in print form by the U.S. Energy Information Administration ("EIA") and predecessor agencies.[37] More recently, the data have been available electronically from the FERC and in more processed forms from commercial vendors. Most of the FERC Form 1 data used in PEG's study were obtained directly from government agencies and processed by PEG. Customer data were drawn from FERC Form 1 in the early years of the sample period and from Form EIA-861 (the *Annual Electric Power Industry Report)* in later years.[38]

Data on U.S. salary and wage prices were obtained from the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor. The GDPPI that we used in the deflation of M&S expenses of U.S. distributors was calculated by the Bureau of Economic Analysis of the U.S. Department of Commerce. Data on U.S. electric utility construction cost *trends* were drawn from the *Handy Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates.

Sample

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

Data for 87 U.S. power distributors were used in our U.S. productivity trend research for Board Staff. Three large California utilities were excluded from the sample because severe wildfires caused their OM&A expenses to surge and remain high towards the end of the sample period. Two of these

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

[38] Data from the two sources for these variables are generally similar. The 861 data have the advantage that they explicitly account for bundled and delivery only electric service to customers. The Form 1 data is ambiguous and the instruction only request that sales be reported which some could interpret as bundled service only.

utilities were also excluded from power transmission productivity trend research in the aforementioned Joint Report of PEG and the THESL witness.[39]

Table 10 lists the sampled utilities. It can be seen that most broad regions of the United States are well represented. Unfortunately, the requisite customer data are not available for most distributors serving Texas. We believe these data form a good base for rigorous research on power distributor productivity trends.

The full sample period for our U.S. productivity research was the twenty-seven (growth rate) years from 1996 to 2022. Data for 2022 are the latest available given the filing date for evidence in this proceeding.

Variables Used in the Study

Costs

The cost of U.S. power distributors considered in our productivity studies was the sum of applicable capital costs and OM&A expenses. We employed a monetary approach to capital cost, price, and quantity measurement which featured geometric physical decay of capital quantities. Capital cost encompassed depreciation expenses and a return on net plant value less capital gains. Plant was valued in current dollars. In addition to costs of *distribution* plant ownership, we included a sensible share of the costs of *general* plant ownership. Taxes and franchise fees were excluded from our calculations. Further details of our capital cost calculations are provided in Appendix section A.1.

[39] The third California utility, Pacific Gas & Electric, had been excluded from the transmission productivity research by both PEG and Clearspring at an earlier point in the proceeding.

Table 10

Electric Utilities Sampled in PEG's Productivity Research

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

Comments

Data for 87 U.S. distributors were used in PEG's U.S. productivity research.

OM&A expenses that we included comprised distribution and customer account expenses and a sensible share of administrative and general expenses.[40] We excluded reported costs that the U.S. utilities reported for power production, procurement, and transmission, customer service and information, and any gas utility services that they provided. CS&I expenses were excluded because in the U.S. they contain conservation program expenses that are often sizable and that THESL doesn't incur.

The following categories of administrative and general expenses were included:

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

Pension and other benefit expenses were excluded. One reason is that these expenses can be sensitive to volatile external business conditions such as stock prices. Another is that THESL proposes variance account treatment for some of these expenses in its new rate plan. Franchise fees are also excluded.

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

Input Prices

Trends in the prices that distributors paid for inputs are useful in productivity research. Our productivity trend research used input price trend indexes that are similar to the trend components of our input price indexes for benchmarking.

OM&A Prices

U.S. labor price trends were calculated using regionalized employment cost indexes of salaries and wages in the utility sector. The requisite data were obtained from the U.S. Bureau of Labor Statistics.

Material and Service Prices

Prices U.S. utilities pay for materials and services are often assumed in statistical cost research to rise over time at the rate of the GDPPI. However, recent research by PEG suggests that the GDPPI tends to materially understate the M&S price inflation of U.S. utilities. In this study we use a new proxy M&S price index that is discussed further in Appendix section A.3.

Capital Prices

As asset price trend indexes for U.S. utilities we used the applicable regional Handy Whitman Indexes of Public Utility Construction Costs for Total Distribution Plant. As general plant asset price indexes for these utilities we used the applicable regional Handy Whitman Indexes of Public Utility Construction Costs for reinforced concrete building construction.

For the rates of return of U.S. utilities we calculated 50/50 averages of rates of return for debt and equity.[41] 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.[42] The construction of capital service prices from these components is discussed further in Appendix Section A.1.

