Exhibit M3

Empirical Research for Enbridge Gas IR

13 August 2024

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Executive Summary

In proceeding EB-2024-0111, Enbridge Gas Inc. ("EGI") has proposed a new incentive rate-setting mechanism for its regulated Ontario gas services. This is a multiyear rate plan in which rates would be escalated by an index formula that includes a productivity factor and a stretch factor. EGI proposes a -1.5% X factor that is the sum of a -1.5% productivity factor and a 0% stretch factor. These proposed parameters are based on productivity and statistical benchmarking research and testimony by Black and Veatch Management Consulting ("BV"). BV used a simple unit cost benchmarking method and a hyperbolic decay capital cost specification that has rarely if ever been used in Ontario Energy Board ("OEB") Incentive Regulation ("IR") proceedings. EGI also proposes use of a different labor price index in its inflation factor formula than the OEB has previously used in IR.

OEB Staff have retained Pacific Economics Group Research LLC ("PEG") to prepare research and testimony on the appropriate inflation factor, productivity factor, and stretch factor for EGI's new rate plan. We critiqued BV's evidence and undertook independent studies of EGI's cost performance and U.S. gas utility productivity trends. We acknowledge that we have a duty to provide opinion evidence to the OEB that is fair, objective, and non-partisan.

Critique of BV's Evidence

We have several major concerns about BV's productivity and transnational (Ontario-U.S.) benchmarking evidence.

- BV used crude unit cost metrics to benchmark EGI even though transnational econometric benchmarking is common for larger electric utilities in OEB IR and econometric benchmarking of gas utility cost is well established and has been used by EGI in past proceedings.
- The peer groups used to establish a productivity factor and a stretch factor for EGI are inappropriate.
- Pension and benefit expenses are not excluded from the calculations, as they typically are in Ontario IR evidence.
- Results are provided only for total cost and multifactor productivity even though valuable results about operation and maintenance ("O&M") and capital cost and productivity can be produced at modest incremental cost.

PEG Empirical Research

Data

The primary source of data used in this study was publicly-available gas utility reports to state regulators. These data are difficult to gather and most efficiently procured from private vendors. There were 57 U.S. utilities in the samples for our econometric cost research and industry productivity trend research.

EGI Cost Benchmarking Results

We developed econometric models of the O&M, capital, and applicable total cost of gas utility services. Numerous cost drivers were identified that had statistically significant and plausible parameter estimates. We used these models to benchmark the corresponding costs of EGI over the historical years from 2019 to 2022.

Total Cost

In the three years from 2020 to 2022, the total cost of EGI was about 23% above our econometric benchmarks on average.[1] This score is commensurate with a bottom quartile performance ranking in our U.S. sample.

Capital Cost

From 2020 to 2022, EGI's capital cost was about 25% above our benchmarks on average. This score is also commensurate with a bottom quartile ranking.

O&M Cost

From 2020 to 2022, the O&M expenses of EGI were about 6% above our benchmarks on average. This score is commensurate with a third quarter ranking in our U.S. sample. A better score for O&M than for capital cost performance makes sense since EGI and its legacy companies have been subject to stronger O&M cost containment incentives under Ontario ratemaking.

[1] All percentages are stated in logarithmic terms.

U.S. Gas Utility Productivity Trends

We calculated trends in the O&M, capital, and total factor productivity ("TFP") of the U.S. gas utilities in our sample. Using even-weighted averages we find that TFP averaged a 1.26% annual decline.[2] O&M productivity growth averaged a slight 0.01% annual decline while capital productivity growth averaged a more substantial 2.17% annual decline.

Productivity growth was slowed by business conditions quite different from those that EGI has recently faced or will face prospectively. National average TFP trends from the U.S. therefore do not provide a suitable basis for establishing a productivity factor for EGI. Most notably, U.S. productivity growth was slowed by federal mandates to improve the safety of transmission and distribution systems whereas EGI has operated under different transmission and distribution safety regulations and has replaced virtually all of its cast iron and bare steel mains.

A more suitable peer group for EGI would be gas utilities that started the sample period with little reliance on cast iron or bare steel mains, did not own much transmission capacity, and had a fairly normal rate of customer growth on average. We have developed a peer group that, specifically,

- had distribution plant exceeding 80% of distribution, transmission, and storage gross plant value
- relied on cast iron and unprotected bare steel mains for less than 5% of their distribution line length.
- Had a normal rate of customer growth as a group.

Eleven utilities satisfied these criteria. Their customer growth averaged 0.95% annually during the sample period, which is close to what EGI anticipates going forward. Their TFP growth averaged a slight 0.20% annual decline. O&M productivity averaged 1.10% growth while capital productivity averaged a 0.84% annual decline.

[2] All growth trends in this report were included logarithmically.

PEG Recommendations

Productivity Factor

PEG believes that the productivity factor for EGI should be reflective of the Company's forward-looking business conditions. We recommend that the productivity factor should equal the -0.20% average annual growth rate in the TFP trend of our custom peer group.

Stretch Factor

PEG recommends a 0.45% stretch factor for EGI. This value is commensurate with our finding that EGI's total cost exceeded by about 23% the prediction of our total cost benchmarking model on average from 2020 to 2022.

X Factor

Insofar as the X factor is the sum of a productivity factor and a stretch factor, PEG recommends an X factor of 0.25% for EGI.

Inflation Factor Formula

We support EGI's proposal to use Ontario's fixed-weight index for average hourly earnings as the labor price index in the inflation factor formula. This index entails less aggregation bias than the (unweighted) average weekly earnings that the OEB has been using in inflation factor formulas. The accuracy advantage is especially pronounced during recessions and the immediately following year. Alberta's utility commission now uses the fixed-weight index in its rate and revenue cap indexes. We have also recommended use of the fixed weight index for average hourly earnings in the new custom IR plan for Toronto Hydro.

We do not object to EGI's proposed alternative cost-share weights for the two inflation factor subindexes in the inflation factor formula. However, we recognize that the OEB may for simplicity prefer the same weights for gas and electric distributor services.

1. Introduction

In Ontario Energy Board proceeding Phase 2 EB-2024-0111, Enbridge Gas Inc. ("EGI" or the Company) has proposed a new incentive rate-setting mechanism ("IRM") plan for its Ontario gas services. This is a multiyear rate plan in which rates would be escalated by an index formula that includes an inflation factor, a base productivity growth target that they call a "productivity factor," and a stretch factor. Supplemental funding for capital expenditures ("capex") would be available from an incremental capital module ("ICM").

EGI proposes a -1.5% X factor that is the sum of a -1.5% productivity factor and a 0% stretch factor. These proposed parameters are based on productivity and statistical benchmarking research and testimony by Black and Veatch. Dr. Lawrence Kaufmann managed this work on behalf of BV. BV used a simple unit cost benchmarking method and a hyperbolic decay capital cost specification that has rarely if ever been used in OEB IR proceedings. EGI also proposes use of a different labor price index in its inflation factor formula than the OEB has previously used in IR.

PEG is North America's leading consultancy on IR and the benchmarking and price and productivity trend research that supports it. In addition to Ontario, we have provided research and testimony on these matters in Alberta, British Columbia, Québec, and many U.S. jurisdictions. OEB Staff has retained PEG to prepare research and testimony on the appropriate inflation factor, productivity factor, and stretch factor for EGI's new rate plan. We critiqued BV's evidence and undertook independent studies of EGI's cost performance and U.S. gas utility productivity trends. We acknowledge that we have a duty to provide opinion evidence to the OEB that is fair, objective and non-partisan.

This is our report on this work. Section 2 provides an introduction to the use of statistical cost research in ratemaking. Section 3 provides an introduction to statistical research on gas utility cost. Methods for statistical benchmarking and the calculation of capital costs and quantities are emphasized. BV's evidence is critiqued in Section 4 and new productivity and benchmarking research by PEG is discussed in Section 5. Section 6 discusses the proposed upgrade to the inflation factor formula. Appendix A provides additional details of our research, while Appendix B discusses our credentials.

2. Use of Statistical Cost Research in Utility Ratemaking

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

2.1. Basic Indexing Concepts

Input Price and Quantity Indexes

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

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

These indexes can provide summary comparisons of the prices and quantities of the various inputs that a company uses. Depending on their design, these indexes can compare the *levels* of prices (and quantities) of different utilities in a given year, the *trends* in the prices (and quantities) over time, or both. Indexes designed to measure only the trends of prices or quantities may be called trend indexes. Indexes designed only to compare the levels of prices at a point in time are said to be bilateral. Indexes designed both to measure trends and compare levels are said to be multilateral.

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

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

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

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

The growth of an input price index that summarizes growth in subindexes for the prices of certain input groups is a cost-weighted average of the growth in these subindexes. The growth of an input quantity index that summarizes the growth in subindexes for the trends in the quantities of certain input groups is, similarly, a cost-weighted average of the growth in these subindexes.

Rearranging terms of [2], it follows that input quantity trends can be measured by taking the difference between cost and input price trends.

