

Appendix

Statistical Cost Research for OPG's Proposed Regulated Hydro-electric CIR Plan

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1. Introduction and Summary

1.1. Introduction

In proceeding EB-2025-0297, Ontario Power Generation (“OPG” or “the Company”) proposes to establish a new Custom Incentive Rate-Setting (“CIR” or “Custom IR”) framework. The proposed framework is a multi-year rate plan (“MRP”) that would operate over the five years from 2027 to 2031. Payment amounts for power sales from prescribed hydroelectric (“hydro”) generating facilities would be escalated by a price cap index with a formula that includes an inflation factor and an X factor that is the sum of a productivity factor and a stretch factor. The Company proposes a 0% productivity factor and a 0.15% stretch factor. This combination would cause 0.15% to be subtracted annually from the Company’s proposed rate growth. Evidence supporting the proposal includes reports on statistical benchmarking and index research by London Economics International LLC (“LEI”).

The OEB has over the years shown a keen interest in reducing forecasted revenue requirements by an externally-based cost efficiency markdown. The OEB’s October 13, 2016, *Handbook for Utility Rate Applications* (“*Rate Handbook*”) calls for a higher cost efficiency growth target than that used in generic price cap incentive rate-setting (“IR”). However, the OEB typically approves the same 0% cost efficiency growth target that it applies to generic incentive rate-setting.

Pacific Economics Group Research LLC (“PEG”) is a leading North American consultancy on incentive ratemaking and the benchmarking 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 LEI’s benchmarking and productivity trend evidence and the Company’s proposed CIR framework.

PEG’s main conclusions about a CIR framework for the Company can be found in the Framework Report. In this Appendix, we discuss the theory supporting the use of indexing in CIR plan design and then discuss our views of LEI’s benchmarking and productivity research and details of our own research for OEB Staff. Section 2 provides an introduction to statistical cost research for utility ratemaking. Please note that Subsection 2.1 includes several new theoretical results of interest in the CIR context. Sections 3 provides key background information while Section 4 discusses the data available for research on hydro generation cost and productivity trends. LEI’s benchmarking and productivity evidence are



critiqued in Sections 5 and 6 respectively. Data used in PEG’s research for OEB Staff in this proceeding are discussed in Section 7. Econometric modelling and benchmarking results are detailed in Section 8. New research by PEG on the productivity trends of hydroelectric generators are discussed in Section 9. X factor and stretch factor recommendations are provided in Section 10. Section 11 discusses additional details of our research. The opinions expressed in both reports are those of the author.

1.2. Summary

Econometric Cost Benchmarking

LEI’s Study

LEI developed econometric benchmarking models for two cost categories: hydroelectric (“hydro”) generation (aka hydraulic power production) operation, maintenance, and administrative (“OM&A”) expenses and OM&A expenses plus capital expenditures (“capex”) for sustaining plant capability. The parameters of these models were estimated using data drawn from a voluntary and confidential benchmarking program. The models were used to benchmark OPG’s costs over a recent four-year historical period (2020-2023).

LEI reported OPG’s total cost performance to have been exceptionally good in recent years. OM&A expenses were 42% lower than the other entities’ costs and the company ranked in the first (best) quintile. Using the other model, these same expenses plus sustaining capex were 15% lower and the company ranked in the second quintile. Using guidelines established by the OEB for Price Cap IR stretch factors,¹ LEI recommends a stretch factor in the range of 0 and 0.15%.

PEG Critique

PEG disagrees with several methods used in LEI’s cost benchmarking study for OPG. Here are some of our larger concerns:

¹ These guidelines are discussed further in Section 2.2.

- LEI used confidential data in their benchmarking study that they would not share with PEG or other parties to the proceeding even if a confidentiality agreement was signed. PEG was accordingly unable to verify the reasonableness of LEI's benchmarking results.
- OPG's forecasted costs and indexed OM&A revenue during the proposed plan were not benchmarked even though this is common practice in statistical benchmarking studies submitted by CIR applicants in Ontario. OPG proposes a marked surge in its OM&A expenses in 2027, the first plan year.
- LEI's benchmarking methods are unlike those typically used by utility statistical benchmarking witnesses in CIR applications and PEG has concerns about many of them.

Based on the foregoing, it is PEG's recommendation that the OEB panel should place little weight on LEI's benchmarking study.

Alternative PEG Benchmarking Research

PEG undertook an alternative econometric benchmarking study of OPG's cost that employed methods more commonly used in OEB proceedings. Our sample for model development included data for twenty U.S. hydro generators and OPG. The sample period was the 21 years from 2004 to 2024. We found that OPG's total hydroelectric generation cost performance was about 8.4% *below* our model's benchmark on average during the three most recent years for which historical cost data were available for the Company (2022-2024). OPG's projected/proposed revenue requirement during the five years of the proposed CIR plan was about 7.1% *above* our benchmarks on average.

PEG also developed models to evaluate OPG's projected/proposed O&M and capital costs. The Company's hydro generation O&M cost was found to be about 11.8% above our benchmarks on average during the three most recent historical years. OPG's forecasted/proposed O&M cost averaged about 30.3% above our model's prediction on average during the five years of the proposed new IR plan. An abrupt decline in O&M cost efficiency in 2027 is notable. This is the first year of the proposed new plan. This raises concern about strategic cost deferrals that PEG discussed in the recent Spending Pattern



Analysis report for OEB staff.² OPG's OM&A revenue has been limited by a rate freeze for several years but the Company nonetheless has not reported an earnings deficiency in these years.

OPG's hydro generation capital cost was found to be about 2.3% below our benchmarks on average during the three most recent historical years. The Company's forecasted/proposed capital cost was about 10.9% above our model's prediction on average during the five years of the proposed new CIR plan.

Indicated Stretch Factor

The forecasted total cost of OPG in each year of the proposed plan term is on average about 7.1% above our econometric total cost benchmark. In Ontario, this score is commensurate with a **0.30%** stretch factor for the Company. We also propose a **0.30%** supplemental capital stretch factor for OPG that we discuss in the Framework Report.

Productivity Trends

LEI's Study

Using indexing methods, LEI calculated the total factor productivity ("TFP") trend of aggregations of OPG and U.S. hydroelectric power generators. The full sample period was 2003-2023 and trends for this period were featured. Net generation volume was the output measure in the productivity index. Capital quantity was measured using a physical method and a monetary method that employed a one hoss shay ("OHS") decay specification. The physical method was to equate capital quantity growth with generation capacity growth. The monetary method was to measure capital quantity growth using deflated plant values. The TFP trend of sampled generators was found to be materially negative using both capital quantity approaches.

PEG Critique

Our primary concerns with LEI's methodology are its output and capital quantity treatments. Hydroelectric generation volumes are volatile and reflect both the volatility and longer-term trends in

² Lowry, Mark N., David Hovde, Matt Makos, and Rebecca Kavan, "Report on Spending Patterns and Capitalization Policy," in EB-2025-0108, OEB Staff Report, January 8, 2026.

weather and climate conditions in regions where facilities are located. Generation capacity is a much more important cost driver and is much less sensitive to weather. The historical volume/capacity trends of the generators LEI sampled differed materially from those that OPG has experienced historically or expects during the proposed plan.

We also believe that monetary methods for measuring capital quantity trends are preferable to LEI's "physical" method when required data are available. Monetary approaches have to date been much more common in North American productivity research to determine productivity factors. Monetary methods can capture trends in the productivity of utilities in making capacity available. Data required for the monetary method are available for investor-owned U.S. utilities engaged in hydro generation. The OEB rejected a physical approach to measuring the capital quantity of power distributors in the 3rd GIRM proceeding.

PEG also questions the OHS decay specification that LEI used in its productivity study. The trend in the capital quantity from each annual cohort of total plant additions is what matters in the study. We show that this quantity tends to decline gradually in contrast to the constant quantity until retirement assumed by OHS. LEI's OHS approach also abstracts from the impact on utility cost trends of depreciation in the value of assets as they age and physically decay.

PEG's Alternative Productivity Trend Study

Given our concerns about LEI's methods and the impracticality of correcting their study to get satisfactory results, we prepared our own study of the hydro generation productivity of 20 U.S. utilities. Generation capacity was the output variable and a monetary method assuming geometric decay was used to measure capital costs and quantities. The full sample period was the 28 growth rate years from 1997 to 2024. We found a pronounced decline in the productivity growth of the sampled hydro generators during this period. Over the most recent fifteen growth rate years for which data were available (2010-2024), the trend in the hydroelectric TFP of our sampled utilities averaged a **0.47%** annual decline. Capital productivity averaged a 0.60% annual decline and O&M productivity averaged a 0.14% decline.

PEG's Productivity Factor Recommendation

PEG has occasionally proposed a negative productivity factor in OEB proceedings, and this is a good proceeding to explain again the reasons it can make sense when there is strong evidence of declining industry productivity that is driven by external business conditions. Productivity is not a pure measure of cost efficiency and can reflect mounting external cost pressures such as an increase in the share of capacity that is quite aged.

In an application to OPG, a negative productivity factor would increase OM&A revenue escalation, but capital revenue escalation would be unaffected using the formula that we set forth in Section 2.1. The supplemental revenue provided by the C factor would fall. OPG would have no legitimate complaint about an implicit stretch factor. Based on this reasoning we note that a **-0.47%** Productivity Factor can make sense for OPG if it is combined with our recommendations for a 0.30% stretch factor and a **0.30%** supplemental capital stretch factor. Consumers would then benefit on balance since capital revenue is much larger than OM&A revenue. Should the panel choose not to approve a negative productivity factor, it may reason that OPG may have taken the implicit stretch factor in proposing a marked increase in its OM&A expenses in 2027 that would then be escalated by I-X.

CIR Plan Design

Section 2.1 of this Appendix updates the mathematical logic for using index research to design IR plans. New sections address negative productivity factors and how to convert revenue caps into price caps. This provides the theoretical foundation for using capacity to measure productivity for use in a price cap index and explains how to just and reasonably integrate negative productivity trends into ratemaking.

2. Statistical Research for ARM Design

In this Section we discuss pertinent principles and methods for using statistical cost research to design attrition relief mechanisms ("ARMs"). We begin by reviewing basic indexing concepts. We next discuss the use of indexing research in the design of rate and revenue cap indexes. This discussion

contains important implications for CIR in Ontario. The section concludes with a discussion of stretch factors. We then discuss some potential contributions of econometric research to rate setting.

2.1. Principles and Statistical Methods for the Design of Indexed ARMs

Basic Indexing Concepts

Input Price and Quantity Indexes

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

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

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

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

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

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

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

This greatly simplifies measurement of some input quantity trends.

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

Productivity Indexes

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

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

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

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

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

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

The scope of a productivity index depends on the array of inputs that are addressed by the input quantity index. A *multifactor* productivity index measures productivity in the use of multiple inputs. These are sometimes called *total* factor productivity indexes even though they rarely address all inputs that a company uses. Some indexes measure productivity in the use of a single class of inputs (e.g., labour or capital). These indexes are sometimes called *partial* factor productivity indexes.

Output Indexes

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

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

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

In designing an output index, choices concerning sub-indices and weights should depend on the way the index is to be used. One possible objective of output research is to study the impact of output on *cost*.⁵ 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.”⁶ 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.⁷ A productivity trend index calculated using a cost-based output index (“*Outputs^C*”) will be denoted as *Productivity^C*.

$$\text{growth } Productivity^C = \text{growth } Outputs^C - \text{growth } Inputs. \quad [6a]$$

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

⁵ 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*.

⁶ The cost elasticity of output *i* is the effect on cost of 1% growth in that output.

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

$$\text{growth Productivity}^R = \text{growth Outputs}^R - \text{growth Inputs}. \quad [6b]$$

Sources of Productivity Growth

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

A second important source of productivity growth is output growth. In the short run, output growth can spur a company's productivity growth to the extent that it has excess capacity. In the longer run, economies of scale can be realized even if capacity additions are required provided that output growth exceeds its impact on cost growth. The realization of scale economies will typically be lower the slower is output growth. Incremental scale economies may also depend on the current scale of operations. For example, larger utilities may be less able than smaller utilities to achieve incremental scale economies from the same rate of output growth. At some level of output, the potential for incremental scale economies may be exhausted.

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

Technological change, scale economies, and X inefficiency are generally considered to be dimensions of operating efficiency. This has encouraged the use of productivity indexes to measure operating efficiency. However, theoretical and empirical research reveals that productivity index growth is also affected by changes in miscellaneous external business conditions, other than input price inflation and output growth, which also drive cost. A clear example for a power distributor is suburban forestation. As forestation increases, productivity growth will tend to slow.

⁸ The seminal paper on this topic is Denny, Fuss and Waverman, *Ibid*.

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.

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

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

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

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

Use of Index Research in ARM Design

Revenue Cap Indexes

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

$$\text{growth Cost} = \text{growth Input Prices} - \text{growth Productivity}^C + \text{growth Outputs}^C.^9 \quad [8]$$

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

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

$$\begin{aligned} \text{Revenue}_t = \text{Revenue}_{t-1} \cdot [1 + \text{growth Input Prices} - (\overline{\text{Productivity}^C} + S) \\ + \text{growth Scale}^C_{\text{Utility}} + Y_t + Z_t] \end{aligned} \quad [9a]$$

where:

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

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

S = stretch factor

The productivity factor (" $\overline{\text{Productivity}^C}$ ") reflects a base growth target for *Productivity*^C that is typically the average trend in the *Productivity*^C indexes of a regional or national sample of utilities. A consistent cost-based output metric is used in the scale escalator and the supportive productivity research. A stretch factor (aka consumer dividend) is often added to the formula which slows revenue cap index growth. This term is discussed further below. The Y and Z variable terms refer to the operations of variance accounts.

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.¹⁰ It then follows that

$$\begin{aligned} \text{growth Cost} &= \text{growth Input Prices} + \text{growth Outputs}^C \\ &\quad - (\text{growth Outputs}^C - \text{growth Input Quantities}) \\ &= \text{growth Input Prices} - \text{growth Productivity}^C + \text{growth Outputs}^C. \end{aligned} \quad [10]$$

⁹ See Denny, Fuss, and Waverman, *op. cit.*

¹⁰ This result is also due to François Divisia.

This derivation provides practitioners with more flexibility as to how productivity growth is measured. For example, if pension and other benefit expenses are accorded variance account treatment they can be excluded from the calculations.

Price Cap Indexes

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

$$growth\ Revenue = growth\ Outputs^R + growth\ Prices^R. \quad [11]$$

Rearranging terms it follows that

$$growth\ Prices^R = growth\ Revenue - growth\ Outputs^R.$$

Assume now that the trend in cost equals the trend in cost growth equals revenue growth. Then

$$trend\ Prices^R = trend\ Cost - trend\ Outputs^R.$$

Recalling the result in [2] it follows that

$$\begin{aligned} trend\ Prices^R &= (trend\ Input\ Prices + trend\ Input\ Quantities) - trend\ Outputs^R \\ &= trend\ Input\ Prices - (trend\ Outputs^R - trend\ Input\ Quantities) \\ &= trend\ Input\ Prices - trend\ Productivity^R \end{aligned} \quad [12]$$

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

$$Prices_t = Prices_{t-1} \cdot [1 + growth\ Input\ Prices - \overline{(Productivity^R + S)} + Y_t + Z_t]. \quad [13]$$

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

Bill determinants can play a large role in output index for $Productivity^R$ research.

Revenue Cap to Price Cap Conversion

Recollecting now the result in [7], note also that

$$growth\ Prices = growth\ Input\ Prices - [growth\ Productivity^C + (growth\ Outputs^R - growth\ Outputs^C)]$$

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

$$Prices_t = Prices_{t-1} \cdot [1 + growth\ Input\ Prices - \overline{(Productivity^C + S + OD)} + Y_t + Z_t] \quad [14a]$$



where

$$OD = \text{Output Differential} = \text{trend Outputs}^R - \text{trend Outputs}^C. \quad [14b]$$

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

Dealing with Negative Industry Productivity Trends

The OEB has been loath to approve negative productivity factors for rate and revenue cap indexes even when the industry productivity trend is demonstrably negative. However, we explained above that productivity growth is not a pure measure of cost efficiency growth and can be slowed by changes in external business conditions. The OEB has long sanctioned automatic rate escalation for one external business condition --- input price inflation --- and has occasionally sanctioned it as well for growth in the number of customers served.

The question then arises why adjustments are ruled out for the net effect on the industry cost trend of *other* external business conditions. If negative productivity factors are eschewed despite industry productivity declines, more utilities will seek a CIR ratemaking treatment. Moreover, utilities may claim that rate and revenue cap indexes contain implicit stretch factors. This weakens the argument for bolstering stretch factors on other grounds such as the need for a supplemental capital stretch factor.

One reason that negative productivity factors may be eschewed is the thought that they might need to be *added* to forecasted capital cost growth under current CIR practice. This problem can be avoided by imposing a restriction on the use of a negative productivity factor to accelerate revenue growth based on a cost forecast as in the following formulas. We begin by noting that CIR commonly entails hybrid attrition relief mechanisms in which there are separate designs for OM&A and capital revenue. Forecasting commonly plays no role in OM&A revenue escalation. It is reasonable then to have revenue escalation indexes that are explicitly separate. The CIR formula for OM&A revenue can then be

$$Revenue_t^{OM\&A} = Revenue_{t-1}^{OM\&A} \cdot [1 + Inflation - (\overline{TFP} + S) + growth Scale^C + Y_t^{OM\&A} + Z_t^{OM\&A}]. \quad [15a]$$

Here \overline{TFP} is the industry TFP trend, be it positive or negative. $Y_t^{OM\&A}$ and $Z_t^{OM\&A}$ designate OM&A costs subject to variance account or Z-factor treatment. The CIR formula for capital can then be

$$Revenue_t^K = Revenue_{t-1}^K \cdot \left(1 + \max \left\{ \begin{array}{l} Inflation - (\overline{TFP} + S) + growth Scale_{Utility}^C \\ growth CK^{Forecasted} - [\overline{TFP} (if\ positive) + S] \end{array} \right\} + Y_t^K + Z_t^K \right). \quad [15b]$$

Y_t^K and Z_t^K designate capital costs subject to variance account or Z factor treatment.

Here are the analogous price cap formulas.

$$Rates_t^{OM\&A} = Rates_{t-1}^{OM\&A} \cdot [1 + Inflation - (\overline{TFP} + S + OD) + growth Scale_{Utility}^C + Y_t^{OM\&A} + Z_t^{OM\&A}]. \quad [15c]$$

$$Rates_t^K = Rates_{t-1}^K \cdot$$

$$\left(1 + \max \left\{ \begin{array}{l} Inflation - (\overline{TFP} + S) + growth Scale_{Utility}^C \\ growth CK^{Forecasted} - [\overline{TFP} (if\ positive) + S] \end{array} \right\} - OD + Y_t^K + Z_t^K \right). \quad [15d]$$

The maximization term determines whether capital revenue should be based on forecasted cost. If \overline{TFP} is negative, less supplemental capital revenue will be needed.