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

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

Scale Variables

We used only one scale variable in our U.S. power distributor productivity research: the number of customers served. As discussed in Section 5, this is the treatment most applicable to revenue per customer indexes and to price cap indexes of utilities that rely heavily on fixed charges. Data from the EIA-861 are preferred when available. Data from the Form 1 are used prior to 2000 and in cases in which the 861 data appear erroneous. Our estimates of distributor output do not reflect any possible changes in distribution reliability that may have occurred during the sample period.[43]

U.S. Productivity Trends

Methodology

We calculated indexes of the OM&A, capital, and multifactor productivity of each sampled U.S. utility in the provision of power distributor services. The annual productivity growth rate of each distributor was calculated as the difference between the growth of its output and input quantity indexes. We calculated even-weighted and cost-weighted averages of the results for individual utilities. The merit of even-weighted averages is that Toronto Hydro is of roughly average scale relative to U.S. distributors and even-weighted averages are less sensitive to special circumstances of large distributors. The merit of cost-weighted indexes is that they are more representative of industry trends.

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

Industry Trends

Tables 11a and 11b report results of our productivity calculations for the full sample period. Using even-weighted averages we found that, over the most recent 15 years for which we have gathered data (2008-2022), the growth in the TFP of sampled U.S. power distributors averaged a slight

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[43] Reliability has been treated as an output variable in distribution productivity research commissioned by the Australian Energy Regulator. See, for example, Denis Lawrence, Tim Coelli and John Kain, *Economic Benchmarking Results for the Australian Energy Regulator's 2020 TNSP Annual Benchmarking Report*, prepared for the Australian Energy Regulator, October 15, 2020, pp. 6-7.

Table 11a

U.S. Power Distributor Productivity Growth

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
1996	-0.29%	-0.80%	0.05%	-0.34%	-1.20%	0.05%
1997	1.89%	3.63%	0.72%	1.50%	2.75%	0.67%
1998	-0.17%	-2.13%	1.09%	-1.80%	-5.63%	1.03%
1999	-0.92%	-2.42%	-0.02%	-0.67%	-2.26%	-0.03%
2000	1.25%	3.21%	-0.07%	0.73%	1.76%	0.13%
2001	2.33%	4.55%	0.78%	2.62%	4.51%	1.27%
2002	1.26%	3.16%	0.03%	0.94%	4.00%	-1.03%
2003	-0.11%	-0.93%	0.37%	0.22%	-0.13%	0.07%
2004	2.37%	5.88%	0.09%	3.27%	8.07%	0.18%
2005	1.09%	1.66%	0.67%	0.90%	0.76%	1.00%
2006	1.76%	3.12%	0.22%	1.37%	2.77%	0.00%
2007	-1.13%	-2.24%	0.50%	-2.06%	-4.24%	0.97%
2008	-1.49%	-1.88%	-0.44%	0.13%	0.16%	0.22%
2009	2.63%	4.49%	0.30%	3.23%	5.32%	0.59%
2010	-0.03%	-0.77%	0.81%	-0.61%	-2.12%	0.85%
2011	0.52%	0.73%	0.42%	0.61%	0.51%	0.71%
2012	0.86%	2.69%	-0.21%	1.50%	3.80%	0.24%
2013	0.82%	2.27%	0.06%	1.55%	3.38%	0.59%
2014	0.21%	-0.04%	0.40%	0.10%	-0.36%	0.42%
2015	0.35%	0.66%	0.26%	1.26%	2.98%	0.30%
2016	-0.40%	-1.21%	0.04%	-0.33%	-1.14%	0.08%
2017	0.30%	1.87%	-0.35%	0.54%	2.76%	-0.20%
2018	-1.46%	-3.42%	-0.67%	-1.22%	-3.16%	-0.49%
2019	-0.03%	2.47%	-1.26%	0.68%	3.79%	-0.78%
2020	0.27%	2.74%	-0.82%	-0.44%	0.40%	-0.63%
2021	-0.12%	1.12%	-0.76%	-0.55%	0.35%	-1.01%
2022	-1.21%	-2.64%	0.15%	-0.62%	-1.48%	0.29%
Average Annual Growth Rates						
All Years (1996-2022)	**0.39%**	**0.95%**	**0.09%**	**0.46%**	**0.98%**	**0.20%**
Last 15 Years (2008-2022)	**0.08%**	**0.61%**	**-0.14%**	**0.39%**	**1.01%**	**0.08%**
Last 10 Years (2013-2022)	**-0.13%**	**0.38%**	**-0.29%**	**0.10%**	**0.75%**	**-0.14%**
Last 5 Years (2018-2022)	**-0.51%**	**0.06%**	**-0.67%**	**-0.43%**	**-0.02%**	**-0.53%**