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

This greatly simplifies input quantity measurement.

Productivity Indexes

The Basic Idea

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

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

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

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

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

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

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

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

Output Indexes

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

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

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

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

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

output indexes.[6] A productivity index calculated using a cost-based output index ("*Outputs*^{C}") will be denoted as *Productivity*^{C}.

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

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

Sources of Productivity Growth

Economists have studied the drivers of productivity growth using mathematical theory and empirical methods.[7] This research has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit firms to produce given output quantities with fewer inputs.

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

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

[6] An early discussion of elasticity-weighted output indexes is found in a classic treatise by Canadian economists. See 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.

[7] The seminal paper on this topic is Denny, Fuss and Waverman, op. cit.

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 efficiency. However, theoretical and empirical research reveals that productivity index growth also depends on changes in miscellaneous external business conditions, other than input price inflation and output growth, which also drive cost. An example for a gas distributor is a change in the government's system safety regulations.

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

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

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

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

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

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

2.2. Rate and Revenue Cap Indexes

Index logic provides the foundation for rate and revenue cap indexes. The logic of both can be usefully reviewed in considering appropriate productivity research methods for Enbridge.

Price Cap Indexes

Index Logic

We begin our demonstration of the index logic for price cap indexes by considering the growth in the prices charged by an industry that earns, in the long **r**un, a competitive rate of return. In such an industry, the trend in revenue equals the long-run trend in cost.

$$\textit{trend Revenue} = \textit{trend Cost}. \quad [8]$$

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

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

Relations [2], [8], and [9] imply that the trend in output prices that permits revenue to track cost is the difference between the trends in the input price index and in a total factor productivity index of TFP^R form.

$$\textit{trend Output Prices}^R = \textit{trend Input Prices} - (\textit{trend Outputs}^R - \textit{trend Inputs}) \quad [10]$$

$$= \textit{trend Input Prices} - \textit{trend TFP}^R$$

The result in equation [10] provides a conceptual framework for the design of price cap indexes that are useful in MRPs. These indexes have the general form

$$\textit{growth Rates} = \textit{growth Input Prices} - (\textit{Productivity} + \textit{Stretch}). \quad [11]$$

where

$$\textit{Productivity} = \overline{TFP}^R$$

Here *Productivity* is a base TFP growth target that is typically the trend in the TFP^R of a utility peer group. A "stretch factor" is often added to the formula which slows price cap index growth in a manner that shares with customers the financial benefits of performance improvements that are expected under the MRP.

In Ontario and some other jurisdictions, the sum of TFP and Stretch is called the X factor.

$$X = TFP + Stretch \qquad [12]$$

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

Revenue Cap Indexes

Cost theory and index logic support the design of rate and revenue cap indexes that can serve as attrition relief mechanisms ("ARMs") in multiyear rate plans. Consider first the following basic result of cost theory:

$$growth\ Cost = growth\ Input\ Prices - growth\ Productivity^C + growth\ Outputs^C. \qquad [13]$$[8]

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

$$Revenue_t = Revenue_{t-1} \cdot [1 + growth\ Input\ Prices - (Productivity + S) + growth\ Scale^{Utility}] + Y_t + Z_t \qquad [14a]$$

where:

$$Productivity = \overline{TFP^C}. \qquad [14b]$$

S = stretch factor

Y_t = Y factor that adjusts allowed revenue for the operation of variance accounts

Z_t = Z factor that adjusts allowed revenue for the financial impact of hard-to-predict events.

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

Here the productivity factor reflects a base productivity growth target ("$\overline{TFP^C}$") which is typically the average trend in the productivity indexes of a regional or national sample of utilities. A consistent cost-based output index is used in the supportive productivity research.

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.[9] It then follows that

$$\begin{aligned} \textit{growth Cost} &= \textit{growth Input Prices} + \textit{growth Outputs}^C \\ &\quad - (\textit{growth Outputs}^C - \textit{growth Input Quantities}) \\ &= \textit{growth Input Prices} - \textit{growth Productivity}^C + \textit{growth Outputs}^C \end{aligned} \quad [15]$$

Dealing with Cost Exclusions

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

$$\begin{aligned} \textit{Revenue}_t^{O\&M} &= \textit{Revenue}_{t-1}^{O\&M} \cdot [1 + \textit{Inflation} - (\overline{Productivity}^{O\&M} + S) \\ &\quad + \textit{growth Scale}^{O\&M}] + Y_t^{O\&M} + Z_t^{O\&M} \end{aligned} \quad [16]$$

The scale escalator involves one or more output variables that drive O&M cost. The number of customers is once again a good candidate for the scale metric.

If the multiyear rate plan provides for certain costs to be addressed by variance accounts, relation [15] similarly provides the rationale for excluding these costs from the X factor research. This principle is widely (if not unanimously) accepted, and certain costs that are frequently accorded variance account treatment in multiyear rate plans (e.g., costs of energy, DSM, and pensions and other benefits) are frequently excluded from the supportive X factor studies.

This reasoning is important when considering how to combine a revenue cap index with multiyear rate plan provisions that furnish extra funding for capex. Many multiyear rate plans with indexed rate or revenue caps have had provisions for supplemental capital revenue. The rationale is

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

that the index formula cannot by itself provide reasonable compensation for capex surges. Reasons that such surges might be needed include the need for "lumpy" plant additions, costly "smart grid" investments or a surge in replacement capex or capacity additions. Provisions for funding capex surges often involve variance accounts that effectively exempt capital revenue or a portion thereof from indexing. In Ontario, for example, a "C factor" is sometimes added to a revenue (or price) cap index formula that helps capital revenue grow at a rate that is close to that of forecasted capital cost.

Inflation Considerations

Suppose, now, that a macroeconomic price index is used as the inflation measure in the revenue cap index formula. In the United States the gross domestic product price index ("GDPPI") has frequently been used this way in multiyear rate plans. If the GDPPI is the sole inflation measure in a revenue cap index formula, for example, relation [13] can be restated as:

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

Relation [17] shows that cost growth depends on GDPPI inflation, growth in operating scale and productivity, and on the difference between GDPPI and utility input price inflation. This difference 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.[10] It can then be shown that the trend in the GDPPI equals the difference between the trends in the economy's input price and (multifactor) productivity indexes.

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

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

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

[10] Final goods and services include consumer products, government services, and exports produced in the U.S.

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

Relation [19] has been the basis for the design of several approved X factors in American multiyear rate plans.[11] Since the multifactor productivity growth of the U.S. economy has tended to be brisk, it has contributed to the approval of substantially negative X factors in several proceedings for Massachusetts energy distributors.

This approach has rarely been used in Canada, however, for two primary reasons.

- MFP growth has historically been considerably slower in Canada's economy.
- Macroeconomic price indexes are less frequently the sole inflation measures used in revenue cap indexes. Most commonly in Canada, the inflation factors in Canadian plans average growth in a macroeconomic price index and a labor price index.

2.3. Statistical Benchmarking

What is Benchmarking?

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

> A fixed point (esp. a cut or mark in a wall, building, etc.), used by a surveyor as a reference in measuring elevations.[12]

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

A quantitative benchmarking exercise involves one or more activity measures. These are sometimes called key performance indicators. The value of each indicator achieved by an entity under

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[11] This approach has, for example, been approved in Massachusetts on several occasions. See 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.

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

scrutiny is compared to a benchmark value that reflects a performance standard. Given data on the cost of a utility called Eastern Gas Distribution, and a certain cost benchmark we might, for instance, measure its cost performance by taking the ratio of the two values:

$$\textit{Cost Performance} = \textit{Cost}^{\textit{Eastern}}/\textit{Cost}^{\textit{Benchmark}} \qquad [20a]$$

or the natural logarithm of same

$$\textit{Cost Performance} = ln(\textit{Cost}^{\textit{Eastern}})/ln(\textit{Cost}^{\textit{Benchmark}}). \qquad [20b]$$

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

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

External Business Conditions

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

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

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

Benchmarking Methods

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

Econometric Modeling

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

The relationship between the cost of utilities and the business conditions they face (sometimes called the "structure" of cost) can also be estimated econometrically. A branch of statistics called econometrics has developed procedures for estimating economic model parameters using historical data on the variables.[13] The parameters of a utility cost function can be estimated using historical data on the costs incurred by a group of utilities and the business conditions they faced. The sample used in model estimation can be a time series consisting of data over several years for a single company, a cross

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

section consisting of one observation for each of several companies, or a "panel" data set that pools time series data for several companies.

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

Basic Assumptions

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

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

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

Cost Predictions and Performance Appraisals

A cost function fitted with econometric parameter estimates is called an econometric cost model. Such models can be used to predict a company's cost given local values for the business condition variables.[14] These predictions are econometric cost benchmarks. Cost performance is measured by comparing a company's cost in year *t* to the cost projected for that year by the econometric model. The year in question can be in the past or the future.