Limitations on Supplemental Capital Revenue

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

- a) A materiality condition could discourage CIR applications when the need for supplemental capital revenue is small. This mechanism could have a dead zone, as do those in the OEB's incremental capital modules.
- b) Capital revenue growth less than forecasted capital cost growth can strengthen capital cost containment incentives and guard against the risk to customers that information asymmetries prompt utilities to file bloated capital cost forecasts.

Both of these concerns can be addressed by adding a supplemental capital stretch factor S_k to the formula. In the case of revenue caps, for instance

$$Revenue_k^K = Revenue_t^K \cdot \left[1 + \max \left(\begin{array}{l} [Inflation - (\overline{TFP} + S) + growth Scale_{Utility}^C], \\ \{growth CK^{Forecasted} - [\overline{TFP} \text{ (if positive)} + S + S_k]\} \end{array} \right) + Y_t^K + Z_t^K \right]. \quad [15e]$$

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

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

$$Revenue_t = Revenue_{t-1}^K \cdot \left\{ \begin{array}{l} 1 + Inflation - (\overline{TFP} + S) + growth Scale_{Utility}^C \\ + \alpha \cdot [growth CK^{Forecasted} - (Inflation - \overline{TFP} + growth Scale_{Utility})] \end{array} + Y_t^K + Z_t^K \right\}. \quad [15f]$$

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

Dealing with Cost Exclusions

If the multiyear rate plan provides for certain costs to be addressed by variance accounts, the index logic detailed in the derivation of relation [10] similarly provides the rationale for excluding these costs from the productivity research. This principle is widely (if not unanimously) accepted, and some costs that are frequently accorded variance account treatment in multi-year rate plans (e.g., costs of energy, CDM, and pensions and other post-employment benefits) are frequently excluded from the supportive productivity studies.

Inflation Factors

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

Relation [8] can be restated as:

$$\begin{aligned} \text{growth Cost} &= \text{growth Input Prices} - \text{growth Productivity}^C + \text{growth Outputs}^C + (I - I) \\ &= I - [\text{growth Productivity}^C + (I - \text{growth Input Prices})] + \text{growth Outputs}^C. \end{aligned} \quad [16]$$

Relation [16] shows that cost growth depends on the I factor, growth in operating scale and productivity, and on the difference between I and utility input price inflation. This difference, which is found in parentheses, is sometimes called the “inflation differential.”

The GDPPI is the U.S. government’s featured index of inflation in the prices of the economy’s final goods and services.¹¹ It can then be shown that the trend in the GDPPI equals the difference between the trends in the economy’s input price and multifactor productivity (“MFP”) indexes.

$$\text{growth GDPPI} = \text{growth Input Prices}^{Economy} - \text{growth MFP}^{Economy}. \quad [17]$$

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

$$[(\overline{\text{Productivity}}^C - \overline{\text{MFP}}^{Economy}) + (\overline{\text{Input Prices}}^{Economy} - \overline{\text{Input Prices}}^{Industry})]. \quad [18]$$

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

Relation [18] has been the basis for the design of several approved X factors in multi-year rate plans in the United States.¹² Since the TFP 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. TFP growth has historically been considerably slower for Canada’s economy, and macroeconomic price indexes are less frequently the sole inflation measures used in rate and revenue cap indexes.

¹¹ Final goods and services include consumer products, government services, and exports.

¹² 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.

Choosing a Productivity Peer Group

Research on the productivity of other utilities can be used in several ways to calculate base productivity growth targets. Using the productivity trend of the entire industry to calibrate X is sometimes likened to simulating the outcome of competitive markets. A competitive market paradigm has broad appeal. Industry productivity trends are usually not very sensitive to results for a handful of utilities.

On the other hand, individual firms in competitive markets routinely experience windfall gains and losses.¹³ Our discussion above of the sources of productivity growth implies that differences in the external business conditions that drive productivity growth can cause utilities to have different productivity trends.¹⁴ There is thus considerable interest in the ratemaking community in methods for customizing base productivity growth targets to reflect local business conditions. The most common approach to customization has been to use the productivity trends of a peer group of similarly situated utilities.

A variety of potential peer groups are usually available. In choosing among these, the following principles are appropriate. First, the group should either exclude the subject utility or be large enough that the average productivity trend of this utility is substantially insensitive to its actions. This may be called the externality criterion. It is desirable, secondly, for the group to be large enough that the productivity trend is not dominated by the actions of a handful of utilities. This may be called the sample size criterion. A third criterion is that the group should be one in which external business conditions are as propitious to productivity growth as those facing the subject utility. This may be called the “no windfalls” criterion. Relevant conditions for a hydroelectric generator include system age, growth in operating scale, and the volume/capacity trend.

¹³ Farmers, for example, experience varied weather conditions and varied needs to replace aging structures and equipment but nonetheless contend with prices set in national or global markets.

¹⁴ Generators experiencing brisk growth in operating scale are more likely to realize economies of scale than generators experiencing average growth.

Customizing Rate and Revenue Cap Indexes

We discussed above how external business conditions affect the pace of utility productivity growth. The issue then legitimately arises as to how rate and revenue cap indexes could be customized to better reflect local business conditions that drive productivity growth. Such a customization could reduce a utility's operating risk without weakening its performance incentives.

Productivity factors in approved ARM formulas for several New England energy distributors have been based on the TFP trends of utilities in the northeastern states rather than the United States as a whole. The X factors in the 4th GIRM of power distributors reflect the TFP trends of Ontario distributors.

Formulas [14a-14b] suggest another straightforward customization for the situation in which the chief concern about the use of a certain peer group is that its output differential differs greatly from that of the subject utility. In that case, the productivity trend of the peer group can be calculated using $Productivity^C$ and the OD term can be company specific. An example is

$$Prices_t = Prices_{t-1} \cdot [1 + growth\ Input\ Prices - \overline{(Productivity^C + S)} + Outputs^C_{Utility} - Outputs^R_{Utility} + Y_t + Z_t]. \quad [19]$$

Both $Output$ growth terms in the formula can if convenient be forecasted. Absent only the input price differential, this is similar to the formula that Alectra Utilities recently proposed for its OM&A price cap.¹⁵

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 retail electric customers were served by distributor A and 20% were

¹⁵ EB-2025-0252, Exhibit 1, Tab 11, Schedule 2.

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.

Measuring Capital Costs and Quantities

The capital cost ("CK") specification is critical in statistical research on the cost and productivity trends of energy utilities because their production technologies are capital intensive. Monetary approaches to capital price and quantity measurement are conventionally used in North American utilities. These approaches permit the decomposition of capital cost into a consistent capital quantity index ("XK") and capital price index ("WK") such that

$$CK = WK \cdot XK. \quad [20]$$

The growth rate of capital cost then equals the sum of the growth rates of the capital price and quantity indexes, a result that is needed for capital and total factor productivity trend research.

$$\text{growth Cost}^{Capital} = \text{growth Price}^{Capital} + \text{growth Quantity}^{Capital}. \quad [21]$$

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. The trends in these costs depend on trends in asset prices, tax rates, and the market rate of return on capital. A capital price index should reflect these trends.

In U.S. electric utility cost research, Handy Whitman indexes of electric utility construction costs are commonly used as the asset price indexes. Capital prices are calculated from these same construction cost indexes and from data on the rate of return on capital.¹⁶ Indexes of construction cost trends that are specific to the electric utility industry have not been available in Canada for many years.

The capital quantity index is typically calculated using formulas that deflate data on plant value using asset price indexes. The quantity added in a study that uses a monetary approach each year is added to the quantity available at the start of the period. These formulas may also provide for some decay over time in the capital quantity that results from each plant addition. Decay can result from many factors that include wear and tear, casualty loss, increased maintenance requirements, technological obsolescence, and a decline in the service life of an asset. The pattern of decay in the quantity from assets over time is sometimes called the age-efficiency profile. These formulas are sometimes called perpetual inventory equations.

Most of the established monetary approaches used in utility cost research are based on the assumption 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 (aka “rental”) 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 can then be interpreted as the annual cost of using the flow of services.

Alternative Monetary Approaches

Several monetary methods for measuring capital cost have been established. A key issue in choosing between these methods is the pattern of decay in the quantity of capital that results from the plant additions that are made each year. Another issue is whether plant is valued in current (aka

¹⁶ If taxes are included in the study, capital prices are also a function of tax rates.

replacement) dollars or in the historical dollars typically used in utility accounting. Replacement valuation is typically well above historical valuation and is more sensitive to construction cost inflation. Cost is therefore often computed net of capital gains.

Here are brief descriptions of the monetary methods that have been most commonly used in research to design rate and revenue cap indexes.

1. **Geometric Decay (“GD”)** The GD method is one of those in which the capital quantity is treated as the flow of services from plant additions in a given year. The service flow from groups of assets to which it is applied is assumed to decline at a constant rate over time. Plant is valued in current (aka replacement) dollars. The capital price is a service price that reflects these assumptions. The GD specification involves formulae for capital price and quantity indexes that are mathematically simple and easy to code and review.

Academic research has supported use of the GD method to characterize depreciation in many industries, and GD has been widely used in productivity studies, including X factor calibration studies.¹⁷ PEG has used the GD method in most of its productivity research for the OEB staff, including the research for 4th GIRM. Statistics Canada uses geometric decay as the default approach to the measurement of capital stocks in the national income and product accounts.¹⁸

2. **Hyperbolic Decay (“HD”)** 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

¹⁷ See, for example, C. Hulten, and F. Wykoff (1981), “The Measurement of Economic Depreciation,” in *Depreciation, Inflation, and the Taxation of Income From Capital*, C. Hulten ed., Washington D.C. Urban Institute and C. Hulten, “Getting Depreciation (Almost) Right”, University of Maryland working paper, 2008.

¹⁸ The BEA states on p. 2 its November 2015 “Updated Summary of NIPA Methodologies” that “The perpetual-inventory method is used to derive estimates of fixed capital stock, which are used to estimate consumption of fixed capital—the economic depreciation of private and government fixed capital. This method is based on investment flows and a geometric depreciation formula.”



valuation of plant. The annual cost of capital is therefore often computed net of capital gains. The capital price is a service price which reflects these assumptions.

Hyperbolic decay has in recent years been used in a few North American X factor and utility benchmarking studies. HD is also used in sectoral studies of the economy by the governments of the United States and Australia.

3. **One-Hoss-Shay (“OHS”)** Under the OHS method, the flow of services from a group of assets to which it is applied is assumed to be constant until the end of their service lives, when it abruptly falls to zero. This is the pattern that is typical of a light bulb. Plant is once again valued at replacement cost and cost is therefore often computed net of capital gains. The design of the capital service price is consistent with the OHS assumption. OHS has been used in a number of utility productivity trend studies intended to help determine a productivity factor.
4. **Cost of Service (“COS”)** The GD, HD, and OHS approaches to calculating capital cost all use assumptions that are quite different from those used to calculate capital cost under traditional cost of service ratemaking.¹⁹ 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.

An alternative COS approach to measuring capital cost has been developed by PEG that is so-called because it is based on 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 is not 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

¹⁹ The OHS assumptions are more markedly different.

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 asset price or construction cost indexes from earlier years and assumptions about the historical plant addition pattern. The year for which this estimate is undertaken is commonly called the “benchmark year” of the capital quantity index. The estimate of the capital quantity in the benchmark year is inexact because we don’t know the vintages of the assets. It is therefore 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 impractical.

2.2. Stretch Factors

Rationale

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

The difference between the productivity trend of the peer group and the subject utility also depends on the utility’s operating efficiency at the start of the MRP. If a company is found to be inefficient, for example, it may take many years to fully rectify the problem. A stretch factor ensures customers the benefit of improving cost management whether or not it occurs. If a company is already quite efficient, it has less potential to exceed the industry productivity trend.

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

- A stretch factor linked to statistical benchmarking focused on costs incurred in the later years of an expiring rate plan and/or the proposed costs for a new plan can serve as an efficiency carryover mechanism. The current total cost benchmarking (“TCB”) program in Ontario, for example, can reward a utility for its efforts to lower future costs with a lower stretch factor.
- In the context of CIR, a stretch factor that slows growth in capital revenue escalation that is otherwise based on a capital cost forecast strengthens cost containment incentives even if it isn’t linked to benchmarking.
- Utilities operating under MRPs sometimes slow cost growth in early plan years only to accelerate growth in later years in a way that can deny customers benefits. A stretch factor is one means of sharing with customers the benefits of cost savings that are achieved. The alternative of adding an earnings sharing mechanism to the plan entails weaker cost containment incentives.
- A stretch factor can also be warranted to address overcompensation concerns that result from supplemental capex funding but are difficult to measure accurately. These concerns are discussed in PEG’s framework report.

Role of Benchmarking

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



Notable Stretch Factor Precedents

Ontario

The OEB is now in its fourth generation of IR for electricity distributors. IR is also used for gas distributors and electricity transmitters. In each generation, IR has featured MRPs with rate or revenue cap indexes. In both the third and fourth generation generic plans, the X factor term in the formulas for these indexes has been the sum of a base TFP growth target and a stretch factor that is linked mechanistically to benchmarking results. Each distributor’s stretch factor depends on its average econometric benchmarking score over the three most recent years. As detailed in the figure below, the best cost performers get a stretch factor of zero while the worst get a stretch factor of 0.60%.²⁰ Additionally, distributors are required to use the OEB’s econometric model to benchmark their forward test year cost proposals in rate cases.²¹

Ontario Energy Board Stretch Factor Assignments

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

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

Larger Ontario electricity distributors, along with the largest power transmitter in the province, typically operate under an alternative approach to PBR called CIR. This approach also usually features

²⁰ 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.

²¹ *Ibid*, pp. 19-20.

MRPs with rate or revenue cap indexes that have formulas with X factors. CIR stretch factors are typically linked to custom econometric benchmarking studies that use multijurisdictional (specifically U.S. and Ontario) data.

Massachusetts

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

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

Determination of Consumer Dividend ("CD") in the National Grid (MA) PBR Adjustment Formula¹

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.

¹National 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.

3. Useful Background

3.1. Overview

OPG is Ontario's largest electric power producer, typically accounting for roughly half of all generation in the province. The Company, wholly owned by Ontario's government, was established in 1999 to own and operate generating stations of Ontario Hydro after that company's breakup. OPG's numerous hydro generating stations are scattered across the province. Hydro generation plays an important role in Ontario's Integrated Energy Plan. The Company also owns extensive nuclear generating capacity and some gas-fired and bio-fueled generating stations.

Section 78.1 of the Ontario Energy Board Act authorizes the Board to set payment amounts for power produced from prescribed generation assets of OPG. Six large hydroelectric generating stations were prescribed for Board regulation in 2005.²² The largest of these are located in the Niagara region [e.g., Sir Adam Beck ("SAB") 1 and 2]. Another 48 hydroelectric stations were prescribed for OEB regulation effective in 2014.²³ These were smaller stations. In total, more than 6,500 MW of hydroelectric generating capacity was subject to OEB rate regulation in 2025.²⁴

OPG also owns some hydroelectric stations with unregulated terms of sale. Power generated from these stations is mostly sold under contracts. Most of these contracts are Energy Supply Agreements ("ESAs") with the Independent Electricity System Operator ("IESO").

From 2017 to 2021, the Company's hydro payments were governed by an IR framework established in EB-2016-0152 that featured a price cap index. OPG's price cap index proposal in that proceeding was supported by productivity research from LEI. PEG addressed this research on behalf of OEB staff and methodological controversies ensued. The appropriate ways to measure trends in operating scale and capital inputs were key issues. LEI found industry TFP growth to be materially

²² Ontario Regulation 53/05 filed February 2005.

²³ Ontario Regulation 312/13 filed November 2013.

²⁴ A1-Staff-285, Attachment 2.



negative while PEG found it to be slightly positive. Navigant provided cost benchmarking evidence. The approved productivity factor was 0% while the approved stretch factor was 0.30%.

From 2022 to 2026, OPG's hydro payment rate was frozen but the Company was able to obtain supplemental capital revenue from a variance account. OPG's Annual Regulatory Returns for 2022-2024 suggest that the Company overearned on its hydro assets in each of these years.

OPG has in proceeding EB-2025-0297 proposed a Custom Incentive Rate-setting ("CIR") plan to determine payment amounts for its power sales from prescribed hydro facilities. LEI has provided supportive statistical cost research for the proposed plan. Here are some provisions of the Company's hydro IR proposal that have a bearing on the benchmarking and productivity trend research. More details can be found in PEG's Framework Report.

- The term of the plan would be the five years from 2027 to 2031.
- Rates for 2027 would result from a cost of service rebasing using a fully-forecasted test year.
- Base rates in the last four years of the plan would be escalated by a "price cap" index with the following growth formula

$$HPA_t = HPA_{t-1} \times [1 + (I - X + C - GRCF)].$$

Here is an explanation for the terms in this formula.

- HPA is a hydroelectric payment amount.
- *I* would be a time-variant inflation factor that is a cost-weighted average of recent historical inflation in Canada's Gross Domestic Product Implicit Price Index - Final Domestic Demand and the Average Weekly Earnings for Ontario – Industrial Aggregate. The proposed weights for these two inflation subindexes would reflect generation industry costs and be based on LEI calculations.
- *X*, the X factor, would be the sum of a fixed 0% Productivity Factor supported by LEI industry productivity trend evidence and a fixed Stretch Factor of 0.15% that is supported by LEI econometric benchmarking evidence.



- C would be a fixed time-variant Custom Capital Factor that is portrayed as providing the supplemental revenue needed to fund the Company's capital projects.
- GRCF is a GRC Factor that would adjust rate escalation so that the revenue requirement for gross revenue charges ("GRC") and other water agreement costs are constant over the IR term.

The C factor and the GRCF together effectively produce an attrition relief mechanism for the last four years of the plan that has a hybrid design.

- Allowed capital revenue would be escalated for the forecasted growth in OPG's capital-related revenue requirement ("CRRR") less the X factor. The CRRR would be based on traditional capital cost accounting.
 - The revenue requirement for GRC-related costs would, non-controversially, be frozen.
 - The revenue requirement for other OM&A expenses would be escalated using the $I - X$ formula.
- An Earnings Sharing Mechanism ("ESM") would asymmetrically share any cumulative earnings for the combined regulated hydroelectric and nuclear operations over the five years of the plan that exceed the established return on equity target by 100 basis points 50/50 between the Company and its customers.
 - A Gross Hydroelectric Capital Variance Account ("GHCVA") would asymmetrically return to customers any cumulative positive difference between the proposed revenue requirement for capital and actual capital cost during the plan term.
 - A Capital-Refurbishment Variance Account ("CRVA") would address variances, positive and negative, between actual and forecasted cost of increasing the output of, refurbishing, or adding operating capacity to a prescribed generation facility.
 - Costs eligible for deferral and/or variance account treatments that are separate from the price cap index would include pensions and other post-employment benefits and changes in the costs of Gross Revenue Charges due to deductions or changes in legislation or regulation.



3.2. Economics of Hydroelectric Generation

Special features of the hydro generation business should be considered in statistical cost research supporting the design of a CIR plan for OPG. We start by noting that hydro generation is unusually capital-intensive even for an energy utility business. The required plant includes generating equipment (e.g., turbines and generators), extensive civil works (e.g., powerhouses, dams, headworks, and spillways), and buildings to house control rooms, work centers, and offices. This has a number of implications.