Table 11b

Details of U.S. Power Distributor Productivity Growth

Year	Simple Averages of Annual Growth Rates				Cost-Weighted Averages of Annual Growth Rates			
	Output Quantity Index	Input Quantities			Output Quantity Index	Input Quantities		
		Total Factor	OM&A	Capital		Total Factor	OM&A	Capital
1996	1.23%	1.52%	2.03%	1.17%	1.17%	1.51%	2.37%	1.12%
1997	1.41%	-0.48%	-2.22%	0.69%	1.37%	-0.12%	-1.38%	0.70%
1998	1.55%	1.71%	3.68%	0.46%	1.62%	3.42%	7.25%	0.59%
1999	0.84%	1.77%	3.26%	0.86%	0.87%	1.54%	3.13%	0.90%
2000	1.15%	-0.10%	-2.05%	1.22%	1.19%	0.46%	-0.57%	1.06%
2001	1.91%	-0.42%	-2.64%	1.13%	3.17%	0.55%	-1.34%	1.91%
2002	0.82%	-0.44%	-2.34%	0.79%	-0.09%	-1.02%	-4.09%	0.94%
2003	1.15%	1.26%	2.08%	0.78%	1.04%	0.81%	1.17%	0.97%
2004	1.15%	-1.22%	-4.72%	1.06%	1.10%	-2.17%	-6.97%	0.92%
2005	1.33%	0.24%	-0.33%	0.67%	1.48%	0.58%	0.72%	0.48%
2006	0.86%	-0.89%	-2.26%	0.65%	0.92%	-0.46%	-1.85%	0.92%
2007	1.00%	2.13%	3.24%	0.50%	1.08%	3.14%	5.32%	0.11%
2008	0.47%	1.96%	2.35%	0.91%	0.61%	0.49%	0.45%	0.39%
2009	0.18%	-2.45%	-4.31%	-0.12%	0.16%	-3.07%	-5.16%	-0.43%
2010	0.40%	0.44%	1.17%	-0.41%	0.39%	1.00%	2.50%	-0.46%
2011	0.24%	-0.28%	-0.49%	-0.18%	0.31%	-0.30%	-0.20%	-0.41%
2012	0.36%	-0.50%	-2.32%	0.58%	0.41%	-1.09%	-3.39%	0.17%
2013	0.39%	-0.43%	-1.87%	0.33%	0.51%	-1.04%	-2.87%	-0.08%
2014	0.63%	0.42%	0.67%	0.23%	0.64%	0.54%	1.00%	0.21%
2015	0.69%	0.35%	0.03%	0.43%	0.76%	-0.50%	-2.22%	0.47%
2016	0.75%	1.15%	1.96%	0.71%	0.94%	1.27%	2.08%	0.86%
2017	0.59%	0.29%	-1.29%	0.94%	0.79%	0.25%	-1.97%	0.99%
2018	0.80%	2.27%	4.22%	1.47%	0.93%	2.15%	4.10%	1.42%
2019	0.73%	0.76%	-1.74%	1.99%	0.88%	0.20%	-2.91%	1.66%
2020	0.92%	0.65%	-1.82%	1.74%	0.92%	1.36%	0.52%	1.56%
2021	0.89%	1.01%	-0.24%	1.64%	0.95%	1.50%	0.60%	1.96%
2022	0.86%	2.07%	3.49%	0.71%	1.03%	1.65%	2.51%	0.74%
Average Annual Growth Rates[1]								
All Years (1996-2022)	**0.86%**	**0.47%**	**-0.09%**	**0.78%**	**0.93%**	**0.47%**	**-0.04%**	**0.73%**
Last 15 Years (2008-2022)	**0.59%**	**0.51%**	**-0.01%**	**0.73%**	**0.68%**	**0.29%**	**-0.33%**	**0.60%**
Last 10 Years (2013-2022)	**0.73%**	**0.85%**	**0.34%**	**1.02%**	**0.84%**	**0.74%**	**0.08%**	**0.98%**
Last 5 Years (2018-2022)	**0.84%**	**1.35%**	**0.78%**	**1.51%**	**0.94%**	**1.37%**	**0.96%**	**1.47%**

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

0.08% annual growth. Distributor OM&A productivity averaged 0.61% annual growth while capital productivity averaged 0.14% annual decline. The cost-weighted averages over 15 years were 0.39% for TFP, 1.01% for OM&A, and 0.08% for capital.