Accuracy of Benchmarking Results

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

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

In addition, statistical theory provides the foundation for the construction of confidence intervals that represent the full range of possible cost model predictions that are consistent with the

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

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

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

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

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

data at a given level of confidence. Wider confidence intervals suggesting reduced benchmarking precision are likely to the extent that:

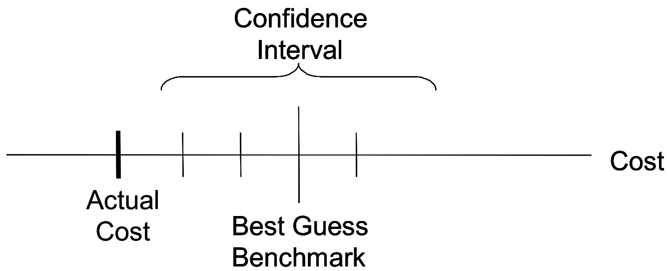
- the model is less successful in explaining the variation in the historical cost data used to estimate the model's parameters;
- the sample of data used in model estimation is smaller;
- the number of business condition variables included in the model is larger;
- the business conditions of sample companies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

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

Testing Efficiency Hypotheses

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

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



Econometric Benchmarking Precedents

Econometric benchmarking is routinely used in Ontario to set the stretch factor terms of rate or revenue cap indexes for provincial power distributors and transmitters. Regulators have also considered econometric benchmarking studies to set stretch factors in Alberta, Massachusetts, and Québec. Econometric benchmarking has also been used by regulators in Australia and Great Britain.[15]

PEG personnel have also provided econometric benchmarking evidence in several North American proceedings. In Ontario, we have performed econometric benchmarking studies for legacy Enbridge Gas Distribution and the Ontario Energy Board. In a recent Alberta proceeding we submitted econometric benchmarking studies of power and gas distributor cost on behalf of the Consumers' Coalition of Alberta. In Québec we submitted an econometric benchmarking study of the cost of Hydro-Québec Transmission on behalf of the Association Québécoise des Consommateurs Industriels d'Électricité. In Massachusetts, we have used it to support stretch factor proposals in IR proceedings for Bay State Gas, Boston Gas, and NSTAR Gas.[16] We have filed testimony on the cost performance of

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

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

San Diego Gas & Electric and Southern California Gas on several occasions. [17] In some Colorado PUC proceedings, we used econometric benchmarking to appraise the forward test year cost proposals for the gas and electric services of Public Service of Colorado. [18] In Vermont, PEG benchmarked the cost performance of Central Vermont Public Service in the provision of power distributor services. This study provided the basis for an article in *The Energy Journal.* [19]

Indexing

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

Index Basics

An index is defined in one dictionary as "a ratio or other number derived from a series of observations and used as an indicator or measure (as of a condition, property, or phenomenon)." [20] In utility performance benchmarking, indexing typically involves the calculation of ratios of the values of performance metrics for a subject utility to the corresponding values for a sample of utilities. The companies for which sample data have been drawn are sometimes called a peer group.

We have noted that a simple comparison of the costs of utilities reveals little about their cost performances to the extent that there are differences in the cost drivers they face. In index-based benchmarking, it is therefore common to use as cost metrics the ratios of their cost to one or more important cost drivers. In a given country, the operating scale of utilities is typically the greatest source of difference in their cost. It makes sense then to compare ratios of cost to operating scale.

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

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

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

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

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

$$\textit{Unit Cost} = \textit{Cost/Scale}. \qquad [21]$$

Each index compares the value of the metric to the average for a peer group.[21] The scale index can be multidimensional if it is desirable to measure operating scale using multiple scale variables.

In comparing the unit cost of a utility to the average for a peer group, we introduce an automatic control for differences between the companies in their operating scale. This permits us to include companies with more varied operating scales in the peer group.

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

One sensible upgrade to unit cost indexes is to adjust them for differences in the input prices that utilities face. This upgrade is especially important in a transnational data set, where the costs of companies are denominated in one or more currencies. The formula for real (inflation-adjusted) unit cost is

$$Unit\ Cost^{Real} = \frac{Cost\ /\ Input\ Prices}{Scale}. \qquad [22]$$

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

$$\textit{Cost} = \textit{Input Prices} \cdot \textit{Input Quantities}$$

it follows that

$$Unit\ Cost^{Real} = \frac{Input\ Quantities}{Scale} = 1/Productivity \qquad [23]$$

[21] A unit cost index for Eastern Distribution, for instance, would have the general form

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

Thus, a real unit cost index will yield the same comparative benchmarking results as the corresponding productivity index. For example, a utility with a 10% productivity advantage also has a 10% real unit cost advantage.

2.4. Capital Cost Issues

Capital cost is an important methodological issue in this proceeding because BV has used a capital cost specification that has rarely if ever been used in Ontario IR evidence.

Some General Remarks on Capital Cost

Since the technologies of energy utilities are capital-intensive, capital cost specifications are important in total cost benchmarking and TFP trend studies. The annual cost of capital ownership that a utility incurs includes depreciation expenses, the opportunity cost to shareholders and bondholders of foregoing alternative investments (aka the return on investment), and some taxes. If the price (unit value) of older assets changes over time, annual cost may be calculated net of any capital gains or losses. Annual capital cost is not the same as the cost of additions made each year to the capital stock.

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

The potential service flows from assets may decay as they age and these flows eventually end even if they are constant for many years. This causes the values of most assets to depreciate over time.

Depreciation and service lives have a material effect on cost trends in capital-intensive industries. One reason is that opportunity cost accounts for a sizable share of the cost of asset ownership. Depreciation of aging assets reduces opportunity cost over time and slows capital cost growth. Following a capex surge, depreciation in the value of surge assets may slow cost growth considerably. To the extent that assets are highly depreciated, on the other hand, a surge in capex can cause cost to rise rapidly.

The service lives of assets can be an important consideration in the choice between assets. For example, utilities have some ability to extend the service lives of aging assets. This is tantamount to choosing between an old asset with a low opportunity cost of ownership and a new asset that contains a large stock of future service flows but also has a high opportunity cost. Buyers also choose between assets with different service lives in other markets. The market for automobiles is illustrative. Households can choose between new and used cars with varied service lives. Asset prices vary with expected service lives. Some households choose used vehicles with few remaining years of service and higher O&M expenses because they cannot afford to tie up money in vehicles with longer service lives or choose not to for other reasons.

Monetary Capital Cost Specifications

The Basic Idea

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

$$CK = WK \times XK. \qquad [24a]$$

This decomposition facilitates productivity and econometric cost research. The growth rate of capital cost can be shown to be the sum of the growth rates of these indexes.[22]

$$growth\ CK = growth\ WK + growth\ XK. \qquad [24b]$$

In utility cost and productivity research, construction of capital quantity indexes involves deflation, using asset price indexes, of the reported annual values of gross plant additions. The quantity of gross plant additions in a given year *t* ("XKA_t") is the ratio of their value ("VKA_t") to the contemporaneous value of an asset price index ("WKA_t").

$$XKA_t = VKA_t / WKA_t \qquad [25]$$

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

These quantities are then subjected to a standardized decay specification. Utilities have various methods for calculating depreciation expenses that they report to regulators and retire their assets at different times. Consequently, when calculating capital quantities using a monetary method, it is desirable to rely on the reporting companies chiefly for the values of their gross plant additions and to use a standardized decay specification for all companies. In research on the productivity and cost performances of U.S. gas and electric utilities, Handy Whitman utility construction cost indexes ("HWIs") have traditionally been used as the asset price indexes.[23]

Since some of the plant a utility owns may be 40-60 years old, it is desirable in these calculations to have gross plant addition data for many years into the past. For earlier years, however, the desired gross plant addition data are not readily available. Consequently, it is customary to calculate the capital quantity in the first year of a time series by finding the reported value of the accumulated plant that a utility owns at the end of the limited-data period ("VK_o") and then to estimate the quantity of capital that it reflects by dividing it by an average of asset prices in earlier years.

$$XK_o = \frac{VK_o}{SUM_s\, w_{t-s} \cdot WKA_{t-s}}$$

The weight for WKA_{t-s} is here denoted by w_{t-s}. This initial year of the capital quantity index is sometimes called the "benchmark year." The value of the index in subsequent years is then determined by a perpetual inventory equation that considers how the quantity of plant changes due to decay and new plant additions.

Since the pattern of older plant additions is not well-known, the estimate of the capital quantity in the benchmark year is likely quite inexact. It is then preferable to base capital and total cost research on a sample period that begins many years after the benchmark year. With this approach, the quantity of capital in the benchmark year will have shrunk considerably due to decay and the importance of the imprecision is reduced. If this is not done, research on capital and total cost will be less accurate, especially in the early years of the sample period.

[23] Statistics Canada used to compute credible electric utility construction cost indexes but these have been discontinued.