- The cost and productivity trends of hydro generators are unusually sensitive to the importance of older plant (which is gradually depreciating) relative to the need for capex. High capex can cause costs to surge, especially when capital cost is calculated using traditional regulatory accounting and the average age of assets is high. In the years following a capex surge, however, cost growth can be unusually slow for many years. Vertically-integrated electric utilities in the United States have on many occasions operated without rate cases for several years after major generating plant additions (e.g., new solid-fuel power plants).
- In a capital-intensive business, containment of capital cost is critical to good cost management.
- The OM&A and (especially) replacement capex of hydro facilities tend to rise as they age. A preponderance of older plant creates a steady stream of opportunities to repair, refurbish, and replace facilities. Replacement becomes rational when the net present value of the O&M cost savings require for an asset exceeds the net present value of the stream of incremental capital costs that capex gives rise to. Utilities nonetheless have considerable discretion as to when hydro generation facilities are refurbished or replaced.

Civil structures such as dams and waterways have unusually long service lives. High capex to replace such assets have to date been rare. The service lives of generators and other equipment used in hydro generation are much shorter. It follows that once a hydro generating plant has been completed, the nature of its ongoing capex changes abruptly. In its 2016-2017 CIR proceeding, OPG stated in response to an interrogatory that



Replacement capital in hydro operations is typically limited to mechanical and electrical parts; the majority of the asset base, roughly 75%, consists of civil works that is rarely “replaced”.²⁵

The subsequent plant additions tend to have a much higher rate of decay and depreciation.

Hydroelectric generation volumes (especially those from run of river facilities) vary with water flows. These flows vary in the short run with weather and in the longer term with climate trends. The cost of owning, operating, and maintaining hydroelectric stations does not vary greatly with volume fluctuations.

The sourcing of water for hydro generators varies. Many use water that has been impounded in reservoirs by dams. Others use water from a flowing river, canals, and/or conduits.

3.3. Special Circumstances of OPG

We should also consider special circumstances of OPG. Here are some salient ones.

- Many of OPG's hydroelectric stations are old. Fourteen have operated for over a century. Most of the Company's hydro generation equipment is more than 50 years old.
- Before its restructuring in 1999, Ontario Hydro's generation assets were valued in historic dollars. However, property, plant, and equipment acquired by OPG in 1999 were recorded at a fair value that reflected the present value of estimated future operating results and cash flows of the acquired business in a deregulated market.²⁶ The net value of OPG's hydroelectric generation assets rose substantially. Plant additions have subsequently been recorded at cost.
- OPG has limited opportunities to increase the scale of its prescribed hydro operations. Some modernization projects increase the generating volume or capacity at existing stations. For example, between 1996 and 2005, OPG completed a series of major upgrades at SAB 2 that increased its potential generating capacity by 194 megawatts. More recently, the Niagara Tunnel Project (“NTP”) expanded the water flow to SAB 1 and 2. This has increased the

²⁵ OPG Response to Staff-233, p. 2.

²⁶ A discussion of this is found in the Summary of Significant Account Policies in OPG's *Annual Report 2000*, pp. 22-23 and 40.

generation volume. There are also some opportunities to build new generation capacity, but these units may not be prescribed. The limited prospects for growth in OPG's prescribed hydroelectric capacity suggests that opportunities to realize incremental scale economies are limited.

- The revaluation of older plant combined with the large recent NTP plant addition tends to slow OPG's capital cost growth and its need for rate growth by magnifying costs that are declining gradually due to depreciation.
- The large number of hydroelectric stations that OPG owns tends to reduce the impact of individual capex projects on the Company's cost and productivity.²⁷ The impact on total cost tends to be greatest for major capital projects at the largest stations. Cost could also, in principle, surge if several smaller stations were refurbished simultaneously.
- The SAB pumped-storage generating station ("GS") is capable of large diurnal swings in generation volumes. Power can be used to pump water to the storage reservoir when prices are low in the bulk power market and produced and sold when these prices are high. Most other OPG hydroelectric stations have some ability to vary generation volumes diurnally, and many operate as baseload units.
- The IESO periodically orders reductions in OPG's hydroelectric generation to manage surplus baseload generation ("SBG"). When cutbacks are ordered, OPG is sometimes compelled to spill water from its facilities rather than save it for future generation.
- PEG understands that a sizable share of OPG's staff is located in the Toronto metro area, a region with high costs.

²⁷In much the same manner, the percentage cost impact of replacing a power distribution substation is much lower for a distributor with fifteen substations than it is for one which has one.

4. Statistical Research on Power Generation Cost

4.1. Sources of Generator Operating Data

In statistical benchmarking and productivity research supporting the selection of X factors and revenue requirements for Ontario utilities a choice must be made of how much to rely on data from other countries and Canadian jurisdictions. The problem is magnified in the case of hydroelectric generation since no peer for OPG exists in Ontario and is subject to OEB reporting requirements. All of the benchmarking and productivity trend peers must therefore come from other jurisdictions. In the case of benchmarking, adding data from multiple jurisdictions increases sample size, can add suitable peers for Ontario utilities, and increases the diversity of business conditions that are faced by sampled utilities. The accuracy of benchmarking models is aided to the extent that the subject utility is not an outlier, and a large and diverse sample aids econometric model development.

However, utilities in other jurisdictions may provide different services, and data may not be readily available on certain business condition variables or certain costs that we wish were itemized. Many jurisdictions lack the many years of standardized data on the value of utility plant that are needed for the monetary approach to the calculation of capital costs and quantities.

LEI explains in its reports why it is not practicable to include data in its hydroelectric benchmarking and productivity trend studies from most other Canadian hydro generators and some U.S. generators. The lack of standardized data gathering on utility operations by Canada's federal government is a key problem. The unavailability of data needed to compute capital costs and quantities using monetary methods is another problem. In the balance of this section, we consider strengths and weaknesses of data available from OPG and the United States hydro generators.

OPG Data

Let's begin by considering the strengths and weaknesses of data that are available on operations of OPG and the Company's external cost drivers.

Major Advantages

- Roughly two decades of standardized data are electronically available on OPG's costs.

- Itemization of cost data facilitates the removal of some costs (e.g., water for power and administrative and general expenses) that may complicate research.
- Pension and other benefit expenses are also itemized beginning in 2016. These expenses are frequently excluded from statistical benchmarking studies of utility cost. Reasons include their sensitivity to volatile financial market conditions and their dependence on a distributor's past financial commitments to retired workers. The pension and benefit expenses of OPG are itemized for easy removal.

The inclusion of pension expenses also complicates calculation of a labour price "patch" between Canada and the United States, where pension and benefit obligations of many utilities are quite different. In Canada, an additional problem with including pension and benefit expenses in cost research is the lack of federal government labour price indexes that address these expenses as well as salaries and wages.

- Good data are available for some important drivers of hydro generation cost including generation volume and capacity, the age of assets, and wage rate trends.

Major Disadvantages

Major disadvantages of the available data on OPG and its business conditions include the following.

- OPG is the dominant hydro generator in the province, so a peer group must be developed from other jurisdictions.
- The valuation of assets that OPG acquired from Ontario Hydro in 1999 was raised substantially so as to reflect their market value in sales to bulk power markets. This greatly complicates measurement of capital costs and quantities using monetary methods.
- OPG owns numerous step-up transformers at its hydroelectric generation stations. In the United States, the capital costs and OM&A expenses associated with such transformers would be classified as transmission expenses and these transmission expenses are insufficiently itemized to be combined with generation costs in benchmarking or productivity trend studies for this proceeding. The Company has indicated that the proportion of property, plant and



equipment associated with step up functions was approximately 2.5%.²⁸ This provides the basis for a sensible data adjustment for the benchmarking work.

- We are unaware of a reliable and publicly-available index of Canadian hydro generation construction costs. In this study, the use of hydro generation construction cost indexes from the United States has as a consequence been explored.

U.S. Data

Overview

The U.S. government has gathered detailed data for decades on the operations of “major” investor-owned electric utilities (“IOUs”). Some of these are hydroelectric power generators. The primary source of data of the cost of these utilities is Federal Energy Regulatory Commission (“FERC”) Form 1.

Hydro generation is also undertaken on a sizable scale by publicly-owned agencies at the federal level (e.g., Western Area Power Administration), municipal level (e.g., Seattle City Light), and public utility district level (e.g., Chelan County PUD). A few of these operate on a scale similar to OPG’s.

Major Advantages

U.S. data have major advantages in the benchmarking of OPG.

- Many years of standardized data are available on FERC Form 1 on the operations of more than 15 utilities engaged in hydroelectric generation.
- OM&A and capital costs of hydraulic power production are itemized on FERC Form 1. A Uniform System of Accounts encourages cost data standardization.
- PEG has gathered data, from FERC Form 1 and antecedent forms, on the net value of hydro generating plant (and other kinds of plant) of IOUs in 1964 and the corresponding gross plant additions since that year. This bolsters the accuracy of capital cost and quantity calculations using monetary methods.

²⁸ A1-Staff-329, part g.

- FERC Form 1 data are also available on hydro generation volumes and some important characteristics of hydro generation facilities. Additional data on hydroelectric generation operations are available on Form EIA 860.
- Extensive itemization of cost data facilitates removal of some costs that are inconvenient for a benchmarking study. For example, we can if desired remove costs of water for power and pensions and other benefits, other administrative and general expenses, and general plant. Removal of these costs is encouraged by the fact that only a small share of them is typically attributable to hydro generation.
- Handy Whitman indexes have been available for many years on regional trends in the costs of constructing hydraulic production plant. Custom indexes can also be purchased (albeit at substantial cost) on trends in prices that generators face for materials and services.

Major Disadvantages of U.S. Data

There are, however, some major disadvantages to using U.S. data in a statistical benchmarking study of OPG's costs.

- U.S. cost data are denominated in U.S. dollars, making it harder to accurately compare prices of generator inputs in the U.S. and Canada.
- The data needed to calculate capital costs using monetary methods are not readily available for publicly owned hydroelectric generating companies, which do not file FERC Form 1 data.
- Unfortunately, the publicly-owned companies include those with hydro generation operations that are as large or larger than those of OPG. OPG is consequently a size outlier compared to our U.S. sample.
- Since only twenty U.S. generators met our minimum-size criterion for inclusion in our study, the sample available for econometric model estimation is much smaller than that available for gas or electric power distribution to measure industry productivity trends or develop econometric benchmarking models.



Other Disadvantages

- IOUs with hydroelectric generation typically generate power by other means and also provide power transmission and distributor services. Some U.S. IOUs also provide gas as well as electric service. This complicates determination of the cost of A&G expenses that can reasonably be allocated to hydro generation. However, this won't matter if A&G expenses are excluded from the model.
- Breakdowns of OM&A expenses into those for labour and other inputs are available for *total* power production but not for *hydraulic production* specifically.

Resolution

Given the limitations of Canadian data and the advantages of U.S. data, it makes sense to rely on U.S. data for the hydro generation cost benchmarking and productivity trend studies in this proceeding. The OEB has previously accepted this approach in designing CIR plans for OPG, Ontario gas utilities, and Hydro One's transmission services. The OEB also used estimates of U.S. power distributor productivity trends to choose the base productivity growth target in its 3rd GIRM for power distributors and has often used U.S. power distributor peers to appraise the proposed cost of distributors in Custom IR applications. Regulators in Alberta and British Columbia have based X factors in IR plans for gas and electric power distributors on the productivity trends of U.S. distributors and have considered benchmarking comparisons to U.S. distributors.

5. LEI's Benchmarking Evidence

5.1. Summary of LEI's Evidence

The approved settlement in OPG's last payment amounts proceeding required the Company to file a "total cost benchmarking" study with its next payment amounts application if it proposed an IRM or CIR plan. LEI prepared the study for this proceeding and OPG proposes to use it as the basis for its proposed stretch factor.

The operating data for LEI's study were drawn chiefly from a database developed by the Electric Utility Cost Group ("EUCG") Hydroelectric Productivity Committee. According to LEI, this is a nonprofit organization formed in 1973 by several utilities. LEI further states that "rigorous policies and guidelines



for data submission by EUCG members and methodical collection and data validation practices ensure that the data is consistent across operators.”²⁹ Participation in EUCG’s program is voluntary and LEI has entered into a non-disclosure agreement (“NDA”) that limits sharing of the data with non-participants.

LEI developed single-equation econometric cost models for two groups of hydro generation costs: OM&A expenses and these same expenses plus capital expenditures for “sustaining plant capability.” OM&A expenses included those for administration and “project-related” O&M (non-recurring major operations). LEI explains that sustaining capital expenditures are

driven by the need to maintain existing assets in good running condition. They usually include equipment replacement and may or may not include technical improvements that extend equipment useful life.³⁰

Sustaining capital expenditures exclude those associated with improvements and additions to generation capacity.

Data were drawn from 13 EUCG participants that included OPG. Most participants were U.S. utilities but there was one additional Canadian utility. The data were gathered at the plant rather than the aggregate company level. LEI used data from 253 individual hydroelectric production units. The sample period for the estimation of both models was the four years from 2020 to 2023. In all, the data set contained 1,012 observations.

Each model that LEI developed had several business condition variables. These included one or more input price indexes, the capacity of each generation unit, and a trend variable. Each model also included a binary variable for each sampled company except OPG. The binary variables estimate the net effect on each utility’s cost of its efficiency and any business condition variables that were excluded from the model. The average value of the parameter estimates for these binary variables affords an estimate of the net impact of efficiency (and any excluded relevant variables) on OPG’s costs during the four years of the sample period. A negative value is good while a positive value is bad. This form of inference is uncommon in benchmarking studies used to set stretch factors in Ontario.

²⁹ LEI Benchmarking Report, p. 5

³⁰ LEI Benchmarking Report, p. 6.

LEI reports that OPG's score for OM&A expenses was -42%. This was a top quintile performance. OPG's score for OM&A expenses and sustaining capital expenditures was -15%. This was a second quintile performance.

Using the table that the OEB has developed to assign stretch factors based on benchmarking results, LEI recommends a stretch factor in the [0, 0.15%] range. OPG proposes a 0.15% stretch factor.

5.2. PEG Critique

Strong Points

LEI's benchmarking work has several positive features.

- They measured cost performance econometrically rather than using simple unit cost indexes.
- Quadratic scale variables controlled for possible scale economies.
- There is some merit in focusing on OM&A expenses and sustaining capex, even if total cost performance should also be examined if practicable.
- The EUCG dataset has some quality control advantages.
- Purchasing power parities rather than exchange rates were used to compare prices in the U.S. and Canada.

Chief Concerns

Here are our chief concerns about LEI's benchmarking evidence.

- Details of the study that include the data used cannot be shared with PEG or other parties to this proceeding due to the non-disclosure agreement that LEI signed with EUCG. This has greatly complicated appraisal of this work by PEG and other parties even though we were willing to sign a confidentiality agreement. LEI even refused to identify the names of sampled companies in response to A1-Staff-283 c). In response to A1-CCC-008, LEI blamed the NDA for its refusal to thoroughly explain what it meant by "sustaining capability" capex.
- Forecasted costs were not benchmarked. LEI stated in response to A1-Staff-282 d) that

This was outside of LEI's scope and workplan for the total cost benchmarking analysis. As explained on page 9 of the benchmarking report, the goal of LEI's benchmarking analysis was to analyze the relative efficiency of the regulated entity (OPG) compared to other peers in the hydroelectric generation industry in order to recommend a stretch factor. LEI believes that use of recent actual data, rather than forecasts, is preferred to address this objective.

However, the OEB bases the stretch factors of distributors operating under 4th GIRM on annually-updated benchmarking studies. Moreover, CIR applicants commonly benchmark their forecasted cost in the bridge year and first year of the plan and the proposed revenue requirement during the out years of the plan. This practice reduces the incentive for utilities to propose rapid revenue escalation during the plan. OPG proposes a dramatic surge in OM&A expenses in the first year of its plan.

- LEI's benchmarking method does not permit appraisal of the *trend* in OPG's cost efficiency. Measurement of such trends is straightforward using the econometric cost benchmarking methods that are customarily featured in studies submitted in Ontario IR proceedings. LEI acknowledged in response to A1-Staff-282 c) "that there are econometric approaches that *can* establish the trend in cost efficiency over time on either on a total cost basis... However, that was not the intent of the LEI benchmarking analysis."
- The benchmarking scores are effectively average scores for OPG's numerous hydro units and are not size-weighted, as LEI confirmed in its response to A1-Staff-282 g) iii. It is therefore possible that OPG scores so well thanks to its performance in managing numerous smaller facilities rather than the large facilities on the Niagara and St. Lawrence rivers that matter most to customers. Econometric total cost benchmarking studies customarily used in Ontario IR are implicitly size-weighted.
- LEI benchmarks OM&A expenses plus certain capital *expenditures*. Sustaining capex was included, but another important capex category, that for improvements and additions to plant capability, was excluded. About 75% of OPG's total capital expenditures for the 2020-2023



period were sustainment capital.³¹ In contrast, the OEB typically relies on total cost benchmarking studies to set stretch factors. These studies consider the *total annual* cost of capital (e.g., depreciation expenses and the return on rate base for all kinds of capital). Thus, LEI's study is arguably not a total cost benchmarking study and is not fully compliant with the provisions of the above-mentioned settlement.

- Pensions and benefits and payroll taxes were included.³² Pension and other benefit expenses are frequently excluded from statistical benchmarking studies submitted in OEB proceedings because they can be volatile and are hard to compare between U.S. and Canadian utilities.
- The input price *levels* of utilities can differ quite a bit at each point in time. Labor prices in California, for instance, tend to be materially higher than those in Alabama. It is accordingly customary in benchmarking studies submitted by utility and staff consultants alike in Ontario IR proceedings to account for differences in these levels at a particular point in time, a process that we call price "levelization". It does not seem that LEI leveled their input price indexes for sampled U.S. utilities at a point in time.³³
- LEI did not use the readily available and inexpensive U.S. Handy Whitman construction cost indexes for hydraulic production plant to deflate capex in its capex modelling. LEI said that they believed that use of the Handy Whitman indexes "would have required adjustments" if used in the studies.³⁴
- Neither the OM&A price nor the capital price have statistically significant parameter estimates in either of LEI's cost models. LEI explained

the timeframe covered by LEI's analysis is relatively short (covering the four-year period from 2020-2023), resulting in limited observed variation in the OM&A price index over the study period. Due to this limited variation, a statistically significant relationship

³¹ A1-Staff-333

³² A1-Staff-284, part f.

³³ A1-Staff-338, part a

³⁴ A1-Staff-341, part c.

between the OM&A price index and OM&A costs was not observed, given the other independent variables and interactions with the fixed effects variables.³⁵

Recall, however, that LEI does not seem to have leveled its prices.