Over the most recent 10 years, the even-weighted averages were a 0.13% decline for TFP, 0.38% growth for OM&A, and a 0.29% decline for capital. Using cost-weighted averages, the results for the same years are 0.10% annual growth for TFP, 0.75% growth for OM&A, and a 0.14% decline for capital.

7. X Factor and Stretch Factor Recommendations

Base Productivity Growth Trend

The following considerations are salient in choosing a base cost efficiency growth trend for THESL.

- In research for the OEB in this proceeding that is reported in Table 11a, PEG has found that the simple average TFP growth of sampled U.S. power distributors over the fifteen years from 2008 to 2022 was 0.08%. During this same period, the OM&A productivity growth of these distributors averaged 0.61% annually. Over the same sample period PEG found that, with cost-weighted averages, TFP growth averaged 0.39% annually while OM&A productivity averaged 1.01% and capital productivity averaged 0.08%.
- TFP growth is slower using shorter sample periods but still positive using cost-weighted averages.
- The trend variable parameter in PEG's featured econometric total cost model, which was estimated using fifteen years of data, implied a -0.22% annual total cost efficiency trend while the analogous parameter in PEG's featured econometric OM&A model implied a 0.07% annual OM&A cost efficiency trend.

Based on the assembled evidence, we believe that a 0.10% base cost efficiency trend that is applicable to both the OM&A and capital revenue of THESL is conservative and reasonable.

Stretch Factor

We have provided evidence on THESL's cost performance that is useful for setting stretch factors. The forecasted total cost of THESL in each year of the proposed plan term is on average about 31% above our econometric benchmarks. Based on these results we recommend a 0.60% stretch factor for THESL. A similar result obtains using the Board's total cost model, which was estimated using Ontario data.

8. Calculating the Revenue Cap Index Inflation Factor

The inflation factor used in OEB-approved rate and revenue cap indexes is a weighted average of the growth rates of the gross domestic product implicit price index for final domestic demand and the average weekly earnings ("AWE") of Ontario workers. We propose to replace the AWE in this formula with the fixed-weighted index of average hourly workers ("FWI AHE"). The fixed weights in the latter index guard against aggregation bias that results when the mix of workers employed changes.

The advantage of the FWI AHE is illustrated in Table 12. This table compares the inflation in the AWEs and FWI AHEs of Canada and Ontario from 2002 to 2023. Recession years are shaded in pink.

During a recession, lower paid workers are more likely to be laid off while during a recovery they are more likely to be added. This causes an AWE to grow too rapidly during a recession and too slowly during a recovery. The table shows that results using the FWI AHE tend to be more reasonable during recessions and recoveries. Note also that the standard deviation of growth rates is lower for FWI AHEs than for AWEs.

In its recent PBR3 decision, the Alberta Utilities Commission replaced an AWE with the FWI AHE in its inflation factor formula.[44]

[44] Alberta Utilities Commission (2023), Decision 27388-D01-2023, pp. 20-21.