Capital Service Flows and Service Prices

A capital good has the capacity to provide a stream of services over some period of time. In rigorous statistical cost research, it is often assumed that the capital quantity index measures the annual service flow. We noted in Section 2.1 that construction of multifactor input price and quantity indexes requires cost share weights. To create a sensible cost share weight for capital, the service flow measure of the capital quantity is conventionally paired with a "service" or "rental" price index. The design of capital service price indexes should be consistent with the assumption about the decay in the service flow. The product of the capital service price index and the capital quantity index is interpreted as the annual cost of using the flow of services. This is sometimes called the user cost of capital.

Monetary Capital Cost Specifications

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

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

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

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

$$XK_t = XK_{t-1} \cdot (1-d) + XKA_t. \qquad [26a]$$

$$= XK_{t-1} \cdot (1\text{-}d) + \frac{VKA_t}{WKA_t}. \qquad [26b]$$

It can be shown that a constant rate of decay in the capital quantity gives rise to a constant rate of asset depreciation.

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

2. <u>One-Hoss-Shay ("OHS")</u> Under the OHS method, the service flow from each group of assets considered is assumed to be constant until the end of its service life, when it abruptly falls to zero. This decay pattern is typical of an incandescent light bulb.

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

   Since reported utility retirements are valued in historical dollars, the quantity of retirements in year *t* is calculated by dividing the reported value of retirements ("*VKR*") by the value of the asset price index for the best guess of the year when the retired assets were added. Assets are typically assumed to be retired at their average service life ("ASL"). Thus,

$$XK_t = XK_{t-1} + XKA_t - XKR_t \qquad [27a]$$

$$= XK_{t-1} + \frac{VKA_t}{WKA_t} - \frac{VKR_t}{WKA_{t\text{-}ASL}}. \qquad [27b]$$

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

3. <u>Cost of Service ("COS")</u>. The geometric decay and one hoss shay approaches for calculating capital cost use assumptions that differ from those used to calculate capital cost in traditional cost of service ratemaking.[24] With both approaches, we have seen that the trend in capital cost is a simulation of the trend in cost incurred for purchasing capital services in a competitive rental market. However, we showed in Section 2.2 that the derivation of a revenue cap index

[24] The OHS assumptions are more markedly different.

using index logic does not require a service price/service flow treatment of capital cost. It can in principle use more familiar capital cost accounting provided that capital cost can still be decomposed into price and quantity indexes.

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

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

4. Hyperbolic Decay ("HD") Under the HD approach the service flow from groups of assets to which it is applied is assumed to decline at a rate that increases as they age. This is appealing because the service flows from many utility assets do decline more rapidly as they age, and the specification is applied to cohorts of assets with varied ages.

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

5. Kahn Method A productivity factor can also be calculated using the simpler Kahn Method. This general approach was developed by Alfred Kahn, the distinguished regulatory economist who was a professor at Cornell University. It has been used by the Federal Energy Regulatory Commission ("FERC") to set the X factors in multiyear rate plans for interstate oil pipelines. In some past proceedings, PEG has upgraded the method Dr. Kahn used to better approximate cost of service capital cost accounting. PEG used this method in recent Massachusetts and Hawaii MRP proceedings.[25]

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

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

$$\textit{growth Allowed Base Revenue}^{Utility} = \textit{growth GDPPI} - X + \textit{growth Outputs}^{C}. \qquad [28]$$

The X factor resulting from such a calculation implicitly reflects the inflation or input price differential that we discussed in Section 2.2 above as well as the average COS productivity trends of sampled utilities. This is a problem in an application to Ontario since the inflation differential for U.S. utilities may differ considerably from that which is pertinent in an Ontario application.

Choosing the Right Monetary Approach

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

Consider the Application

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

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

Recall also that, as explained in Section 2.2, when a macroeconomic inflation measure like the gross domestic product implicit price index ("GDP-IPI") is the sole revenue (or price) cap index inflation measure, its ability to track the input price trend of utilities becomes an issue as well as the productivity trend when choosing an X factor. The capital price index as well as the capital quantity index then becomes a criterion in the choice of the capital cost specification since an input price differential must be chosen. The capital service prices used in OHS, GD, and HD are volatile and were not designed to provide an estimate of the implicit capital price in utility cost accounting. X factor witnesses in past proceedings have often downplayed the importance of the input price differential, declaring it to be zero, but more recently X factor witnesses for utilities in Massachusetts have touted the appropriateness of a large negative input price differential that benefitted their clients, and the Massachusetts regulator on several occasions embraced their analysis. Large input price differentials do not always favor utilities. In a proceeding to approve a price cap index for Central Maine Power,[26] a witness for consumer interests asked for a large *positive* input price differential.

Criteria for Choosing Between Alternative Capital Cost Specifications

Based on our extensive experience using alternative capital cost specifications in utility cost benchmarking and productivity research, we recommend the following criteria for choosing between the specifications.

- Relevant to the purposes of the research
- Easy to understand and implement
- Realistic capital quantity decay

One Hoss Shay Pros and Cons

OHS Advantages

The one hoss shay specification reasonably approximates the service flows of many individual utility assets. Another advantage of one hoss shay is that the data are unavailable in some jurisdictions to accurately calculate capital quantities using monetary methods. In these jurisdictions, the

[26] Maine PUC Docket 1999-00666

assumption of a one hoss shay service flow legitimizes using available data on capacity (e.g., line miles) to measure capital quantities.[27]

OHS Disadvantages

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

- Some utility assets do not exhibit a constant service flow until their retirement. For example, many assets tend to have diminished reliability and/or are less safe or environmentally benign as they age, thereby requiring more inspections and maintenance.
- In cost benchmarking and productivity trend studies, capital quantity trends are rarely calculated for *individual* assets. Instead, they are typically calculated from data on the total value of *all* of the additions to (and, in the case of one hoss shay, retirements of) the various kinds of assets that a utility uses. Even if each individual asset did have a constant service flow, the flow from total plant additions could be poorly approximated by one-hoss shay.[28]
- If an asset has an OHS service flow its value will typically depreciate as it ages because of diminution in its expected future service flows. This slows cost growth. However, the simple OHS approach used in statistical cost research abstracts from this asset value depreciation since the service flow from the asset is assumed constant and the price of capital services is one that is commensurate with a competitive rental market. This matters for several reasons.

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

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

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

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

a. We have noted that depreciation reduces the opportunity cost of owning assets, and this is a material consideration when benchmarking utility cost. Using a simple OHS approach in a cost benchmarking study, a utility's effort to delay replacement of assets may not be adequately recognized.[29]

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

- OHS is more difficult to implement accurately than other capital cost specifications. To understand why, consider first that all monetary methods require deflation of gross plant *additions*. Accurate calculations of the quantities of additions are facilitated by the fact that the years in which given additions are made are known exactly, making it easy to choose the matching value of the asset price deflator. The challenge with OHS is that it also requires deflation of plant *retirements*, and the vintages of reported retirements are not readily available for a large number of utilities. We noted above that OHS practitioners commonly address this challenge by deflating the value of retirements by the value of an asset price index for a year in the past which reflects the assumed average service life of the assets. Deflation of retirement values by this means can be well off the mark.
- For various reasons, OHS studies have sometimes produced negative capital quantities.
- OHS service price formulas are complicated and difficult to explain.
- OHS capital service prices are naturally volatile and inconsistent with COS accounting. When a macroeconomic index is the sole inflation measure in a rate or revenue cap index, they are not well-suited for the calculation of an input price differential.

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

Geometric Decay Pros and Cons

GD Advantages

The GD capital cost specifications have several well-established advantages.

- GD service price and quantity formulas are simple and intuitively appealing.
- The difficult task of calculating the age of retirements is sidestepped.
- Results are not very sensitive to the ASL assumption.
- By assuming that the quantity of service from a group of assets declines as they age, the capital cost of the group declines. GD thereby takes some account of the slower cost growth that results over time from a cohort of diverse assets. In a productivity study, GD is therefore more sensitive than OHS to any capex cycle that a utility or utility industry might display. Efficiency scores are more sensitive to system age in a benchmarking study. A successful effort by a utility to extend asset life can be recognized.

GD Disadvantages

- The assumption of constant decay means that decay in the service flow is greater than the typical flow of utility assets in the early years of their service lives and slower in later years.
- GD capital service prices are naturally volatile and inconsistent with COS accounting. When a macroeconomic index is the sole inflation measure in a rate or revenue cap index, GD capital service prices are not well-suited for the calculation of an input price differential.

Hyperbolic Decay Pros and Cons

Hyperbolic decay is effectively the middle ground between the OHS and GD approaches.

HD Advantages

- The pattern of service flow decay is more realistic than those of GD and OHS.
- Cost does decline somewhat as the asset ages.

HD Disadvantages

- There is no clear consensus about the appropriate HD service price index. Some formulas in use are complex, controversial, and difficult to understand and explain.
- HD service prices are volatile and inconsistent with traditional COS accounting. When a macroeconomic index is the sole inflation measure in a rate or revenue cap index, they are not well-suited for the calculation of an input price differential.

Cost of Service Pros and Cons

COS Advantages

- By mimicking the approach to capital cost accounting used in North American ratemaking, COS is well-suited for choosing the productivity factor of a rate or revenue cap index.
- A COS capital price is well-suited for calculating an input price differential.