- The short sample period used to estimate LEI's models was one in which utility costs were jostled by the Covid pandemic, as LEI acknowledged in response to A1-Staff-297.
- LEI's method for estimating standard errors was not robust with respect to violations of several fundamental ordinary least squares ("OLS") regression assumptions. In a model featuring panel data and a small sample, the assumptions of homoskedasticity, no serial correlation, and normal distribution of the error terms are likely to be violated. Observations are correlated spatially, across time, within companies, and within plants. Standard error estimates, test statistics, and hypothesis tests are invalid when these assumptions are violated. Unless and until LEI can provide clear evidence that their model does not violate these assumptions or provides standard error estimates which are robust to these violations, their t stats are not suitable for statistical inference.
- The EUCG data set evidently contains quite a lot of data on other potential cost drivers and it is not clear which of these were tested by LEI as potential business condition variables. LEI did not identify all of the business condition variables it tested in its econometric modelling.³⁶

Other Concerns

Here are some smaller concerns we have with LEI's benchmarking evidence. We do not believe that these problems individually had a major impact on the benchmarking results. However, future benchmarking studies, for OPG and other utilities, that steer clear of these problems will have more credibility.

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

³⁵ A1-Staff-339, part a.

³⁶ A1-Staff-340, parts a-d.

- Due to limitations of the EUCG data, we understand that the OM&A expenses included those for improvements and additions to generation capacity even though the included capex expenses do not.

6. LEI's Productivity Evidence

6.1. Summary of LEI's Evidence

In the approved settlement resolving its payment accounts in proceeding EB-2020-0290, OPG also agreed to submit a hydro generation TFP trend study with its next payment amounts application if it proposed an IRM or CIR plan. For this proceeding, LEI studied the TFP trend of a group of North American utilities in the provision of hydro generation.

As in its 2016 study for OPG, LEI used the hydroelectric generation volume of sampled utilities as the sole scale variable. Two methods were considered for measuring the capital quantity trend. One was a "physical" approach in which capital quantity growth equaled the growth in generation capacity. The other was a monetary approach in which the decay in the estimated service flow from gross plant additions was made to conform to an OHS specification as discussed in Section 2.1. Capital costs include certain taxes. Investments were valued in current dollars and capital cost was reduced by estimated capital gains.

The O&M cost data used in the study excluded the administrative and general expenses of U.S. utilities but not those of OPG. Pension and other benefit expenses were presumably excluded along with other A&G expenses. Water for power expenses were removed for all sampled utilities. In the case of OPG these are water rental and GRC fees.

When LEI used the physical approach to capital quantity measurement the sample for its productivity trend calculations comprised OPG and 20 U.S. utilities. 16 of the U.S. utilities were investor-owned and annually file operating data on FERC Form 1. This sample also included four publicly-owned utilities: the Western Area Power Administration ("WAPA") and Southeastern Power Administration, Seattle City Light, and the Chelan County (Washington) Public Utility District. When the monetary approach to capital cost and quantity measurement was employed, LEI used a smaller sample



comprising the 16 investor-owned U.S. firms plus OPG because FERC Form 1 data are more suitable for implementing this approach.

The full sample period was the 21 growth rate years from 2003 to 2023. LEI featured productivity results from this period, stating on page 22 that "the longest timeframe allowed by the availability of data (2002-2023) is appropriate for this study." However, LEI itemized results for some shorter (e.g., 15 year) sample periods. LEI reported productivity trends for the aggregation of the sampled companies.

Due chiefly to the volatility of generation volumes, the average annual growth rate of TFP was unusually sensitive to results in the first and last years of the sample period. LEI attempted to smooth results by calculating TFP trends econometrically using the following "trend regression" formula for annual indexes, where the parameters β_0 and β_1 were estimated and the estimate of β_1 is deemed to be the TFP trend:

$$\ln(TFP^{Industry}) = \beta_0 + \beta_1 \times Trend.$$

Here are LEI's TFP trend results using these regressions.³⁷

Sampled Companies	Capital Quantity Treatment	TFP Trend
21 Years (2003-2023)		
20 US peers + OPG	Physical	-0.40%
16 US peers + OPG	Physical	-0.61%
16 US peers + OPG	Monetary	-1.01%
15 Years (2009-2023)		
16 US peers + OPG	Physical	-0.35%
16 US peers + OPG	Monetary	-1.03%

It can be seen that both capital measurement approaches resulted in materially negative industry TFP trends. The trends using the two capital quantity approaches are fairly different over both the full sample period that LEI features and in the most recent 15 years ending in 2023.

³⁷ Table adapted from Figures 33 and 34 of LEI's Productivity Report, p. 55.

OPG proposes a 0% productivity factor for its hydro operations. In addition to the fact that the OEB has to date eschewed negative productivity factors, this likely reflects the fact that the supplemental revenue provisions of the proposed plan provide nearly full compensation for the Company's forecasted capital cost growth. OPG evidently believes that it can live with I-X escalation including a 0% productivity factor for OM&A revenue.

6.2 PEG Critique

Strong Points of LEI's Work

- LEI uses several techniques in its productivity trend research that are considered good practice. For example, growth rates are calculated using indexes of chained Fisher Ideal form. In computing the capital quantity in the benchmark year, gross rather than net plant value was deflated.³⁸
- LEI upgraded their techniques in response to some concerns raised by PEG and the OEB panel in the 2017 CIR proceeding. The use of trend regressions to smooth the TFP trend has been noted. Productivity trends were calculated using a monetary as well as a physical approach to measuring capital quantities.
- LEI's report provides a helpful discussion of the problems encountered in trying to include Canadian and publicly-held U.S. utilities in a hydroelectric productivity study. We are persuaded by these remarks and our own experience that the inclusion of companies from these sources is quite problematic due chiefly to data availability issues.
- We also acknowledge that including four publicly owned utilities in the study took a lot of effort. The hydro capacity of all four of these utilities is sizable, like that of OPG. However, these companies could only be included using the physical approach to capital quantity measurement and the resultant sample is still much smaller than those the OEB has used to calculate

³⁸ Other consultancies that include Christensen Associates and NERA have repeatedly defended the counterintuitive use of *net* plant value in these "benchmark year" calculations when using OHS.

productivity factors for IR plans for energy distributors. The latter is also a concern in PEG's study.

- The input price trend indexes used in the LEI and PEG productivity trend studies were similar.
- LEI's report on its productivity research was generally thorough and well-written. There is a worthwhile discussion of alternatives to the index approach to productivity trend measurement.

Major Concerns

Output Specification

Our biggest concern with LEI's productivity trend research is the use of generation volume as the sole output quantity metric. This variable does have a few advantages in a study of hydroelectric generation productivity that should be acknowledged.

- OPG has proposed a price cap index, and a price cap plan makes sense for OPG since it incentivizes the Company to maintain or boost output.
- We noted in Section 2.1 above that the calculation of a productivity factor for a price cap index should consider in some fashion the trend in billing determinants. Generation volume is the biggest billing determinant in OPG's payments for hydroelectric generation.
- Data on hydroelectric generation volumes are readily available, reported fairly consistently, and presumably accurate.
- Volume captures the efficiency gains from some hydroelectric upgrade projects.
- In its 2017 decision on IR for OPG, the OEB panel endorsed the use of volume to measure output in studies of hydroelectric generation productivity on the following grounds.

MW as an output does not seem reasonable as an underutilized asset will still be considered to be productive. How many MWh can be produced from a plant of a particular MW capacity must bear some relationship to productivity, as, for example, improvements in maintenance (e.g. shorter down time) may result in more output from a plant of the same capacity.

In OPG's situation, the major capital investment in the Niagara Tunnel is intended to result in greater production even if the capacity of the Sir Adam Beck plants is not increased.



However, at the same time, there are also factors, such as water availability, which are beyond the control of the plant operator. Not all hydroelectric generation is used as base load, so output may also be reduced due to market conditions.³⁹

Arguments against reliance on hydroelectric generation volumes start with the fact that they are sensitive to weather volatility and climate trends. The volatility of generation volume is manifest in Figures 12 and 26 of LEI's Productivity Report. The absolute value of the annual percentage change in volume exceeds 10% in five years of the full sample period. Figure 29 shows that TFP growth is also quite volatile, with the absolute value of the annual percentage change exceeding 10% in the same five years. LEI stated in response to A1-SEC-020 b) that "the year over year volatility [in productivity growth] is primarily due to the variability in annual hydroelectric output."

The sensitivity of hydroelectric generation volumes to weather and climate can lead to several problems.

- a) Calculated TFP trends can be quite sensitive to the choice of a sample period. As LEI notes on p. 21 of its Productivity Report, "Annual generation is influenced by hydrology, which can create bias around specific endpoint values".
- b) The volume (and therefore productivity) trends during the sample period may be unrepresentative of those of the *peer group* going forward.
- c) Even if the volume trend is representative of the peer group going forward, they may not be representative of *OPG's*. One reason for concern here is that most of the sampled utilities are located in the western U.S., where generation volumes had a material downward trend during the sample period. LEI acknowledges on p. 31 of its Productivity Report that

In recent decades, western states such as California, Arizona, and Nevada (home to WAPA's Central Valley, Parker-Davis, and Boulder Canyon projects) have experienced multiple severe drought cycles. These drought conditions have had a direct impact on reservoir levels and water availability, thereby constraining hydroelectric output and contributing to fluctuations in annual generation.

³⁹ Ontario Energy Board (2017), Decision and Order EB-2016-0152 Ontario Power Generation, p. 127.

OPG in contrast serves the Great Lakes region, which has a humid continental climate with cool summers.

OPG did not provide a volume forecast for the years after 2027. Volumes were forecasted in the Company's 2025-2031 Business Plan and gradual generation volume *growth* was forecasted. However, this is not an official and up to date volume forecast.

LEI attempts to reduce concerns about its reliance on a volumetric scale metric by lengthening the sample period and using trend regressions. These measures can mitigate problems a) and b) but not problem c). For LEI's full sample period, generation capacity exhibited a materially rising trend that is more pronounced in the later years of the sample period. Meanwhile, generation volume exhibited a materially declining trend, estimated as a 0.59% annual decline using LEI's trend regression method over the full sample period.

LEI's strong advocacy of a volumetric output metric for generation contrasts with its use of the number of customers as an output metric in research and testimony on TFP trends of energy distributors. In response to A1-Staff-278 d), for example, LEI acknowledged that it used the number of customers as the scale metric in recent gas distributor productivity research and testimony for Yankee Gas in Connecticut.⁴⁰ This decision is all the more notable because many of the arguments that LEI has ventured in support of a volume variable in a generation application also apply in an application to energy distributors. For example, the delivery volumes of energy distributors are readily available, consistently reported, and an essential output being produced by every distributor. Volume is also an important billing determinant for many U.S. distributors. Ms. Frayer is also known to have used the number of customers as an output measure in output indexes constructed for energy distributor productivity studies in Alberta (Proceeding 566), Ontario (EB-2007-0673), and Massachusetts (D.P.U. 19-120).

⁴⁰ Ms. Frayer is also known to have used the number of customers as an output measure in output indexes constructed for energy distributor productivity studies in Alberta (Proceeding 566), Ontario (EB-2007-0673), and Massachusetts (D.P.U. 19-120).

LEI's stance on the appropriate output metric is reminiscent of that of utility witnesses in a succession of Alberta's generic PBR proceedings for power distributors. Some utility witnesses (e.g., NERA, Brattle Group, and Christensen Associates) advocated the use of a national U.S. sample (rather than a regional peer group such as all western U.S. utilities) and a completely volumetric output index in distributor TFP studies even though U.S. volume growth has been materially slowed for many years by energy conservation in the States, demand growth is generally slower in the East, and Alberta didn't have conservation programs. The use of a volume metric made the industry TFP trend materially more negative.

In 2011 testimony for the power distributor FortisAlberta in one of the Alberta generic IR proceedings, Ms. Frayer criticized sole reliance on a volumetric index to measure the productivity growth of power distributors stating that

in my experience, estimates of the TFP growth rates are typically sensitive to the model selection. NERA only used one parameter to define the output index – system throughput (consumption). Most electricity distribution TFP studies also include customer numbers to reflect utility fixed charges and some TFP studies also include a proxy for network capacity to better measure the service provided to larger industrial customers. Both of these additional outputs act to smooth volatility and produce more stable output and hence, TFP indices. Indeed, NERA's annual rate of change in productivity is quite volatile, as seen in the figure below.⁴¹

In view of these and other concerns that PEG has about LEI's output specification, we believe that it is desirable to use an alternative scale variable: the MW of hydroelectric capacity. This variable has several advantages in a study of hydro generation productivity:

- Capacity growth is much more stable than volume growth. This makes a shorter sample period more feasible as a means for estimating long-term productivity trends.
- As reported in Section 8 below, PEG's econometric research for Staff in this proceeding demonstrates that generation capacity is a far more important driver of hydroelectric

⁴¹ Julia Frayer (2011), "Prepared Testimony of Julia Frayer," filed in Alberta Utilities Commission Proceeding 566 as part of exhibit 100.02, p. 56.

generation cost than generation volume. In LEI's econometric cost modelling for this project, generation capacity was also found to be a highly significant cost driver and generation volume variable was not included in either LEI model. LEI stated in response to A1-Staff-278 b) that "For the benchmarking study, the annual capacity measured in MW was indeed used as a way to adjust or control the costs for scale of the facilities." LEI stated relatedly in response to A1-SEC-021 that "LEI did factor in the scale of operations as part of the benchmarking study. Specifically, LEI controlled the impact on costs from the size of the plant measured in MW." LEI discussed its selection of capacity as an output measure for its econometric benchmarking study in response to A1-Staff-340 c).

The decision to use capacity in lieu of generation was not simply because of statistical significance. LEI also considered overall model fit balanced against complexity and economic intuition.

- LEI acknowledged in response to A1-Staff-278 e) that "capacity markets are in place in several regions across the US, as well as in Ontario." Thus, capacity is a billing determinant. PEG believes that there are capacity markets managed by ISO New England, the New York ISO, the Midcontinent ISO, and the PJM Interconnection, as well as bilateral capacity contracts.
- Standardized data are available on hydroelectric generation capacity.
- We explain below that generation capacity should not be used as a capital quantity proxy. Thus, capacity data are available to measure the trend in the operating scale of sampled utilities.
- Capacity has been used as an output variable in several generation cost and productivity studies.⁴²

⁴² See, for example, Barros, C. P., & Peypoch, N. (2007). "The determinants of cost efficiency of hydroelectric generating plants: A random frontier approach." *Energy Policy*, 35 (9), 4463-4470. Barros, C. P., Chen, Z., Managi, S., & Antunes, O. S. (2013). "Examining the cost efficiency of Chinese hydroelectric companies using a finite mixture model." *Energy Economics*, 36, 511-517. Briec, W., Peypoch, N., & Ratsimbanierana, H. (2011). "Productivity growth and biased technological change in hydroelectric dams." *Energy Economics*, 33 (5), 853-858. PEG's 2016 TFP study in the prior Ontario Power Generation hydroelectric price cap IR proceeding also relied on capacity as an output measure.

- To gauge the impact of using generation capacity instead of generation volume as the sole scale variable on TFP trend results, PEG has prepared Table 1 that provides trend regressions for volumes, capacity, and TFP calculated using volumes or capacity. It can be seen in Table 1 that if capacity as the scale variable is combined with the monetary approach to calculating the capital quantity the TFP trend over the full sample period rises from -1.01% annual growth to -0.29% annual growth. The analogous TFP trend over the last 15 years rises from -1.03% annual growth to -0.34% annual growth.

Table 1
Expanded LEI TFP Trend Regression Results

LEI TFP Trend Regression Growth Rates (Monetary)					
Period (years)	Input	Output		TFP	
	Total Factor	Volumetric (MWh)	Capacity (MW)	Volumetric Output	Capacity Output
21	0.42%	-0.59%	0.13%	-1.01%	-0.29%
20	0.45%	-0.65%	0.11%	-1.10%	-0.33%
15	0.59%	-0.44%	0.24%	-1.03%	-0.34%

Recall, however, that our ultimate goal in this proceeding is to establish a *price* cap index for OPG, where price is \$/MWh generated. This requires that productivity research take some account of the trend in generation volumes. However, the research need not use the trend in this index for a productivity peer group. Instead, we can use relation [7] from Section 2.1 to decompose the trend in productivity using a revenue weighted index into the trend in a cost efficiency index and an *output differential* that is specific to the subject utility.

$$\begin{aligned}
 \text{trend Productivity}^R &= \text{trend TFP}^C + (\text{trend Outputs}_{\text{Utility}^R} - \text{trend Outputs}_{\text{Utility}^C}) \\
 &= \text{trend TFP}^C + \text{Output Differential}_{\text{Utility}}.
 \end{aligned}
 \tag{22}$$

Our research suggests that the relevant output differential for OPG is the difference between the trends in delivery volumes and capacity. The expected trend in the output differential can be very different for OPG than it was for other sampled producers during a particular period. We can establish

an appropriate TFP^c growth target using capacity to measure output and adjust this if necessary to reflect the expected output differential of OPG.

$$growth\ Rates = Inflation - \overline{TFP^c} + trend\ Capacity_{OPG} - trend\ Volume_{OPG}. \quad [23]$$

This would be analogous to the price cap index construction in the current CIR proposal of Alectra Utilities.

The output differential can be the recent historical difference between the *trend* in the hydro generation volume and capacity of OPG. Some information germane to this assessment is found in Table 2 below. It can be seen that the trends in OPG's generation volume and capacity have been quite similar. For example, the trend in the output differential during the twenty-one years ending in 2023 was only 0.11% growth per annum.

We can alternatively use capacity as a scale escalator that is commensurate with a revenue cap index and then convert the revenue cap index to a price cap index using a forecast of OPG's volume growth. However, OPG has not provided an up to date forecast of its generation volume in its evidence in this proceeding. The Company stated in response to A1-CCC-003 that

As the 2028-2031 regulated hydroelectric payment amounts would be determined mechanistically, under the proposed rate-setting framework, production forecasts beyond 2027 are not required.

We noted above however that gradual growth was predicted in a recent Company submission.

Table 2

Comparing Trends in OPG's Volume and Capacity Growth

Year	Generation Capacity		Generation Volume		Output Differential
	MW	Growth Rate [A]	MWh	Growth Rate [B]	Growth Rate [B] - [A]
2002	6,899		33,977,759		
2003	6,926	0.39%	33,202,786	-2.31%	-2.70%
2004	6,958	0.46%	35,351,273	6.27%	5.81%
2005	6,924	-0.49%	33,487,118	-5.42%	-4.93%
2006	6,971	0.68%	34,329,431	2.48%	1.81%
2007	6,971	0.00%	32,986,718	-3.99%	-3.99%
2008	6,999	0.40%	37,423,326	12.62%	12.22%
2009	6,905	-1.35%	36,302,957	-3.04%	-1.69%
2010	6,906	0.01%	30,568,258	-17.19%	-17.21%
2011	6,422	-7.27%	30,359,921	-0.68%	6.58%
2012	6,422	0.00%	28,458,915	-6.47%	-6.47%
2013	6,433	0.17%	30,347,392	6.42%	6.25%
2014	6,433	0.00%	30,625,600	0.91%	0.91%
2015	6,433	0.00%	30,587,106	-0.13%	-0.13%
2016	6,433	0.00%	29,736,587	-2.82%	-2.82%
2017	6,433	0.00%	31,040,565	4.29%	4.29%
2018	6,428	-0.08%	30,097,653	-3.08%	-3.01%
2019	6,420	-0.12%	32,271,827	6.97%	7.10%
2020	6,420	0.00%	32,818,297	1.68%	1.68%
2021	6,420	0.00%	31,236,814	-4.94%	-4.94%
2022	6,420	0.00%	34,217,553	9.11%	9.11%
2023	6,534	1.76%	34,064,572	-0.45%	-2.21%
2024	6,556	0.34%	32,500,000	-4.70%	-5.04%
2025	6,566	0.14%	33,000,000	1.53%	1.38%
2026	6,572	0.09%	32,800,000	-0.61%	-0.70%
2027	6,584	0.19%	32,500,000	-0.92%	-1.11%
2028	6,605	0.32%	32,700,000	0.61%	0.29%
2029	6,628	0.35%	33,000,000	0.91%	0.57%
2030	6,633	0.07%	33,000,000	0.00%	-0.07%
2031	6,633	0.00%	32,900,000	-0.30%	-0.30%
Average Annual Growth Rates					
2009-2023 (15 growth rates)		-0.46%		-0.63%	-0.17%
2003-2023 (21 growth rates)		-0.26%		0.01%	0.27%
2027-2031		0.19%		0.06%	-0.12%
Trend Regressions					
2009-2023		0.15%		0.25%	0.10%
2003-2023		0.03%		0.14%	0.11%



Capital Cost and Quantity Specification

The treatment of capital quantity is a second area where we have serious concern about LEI's methods. We explained in Section 3 that the capital cost specification is of central importance in studies of hydroelectric power generation input price and productivity trends.