Table 12

Historical Labour Price Trend Indicators for Canada and Ontario

	Canada						Ontario					
	Average Weekly Earnings		Average Hourly Earnings		FWI of Average Hourly Earnings		Average Weekly Earnings		Average Hourly Earnings		FWI of Average Hourly Earnings	
Year	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
2001	657.0		16.3		98.0		695.9		17.0		98.2	
2002	672.7	2.36%	16.7	1.94%	100.1	2.18%	710.9	2.14%	17.3	1.63%	100.1	1.96%
2003	690.9	2.67%	17.2	3.07%	103.1	2.89%	728.5	2.44%	17.9	3.18%	102.8	2.66%
2004	709.1	2.60%	17.7	2.93%	105.9	2.72%	748.8	2.75%	18.4	2.87%	105.4	2.45%
2005	736.8	3.83%	18.3	3.34%	109.3	3.11%	776.1	3.58%	18.8	2.36%	108.7	3.15%
2006	754.9	2.43%	18.8	2.48%	112.1	2.54%	788.6	1.60%	19.2	1.89%	111.3	2.34%
2007	787.2	4.20%	19.5	3.87%	117.2	4.49%	818.9	3.77%	19.8	3.23%	115.7	3.83%
2008	809.9	2.84%	20.2	3.43%	121.3	3.45%	838.0	2.31%	20.3	2.34%	119.3	3.08%
2009	822.3	1.52%	20.5	1.38%	124.9	2.93%	848.6	1.26%	20.2	-0.44%	122.8	2.89%
2010	852.2	3.57%	21.0	2.42%	129.0	3.18%	881.3	3.78%	20.9	3.17%	127.5	3.80%
2011	873.5	2.47%	21.7	3.70%	131.6	2.06%	893.4	1.37%	21.6	3.62%	129.6	1.59%
2012	895.3	2.46%	22.3	2.36%	134.3	1.97%	905.8	1.38%	22.0	1.47%	131.3	1.34%
2013	911.2	1.76%	22.9	2.62%	136.5	1.63%	919.8	1.53%	22.4	2.07%	133.2	1.42%
2014	935.4	2.62%	23.3	1.78%	139.6	2.30%	938.3	1.99%	22.7	1.42%	135.3	1.57%
2015	952.0	1.76%	23.6	1.37%	143.1	2.46%	963.1	2.61%	23.1	1.66%	139.0	2.70%
2016	956.6	0.48%	23.9	1.18%	146.0	1.98%	974.0	1.12%	23.7	2.44%	142.2	2.27%
2017	975.8	2.00%	24.3	1.70%	149.1	2.11%	992.6	1.89%	24.0	1.13%	144.9	1.86%
2018	1001.1	2.56%	25.1	3.28%	152.4	2.16%	1021.2	2.84%	24.7	3.20%	148.2	2.29%
2019	1028.1	2.66%	25.8	2.64%	156.3	2.54%	1049.0	2.68%	25.5	3.22%	152.4	2.79%
2020	1097.7	6.54%	27.0	4.67%	161.8	3.49%	1127.3	7.20%	26.6	4.22%	157.5	3.27%
2021	1130.1	2.91%	27.6	2.42%	166.4	2.76%	1165.8	3.36%	27.3	2.45%	161.9	2.78%
2022	1165.2	3.06%	28.6	3.52%	173.1	3.93%	1193.3	2.33%	28.1	2.89%	168.6	4.04%
2023	1204.9	3.35%	29.7	3.64%	179.1	3.45%	1231.9	3.18%	29.2	3.77%	173.6	2.95%
Average Annual Growth Rates												
Last 15 years (2009-2023)		**2.65%**		**2.58%**		**2.60%**		**2.57%**		**2.42%**		**2.50%**
Last 10 years (2014-2023)		**2.79%**		**2.62%**		**2.72%**		**2.92%**		**2.64%**		**2.65%**
Last 5 years (2019-2023)		**3.71%**		**3.37%**		**3.23%**		**3.75%**		**3.31%**		**3.17%**
Standard Deviations												
Last 20 years (2004-2023)		**0.012**		**0.009**		**0.007**		**0.014**		**0.011**		**0.008**
Last 15 years (2009-2023)		**0.013**		**0.010**		**0.007**		**0.015**		**0.012**		**0.008**

Notes

Average weekly earnings data sourced from Statistics Canada. Table 14-10-0223-01 Employment and average weekly earnings (including overtime) for all employees by province and territory, monthly, seasonally adjusted

Average hourly earnings data sourced from Statistics Canada. Table 14-10-0206-01 Average hourly earnings for employees paid by the hour, by industry, annual

Fixed Weighted Index (FWI) for average hourly earnings data sourced from Statistics Canada. Table 14-10-0213-01 Fixed weighted index of average hourly earnings for all employees, by industry, monthly

Pink shading indicates recession years in Canada.

Pacific Economics Group Research, LLC

Appendix: Additional Information on Research Methods

A.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

$$CK = WK \cdot XK.^{45} \qquad \text{[A1]}$$

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

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[45] 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.