COS Disadvantages

- COS input price and quantity formulas are complex and difficult to understand and explain. This problem can be finessed by using the Kahn method to choose the productivity factor.

Popularity of Alternative Capital Cost Specifications

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

- The U.S. Bureau of Labor Statistics, Australian Bureau of Statistics, and Statistics New Zealand all use HD in their multifactor productivity studies of the economy and important sectors thereof.[30] We understand that Statistics Canada uses GD in such studies.[31]

  Table 1 reports capital cost specifications that have been used in North American energy utility productivity studies in the public domain. It shows that GD has been by far the most common

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

[31] See for example, Baldwin, J.R., Gu, W. and Yan, B., "User Gude for Statistics Canada's Annual Multifactor Productivity Program," The Canadian Productivity Review, Catalogue no. 15-206-XIE, No. 14, ISSN 1710-5269, ISBN 978-0-662-47375-6, December 2007

Table 1

Capital Cost Specifications Used in North American Energy Utility Productivity Evidence

Power Industry Studies

Year	Jurisdiction	Author	Client	Industry Studied	Capital Cost Specification
1994	Maine	PEG personnel[1]	Utility	Northeast Bundled Power Service	Geometric Decay
1995	New York	PEG personnel[1]	Utility	US Bundled Power Service	Geometric Decay
1998	California	PEG personnel[1]	Utility	US Power Distributors	Geometric Decay
1999	Hawaii	PEG	Utility	US Bundled Power Service	Geometric Decay
1999	Maine	NERA	Utility	Northeast Power Distributors	One Hoss Shay
2000	Alberta	NERA	Utility	Western Power Distributors	One Hoss Shay
2001	Maine	PEG	Utility	Northeast Power Distributors	Geometric Decay
2002	California	PEG	Utility	US Power Distributors	Geometric Decay
2004	California	PEG	Utility	US Power Distributors	Geometric Decay
2005	Massachusetts	PEG	Utility	Northeast Power Distributors	Geometric Decay
2006	California	PEG	Utility	US Power Distributors	Geometric Decay
2006	Kansas	Christensen Associates	Utility	US Power Distributors	Geometric Decay
2006	Kansas	Christensen Associates	Utility	US Bundled Power Service	Geometric Decay
2006	Kansas	Christensen Associates	Utility	US Power Generation	Geometric Decay
2006	Kansas	Christensen Associates	Utility	US Power Transmission	Geometric Decay
2007	Maine	PEG	Utility	Northeast Power Distributors	Cost of Service
2008	Maine	Christensen Associates	Regulator	Northeast Power Distributors	Geometric Decay
2008	Vermont	PEG	Utility	US Power Distributors	Cost of Service
2008	Ontario	PEG	Commission	Ontario Power Distributors	Cost of Service
2008	Ontario	LEI	Utility	Ontario Power Distributors	One Hoss Shay (Physical Asset)
2010	California	PEG	Utility	US Power Distributors	Geometric Decay
2010	Alberta	NERA	Commission	US Power Distributors	One Hoss Shay
2011	District of Columbia	PEG	Utility	Northeast Power Distributors	Cost of Service
2011	Maryland	PEG	Utility	Northeast Power Distributors	Cost of Service
2011	Maryland	PEG	Utility	Northeast Power Distributors	Cost of Service
2011	New Jersey	PEG	Utility	Northeast Power Distributors	Cost of Service
2011	Alberta	LEI	Utility	Ontario Power Distributors	One Hoss Shay (Physical Asset)
2012	Delaware	PEG	Utility	Northeast Power Distributors	Cost of Service
2013	British Columbia	Black & Veatch	Utility	US Power Distributors	Kahn Variant
2013	British Columbia	PEG	Consumer Advocate	US Power Distributors	Cost of Service
2013	Massachusetts	PEG	Utility	Northeast Power Distributors	Cost of Service
2013	Massachusetts	Acadian Consulting	Consumer Advocate	Northeast Power Distributors	Cost of Service
2013	Maine	PEG	CMP	Northeast Power Distributors	Cost of Service
2013	Ontario	PEG	Regulator	Ontario Power Distributors	Geometric Decay
2015	Alberta	Brattle Group	Utility	US Power Distributors	One Hoss Shay
2015	Alberta	PEG	Consumer Advocate	US Power Distributors	Geometric Decay
2015	Alberta	Christensen Associates	Utility	US Power Distributors	One Hoss Shay
2016	Ontario	LEI	Utility	US Hydro-electric Generation	One Hoss Shay (Physical Asset)
2016	Ontario	PEG	Regulator	US Hydro-electric Generation	Geometric Decay
2017	Massachusetts	Christensen Associates	Utility	US Power Distributors	One Hoss Shay
2017	US	PEG	Government	US Power Distributors	Geometric Decay
2017	Ontario	NERA	Utility	US Power Distribution	One Hoss Shay
2018	Massachusetts	Acadian Consulting	Consumer Advocate	US Power Distributors	Geometric Decay
2018	Massachusetts	Christensen Associates	Utility	US Power Distributors	One Hoss Shay
2019	Massachusetts	PEG	Attorney General	US Power Distributors	Geometric Decay and Kahn Variant
2018	Ontario	Power Systems Engineering	Utility	US Power Transmitters	Geometric Decay
2019	Ontario	PEG	Regulator	US Power Transmitters	Geometric Decay
2019	Ontario	Power Systems Engineering	Utility	US Power Transmitters	Geometric Decay
2019	Ontario	PEG	Regulator	US Power Transmitters	Geometric Decay
2019	Hawaii	PEG	Utility	US Bundled Power Service	Kahn Variant
2020	Hawaii	Ronald Binz	Environmentalist	US Bundled Power Service	Kahn Variant
2021	Quebec	Brattle Group	Utility	US Power Transmitters	One Hoss Shay
2021	Quebec	PEG	Industrial	US Power Transmitters	Geometric Decay
2022	Ontario	Clearspring Energy Advisors	Utility	US Power Transmitters	Geometric Decay
2022	Ontario	PEG	Regulator	US Power Transmitters	Geometric Decay
2022	Massachusetts	Christensen Associates	Utility	US Power Distributors	Hyperbolic Decay
2023	Massachusetts	Christensen Associates	Utility	US Power Distributors	Hyperbolic Decay
2023	Alberta	NERA	Regulator	US Power Distributors	One Hoss Shay
2023	Alberta	Christensen Associates	Utility	US Power Distributors	Hyperbolic Decay
2023	Alberta	PEG	Consumer Advocate	US Power Distributors	Geometric Decay
2024	New Hampshire	Ankura Consulting Group	Utility	US Power Distributors	One Hoss Shay
2024	Ontario	PEG	Regulator	US Power Distributors	Geometric Decay

Table 1 (continued)

Capital Cost Specifications Used in North American Energy Utility Productivity Evidence

Gas Industry Studies

Year	Jurisdiction	Author	Client	Industry Studied	Capital Cost Specification
1995	California	PEG personnel[1]	Utility	US Gas Utilities	Geometric Decay
1996	Massachusetts	PEG personnel[1]	Utility	US Gas Utilities	Geometric Decay
1997	British Columbia	PEG personnel[1]	Utility	US Gas Utilities	Geometric Decay
1997	Georgia	PEG personnel[1]	Utility	US Gas Utilities	Geometric Decay
1998	California	PEG personnel[1]	Utility	US Gas Utilities	Geometric Decay
1999	Ontario	Christensen Associates	Utility	Company-specific	Geometric Decay
2002	California	PEG	Utility	US Gas Utilities	Geometric Decay
2003	Massachusetts	PEG	Utility	Northeast Gas Distributors	Geometric Decay
2004	California	PEG	Utility	US Gas Utilities	Geometric Decay
2006	California	PEG	Utility	US Gas Utilities	Geometric Decay
2007	Ontario	PEG	Regulator	US Gas Utilities	Cost of Service & Geometric Decay
2007	Ontario	Brattle Group	Utility	US Gas Utilities	Cost of Service & Geometric Decay
2010	California	PEG	Utility	US Gas Utilities	Geometric Decay
2011	Quebec	PEG	Utility and Consumer Advocate:	US Gas Utilities	Cost of Service
2011	Ontario	PEG	Regulator	Gas Utilities	Cost of Service
2012	Ontario	Power Systems Engineering	Utility	Gas Utilities	Cost of Service
2012	Quebec	PEG	Utility	US Gas Utilities	Cost of Service
2013	British Columbia	PEG	Consumer Advocate	US Gas Utilities	Cost of Service
2013	British Columbia	Black & Veatch	Utility	US Gas Utilities	Kahn Variant
2013	Ontario	Concentric Energy Advisors	Utility	US Gas Utilities	Geometric Decay
2018	Ontario	PEG	Regulator	US Gas Utilities	Geometric Decay
2019	Massachusetts	LEI	Utility	US Gas Distributors	One Hoss Shay
2020	Massachusetts	PEG	Attorney General	US Gas Distributors	One Hoss Shay
2020	Massachusetts	Christensen Associates	Utility	US Gas Distributors	One Hoss Shay
2022	Ontario (EGI Phase 1)	Black & Veatch	Utility	US Gas Distributors	Hyperbolic Decay
2024	Ontario (EGI Phase 2)	Black & Veatch	Utility	US Gas Distributors	Hyperbolic Decay

Oil Pipeline Industry Studies

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

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

method used in these studies. In Ontario, for example, GD has been routinely used in productivity and benchmarking studies that are filed by OEB Staff and utility witnesses. PEG's 2017 study of power distributor productivity for Lawrence Berkeley National Laboratory also used geometric decay.[32] GD has also been used in numerous studies of telecommunications and cable television productivity. Table 1 also shows that the cost of service and Kahn methods have both been used more frequently than HD or OHS.