One Hoss Shay PEG has several concerns with the OHS specification that LEI used when implementing its monetary approach to capital cost and quantity measurement. The use of OHS in productivity studies submitted in IR proceedings is not uncommon in North America. However, productivity and statistical benchmarking research by utility and staff witnesses alike has usually used a geometric decay specification in OEB proceedings.

The traditional rationale for an OHS decay specification is that the stream of services from capital assets is fairly constant until they are retired. LEI states on p. 19 of its Productivity Report that "Hydroelectric generation assets tend to have long lives and produce a relatively constant flow of services over their useful lives (provided they are properly maintained)."

There are, however, several reasons to doubt the appropriateness of a constant service flow specification in a study of hydro generation productivity trend or benchmarking study.

- LEI applies the OHS assumption to the *total* value of each year's cohort of plant additions and not to individual assets or groups of similar assets. Even if each *individual* asset had a constant service flow, the service flow trend of the *aggregation* of annual plant additions could be poorly approximated by OHS for several reasons. Different kinds of assets in the cohort can have markedly different service lives. Assets of the same kind could end up having different service lives. Individual assets frequently have components with varied service lives.⁴³

Some important kinds of hydraulic production assets (e.g., generators) do not in any event generally have stable service flows. LEI states on p. 19 of its Productivity Report that "physical deterioration is generally very limited in hydroelectric plants as the majority of the capital equipment deployed is not electrical or mechanical, but structural." This implies that electrical

⁴³ The alternator in a motor vehicle, for example, can need replacement before the body of the vehicle does.

or mechanical assets *are* prone to physical deterioration. Thus, OHS doesn't fit the capital service flow from a cohort of annual generation capacity additions particularly well. Alternative capital cost specifications such as GD and HD are designed to measure declining service flows from a cohort of varied assets.⁴⁴

- LEI acknowledges in response to A1-Staff-280 d) that “there is an increased need for maintenance expenditure for aging power plants.” Refurbishment expenses also rise with plant age. Rising expenditures of both kinds can be viewed as a response to a decline in the service flow from the *original* plant addition that nonetheless is assumed under OHS to have a constant service flow. LEI states in response to A1-Staff-280 e) that examples of hydroelectric generation assets that typically have rising costs as they age include turbines, transformers, and civil work. Not much capacity was added by the utilities that LEI studies during the sample period, so their study chiefly considers productivity in the management of aging assets.
- In its IR decision for OPG in 2017, the OEB cited decay (which is called “functional” depreciation) as one of the reasons to explore a monetary capital cost and quantity specification. The panel stated that

The OEB questions LEI’s physical approach which uses MW capacity as an input, as this measure does not take into account financial considerations, such as the capital costs.

⁴⁴ Consistent with these remarks, the authors of a capital research manual for the Organization of Economic Cooperation and Development (“OECD”) stated on page 12 of the Executive Summary of their *Measuring Capital OECD Manual 2009* that

In practice, cohorts of assets are considered for measurement, not single assets. Also, asset groups are never truly homogenous but combine similar types of assets. When dealing with cohorts, retirement distributions must be invoked because it is implausible that all capital goods of the same cohort retire at the same moment in time. Thus, it is not enough to reason in terms of a single asset but age efficiency and age-price profiles have to be combined with retirement patterns to measure productive and wealth stocks and depreciation for cohorts of asset classes. An important result from the literature, dealt with at some length in the Manual is that, for a cohort of assets, the combined age-efficiency and retirement profile or the combined age-price and retirement profile often resemble a geometric pattern, i.e. a decline at a constant rate. While this may appear to be a technical point, it has major practical advantages for capital measurement. The *Manual therefore recommends the use of geometric patterns for depreciation* because they tend to be empirically supported, conceptually correct and easy to implement. [italics in original] OECD, *Measuring Capital OECD Manual 2009*, Second Edition, p. 12.



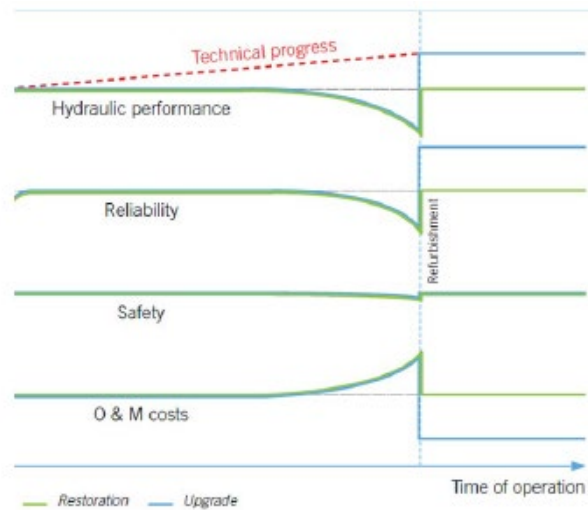
Although many hydroelectric generation assets have very long useful lives, the OEB is not convinced that there is no functional depreciation until end of life. In fact, reviews of capital projects to sustain, refurbish and replace hydroelectric stations and assets in OPG's prior payment amount applications confirm that capital expenditures and operating costs are needed to maintain capacity to the end of a station's life. Absent ongoing capital and operating expenditures, hydroelectric generation assets will depreciate over time. In the OEB's view, LEI's physical method, which assumes no depreciation until the end of life, is not a realistic basis for the analysis of productivity of hydroelectric generation facilities.

PEG's financial approach, which does take into account depreciation of assets in some form, is in the OEB's view more realistic than LEI's approach, although the OEB observes that there is no consensus on the best method for accounting for economic and physical depreciation or deterioration of assets in these types of analyses.⁴⁵

The question is whether a monetary approach based on OHS addresses the panel's concern.

- In response to A1-Staff-280 d), LEI presents a figure, replicated below, that is apparently drawn from a Hydro Equipment Association publication. The figure shows that, after being steady for many years, the hydraulic performance and reliability of hydroelectric generation assets tends to decline while operation and maintenance ("O&M") costs tend to rise. O&M and refurbishment inputs can help maintain and even improve hydraulic performance. However, this is not an OHS service flow pattern for the original asset. Moreover, since most generation assets in LEI's study were far from new during the sample period, it may be that the sampled utilities were typically operating in the period of declining hydraulic performance in LEI's figure.

⁴⁵ Ontario Energy Board (2017), Decision and Order EB-2016-0152 Ontario Power Generation, pp. 126-127.



- LEI asserts that utility productivity studies used to determine productivity factors must track the trend in the industry’s technical efficiency and suggests that this means that capital quantity indexes developed using monetary methods should track service flows. On p. 18 of its Productivity Report LEI states that “a TFP study is only concerned with physical deterioration of the asset and its ability to function and produce a product or service.”

However, the index logic, detailed in Section 2.1, that supports the use of productivity research in the design of price cap indexes does not require the capital quantity index to measure the flow of capital services. The I-X mechanism is intended to adjust rates between conventional rebasings. It is reasonable for I-X to simulate industry cost trends by some means. The value of assets tends to decline as they age due to decay and the shrinkage of their remaining service lives. This depreciation constitutes a real cost saving for the owner that can be extended by postponing asset replacement. The cost trend of the industry therefore depends on how the age of existing assets compares to the need for new capex. OHS does not account for these realities well. Moreover, the ownership of capital involves other meaningful quantity dimensions such as the remaining years of each asset’s service life in addition to service flows. The owner of a new substation, for example, has invested in an asset that should provide service for decades.

- Depreciation can affect capital quantity trends even under constant capital service flows. To understand why, consider that the capital cost of a utility is the sum of the costs of assets of various ages. Depreciation of asset value due to decay and shrinking service life reduces the cost of owning assets as they age. An increase in the average age of an asset fleet is therefore tantamount to replacing newer assets with older and cheaper assets. Since

$$\text{growth Quantities}^{\text{Capital}} = \text{growth Cost}^{\text{Capital}} - \text{growth Prices}^{\text{Capital}} \quad [24]$$

anything that slows capital cost growth more than it slows capital price growth slows capital *quantity* growth and that affects productivity growth. The trend in capital prices is largely beyond utility control. A decline in capital cost due to depreciation is therefore tantamount to a decline in the capital quantity. Analogously, a *drop* in the average age of assets is tantamount to replacing older assets with newer and more costly assets. This is tantamount to an *increase* in the capital quantity. The phenomenon is accentuated when plant is valued in replacement dollars.

Consideration of analogous situations can help to elucidate this point. For example, a utility can slow labor quantity growth and bolster productivity growth if it can find a way to maintain output while replacing kinds of workers that have high wage rates in labor markets with kinds of workers that have lower wage rates. A household can cut its cost of capital by continuing to drive the family car for a few more years instead of buying a new one. The resale value of the car is lessened each year due to depreciation. The household has no control over trends in used car prices or the rate of return on alternative investments. Cost growth is instead slowed by (implicitly) reducing the quantity of automotive assets that the household owns by implicitly choosing an older, less valuable car each year. Money freed up by not buying a newer car can be spent or invested in other assets.

Common OHS treatments gloss over the issue of vintaging by valuing all capital services by a "user cost" of capital methodology in which the capital service price is a function of prices of new assets. This treatment is tantamount to treating capital services from all assets as purchases from a market in which prices of services do not depend on the age of assets. Capital



service markets in which asset age doesn't matter much may exist for some assets (e.g., boxcar leases), but the cost and efficiency of firms that supply these markets depends very much on how they manage the vintages of their assets. OPG is chiefly a manager of assets rather than a renter of capital services.

There are additionally some practical complications with using OHS in productivity studies.

- When deflating an asset value, the researcher must decide which value of the asset price index to use. Implementation of the GD, HD, and OHS specifications all require deflation of each year's gross plant *additions*. The choice between index values in different years is straightforward in this instance since the dates of the additions are known. However, implementation of OHS requires, additionally, deflation of plant *retirements* and the vintages of these retirements are unknown. Productivity results using OHS are sensitive to the assumption concerning the vintage of the assets being retired. These assumptions are usually based on an estimate of the average service life of the assets being retired. LEI explains on p. 41 of its Productivity Report that

The adjustment to retirements is more complicated. The retirements are capital assets that are assumed to have exhausted their service life. Because retirements are recorded at their original historical cost, they need to be re-based (inflated) to reflect their full monetary value in real dollar terms at retirement (i.e., t minus the average service life s).

However, seemingly reasonable service life estimates can produce negative capital quantities under the OHS methodology.⁴⁶ For example, LEI stated in response to A1-Staff-344 a) that it

has seen in its work and the work of others that a combination of specific Handy Whitman Indexes trends applied to reported retirements and long asset lives can create negative real capital stock values. This tends to happen for a few companies that may have had a particular combination of investment and retirements.

⁴⁶ Sensitivity to service life assumptions under OHS can be reduced by using plant addition and retirement data that are itemized with respect to asset type, but LEI did not do this. Itemization is especially desirable in studies of hydroelectric generation productivity because roughly half of all assets by value have unusually long service lives, while the average lives of most other assets are considerably shorter.

- PEG has found TFP trend results using the OHS capital cost specification to be much more sensitive to the assumed average service life of assets than those using geometric decay.
- We noted in Section 2.1 that a monetary approach requires a capital price as well as a quantity to calculate the capital costs needed to compute cost shares. The one-hoss-shay capital service price index formula is not intuitively appealing. The GD capital service price is more intuitively appealing.

These disadvantages of the OHS specification help to explain why alternative decay specifications are more the rule than the exception in capital quantity research. For example, GD has been used in numerous productivity studies intended to help determine productivity factors in the energy and telecommunications industries, including many studies prepared for utilities and entered into evidence. We noted in Section 2.1 that Statistics Canada uses GD in its multifactor productivity studies for sectors of the economy while the U.S. Bureau of Labor Statistics, the Australian Bureau of Statistics, and Statistics New Zealand assume hyperbolic decay in their sectoral MFP studies.

For these and other reasons, OHS is likely not the ideal decay specification but neither is geometric decay. This would accordingly have been a good proceeding to explore the intermediate hyperbolic decay (HD) specification. This specification has been employed in TFP studies in several recent IR proceedings for North American energy distributors. For example, Larry Kaufmann used an HD specification in recent CIR testimony for Enbridge Gas.

Physical Approach To implement its physical approach to capital quantity measurement LEI used the maximum continuous rating of OPG. For the sampled U.S. electric utilities, LEI used the nameplate rating of their hydroelectric generation assets as reported on FERC Form 1.

LEI advances the following valid arguments in support of using generation capacity as the capital quantity index.

- The many years of plant value data required to accurately calculate capital quantity indexes using monetary methods are unavailable for many utilities. LEI stated on page 28 of its Productivity Report that “for the TFP calculations using the monetary approach LEI was not able

to find sufficient data related to annual capital investment for the non-FERC regulated hydroelectric companies.” That’s unfortunate because these are desirable peers.

- LEI notes in Appendix C of its Productivity Report that capacity is used to measure the capital quantity in most generation-related productivity studies that it surveyed.

On the other hand, there are numerous arguments against the physical approach that LEI used.

- Capacity is very useful as the *scale* metric in a generation productivity study, as we noted above. It cannot be used as both the scale metric and a capital quantity index in the same TFP index.
- The physical approach to capital quantity measurement ignores trends in the quantities of inputs that generators use to provide a unit of capacity to the marketplace. Management of these inputs can be an important determinant of capital and total factor productivity growth. Efforts by utilities to reduce the cost of capital needed to provide capacity are ignored. An example would be extra effort by a generator to extend the service life of its assets.
- A capital cost weight is needed to calculate the total factor input quantity trend and there is no consistent capital cost measure to pair with generation capacity. LEI uses a “guesstimate” of the appropriate capital cost which it calls the “endogenous” approach on p. 45 of its Productivity Report. This is explained on p. 46 of the Productivity Report as the difference between a utility’s revenue and operating costs. Data on the revenue yielded by hydroelectric generation is not readily available for most sampled companies, so LEI had to estimate this revenue using complicated methods that it discusses on p. 33 of its Productivity Report.
- The trends in OPG’s capital quantities using the physical and monetary approaches to capital quantity measurement are fairly different as shown in Figure 32 of LEI’s Productivity Report.
- Using the physical approach, the capacity of OPG does not increase due to the Niagara Tunnel Project. This project increased the Company’s cost. The NTP did affect OPG’s capital quantity growth using the monetary method.

It should also be noted that LEI’s sample for productivity trend research consists chiefly of investor-owned utilities in the United States that *have* filed the requisite capital cost data for the

monetary approach for many years in their FERC Form 1 reports. The requisite plant value data are also available for OPG.

- The OEB rejected a physical asset approach to capital quantity measurement used by LEI in the 3rd GIRM proceeding.⁴⁷

Note also that Figure 32 in LEI's Productivity Report indicates that the hydro capacity of sampled generators trended upward over the full sample period and grew most briskly after 2011. This means that capacity will slow productivity growth if used as an *input* quantity but accelerates it if used as an *output* quantity. Plainly, LEI chose the approach that favored its client.

Sample Period

The 21-year 2003-2023 sample period that LEI chose to feature in its productivity trend calculations is much longer than the 15-year period that is commonly used to compute productivity trends in IR proceedings.

O&M Input Quantity Trends

LEI calculated the trend in O&M input quantities with a "residual" approach like PEG also typically uses. Effectively,

$$\text{trend Inputs}^{O\&M} = \text{trend Cost}^{O\&M} - \text{trend Input Prices}^{O\&M}.$$

The O&M input price index requires cost share weights for the chosen subindexes for labor and material and service inputs. The O&M input price indexes for OPG and the U.S. utilities used a fixed labor cost share of 62.6% that was "suggested by average trends observed in the confidential [Electric Utility Cost Group] database which includes reported data for 16 hydroelectric generation companies

⁴⁷From Ontario Energy Board, *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, Proceeding EB-2007-0673, September 17, 2008, p. 12, "Of greatest concern with Ms. Frayer's approach is the measurement of capital, which is inconsistent with the prior Ontario TFP studies and does not appear to have been adopted in any jurisdiction other than New Zealand. While the Board recognizes Ms. Frayer's efforts to construct an Ontario-specific TFP trend, the Board does not believe that the methodology advocated by Ms. Frayer is appropriate."

over the 2006-2023 timeframe.”⁴⁸ This estimate of the labor cost share cannot be vetted and is out of line with US power generation experience. We suspect that the labor cost that they used in this calculation included contract labor and pension and benefit expenses.

Calculating the Peer Group Trend

To summarize the TFP trends of its peer groups LEI aggregated the generation volume, capacity, and O&M expense data of the sampled utilities. This weights results for individual companies on the basis of their size implicitly. We believe that it is preferable to *explicitly* calculate results for individual utilities. It is then easy to calculate simple-weighted as well as size-weighted averages. Appraising results for individual utilities is a good diagnostic tool. Furthermore, results for OPG would then be readily available. Note also that aggregation (as well as size-weighting) gives substantial weights to results for a few companies in the sample that are much larger than the sample norm. This was also a problem with PEG’s study.

Transparency of Presentation

Trends in O&M and capital quantities and productivity were not itemized in LEI’s productivity report using either average annual growth rates or trend regressions. This complicates review of LEI’s results by PEG and other parties. This is all the more problematic because of the volatile output metric and LEI’s choice to feature the more complicated and novel trend regression approach in its Productivity Report.

Precedents for LEI’s Methodology

LEI has a tendency to exaggerate the precedents supporting its productivity research methods. For example, on page 48 of its Productivity Report LEI mentions two well-known studies as early precedents for the design of its service price index.⁴⁹ However, these studies did not use an OHS decay specification. Also, when LEI states on the same page that “capital input price formulas similar to LEI’s

⁴⁸ LEI Productivity Report p. 35.

⁴⁹ Exhibit A1, Tab 3, Schedule 2, p. 48.

formula are in widespread use in productivity studies around the world,” PEG believes that LEI is referring to the use of service price indexes generally and not those with OHS designs.