[46] 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.[47] 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

[47] 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.[48] 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

[48] 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 a regional Handy Whitman Index of reinforced concrete building construction cost for periods ending in the benchmark year. A triangularized weighted average places a greater weight on more recent values of the construction cost index. This makes sense intuitively since more recent plant additions are less depreciated and to that extent tend to have a bigger impact on net plant value.

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

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

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:

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

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.

A.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.[49] 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.

Here is an analogous model of *translog* form:

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

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

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. 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 with a fixed-b procedure. 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 Toronto Hydro 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.

A.3 Material and Service Price Index

Stylized Facts

In research and testimony for Puget Sound Energy in a recent Washington state proceeding, PEG found the following results for twenty (growth rate) years ending in 2022.[50]

- An M&S price index ("WMS") for power distribution calculated by Standard and Poor's Power Planner service averaged **3.33%** annual growth.
- Our examination of Standard and Poor's methodology revealed that this index is really a measure of materials prices and does not track service prices well.
- The ECI for salaries and wages of all private industries averaged **2.62%** annual growth.
- A "corrected" WMS for U.S. power distribution that took better account of the labor intensiveness of services might average (2/3) x 3.33% + (1/3) x 2.62% = 2.22 + 0.87 = **3.09%**;
- The GDPPI averaged **2.23%** annual growth and therefore substantially understated WMS growth either way that it was measured. The inflation differential using Standard and Poor's WMS was 3.33-2.23 = **1.1%.** The inflation differential using the corrected WMS was 3.09% - 2.23% = **0.86%.**
- The MFP of the U.S. private business sector meanwhile averaged **0.73%** annual growth.

Over the *15* years ending in 2022, we found the following.

[50] Washington Utilities and Transportation Commission Docket UE-240004, Second Exhibit (Nonconfidential) to the Prefiled Direct Testimony of Mark Newton Lowry, February 15, 2024.

- The Power Planner WMS for power distribution averaged **3.05%** annual growth.
- The ECI for salaries and wages of all private industry workers averaged **2.56%** annual growth.
- A "corrected" WMS for U.S. power distribution averaged (2/3) x 3.05% + (1/3) x 2.56% = 2.03% + 0.85 = **2.88%.**
- The GDPPI averaged **2.08%** growth and therefore once again substantially understated WMS growth. The inflation differential using WMS was 3.05% - 2.08% = 0.97%. The inflation differential using corrected WMS was 2.88% - 2.08% = 0.80%.
- The MFP of the U.S. private business sector averaged **0.53%** annual growth.

The 15 years ending in *2019* are not distorted by the unusual circumstances of the recent pandemic. During these years the following occurred.

- The Power Planner WMS for power distribution averaged **2.32%** annual growth.
- The ECI for salaries and wages of all private industry workers averaged **2.34%** annual growth.
- A "corrected" WMS for U.S. power distribution averaged (2/3) x 2.32% + (1/3) x 2.34% = 1.55% + 0.78 = **2.33%.**
- The GDPPI averaged **1.83%** growth. The inflation differential using WMS was 2.32-1.83% = 0.49%. The inflation differential using *corrected* WMS was 2.33 – 1.83 = 0.50%.
- The MFP of the U.S. private business sector averaged **0.58%** annual growth.

We conclude from the stylized facts that the GDPPI has tended to materially understate inflation in utility M&S prices. The importance of this distortion has grown as utilities outsource more of their services.

Solutions

There are several possible ways to upgrade the U.S. WMS based on this research.

1. Adjust GDPPI by the historical inflation differential between GDPPI and the Power Planner WMS index.

2. The GDPPI measures inflation in the output prices of the U.S. economy. It can be converted into an input price index for the economy by adding the MFP growth of the U.S. private business sector in some fashion. The MFP growth could be contemporaneous, an average for the full sample period (e.g., 15 years), or a moving average of recent MFP growth.

3. Use (1) or (2) as a proxy for *materials* price inflation in a formula like

growth WMS = (2/3) x *growth adjusted GDPPI* + *(1/3)* x *growth ECI*

We have chosen method 3) for our research in this project. The input price inflation of the U.S. economy is measured each year as the difference between GDPPI growth and a three-year moving average of the MFP growth of the U.S. private business sector.

As for Canada, the GDPPIFDD is in our view an adequate measure of materials price inflation. The MFP trend of the Canadian private business sector tends to be close to zero or negative. However, it is reasonable to calculate WMS as a 50/50% weighted average of GDPPIFDD and FWI AHE inflation.

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