- There has recently been an uptick in (utility-funded) studies using one hoss shay. In addition to two Massachusetts *gas* distributor studies, there have been two Massachusetts *power* distributor studies. In one proceeding the Massachusetts Department of Public Utilities explicitly embraced the one hoss shay specification for X factor studies.
- Hyperbolic decay has been used thus far in only a few utility statistical cost studies filed in recent IR proceedings. Utility productivity and benchmarking studies in Massachusetts proceedings are rarely challenged by a real expert on these methods. The application of HD to utility benchmarking and productivity research is therefore not as well vetted as alternative methods.

Conclusions

The COS capital cost specification has many advantages in the determination of X factors for rate and revenue cap indexes. However, the math is complicated, and the assumption of historical plant valuations is not ideal for a benchmarking study. GD, OHS, and HD all have service prices that are disadvantageous in the calculation of input price differentials. However, this doesn't matter much in Canadian proceedings where these differentials are less of an issue. Hyperbolic decay may make the most sense for benchmarking and other cost efficiency studies. However, its use in utility research is not yet widespread and some bugs may remain to work out. Geometric decay is a serviceable alternative for both X factor and benchmarking research.

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

3. Statistical Research on Gas Distributor Cost

3.1. The Gas Distribution Business

Reader understanding of the empirical research we discuss in this report may be aided by a brief discussion of the gas utility business. Gas utilities deliver methane gas using underground mains and service lines to end user premises. The business long antedates the electric utility business. Most gas utilities also provide metering, billing, information, and other services to their customers. The additional customer services often include DSM.

Distributors today receive most of the gas that they deliver from independent transmission companies that carry gas from distant fields and storage facilities. Some distributors also own gas transmission and/or storage facilities. These facilities are usually located in the same region in which they distribute gas. In the United States, some gas distributors (e.g., Pacific Gas and Electric) also provide extensive electric services that may include generation and transmission as well as distributor services.

The principal assets used in gas distribution are mains, services, and meters. Other notable distribution assets include regulators, buildings, and land. Distributors usually own most of these assets and thereby incur substantial capital costs. Costs are also incurred in the operation and maintenance of these facilities and the provision of customer services. Additionally, certain administrative and general costs are incurred jointly in the provision of various gas utility services and any other (e.g., electric) services that are provided.

Gas mains have been made of many materials over the long history of the industry. Mains made from certain materials, and old mains generally, raise more concerns about methane leaks, reliability, and safety. Contending with these problems raises cost. Concern has been most widespread about mains made from cast iron and unprotected bare steel. Mains made from these materials were commonly used in gas distribution in the early days of the North American industry. They are still extensively used in some of the older distribution systems in midwestern and eastern states. More recently, most mains have been made of plastic. Some kinds of plastic pipe have proven problematic and require early replacement. The prevalence of problematic mains in gas utility systems varies widely.

Over the past twenty years, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") has approved a series of rules designed to increase the safety of the U.S. gas delivery system. One rule required gas transmitters to implement integrity management programs by 2004.[33] These programs required transmission operators to identify high consequence (e.g., highly populated or frequently used) areas. In these areas, integrity management programs have included assessments of the segments of their systems that are in high consequence areas, remediation of problems found during those assessments, performance measurement, communications plans, quality assurance, management of change, and provisions to update assessments periodically. Transmitters were also expected to be able to provide data on their systems to PHMSA and state regulators, regularly report on their performance, and to continually improve their programs.

The PHMSA has more recently established a "mega rule" that has increased the attention of utilities to the safety of their transmission lines. This rule addressed holes in pipeline safety regulation that were discovered during investigations into the 2010 explosion of a Pacific Gas and Electric pipeline in a residential area of San Bruno, California near San Francisco and other incidents. The rule focused on transmission integrity management and had 3 parts that went into effect over the 2020-2023 period. Part one of the rule took effect in 2020 and focused on material verification, assessment expansion, and record keeping. Parts two and three of the rule took effect in May 2023 and focused on integrity management, corrosion control, and inspection requirements. One difference between the mega rule and the prior rule on transmission integrity management was that this rule applied to the entirety of a gas transmitter's system instead of just portions of their systems that were in high consequence areas.

PHMSA also required natural gas distributors to establish and implement distribution integrity management programs ("DIMPs") by 2011. The contents of DIMPs were prescribed in PHMSA's rules and had to include a demonstration that the utility understood the design of its system and its operating environment; an identification of existing and potential threats to its systems; an evaluation and ranking of those risks; a plan to identify and implement measures to address risks; a system to measure the program's performance, monitor results, and evaluate the program's effectiveness; a means of undertaking periodic assessments and improvements to the DIMP; and reporting requirements to

[33] This rule was the result of the passage of the Pipeline Safety Improvement Act of 2002.

PHMSA and the states. As part of this rulemaking, PHMSA mandated the installation of excess flow valves in certain new and replaced residential service lines.

These policies combined would likely lead to increased O&M expenses that reflect the cost of developing and implementing integrity management programs and addressing the findings of major incident investigations. Some of the increased O&M expenses would be temporary. For example, in the aftermath of the San Bruno incident, Pacific Gas and Electric requested more than $500 million for various activities related to upgrading their transmission pipeline records.[34] O&M expenses may also increase if a distributor finds that it needs to implement or alter its leak management program to meet the PHMSA's requirements.

Capex would likely increase in subsequent years, as distributors relied on the data compiled from implementing integrity management programs and addressing the findings of major incident investigations to identify assets needing replacement due to a high risk of failure. To help ensure that integrity management program costs are funded, regulators in several states (e.g., Colorado, Connecticut, Massachusetts, and Michigan) have approved trackers to address some, or all, of these costs. These policies have thereby slowed measured productivity growth. The challenge has had a disproportionate impact on utilities that own large transmission lines and are unusually reliant on mains made from problematic materials.

3.2. U.S. Gas Distributor Operating Data

Statistical research on gas utility cost has been underway for decades. PEG President Mark Newton Lowry submitted his first study of gas utility productivity trends for Southern California Gas in 1995 and his first gas utility cost benchmarking study for Boston Gas in 1996.[35]

The chief source of data on the costs of U.S. gas distributors is their annual reports to state regulators. These reports are fairly standardized across the U.S. since they often use as templates the Form 2 that interstate natural gas transmission companies file annually with the FERC. A Uniform

[34] California Public Utilities Commission Rulemaking 11-02-019

[35] California Public Utilities Commission proceeding 95-06-002, "Productivity Trends of U.S. Gas Distributors," January 1995 and Massachusetts Department of Public Utilities proceeding 96-50, "Productivity Trends of U.S. Gas Distributors in The Provision of Gas Delivery Services," filed April 12, 1996.

System of Accounts is available for Form 2, which encourages standardization of cost calculations. Data on the number of customers and delivery volumes of each distributor are available from Form EIA 176.

These data have been available in standardized form for dozens of U.S. gas distributors for several decades. The business conditions faced by these companies vary greatly. A large sample of data for utilities facing varied business conditions facilitates econometric cost model development, as we discussed in Section 2.3 above. Costs of gas production, purchases, and transmission by others, customer service and information, and pensions and other benefits are typically itemized on the state reports so that they can be removed from calculations if desired.

Here are some other advantages of U.S. gas utility operating data.

- Data on the miles, age, and composition of gas transmission and distribution lines are available for dozens of utilities for many years from the PHMSA.
- Regional Handy-Whitman indexes can be purchased at modest cost on trends in the costs of gas distribution, transmission, and storage plant construction.
- Indexes can also be purchased (albeit at substantial cost) that measure inflation in the prices of materials and services used in gas transmission, distribution, storage, and administrative and general activities. The same vendor forecasts growth in these indexes, wage rate indexes, and Handy-Whitman gas utility construction cost indexes.
- The reports to state commissions contain data that are useful in standardized calculations of capital costs, prices, and quantities using monetary methods discussed in Section 2.4 above.

U.S. data on gas utility operations also have some limitations.