LEI notes on pp. 64-66 of its Productivity Report that amongst 18 generation productivity studies that it has surveyed generation volume is commonly used as an output metric and generation capacity as a capital quantity metric. However, most of these studies were not based on the FERC Form 1 data that facilitate the monetary approach to capital cost and quantity measurement. If generation capacity is by necessity used to measure the capital quantity, it is unavailable for use as an output metric.

Smaller Concerns

Our review also raised the following notable smaller concerns about LEI’s productivity research.

- The ECI that LEI uses to deflate labor cost is a fixed weight index. This is a more accurate wage rate index in recessionary periods like that recently triggered in North America by the pandemic. However, LEI also uses the AWE for Ontario industry to deflate OPG’s labor costs. This index is not fixed-weighted. LEI indicated that this was done to ensure consistency in its results across its inflation analysis, benchmarking study, and productivity study.⁵⁰ The analogue to the ECI in Ontario is the fixed weighted index (“FWI”) of average hourly earnings.
- It is understandable that LEI excluded A&G expenses from its productivity study but please note that this was a plausible source of productivity growth during the sample period.
- LEI uses the Gross Domestic Product Price Index (“GDPPPI”) to measure the trend in U.S. material and service prices. This index tends to understate inflation in these prices and thereby to understate total factor and (especially) O&M productivity trends. This is also a limitation of PEG’s work, but the potential for downward bias in TFP trend results should be noted.
- In response to A1-Staff-280 o), LEI acknowledged that it did not use region-specific HWIs to deflate the plant values of the sampled US utilities even though these were readily available.

⁵⁰ A1-Staff-337, part e.

- LEI made some errors in reporting results of their trend regressions. Please see Table 3 below for details. The correct values can be found in the column TFP (MWh) Calculated, while the erroneous values are in the column TFP (MWh) LEI Figure 34. PEG acknowledges that some errors can occur in a large and complicated empirical study.

Table 3

LEI's Reported Trend Regression Apparent Errors

LEI MONETARY MODEL FERC Peers + OPG (16 peers + OPG)						
TREND REGRESSION						
	Input	Output (MWh)	TFP (MWh)		Output (MW)	TFP (MW)
			Calculated	LEI Figure 34		
21 years	0.42%	-0.59%	-1.01%		0.13%	-0.29%
20 years	0.45%	-0.65%	-1.10%	-0.41%	0.11%	-0.33%
15 years	0.59%	-0.44%	-1.03%	-0.88%	0.24%	-0.34%
AVERAGES						
	Input	Output (MWh)	TFP (MWh)		Output (MW)	TFP (MW)
			Calculated	LEI Figure 34		
21 years	0.38%	-0.20%	-0.58%		0.25%	-0.13%
20 years	0.40%	-0.63%	-1.03%	-1.40%	0.13%	-0.27%
15 years	0.59%	-0.17%	-0.76%	-0.92%	0.24%	-0.36%

LEI PHYSICAL MODEL FERC Peers + OPG (16 peers + OPG)						
TREND REGRESSION						
	Input	Output (MWh)	TFP (MWh)		Output (MW)	TFP (MW)
			Calculated	LEI Figure 34		
21 years	0.02%	-0.59%	-0.61%		0.13%	0.11%
20 years	-0.03%	-0.65%	-0.62%		0.11%	0.14%
15 years	-0.09%	-0.44%	-0.35%		0.24%	0.34%
AVERAGES						
	Input	Output (MWh)	TFP (MWh)		Output (MW)	TFP (MW)
			Calculated	LEI Figure 34		
21 years	0.21%	-0.20%	-0.41%		0.25%	0.05%
20 years	0.07%	-0.63%	-0.70%		0.13%	0.06%
15 years	-0.05%	-0.17%	-0.11%		0.24%	0.29%

LEI PHYSICAL MODEL Peer Industry (20 peers + OPG)						
TREND REGRESSION						
	Input	Output (MWh)	TFP (MWh)		Output (MW)	TFP (MW)
			Calculated	LEI Figure 34		
21 years	0.07%	-0.33%	-0.40%		0.06%	-0.01%
20 years	0.03%	-0.38%	-0.41%	-0.34%	0.05%	0.02%
15 years	-0.09%	-0.37%	-0.28%	-0.74%	0.11%	0.20%
AVERAGES						
	Input	Output (MWh)	TFP (MWh)		Output (MW)	TFP (MW)
			Calculated	LEI Figure 34		
21 years	0.21%	-0.42%	-0.63%		0.11%	-0.10%
20 years	0.09%	-0.80%	-0.89%	-0.49%	0.04%	-0.05%
15 years	-0.05%	-0.28%	-0.22%	-0.78%	0.09%	0.14%

LEI PHYSICAL MODEL Peer Industry less OPG (20 peers)						
TREND REGRESSION						
	Input	Output (MWh)	TFP (MWh)		Output (MW)	TFP (MW)
			Calculated	LEI Figure 34		
21 years	0.14%	-0.32%	-0.46%		0.16%	0.02%
20 years	0.09%	-0.40%	-0.48%		0.15%	0.06%
15 years	-0.07%	-0.47%	-0.40%		0.21%	0.28%
AVERAGES						
	Input	Output (MWh)	TFP (MWh)		Output (MW)	TFP (MW)
			Calculated	LEI Figure 34		
21 years	0.28%	-0.59%	-0.87%		0.18%	-0.10%
20 years	0.13%	-1.14%	-1.27%		0.10%	-0.03%
15 years	0.00%	-0.12%	-0.12%		0.19%	0.19%

6.2.

6.3. Conclusions Regarding LEI's Productivity Trend Study

LEI does not recommend a specific productivity factor, but its study should nonetheless raise serious concerns about its relevance to setting a productivity factor for OPG. A correctly calculated industry TFP trend may differ considerably from LEI's estimates. Our chief concerns with LEI's methodology are the output and capital specifications. Other aspects of LEI's methodology are not best practice but are nonetheless unlikely to affect results greatly.

7. Data Used in PEG’s Research

In this section of the report, we discuss the data used in PEG’s alternative cost benchmarking and productivity research for this proceeding. Since most of the data used are from the United States we start with a discussion of these data before turning to the Ontario data.

7.1. Data Sources and Sample

United States

Data Sources

The primary source of data on the cost of U.S. hydroelectric generators that we used in our research was FERC Form 1. Recall that this form is used by major investor-owned utilities, some of which have hydro generation. Selected FERC Form 1 data were for many years published by the U.S. Energy Information Administration (“EIA”).⁵¹ More recently, these data have been available in raw form electronically from the FERC. They are also available (for a sizable fee) electronically in more processed forms from commercial vendors.

Data used in this study for years after 1993 were downloaded directly from the U.S. government and processed by PEG. PEG transcribed data for prior years from EIA publications.

Operating data for the generator age and mode of operation variables in the econometric model were drawn primarily from the EIA 860 Generator, Plant, and Ownership database files. These data were supplemented with data from Oak Ridge National Laboratory’s (“ORNL”) Hydrosorce platform wherever data missing from the EIA 860 files were available in the ORNL files^{52,53}.

⁵¹ This publication series had several titles over the years. A recent title is *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*.

⁵² M.M. Johnson, S.-C. Kao, and R. Uria-Martinez, Existing Hydropower Assets Unit database, 2025. HydroSource. Oak Ridge National Laboratory, Oak Ridge, TN.

⁵³ M.M. Johnson, S.-C. Kao, and R. Uria-Martinez, Existing Hydropower Assets Plant database, 2024. HydroSource. Oak Ridge National Laboratory, Oak Ridge, TN.

U.S. generation cost and volume data were drawn from FERC Form 1 reports. Data on the nameplate capacity of U.S. hydro generation plants were drawn from Form EIA 860 (*Annual Electric Generator Report*) and predecessor forms (e.g., Form EIA 767).

Data on U.S. labour prices were obtained from the Bureau of Labor Statistics (“BLS”) of the U.S. Department of Labor. The gross domestic product price index (“GDPPI”) that we used as the proxy for an M&S price trend index was calculated by the Bureau of Economic Analysis of the U.S. Department of Commerce. Data on the *levels* of heavy construction costs in various U.S. and Canadian cities were obtained from RSMMeans. Data on electric utility construction cost *trends* were drawn from the *Handy Whitman Index of Public Utility Construction Costs*. The specific data drawn from these sources are noted below.

Sampled Companies

Data were eligible for inclusion in the sample from OPG and all major U.S. investor-owned electric utilities that generated power hydraulically and, together with any important predecessor companies, filed the FERC Form 1 in 1964 (the benchmark year for the calculation of capital cost) and have reported the necessary data in the years since then. A further screen was that utilities had hydro generating plant exceeding \$100 million in 2014. To be included in this study, the data also were required to be of good quality and plausible.

Table 4 lists all of the sampled utilities that contributed data to PEG’s benchmarking and productivity trend studies in this proceeding. It can be seen that data from 20 U.S. hydroelectric generators and OPG were included. Most broad regions of the U.S. are represented. In contrast, our econometric studies of U.S. power distributor cost typically employ a sample of data from more than eighty distributors. OPG data were included in the econometric model estimation but not in the calculation of industry productivity trends.

Sample Period

The full sample period for which we calculated productivity trends was the 28 growth rate years from 1997 to 2024. The featured sample period for productivity trend research was the 15 years ending in 2024 (i.e., 2010-2024). Parameters of the econometric benchmarking model were estimated using data from the 21 years ending in 2024. While PEG often uses 15-year sample periods in econometric



Table 4

Companies Used in PEG’s New Hydro Generation Research

Company	Hydro Generation Capacity (MW) in 2024	Share of US Total
Ontario Power Generation	6,556	NA
Pacific Gas and Electric ¹	3,640	17.6%
Duke Energy Carolinas ¹	3,539	17.1%
Virginia Electric and Power ¹	1,996	9.6%
Idaho Power ¹	1,818	8.8%
Alabama Power ¹	1,730	8.4%
Southern California Edison ¹	1,163	5.6%
Georgia Power ¹	1,085	5.2%
Avista ¹	943	4.6%
PacifiCorp ¹	896	4.3%
South Carolina Electric & Gas ¹	832	4.0%
Appalachian Power ¹	749	3.6%
Union Electric ¹	741	3.6%
Portland General Electric ¹	406	2.0%
Public Service Company of Colorado	324	1.6%
Puget Sound Energy	260	1.3%
Duke Energy Progress ¹	222	1.1%
ALLETE (Minnesota Power)	122	0.6%
Green Mountain Power	107	0.5%
New York State Electric & Gas ¹	58	0.3%
Rochester Gas and Electric	55	0.3%
US Total	20,685	100%

¹ These companies were in LEI's sample for TFP trend research.

model estimation, the relatively small number of companies in the sample elevated our concern about a large enough sample for precise parameter estimates over our concern about the relevance of older data.

We believe that this data set is nonetheless the best available at reasonable cost for rigorous research on industry productivity trends and the total cost performance of OPG. It is large and varied enough to permit development of credible econometric cost models with several statistically significant business condition variables.

Ontario Data

Data Sources

Data on the cost and operations of OPG were drawn chiefly from Company responses to information requests. Most of the Canadian price data used in this study were obtained from Statistics Canada. However, data on electric utility construction cost *trends* were drawn from the *Handy Whitman Index*. Recent research by PEG found that Handy Whitman indexes were the best of several options considered for deflating the gross plant additions of Ontario power distributors.

Sample Period

Circumstances that we considered when choosing a sample period for OPG cost benchmarking research include the following:

- Standardized data on the Company's OM&A expenses are not readily available for years before 2002.
- The company has indicated that the data prior to 2016 are not comparable to data since 2016 due to a corporate reorganization.⁵⁴
- OPG's assets were revalued in April 1999.
- 1998 was the benchmark year we chose for the calculation of OPG's capital cost and quantity. This was the last value prior to revaluation. Recall from Section 2.1 above estimates of utility

⁵⁴ A1-Staff-285, part a) iv and F1-AMPCO-099.

capital costs and quantities are ideally built up from many years of data on the value of gross plant additions.

- There is understandable interest in OPG’s cost performance in the years since it started operating under more incentivized forms of ratemaking such as IR and rate freezes.

Based on these considerations, we decided to benchmark OPG’s costs starting in 2016.

7.2. Variables Used in PEG’s Benchmarking Models

We used the same approach to establishing labour price levels that we use in our transnational (U.S./Canadian) benchmarking studies for U.S. power distributors. This makes sense for several reasons.

- Prices that utilities pay for hydroelectric generation inputs are likely roughly proportional to those paid for distributor inputs.
- A sizable portion of hydroelectric generation labor often works out of offices in the larger cities that utilities serve.

The total cost of hydroelectric power generation considered in the study was the sum of applicable O&M expenses and capital costs. We consider each in turn for the U.S. and OPG.

Cost Data: U.S.

The cost of U.S. utilities that we used in our research was the sum of applicable operation and maintenance expenses and capital cost.

O&M Expenses

The applicable O&M expenses were those for hydraulic power generation (except those for “water for power”). Pension and benefit expenses were excluded from the study for several reasons. They will likely be addressed by variance accounts in OPG’s new plan, are difficult to compare to those in Canada, and are difficult to calculate reasonably for U.S. utilities since those for hydroelectric generation workers are not itemized on FERC Form 1. The third reason also provided the grounds for our exclusion all other administrative and general expenses.

Expenses for labor and other O&M inputs were not readily separable.⁵⁵ We set the share of labor in O&M expenses at 37%. This was the ratio of power production O&M labor expenses to total non-fuel production O&M expenses for utilities in the sample common to PEG and LEI that generated at least 10% of their production volume from hydroelectric generators.

Capital Cost

We calculated the cost of owning hydraulic production assets. Costs of general plant were excluded from the calculations. In the benchmarking and productivity trend research alike, we employed a monetary approach to capital cost, price, and quantity measurement that featured a geometric decay specification. We broke down capital cost into two parts: cost resulting from plant additions prior to 1985 and cost resulting from plant additions in later years of the sample period. We did this because by 1985 nearly all hydro generating stations of utilities in our sample had been constructed. Subsequent to this date we are accordingly confident that a different mix of plant additions was made, and we could assume a different decay rate and asset price index.

For each utility, capital cost of each kind was the product of a capital quantity index and a capital service price index. The capital quantity index was constructed using data on the deflated value of plant. We required the net plant value of the utility in the benchmark year and the value of gross plant additions in subsequent years.⁵⁶ Plant was valued in current dollars rather than the historical dollars used to set revenue requirements in rebasing proceedings. Capital cost effectively included depreciation expenses and a return on net plant value. Taxes and franchise fees were excluded from our capital cost calculations. Capital cost was calculated net of capital gains. The benchmark year for calculating the cost of the older plant of sampled U.S. utilities was 1964. Further information on capital cost that includes the formulas we used in our calculations is provided in Section 11.1.

⁵⁵ Data on these expenses are itemized on the FERC Form 1 for power generation but not for hydroelectric generation specifically.

⁵⁶ For the post 1985 capital quantity index the initial capital stock was zero.

Total Factor Input Prices and Quantities

Total factor input price indexes were required for the econometric total cost benchmarking. For this purpose, we calculated the total factor input price level in 2021 and then escalated it backwards and forwards using total factor input price trend indexes. The summary total factor input price trend indexes that we used was a cost-weighted average of capital and summary O&M price trend indexes.

The growth of the total factor input quantity index for each company was a cost-weighted average of the growth in quantity subindexes for O&M and plant inputs. The average share of capital in the applicable total cost of the sampled utilities was 76%.

Cost Data: OPG

O&M Expenses

The O&M expenses of OPG that we used in our research included those for hydroelectric generation operation and maintenance. Expenses for pensions and other benefits and administration were excluded from the study. We also excluded expenses that OPG reported for water for power (e.g., Gross Revenue Charges and water rental costs).

Capital Costs

Plant value data were obtained from the Company. We used data on the net value of the Company's hydro plant in 1998 --- just before revaluation --- and data on the gross value of hydro plant additions in subsequent years.

Input Prices: U.S.

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

O&M Prices

Our benchmarking and productivity research requires indexes of labour and M&S input prices.

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

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

Materials and Services Prices that U.S. utilities pay for M&S inputs are often assumed in statistical cost research to rise over time at the rate of the GDPPI. This is the U.S. government's featured index of inflation in prices of the economy's final goods and services. Final goods and services include consumer products, business equipment, and exports. We used the GDPPI as the M&S deflator even though research by PEG suggests that the GDPPI tends to materially understate the M&S price inflation of U.S. utilities.

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

Summary O&M Price Indexes We used the labour and M&S price indexes to construct summary O&M price trend indexes. Growth in the summary index for each utility was a cost-weighted average of the growth of the two subindexes. The cost share of labour was set at 37%.

Capital Asset Prices

The monetary approach to the calculation of capital cost that we used required us to construct capital (service) price indexes from asset price indexes and rates of return on capital. A multistep

process was once again used to construct the requisite capital asset prices. We first calculated an index of construction cost levels which varied between the service territories of sampled utilities in 2008 in proportion to the relative cost of local construction as measured by total heavy construction cost indexes published by RSMeans. RSMeans index values are available for multiple cities in the service territories of sampled utilities. For these utilities, we typically computed a weighted average of these values using as weights the approximate populations of the pertinent cities.⁵⁷

To obtain levelized asset price index values for other years, we trended the values for 2008 backwards and forwards using asset price trend indexes. As asset price trend indexes for the older hydro generating plant of U.S. utilities, we used the applicable regional HWIs for total hydraulic production plant. This makes sense because the older plant includes the long-lived reservoirs, dams, and water ways. As asset price trend indexes for newer plant, we used the applicable regional HWI for water wheels, turbines, and generators.

For the rates of return of U.S. utilities, we calculated 50/50 averages of rates of return for debt and equity. For debt we used the embedded average interest rate on long-term debt of a large group of electric utilities as calculated from FERC Form 1 data. For equity we used the average allowed ROE approved in electric utility rate cases as reported by the Edison Electric Institute.⁵⁸

Input Prices: OPG

O&M Prices

A price “patch” is required between O&M input prices in the U.S. and Canada. Canadian data are expressed in Canadian Dollars and the U.S. data in U.S. Dollars. When price indexes are constructed, care must be taken to make the index number for the different jurisdictions reflect the differences in currencies as well as the specific price pressures in relevant regions of a country.

⁵⁷ When multiple utilities served a city, we counted only a portion of the population.

⁵⁸ 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 backup data to *EEI Rate Case Summary* quarterly reports.

The O&M price patch that we used was a bilateral index in the form of a cost-weighted average of Canadian/U.S. price ratios for labor and M&S inputs. To calculate the labor price ratio, we relied on average annual earnings data for the utilities sectors of the United States (as computed by BLS) and Ontario (as computed by Statistics Canada. For 2021 (a census year in Canada) we calculated an index of labour price levels. This was based on itemized data that are published by Statistics Canada on median wages, salaries and commissions for utility sector workers by city.⁵⁹ Because the U.S. work was done for 2019 and the Canadian work was done for 2021, an adjustment for the two intervening years was also made. For M&S prices Purchasing Power Parities between the U.S. and Canada in 2021 were used in place of the wage rate ratio. For weights we used an average of the O&M cost shares for OPG and the US sample.