- It is difficult to gather gas operating data from the various American states. Statistical research on gas utility cost is therefore usually based on data obtained from commercial vendors. We obtained most of these data (at material cost) from S&P Global Market Intelligence LLC ("S&P"). These data are the property of S&P and therefore should not be examined by parties to this proceeding until an appropriate confidentiality agreement is signed. Another commercial vendor of gas utility data that we approached (Ventyx) in preparing a recent benchmarking study refused to rent us their data stating concerns about confidentiality breaches.

- The data gathered by commercial vendors only go back to the 1990s.[36]
- The O&M expenses of most gas utilities are not broken down into those for salaries and wages and materials and services. Since the input price trends of gas utilities are cost-weighted averages of the trends in the prices of major input groups, the absence of such breakdowns reduces the accuracy of O&M cost benchmarking and productivity trend research.

On balance, however, U.S. data are the best in the world for calculating the costs and price and quantity indexes needed for statistical research on gas distributor cost.

3.3. EGI Data

A uniform system of accounts was established for Ontario's Class A gas utilities in 1996.[37] This system features a detailed account structure that is broadly similar to that used in the United States. It includes plant, operating, and maintenance expenses by function.

The OEB's Natural Gas Reporting and Record Keeping Requirements ("Natural Gas RRR") mandates reporting of data on various topics including outputs (e.g., customer numbers and volumes) and customer service (e.g., disconnections and customer complaints).[38] As part of the Natural Gas RRR filing requirements, EGI is required to report annual trial balances in the uniform system of accounts format to support its audited financial statements.[39] However, the OEB does not require routine filing of detailed O&M expense and plant in service data as part of the Natural Gas RRR. Neither EGI nor its legacy companies have accordingly regularly filed publicly available reports on the costs and plant in service of their regulated operations.

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[36] PEG has gathered the analogous data for electric utilities back to the 1960s.

[37] https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2019-01/Uniform-System-of-Accounts-for-Class-A-Gas-Utilities.pdf

[38] The most recent version of the OEB's "Natural Gas Reporting & Record Keeping Requirements (RRR) Rule for Gas Utilities" was dated March 27, 2024.
https://www.oeb.ca/sites/default/files/Natural%20Gas%20for%20Utilities%20RRR%20version_March%202024.pdf

[39] PEG reviewed the trial balance information filed by EGI and found that it lacked details on operating expenses (e.g., all operating expenses were lumped into one amount).

The data BV relied upon for their study were obtained from the Company directly.[40] These data have limitations in productivity and cost benchmarking research which should be recognized. These include the following.

- The O&M data are not consistent with the uniform system of accounts, as EGI allocated shares of eligible O&M expenses to the distribution, transmission, and storage functions rather than itemizing these costs in specific distribution, transmission, and storage accounts as outlined in the uniform system of accounts. EGI explained in an undertaking response to School Energy Coalition that "Enbridge Gas does not track O&M into these categories on a day-to-day basis and relied on the breakdown of previously OEB-approved cost studies to allocate O&M costs for the legacy Union Gas and EGD rate zones prior to 2019, and for Enbridge Gas afterwards."[41]

- The Company's O&M salaries and wages, like those of many U.S. gas utilities, are not itemized by function.[42] BV calculated annual estimates of O&M salaries and wages by function by multiplying total O&M salaries and wages by the same functional allocators that BV calculated for EGI's O&M expenses.

- Data needed to calculate consistent capital cost and quantity indexes using monetary methods are available only since 1997.[43] This limits the accuracy of statistical research on the capital cost and total cost performance of EGI, especially in the early years for which data are available. The accuracy of the Company's plant addition and O&M cost data are not affected by this problem.

[40] See Interrogatory Response Exhibit I.10.1-STAFF-83, July 8, 2024.

[41] Exhibit JT1.38.

[42] Attachment 1 to Exhibit I.10.1-STAFF-83, July 8, 2024.

[43] Both BV and PEG relied on a 1998 benchmark year for EGI.

4. A Critique of the Black and Veatch Work

4.1. Summary of BV's Work

BV's productivity and transnational benchmarking research methods in this proceeding seem to have evolved from 2020 research and testimony for Boston Gas by a team led by Christensen Associates ("Christensen"). Christensen testified on the input price and TFP trends of a large sample of US utilities in the provision of gas distributor services. Input price trends were an issue in that proceeding as well as productivity trends because National Grid was proposing to use the GDPPI as the sole inflation measure in a revenue cap index formula. Dr. Kaufmann testified in that proceeding on benchmarking work that used Christensen's data for the same utilities. A one hoss shay capital cost specification was used in both studies for Boston Gas.

In 2022, Dr. Kaufmann played a similar role in a team led by Christensen that prepared power distributor input price, TFP, and benchmarking studies for Eversource Energy in Massachusetts. These studies used a hyperbolic decay capital cost specification. Around the same time, Dr. Kaufmann prepared benchmarking research and testimony for a small Massachusetts gas distributor (Berkshire Gas) using hyperbolic decay.

For their EGI evidence, BV used data on operations of 54 U.S. gas distributors. The main source of utility operating data used in their study was reports to state regulators. BV calculated the TFP trends of EGI and the sampled U.S. gas distributors and benchmarked EGI's cost using U.S. data. Capital cost, prices, and quantities were calculated using an HD specification.

TFP trends of EGI and the sampled U.S. gas utilities were calculated over the 16 (growth rate) years from 2007 to 2022. EGI's productivity trend was calculated with respect to its distributor services and all of its regulated services. However, the productivity of US gas utilities was calculated only with respect to distributor services. During these years, the TFP of all sampled U.S. utilities averaged a 1.52% annual decline. Customer growth averaging 0.68% annually fell well short of input growth averaging 2.20% annually.

Over the same years, the TFP growth of EGI's distributor services averaged a more modest 0.48% annual decline. Output growth averaging 1.45% annually was modestly slower than input growth averaging 1.93% annually. The Company's TFP growth in providing all regulated services (which include transmission and storage) averaged a 0.27% annual decline. Output growth averaging 1.45% annually was a little slower than input growth averaging 1.72% annually.

BV benchmarked the cost of EGI's distributor services from 2020 to 2022 using U.S. operating data and simple unit cost (specifically cost per customer) metrics. A custom peer group was chosen consisting of seven large distributors from various regions of the United States. In all but one case (Consumers Energy) the peer group distributors serve large congested urban areas. BV also maintained that benchmarking results for a northeast peer group are more relevant to the situation of EGI than results for a national peer group. The unit cost of EGI was well below the average unit cost of BV's custom peer group, its sampled of Northeast gas distributors, and its full U.S. sample.

On the basis of its benchmarking research, BV advocates a 0% stretch factor for EGI. They propose a -1.5% productivity factor that is based on the TFP trend of the full U.S. sample. BV also proposes an industry-specific inflation factor that is based 75% on the growth of the Canadian gross domestic product implicit price index for final domestic demand ("GDP-IPI-FDD") and 25% on the growth in Ontario's fixed weighted index ("FWI") of average hourly earnings ("AHE").

4.2. PEG's Critique

Dr. Kaufmann worked with PEG for many years and some of the methods he uses are similar to ours. We nonetheless have concerns about some research methods that BV used and some statements that Dr. Kaufmann and BV have made in their work for EGI.

Major Concerns

Statistical Benchmarking

Unit Cost Benchmarking

The unit cost approach to benchmarking that BV uses is not best practice. As we discuss in Section 2.3 above, unit cost metrics provide a control only for differences in the operating scale of utilities. Even that control is imperfect because it doesn't account for how opportunities for scale economies differ at the different operating scales of sampled utilities. Econometric benchmarking can control, additionally, for differences between utilities in numerous additional cost drivers. In the case of gas utilities, these additional drivers can include input prices, the length and composition of gas mains, and the extent of the utility's involvement in gas transmission and storage and electric services. Data needed to develop solid econometric models of gas utility cost are available at reasonable cost.

Dr. Kaufmann's preference for unit cost benchmarking in recent proceedings in which he has testified is particularly surprising given his criticism, in work for the OEB in an Enbridge Custom IR proceeding, of a study by Concentric Energy Advisors ("CEA" or "Concentric").[44] He stated on page 42 that

> PEG believes that CEA's benchmarking results provide no persuasive evidence on EGD's cost efficiency for four primary reasons. First, CEA relies entirely on a peer group benchmarking approach, which is almost never sufficient to yield robust inferences on utility efficiency.

Unit cost benchmarks don't even control for the biggest differences in the input prices of sampled peers. Accuracy would be increased by controlling for differences in input prices as well as operating scale. As we explain in Section 2.3 above, this could be accomplished by converting the unit cost indexes to productivity level indexes. Dr. Kaufmann stated in response to Staff-62(b) that "stakeholders and regulators sometimes find it difficult to interpret measured productivity levels."[45] However, if parties to regulation can process productivity trend studies, they should also be able to process productivity level benchmarking. PEG has provided productivity level indexes in some of its studies for OEB Staff. Dr. Kaufmann presented productivity level benchmarking results in his 2020 testimony for Boston Gas.[46]

Dr. Kaufmann argued in his response to Staff-62(b) that "it is often more valuable to use simpler unit cost measures (*e.g.* costs per customer) in regulatory proceedings. Unlike more technically complex techniques, these metrics are intuitive, easily understood, and often more pragmatic and valuable to interested parties." However, econometric benchmarking is the norm in the OEB's regulation of electric utilities and has recently been used in Alberta and Québec IR proceedings as well. PEG has prepared

[44] Kaufmann, L. (2013), "Enbridge Gas Distribution's Customized Incentive Regulation Proposal: Assessment and Recommendations", October 23, Filed in Ontario Energy Board Case EB-2012-0459 as Exhibit L, Tab 1, Schedule 2.