For other years of the sample period, we escalated the O&M price index for OPG using an O&M price index. The growth rate of this index was a cost-weighted average of the growth rates of the Ontario fixed weighted index of average hourly earnings (“FWI AHE”) and the gross domestic product implicit price index for final domestic demand (“GDPIPI^{FDD}”) of Canada. The GDPIPI^{FDD} is preferable to the more comprehensive GDPIPI because the latter is quite sensitive to the volatile prices of Canada’s sizable commodity (e.g., oil, gas, metals, and wood) exports.

Capital Prices

The capital price for OPG will differ from those for US generators due to the asset price trend, the asset price level, and the rate of return used. The asset price index used for each generator was assigned a level in 2008 using the city cost indexes published by RSMeans. These index numbers all reference a 30 US city average and control for currency differences. Values for other years were obtained by trending forward and backward from 2008 using the appropriate asset price trend index. The levelized asset price indexes were used to calculate capital service prices for each generator. These price indexes are all consistent because the asset price reference the same 30 city reference point. The

⁵⁹ These data are found in Statistics Canada table 11-10-0073-01: Wages, salaries and commissions of tax filers aged 15 years and over by main industry sector and sex. The utility sector of Canada’s economy includes gas, water, and sewage utilities as well as electric utilities. The table reports median wages, salaries and commissions for various industries including the utilities sector.

Handy Whitman Indexes of electric utility construction cost for hydraulic power production plant were used as the asset price trend indexes. For OPG, we used the average value from RS Means for all available Ontario cities in 2008. The HWI for the North Atlantic region was used for OPG. We obtained data on the target rate of return on capital ownership from OPG.

Scale Variables

Two scale variables were considered in our benchmarking and productivity trend research: hydroelectric generation capacity and volume. Other variables that we considered --- the number of generation units and generating stations (plant) operated, behave like scale variables. The parameters of the first-order terms of all these variables should have positive signs in all three econometric cost models. Our research consistently found that when both capacity and volume variables were included in the model the parameter estimate for the volume variable was statistically insignificant whereas that for the capacity variable was highly significant.

Other Business Condition Variables

Several other business condition variables were considered in our econometric hydro generation cost modelling. There are two age variables. One is the share of conventional hydro generation capacity that was established prior to 1964. Recall that this was the benchmark year for calculating the cost and quantity of older plant. This variable captures the net effect of owning and operating unusually old stations and any inaccuracy of the benchmark year adjustment. The second age variable is the capacity-weighted average age of conventional hydro generating plants. There is no predicted sign for either variable in any of the cost models.

The model also includes variables measuring the number of plants that are run of river and the share of generation capacity that involves pumped storage. The first of these variables should have a negative sign in all three cost models because these kinds of hydro facilities typically don't involve dams. The sign on the pumped storage variable is indeterminate in all three models.

The model also contains a trend variable. This captures the typical net effect on cost of business conditions that are excluded from the model. These conditions include change in production technology



and in any business conditions that are excluded from the model. There is no expected sign for the trend variable parameter.

8. PEG's Alternative Cost Benchmarking Research

Relying on our own U.S. data, PEG developed alternative econometric benchmarking models of the total cost, O&M, and capital costs of hydro generation. The incremental cost of benchmarking O&M and capital cost is modest as the business condition variables meriting consideration are largely the same as those in total cost research and there are other shared costs. Despite the low cost, these models yield insights and may help drive performance improvements.

8.1. Differences from LEI's Benchmarking Methodology

Here are some salient differences from LEI's benchmarking methodology.

- We provide separate cost benchmarking models for O&M, capital, and total cost.
- Capital cost was the annual cost of capital ownership. Calculated using a monetary method, it includes depreciation expenses and a pro forma return on asset value. Gross plant additions for improvements and capacity expansions were included.
- Quadratic terms for scale variables permitted consideration of achievable scale economies.
- The focus is on the total cost of hydro generation and not an unweighted *average* of the cost of individual hydro units. This implicitly gives more weight to the larger generating units that matter more to customers.
- The trend in OPG's recent historical cost performance was measured and forecasted costs and revenue requirements were benchmarked.
- The sample period for cost model estimation was 21 years, not four years. This facilitated precise parameter estimation and reduced the sensitivity of parameter estimates to the special conditions of the Covid pandemic.



- To deflate OPG’s plant values for use in benchmarking we used regional HWIs for hydro production plant, not a macroeconomic inflation index.
- We levelized the input price indexes of sampled U.S. utilities.
- PEG’s input price index for materials and services was quarter-levelized. This approach permits M&S prices to be higher where labour prices are higher.
- We use the “Fixed-b” standard error correction to Driscoll-Kraay to improve the robustness of our estimates of standard errors.^{60,61} This increased the accuracy of statistical tests of the significance of model parameter estimates.
- Our benchmarking data are available for perusal by all parties although they will be required to sign a confidentiality agreement.

8.2. Econometric Modelling 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.

Each table reports econometric estimates of parameters of the model’s business condition variables 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.

Our estimates of the parameters of the number of plants and units were much higher than expected. In each model one or the other of these variables predominated. Model explanatory power

⁶⁰Paper available at: <https://www.princeton.edu/~erp/erp%20seminar%20pdfs/papersspring09/hansen.pdf>

⁶¹Code available from Tim Vogelsang, a professor at Michigan State University, on his academic website: <https://sites.google.com/view/tim-vogelsang-msu/code>

was enhanced by adding quadratic terms for capacity and the number of either units or plants in each model.

Econometric results for PEG's hydroelectric generation total cost model are presented in Table 5. Here are some salient results.

- The parameter estimates of the capacity and generation units variables were both highly significant and positive. The units variable likely captures the cost impact of having generating units in multiple locations. The parameter estimates for the quadratic term associated with the units variable was also highly significant. The relationship of cost to this variable was therefore significantly nonlinear.
- Total cost was higher the higher was the share of capacity that was established prior to 1964. However, it was lower the higher was the average age of generating stations. This suggests that there was a general tendency of capacity cost to fall with system age until a sizable number of plants had advanced age.
- Total cost was also lower the higher was the share of generating capacity devoted to pumped storage and the greater was the number of the company's run of river stations.
- The estimate of the trend variable parameter suggests that there was about a 2.88% annual increase in real total cost over the 21-year sample period for reasons other than changes in the values of the included business condition variables.
- The 0.973 adjusted R^2 statistic suggests that the model had a high degree of explanatory power. However, these statistics tend to have high values in models of this kind.



Table 5

PEG's Econometric Model of Total Hydroelectric Generation Cost

VARIABLE KEY

MW Cap = Total MW Capacity
 Units = Number of Generator Units
 Units Sq = Number of Generator Units squared
 % MW PS = % MW Pumped Storage
 %CH = % Conventional Hydroelectric pre-1964
 CH Gen Age = Weighted Average CH Generator Age
 PlantsRiver = Number of Plants Run of River
 TREND = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
MW Cap	0.590***	126.323	0.000
Units	0.684***	39.217	0.000
Units Sq	0.499***	12.445	0.000
% MW PS	-0.0641***	-6.891	0.000
%CH	0.689***	56.783	0.000
CH Gen Age	-1.375***	-33.635	0.000
PlantsRiver	-0.245***	-18.573	0.000
TREND	0.0288***	26.387	0.000
CONSTANT	17.75***	683.093	0.000

Adjusted R² **0.973**

Sample Period 2004-2024

Number of Observations 429



Capital Cost

Details of PEG's hydroelectric generation capital cost model are presented in Table 6. Here are some key findings.

- The parameter estimates for the capacity and generating unit variables were highly significant and positive. The parameter estimates for the extra quadratic terms for these variables were also highly significant. This suggests that the relationship of capital cost to both variables was significantly nonlinear.
- Both age variables were also highly significant. Capital cost was higher the greater was the share of generation capacity built before 1964. Capital cost was lower, however, the higher was the average age of plants.
- Generation capital cost was lower the greater was the percentage of capacity dedicated to pumped storage and the number of run of river plants.
- The estimate of the trend variable parameter indicates that there was a substantial 3.56% annual increase in capital cost for reasons other than changes in the values of the model's business condition variables.
- The 0.957 value of the adjusted R^2 for the model was a little lower than that for the total cost model.



Table 6

PEG's Econometric Model of Hydroelectric Generation Capital Cost

VARIABLE KEY

MW Cap = Total MW Capacity
 MW Cap Sq = Total MW Capacity squared
 Units = Number of Generator Units
 Units Sq = Number of Generator Units squared
 % MW PS = % MW Pumped Storage
 %CH = % Conventional Hydroelectric MW pre-1964
 CH Gen Age = Weighted Average CH Generator Age
 PlantsRiver = Number of Plants Run of River
 TREND = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
MW Cap	0.635***	40.964	0.000
MW Cap Sq	0.0672***	6.103	0.000
Units	0.643***	20.435	0.000
Units Sq	0.412***	6.953	0.000
% MW PS	-0.0197*	-2.060	0.039
%CH	0.865***	24.931	0.000
CH Gen Age	-1.767***	-31.764	0.000
PlantsRiver	-0.253***	-15.467	0.000
TREND	0.0356***	43.643	0.000
CONSTANT	15.02***	500.200	0.000

Adjusted R² **0.957**
 Sample Period 2004-2024
 Number of Observations 429



O&M Expenses

Results of PEG's hydroelectric generation O&M cost research are presented in Table 7. Please note the following.

- The parameter estimates for the capacity and plants variables were both highly significant and positive. The parameter estimates for the extra quadratic terms for these variables were also highly significant. This suggests that the relationship of O&M cost to both variables was significantly nonlinear.
- O&M expenses were higher the higher was the share of generation capacity built before 1964. However, the impact of this variable was much lower than in the capital cost model. This plausibly suggest that system age primarily affects capital cost.
- O&M expenses were lower to the extent that a high share of capacity was devoted to pumped storage and the higher was the number of utility-owned run of river plants.
- The trend variable parameter estimate indicates that O&M cost growth grew by about 0.88% per year for reasons other than changes in the values of the business condition variables included in the model during the sample period.
- Table 7 also reports a 0.942 adjusted R^2 statistic for the O&M model. This is modestly below the corresponding statistics for the total cost and capital cost models. Evidently, the O&M expenses of sampled generators proved more difficult to accurately model than their capital cost or total cost.



Table 7

PEG's Econometric Model of Hydroelectric Generation O&M Expenses

VARIABLE KEY

MW Cap = Total MW Capacity
 MW Cap Sq = Total MW Capacity squared
 Plants = Number of Plants
 Plants Sq = Number of Plants squared
 % MW PS = % MW Pumped Storage
 %CH = % Conventional Hydroelectric MW pre-1964
 PlantsRiver = Number of Plants Run of River
 TREND = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
MW Cap	0.615***	16.822	0.000
MW Cap Sq	-0.105***	-3.982	0.000
Plants	0.470***	26.609	0.000
Plants Sq	0.289***	20.513	0.000
% MW PS	-0.210***	-17.547	0.000
%CH	0.228***	4.715	0.000
PlantsRiver	-0.0939***	-7.314	0.000
TREND	0.00875*	2.407	0.016
CONSTANT	16.93***	217.426	0.000

Adjusted R² 0.942

Sample Period 2004-2024

Number of Observations 429



8.3. Business Conditions Facing OPG

The external cost drivers faced by OPG should be considered when benchmarking the Company's cost. Table 8 compares OPG's cost and external business conditions to the sample mean values in 2023. The following results are notable.

- OPG's total cost was about 4.33 times the sample mean. The input prices that the Company faced were about 1.06 times the mean. Thus, the Company's real total cost was $4.33/1.06 = 4.08$ times the mean.
- OPG's capacity was meanwhile about 5.04 times the mean, while its number of plants was about 3.25 times the mean and number of generation units was about 4.56 times the mean.
- OPG's total number of plants using run-of-river was about 5.57 times the mean, while its percentage of total hydroelectric capacity that is pumped storage was about 0.11 times the mean.
- The Company's percentage of in-service conventional hydro generation units that were installed prior to 1964 was 1.03 times the mean. OPG's overall average age of in-service generators in years was about 0.90 times the mean. Importantly, these results together mean that the age of OPG's generating stations is similar to sample norms.

8.4. Econometric Benchmarking Results

We benchmarked the O&M, capital, and total hydroelectric generation cost of OPG in each year of the historical 2016-2024 period as well as in the 2025-2031 period for which the Company has provided cost forecasts or, in the case of O&M revenue, has proposed to index escalation. All benchmarks were based on our econometric model parameter estimates and values for the business condition variables which are appropriate for the Company in each year.



Table 8

How Business Conditions Facing OPG Compare to the Sample Mean (2023)

	OPG	Sample	OPG/Sample
Cost	\$ 682,324,633	\$ 157,682,757	432.7%
O&M	\$ 196,560,000	\$ 40,505,105	485.3%
Capital	\$ 485,764,633	\$ 117,177,652	414.6%
Scale			478.5%
Total Capacity in MW	6,556	1,300	504.3%
Total Generating Units	206	45	456.3%
Total Plants	54	17	324.9%
Input Price	1.28	1.20	106.4%
O&M	1.72	1.45	119.1%
Capital	9.94	10.10	98.4%
Business Conditions			
% Pumped Storage MW of Total Capacity	3%	23%	11.3%
% Conventional Hydro Generator Units pre-1964	82%	79%	103.4%
Average Age in Years, Weighted by Generation MW	69	77	90.3%
Number of Plants Run-of-River	39	7	557.1%

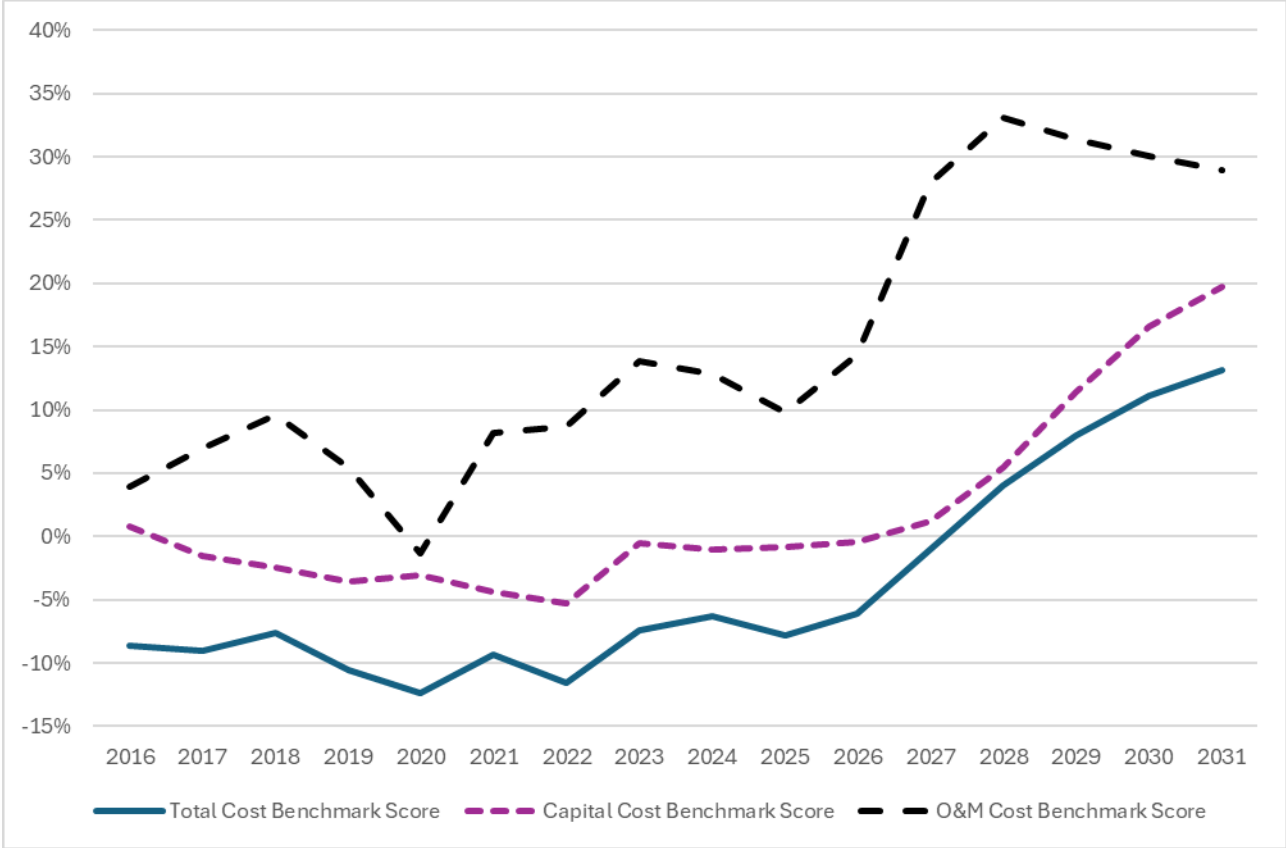
Table 9 and Figure 1 report results of this benchmarking work. For each cost considered, the table shows results for each year and highlights the average results for all historical years, the last three historical years, and the seven forecasted years that include the five years of the proposed rate plan.



Table 9
Year-by-Year Hydro Generation Cost Benchmarking Results
 [Actual - Predicted Cost]

Year	Total Cost Benchmark	Capital Cost Benchmark	O&M Cost Benchmark
	Score	Score	Score
2016	-8.65%	0.84%	3.94%
2017	-9.06%	-1.55%	6.96%
2018	-7.65%	-2.43%	9.59%
2019	-10.53%	-3.53%	5.43%
2020	-12.36%	-3.10%	-1.30%
2021	-9.33%	-4.40%	8.20%
2022	-11.52%	-5.27%	8.70%
2023	-7.45%	-0.58%	13.81%
2024	-6.29%	-1.05%	12.85%
2025	-7.78%	-0.88%	9.76%
2026	-6.09%	-0.45%	14.33%
2027	-1.05%	1.17%	27.97%
2028	4.03%	5.46%	33.07%
2029	7.99%	11.43%	31.41%
2030	11.17%	16.61%	30.09%
2031	13.14%	19.77%	28.93%
Averages			
2016-2024	-9.20%	-2.34%	7.58%
2022-2024	-8.42%	-2.30%	11.79%
Forecast Period 2025-2031	3.06%	7.59%	25.08%
CIR Period 2027-2031	7.06%	10.89%	30.30%

Figure 1
Cost Benchmarking Results Using PEG's Models



Total Cost

The results of our hydro generation *total* cost benchmarking show that OPG's total cost was appreciably below the model's predictions in all historical years. Total cost was about 8.4% below the model's prediction on average in the last three years of the historical period (2022-2024). The efficiency implicit in the Company's revenue requirement projection will deteriorate materially during the proposed CIR plan. Projected/proposed total cost will be above the benchmarks by about 7.1% on average during the 2027-2031 term of the plan.

Capital Cost

The results of our hydro generation *capital* cost benchmarking show that OPG's capital cost efficiency tended to be a little above average during the historical years considered. During the last three historical years capital cost was 2.3% below the model's prediction on average. Capital cost performance will deteriorate materially during the proposed CIR plan, however, averaging about 10.9% above the model's predictions.

O&M Expenses

OPG's O&M costs efficiency tended to be a little worse than the norm during the historical years considered. These costs were about 11.8% above the model's predictions on average during the 2022-2024 period. Controversially, O&M cost performance will deteriorate dramatically in 2027, the first year of the new plan. Over the five years of the proposed CIR plan cost would be about 30.3% above our model's prediction on average. This raises concerns about deferral of O&M expenses by the Company during the last few years. This could reflect pressures to contain O&M expenses during the expiring rate freeze. Strategic deferral of costs was the topic of a recent Spending Pattern Analysis paper by PEG for OEB Staff.⁶²

9. Hydroelectric Generation Productivity Trends

Given our concerns about LEI's productivity trend research methods and the impracticality of correcting their study to get satisfactory results, PEG prepared an independent study of the productivity trends of hydroelectric generators. Our recommended productivity factor for OPG is based on the trends in the hydro generation TFP of a sample of 20 US electric utilities. We also calculated the trends in the O&M and capital productivity of sampled generators.

⁶² Lowry, Mark N., et al., "Report on Spending Patterns and Capitalization Policy," *op. cit.*

Sample Period

The full sample period considered was the 28 growth rate years from 1997 to 2024. Our featured productivity trend results are for the fifteen-year 2010-2024 period. We also report productivity trend results for the 2003-2023 and 2009-2023 periods that are featured in LEI's report.

Details of the Productivity Calculations

Here are some salient details of our productivity trend calculations.

- The output or scale variable for the study was hydro generation capacity. Recall that the parameter estimate for the volume variable was not statistically significant in our econometric research.
- The capital cost and quantity of each generator was calculated using a monetary method that featured geometric decay. The benchmark year for the calculation of old plant was 1964, not 1994 as in the LEI study.
- The growth (rate) of productivity was measured as the difference between the growth of capacity and the growth of an input quantity index. We feature results using capacity as the scale metric although results using volume are also reported.
- We computed cost-weighted averages of the results for individual generators. This approach yields much more information than the approach that LEI used, which was to compute the productivity of an aggregated utility industry.
- PEG calculated the O&M, capital, and total factor productivity growth of each sampled generator. Growth of the O&M input quantity index was calculated as the difference between the growth of included O&M expenses and the growth of an O&M input price trend index. Growth of the total factor input quantity of each generator was then calculated as a weighted average of the growth of its O&M and capital quantity indexes using company-specific and time-variant cost share weights.
- We used chain-weighted Tornqvist forms for the multifactor input quantity indexes and input price indexes that we used in our calculations. This form has good statistical properties and is



widely used in productivity research.⁶³ It is more intuitively appealing and easier to code and review than the chained Fisher Ideal form and should produce similar results.

Productivity Trend Results

Table 10 provides summary cost-weighted results of our productivity growth calculations. In our research as in LEI's, this gives substantial weights to a handful of sampled utilities. For example, the data in Table 3 above suggests that the shares of Pacific Gas & Electric, Duke Energy Carolinas, Virginia Electric, Idaho Power, and Alabama Power in the 2024 hydro generating capacity of PEG's sample of utilities were 18%, 17%, 10%, 9%, and 8% respectively.

Inspecting the results in Table 10, it can be seen that there was a remarkable decline in the capital and total-factor productivity growth of the industry over the full sample period. For example, TFP growth was generally brisk in the early years of the period, averaging 0.91% annual growth from 1997 to 2014. Over the featured 15-year sample period, however, TFP growth averaged a 0.66% annual decline. Note also that productivity trends would be much more negative using volume as the scale variable.

Table 10 also reports the standard deviations of the growth rates of the productivity indexes and some components for our 15- and 20-year sample periods. It can be seen that O&M input quantity and productivity growth are much more volatile than the corresponding results for capital. We therefore also calculated and report in Table 10 trend regressions like those that LEI calculated. It can be seen that the 15-year TFP growth trend was -0.47%. We recommend this as the best available estimate of the recent TFP trend of the hydro generation industry. The O&M productivity growth trend was -0.14% using trend regressions while the capital productivity growth trend was -0.60%.

⁶³ LEI, *op. cit.*, p. 52.

Table 10

Hydroelectric Generation Productivity Growth of US Investor-Owned Electric Utilities: Cost-Weighted Averages¹

Year	Output			Inputs			Multifactor Productivity		O&M Productivity	Capital Productivity
	Capacity [A]	Volume [B]	Differential [A-B]	Capital	O&M	Multifactor	Capacity	Volume	(Capacity)	(Capacity)
1997	0.30%	-0.28%	-0.58%	-1.95%	-6.62%	-2.70%	3.00%	2.42%	6.92%	2.25%
1998	0.12%	5.32%	5.20%	-1.43%	-4.48%	-1.97%	2.09%	7.29%	4.60%	1.55%
1999	-0.67%	-14.69%	-14.02%	-2.08%	8.31%	-0.59%	-0.08%	-14.10%	-8.98%	1.41%
2000	2.00%	-10.91%	-12.91%	-1.89%	-10.66%	-2.20%	4.20%	-8.71%	12.66%	3.89%
2001	0.31%	-15.63%	-15.94%	-1.98%	4.40%	-1.65%	1.95%	-13.99%	-4.09%	2.29%
2002	2.00%	10.05%	8.05%	-1.83%	-1.15%	-1.76%	3.76%	11.81%	3.15%	3.83%
2003	2.00%	17.16%	15.16%	-1.65%	4.96%	-0.61%	2.61%	17.77%	-2.96%	3.65%
2004	-0.27%	-9.70%	-9.43%	-1.91%	4.68%	-0.72%	0.45%	-8.98%	-4.95%	1.64%
2005	0.51%	4.78%	4.27%	-1.31%	2.43%	-0.80%	1.31%	5.58%	-1.93%	1.82%
2006	0.24%	2.32%	2.08%	1.24%	-5.14%	0.22%	0.02%	2.10%	5.38%	-1.00%
2007	1.67%	-31.83%	-33.50%	-1.40%	10.79%	0.96%	0.70%	-32.79%	-9.12%	3.06%
2008	-0.14%	2.94%	3.08%	-0.93%	2.15%	-0.20%	0.05%	3.14%	-2.30%	0.79%
2009	0.11%	20.40%	20.30%	-0.71%	5.23%	0.65%	-0.55%	19.75%	-5.13%	0.82%
2010	-0.01%	-1.32%	-1.31%	-0.76%	2.96%	0.24%	-0.25%	-1.57%	-2.97%	0.75%
2011	0.05%	3.45%	3.40%	1.01%	1.23%	1.26%	-1.21%	2.19%	-1.18%	-0.96%
2012	-0.05%	-21.33%	-21.29%	0.81%	0.23%	0.65%	-0.69%	-21.98%	-0.28%	-0.85%
2013	1.66%	6.12%	4.46%	1.74%	0.73%	1.46%	0.20%	4.66%	0.93%	-0.08%
2014	0.82%	-12.66%	-13.48%	2.88%	0.13%	2.01%	-1.19%	-14.67%	0.68%	-2.07%
2015	-0.37%	-9.66%	-9.29%	0.66%	2.87%	1.20%	-1.57%	-10.86%	-3.24%	-1.03%
2016	0.60%	29.18%	28.58%	-0.21%	1.35%	0.02%	0.58%	29.16%	-0.76%	0.81%
2017	-0.05%	12.81%	12.86%	0.62%	-0.77%	0.27%	-0.32%	12.54%	0.72%	-0.67%
2018	0.22%	-9.10%	-9.32%	0.11%	-5.06%	-1.28%	1.50%	-7.82%	5.28%	0.11%
2019	-0.11%	4.42%	4.53%	0.65%	1.77%	0.99%	-1.10%	3.43%	-1.88%	-0.76%
2020	-0.35%	-19.29%	-18.94%	0.36%	4.86%	2.20%	-2.55%	-21.49%	-5.21%	-0.71%
2021	0.26%	-17.31%	-17.57%	1.48%	-11.93%	-2.37%	2.63%	-14.94%	12.18%	-1.22%
2022	-0.82%	7.11%	7.93%	-0.63%	3.96%	0.36%	-1.18%	6.75%	-4.78%	-0.19%
2023	0.34%	10.61%	10.27%	0.62%	4.33%	1.39%	-1.05%	9.22%	-3.99%	-0.28%
2024	-0.87%	-1.93%	-1.06%	1.31%	6.79%	2.87%	-3.74%	-4.79%	-7.66%	-2.18%
Average Annual Growth Rates:										
1997-2014	0.59%	-2.55%	-3.14%	-0.67%	1.12%	-0.32%	0.91%	-2.23%	-0.53%	1.27%
2003-2023 (21 recent years)	-0.30%	0.52%	0.82%	-0.13%	-1.51%	-0.38%	0.08%	0.90%	1.21%	-0.17%
2009-2023 (15 recent years)	0.15%	0.23%	0.08%	0.58%	0.79%	0.60%	-0.45%	-0.38%	-0.64%	-0.42%
2005-2024 (last 20 years)	0.18%	-1.02%	-1.20%	0.38%	1.45%	0.60%	-0.42%	-1.62%	-1.26%	-0.19%
2010-2024 (last 15 years)	0.09%	-1.26%	-1.35%	0.71%	0.90%	0.75%	-0.66%	-2.01%	-0.81%	-0.62%
2015-2024 (last 10 Years)	-0.12%	0.68%	0.80%	0.50%	0.82%	0.56%	-0.68%	0.12%	-0.93%	-0.61%
Trend Regressions										
2003-2023 (21 recent years)	0.29%	-1.04%	-1.32%	0.33%	1.32%	0.52%	-0.24%	-1.56%	-1.03%	-0.05%
2009-2023 (15 recent years)	0.20%	-0.77%	-0.97%	0.72%	0.33%	0.61%	-0.41%	-1.38%	-0.13%	-0.52%
2005-2024 (last 20 years)	0.22%	-0.96%	-1.19%	0.50%	1.07%	0.61%	-0.39%	-1.57%	-0.84%	-0.28%
2010-2024 (last 15 years)	0.15%	-1.08%	-1.23%	0.74%	0.29%	0.61%	-0.47%	-1.69%	-0.14%	-0.60%
Standard Deviations										
2005-2024 (last 20 years)	0.66%	14.80%	14.90%	1.11%	4.79%	1.21%	1.43%	14.91%	4.83%	1.26%
2010-2024 (last 15 years)	0.63%	13.87%	13.77%	0.93%	4.51%	1.33%	1.54%	13.90%	4.76%	0.86%

¹ Growth rates are calculated logarithmically.

10. X Factor and Stretch Factor Recommendations

10.1. Base Productivity Growth Trend

Our results suggest that the hydroelectric TFP growth of the sampled US utilities is considerably more negative than in the past. Utilities are no longer realizing appreciable scale economies and as their facilities age, maintenance and replacement costs have loomed larger relative to their depreciating capital stock of older plant. Most hydroelectric generators in the States are not, like the power transmitters considered in the last Hydro One IR proceeding, operating under incentive-weakening formula rates.

PEG has occasionally proposed a negative productivity factor in OEB proceedings and this is a good proceeding to remind the panel of the reasons that it can make sense when there is strong evidence of declining industry productivity that is driven by external business conditions.⁶⁴ Productivity is not a pure measure of cost efficiency and can reflect mounting and widespread external cost pressures such as an increase in the share of generation capacity that is quite aged. A negative productivity factor can reduce the recourse of utilities to CIR and their complaints about implicit stretch factors. These complaints are sometimes legitimate as they pertain to OM&A revenue and thereby reduce the reasonableness of beefing up stretch factors on other grounds. We provide ratemaking formulas for implementing a negative productivity factor in Section 2.1.

In an application to OPG, a negative productivity factor would increase OM&A revenue escalation compared to the Company's proposal, but capital revenue escalation would be unaffected using the ratemaking formula we set forth in Section 2.1. A non-negativity restriction prohibits adding a negative productivity factor to capital revenue requirement growth that is based on a cost forecast. The revenue supplement provided by the C factor would then since I-X grows more rapidly. OPG would have no legitimate complaint about an implicit stretch factor and the panel would have more freedom to increase stretch factors on other grounds.

⁶⁴ See, for examples, EB-2024-0111, Exhibit M3, "Empirical Research for Enbridge Gas IR," August 13, 2024 and EB-2021-0110, Exhibit M, "Incentive Rate-Setting for Hydro One Transmission and Distributor Services," January 12, 2022.



Based on this reasoning we note that a **-0.47%** Productivity Factor can make sense for OPG if it is combined with our recommendation for a **0.30%** supplemental capital stretch factor. Consumers would then benefit on balance, since the slowdown in capital base revenue is much larger than the acceleration in OM&A base revenue.

Should the panel choose not to approve a negative productivity factor, it may reason that OPG has anticipated the implicit stretch factor in proposing a marked increase in its OM&A expenses in 2027. Furthermore, the OM&A productivity decline of the industry in the last 15 years has averaged only 0.14%.

10.2. Stretch Factor

We have provided evidence on the cost performance of OPG that is useful for setting stretch factors.

- The forecasted total cost of the Company in each year of the proposed CIR plan is on average about 7.1% above our econometric total cost benchmark. This is commensurate with a 0.30% stretch factor in Ontario.
- The utilities in the sample did not operate in an unusually weak incentive environment like the formula rates that are typical in FERC power transmission regulation.

Based on these results PEG recommends a **0.30%** stretch factor for the Company.

11. Additional Information on Research Methods

11.1 Capital Cost Specification

For this proceeding we used a geometric decay specification in our research on capital and total factor productivity trends and capital and total cost benchmarking. This specification was applied separately to older plant and to plant added from 1985 onwards. Data previously processed by PEG permitted us to use 1964 as the initial year for our U.S. capital cost and quantity calculations for older plant. The value of the “old” capital quantity index for each U.S. utility in 1964 depended on the net (“book”) value of hydraulic production 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 49 consecutive values of the applicable regional HWI for total hydraulic production plant. A triangularized weighted average places a greater weight on more recent values of the construction cost index. This makes sense intuitively since more recent plant additions are less depreciated and to that extent tend to have a bigger impact on net plant value.

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

$$XK_{j,t} = (1-d) \cdot XK_{j,t-1} + \frac{VKA_{j,t}}{WKA_{j,t}}. \quad [25]$$

Here, the parameter d is the assumed (constant) decay rate and $VKA_{j,t}$ is the value of gross additions to utility plant. To determine a value for d for the old plant of U.S. utilities we assumed a 1.65 declining balance rate for equipment and a 0.91 declining balance rate for structures d . To determine the value of d for new plant we used only the 1.65 declining balance rate for equipment.

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

$$WKS_{j,t} = d \cdot WKA_{j,t} + r_t \cdot WKA_{j,t-1} + (WKA_{j,t} - WKA_{j,t-1}). \quad [26]$$

The first term in this formula corresponds to the cost of depreciation. The second term corresponds to the return on capital. The term in parentheses corresponds to capital gains.⁶⁵ In these calculations, we used the applicable regional HWI for total hydraulic production plant to calculate the WKA for old plant and the applicable regional HWI for water wheels, turbines, and generators to calculate the WKA for new plant.

⁶⁵ The capital gains term is smoothed. A 15-year compound annual growth rate is calculated for the asset price. This is multiplied by the lagged asset price to calculate the change in the value of WKA shown in the formula.

11.2 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:

$$C_{h,t} = a_0 + a_1 \cdot CAP_{h,t} + a_2 \cdot N_{h,t}. \quad [27]$$

Here, for each company h in year t , $C_{h,t}$ is cost, $CAP_{h,t}$ is generation capacity and $N_{h,t}$ is the number of generating plants. Here is an analogous cost model of *double log* form:

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln CAP_{h,t} + a_2 \cdot \ln N_{h,t}. \quad [28]$$

The double log model is so-called because the right- and left-hand side variables in the equation are all logged.⁶⁶ 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 [28] indicates the percentage change in cost resulting from 1% growth in capacity.

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 log-linear quadratic form:

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln CAP_{h,t} + a_2 \cdot \ln N_{h,t} + a_3 \cdot \ln CAP_{h,t} \cdot \ln CAP_{h,t} + a_4 \cdot \ln N_{h,t} \cdot \ln N_{h,t} \quad [29]$$

⁶⁶ 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 terms. These are sometimes called second-order terms. Quadratic terms like $\ln CAP_{h,t} \cdot \ln CAP_{h,t}$ permit the elasticity of cost with respect to output growth to depend on 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.

The log-linear quadratic 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. One disadvantage of the translog form is that it involves many more variables. As the number of variables in a cost model increases, we have noted that the precision of a model’s parameter estimates and cost predictions falls. It is therefore common in econometric cost research to limit the number of variables accorded quadratic treatment.

In our econometric work for this proceeding, we have chosen a functional form that has second-order terms only for the scale and scale-related variables. All of the quadratic 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, 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 estimation methods with robust Driscoll-Kraay standard errors calculated using fixed-b asymptotics. The resulting standard errors are robust to heteroskedasticity, autocorrelation, and spatial correlation, and the test statistic thresholds are adjusted for the small sample size.



11.3 Additional Details of the Productivity Research

Input Quantity Indexes

The quantity subindex for O&M was the ratio of applicable O&M expenses to an O&M input price index. The growth rate of the summary O&M input price index was a cost-weighted average of the growth rates of input price subindexes for labor and M&S inputs. The share of labor in O&M expenses was fixed for the sample period at about 37%.

The growth rate of the labor price index was calculated for later years of the sample period as the growth rate of the national employment cost index (“ECI”) for the salaries and wages of the utility sector of the US economy plus the difference between the growth rates of the *multi-sector* ECI for workers in each utility’s service territory and the multisector ECI for the nation as a whole.⁶⁷ In the early years we used the ECI for the electric, gas, and sanitary sector in this formula. We used the gross domestic product price index (“GDPPI”) as a proxy for the M&S price index.

The summary input quantity index for each company was of chain-weighted Törnqvist form.⁶⁸ This means that its annual growth rate was determined by the following general formula:

$$\ln\left(\frac{\text{Inputs}_t}{\text{Inputs}_{t-1}}\right) = \sum_j \frac{1}{2} \cdot (sc_{j,t} + sc_{j,t-1}) \cdot \ln\left(\frac{X_{j,t}}{X_{j,t-1}}\right). \quad [30]$$

Here in each year t ,

Inputs_t = Summary input quantity index

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

$sc_{j,t}$ = Share of input category j in the applicable cost.

It can be seen that the growth rate of the index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities

⁶⁷ Utilities no longer report on their FERC Form 1 the number of workers that they employ.

⁶⁸ For seminal discussions of this index form, see Törnqvist (1936) and Theil (1965).

in successive years. Data on the average shares of each input in the applicable cost of each utility in the current and prior years served as weights.

Productivity Growth Rates and Trends

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

$$\ln\left(\frac{Productivity_{j,t}}{Productivity_{j,t-1}}\right) = \ln\left(\frac{Output\ Quantities_{j,t}}{Output\ Quantities_{j,t-1}}\right) - \left(\frac{Input\ Quantities_{j,t}}{Input\ Quantities_{j,t-1}}\right). \quad [31]$$

The long-run trend in each productivity index was calculated as its average annual growth rate over the full sample period.



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