[45] Exhibit I.10.1-Staff-62(b)

[46] Massachusetts D.P.U. 20-120

benchmarking research and testimony for legacy Enbridge Gas Distribution ("EGD") that used econometric methods.[47]

Dr. Kaufmann argued in his response to Staff-62(c) that econometric benchmarking is ill-suited for handling the energy transition. However, this is much more a problem of the future than it is of the present or recent past. Toronto Hydro, for instance, has emphasized the importance of the energy transition in its current rebasing proceeding while forecasting declining peak demand in the next five years. The slower growth in gas utility customers that is likely to come from the energy transition is easy to handle with historical data.

In response to Staff-62(c), Dr. Kaufmann argues that

> econometric cost benchmarking models assess cost performance by examining the *residual* of the statistical analysis… For this methodological approach to be robust and reliable, the variables used in the model must capture every important and statistically significant cost driver. If the model excludes a variable that tends to increase cost, and which is in fact increasing the costs of one or more sampled utilities, the econometric model's estimate of expected cost will be lower than it should be, because the model has not captured an important set of costs.[48]

The force of this argument is diminished by several considerations.

- Econometric benchmarking of gas utility costs has been underway for decades, and numerous business condition variables have been developed for use in these models. This reduces the likelihood that important relevant variables would be excluded from cost models.
- The effects on cost of any excluded relevant variables may cancel out and thereby not bias econometric benchmarking scores on balance.

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[47] EGI response to Staff-62(e) RP-2003-0203 - Enbridge Gas Distribution 2005 Rates

Enbridge Gas Distribution commissioned Pacific Economics Group (PEG) to provide an update to work previously performed in 2002 with regard to a statistical benchmarking of Enbridge Gas Distribution's O&M expenses. Lowry, M.N., Hovde, D., and Getachew, L. "The O&M Cost Performance of Enbridge Gas Distribution," filed January 23, 2003 and Lowry, M.N., Hovde, D., Kalfayan, J., and Fenrick, S., "The O&M Cost Performance of Enbridge Gas Distribution," filed February 4, 2004.

[48] Exhibit I.10.1-Staff-62(c).

- Unit cost benchmarking also uses residuals as measures of efficiency. There are more excluded relevant variables to worry about than in the econometric approach and this complicates the choice of appropriate peer groups.

  In response to Staff-62 c, Dr. Kaufmann further stated that

> econometric cost models treat output measures (*e.g.* customer numbers, gas volumes) as if they are entirely exogenous. This assumption directly impacts the estimates of scale economies within cost benchmarking models. Estimated scale economies, in turn, play an important role in the calculation of expected total cost and therefore the overall evaluation of a utilities' performance.

He further observes that Enbridge Gas Distribution and Union Gas likely achieved scale economies from their merger.

However, econometric benchmarking models for EGI would not be estimated using EGI data. Moreover, there haven't been that many mergers and acquisitions of sampled gas utilities in the last fifteen years or so to seriously violate the exogeneity assumption on which econometric estimation is based. If the Enbridge Gas Distribution/Union Gas amalgamation achieved substantial cost reductions, this would be recognized in an econometric cost benchmarking study.

Focus on Historical Cost In contrast to the common practice in the OEB's custom IR proceedings for larger electric utilities, the Company's forecasted costs in 2023 and its forecasted/proposed costs for 2024 were not benchmarked. This hindered appraisal of the extent to which the expiring IR plan produced benefits for customers.

U.S./Canadian Price Patch BV used the purchasing power parity ("PPP") of gross domestic product as the price "patch" that compares the input prices of EGI and the sampled U.S. utilities. A better practice is to use the PPP only for materials and services since there are alternative and more accurate sources of data on relative wage rates and construction costs in the U.S. and Canada. This would have produced a much different result as the PPP shows a higher price level than indicated by either average weekly earnings or construction costs according to PEG research.

Concerns Involving Both Benchmarking and Productivity Research

Peer Groups The choice of a peer group is a key issue in both unit cost benchmarking and choice of a productivity factor using index research. In addition to utility operating efficiency, cost levels and productivity growth depend on numerous external business conditions and these conditions vary considerably across North America. Complicating things further is the fact that the best peer group to benchmark the level of cost might differ from the best one to establish a productivity growth target.[49]

The choice of a peer group for EGI is particularly difficult because the business conditions it faces are quite different than those of many utilities in the surrounding region. Dr. Kaufmann stated on page 16 of his report that operating scale and urban density were the main cost drivers that should guide selection of gas utility peers for unit cost benchmarking. This contention is somewhat surprising since the unit cost metric that BV uses already provides some control for differences in operating scale and econometric research has shown that there are other important drivers. It is not obvious that unusually large operating scale, together with urban density, are more important in gas utility cost benchmarking than some other cost drivers such as input price levels or the composition of mains. Such a contention should in any event be supported by empirical research. When asked to provide evidence from an econometric gas utility cost study to support his peer group selection criteria, Dr. Kaufmann provided evidence from an econometric study of *power* distributor costs.

BV's contention that a northeast peer group is more relevant for EGI than a national peer group is also controversial. The Company is much larger than the typical LDC in the northeast U.S. and has much less reliance on cast iron and bare steel mains than many northeast utilities. Polyethylene piping lasts longer in colder environments. BV based their proposed productivity factor on results for the full national sample, not their northeast sample.

EGI's system is also much younger than that of typical northeast utilities. In response to Staff-82, EGI reported that there are currently 132 km of distribution main installed pre-1950s and 135 km installed pre 1940s.[50] This means that a miniscule 0.161% of mains were installed pre-1950s and 0.164%

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[49] Dr. Kaufmann acknowledged this in response to Exhibit I.10.1-Staff-60(d).

[50] Exhibit I.10.1-Staff-82

were installed pre-1940s. For PEG's northeast US sample in 2022, in contrast, 0.82% of mains were installed between 1940 and 1949 and 8.35% were installed pre-1940s. For PEG's full US sample in 2022, 1.04% of mains were installed between 1940 and 1949 and 4.18% were installed pre-1940s. Thus, the EGI system has fewer old mains than the national as well as the Northeast norms.

Dr. Kaufmann's criticisms of the CEA benchmarking study mentioned above also contained this statement.

> There is no justification for the similar-weather criterion CEA uses to select its peer group. This criterion tilts the peer group towards a high cost set of US rust belt distributors struggling with slow customer growth and aged delivery systems constructed with materials prone to gas leaks, rather than distributors like EGD operating and maintaining a nearly 100% PE network for a rapidly growing customer base.[51]

The best peer group for calculating productivity factors for Ontario gas utilities was a big issue in the EB-2007-0606/0615 Ontario gas utility IR proceeding. EGD's expert witness, the Brattle Group, advocated the use of a productivity growth target based on a Northeast and national industry standard at different points in the proceeding. PEG advocated productivity growth targets for peer groups that were derived from econometric cost research.[52]

Capital Cost Specification We explain in Section 2.4 above that since the gas delivery business is capital-intensive, the capital cost specification matters greatly in TFP trend and cost benchmarking studies. We have used GD specifications in most of our work for OEB proceedings. In TFP studies that consultants have done over the years for EGI legacy companies, Christensen used GD in 1999 evidence for Union Gas, Brattle used COS and GD in 2007 evidence for EGD while Concentric used GD in 2013 evidence for EGD, Steve Fenrick used COS in 2012 evidence for EGD, and NERA used OHS in 2017-2018 evidence for EGD. In the latter proceeding, the capital cost specification was a topic of lively debate between NERA and PEG.[53] The OEB did not rule on this matter in its decision.

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[51] Kaufmann, L., "Enbridge Gas Distribution's Customized Incentive Regulation Report: Analysis and Recommendations, EB-2012-0459, Exhibit L, Tab 1, Schedule 2, October 10, 2013, p. 44.

[52] Ontario Energy Board Case EB-2007-0615, Exhibit B, Tab 3, Schedule 7, p. 7. This proceeding was resolved by a settlement approved by the OEB that did not explicitly resolve this issue.

[53] EB-2016-0306/0307

BV has instead used a hyperbolic decay capital cost specification in this proceeding. We explained in Section 2.4 above that HD is a potentially reasonable alternative to GD for cost efficiency studies and is serviceable for use in choosing a productivity factor, especially in a jurisdiction where the inflation differential is not a major issue. However, its use in utility productivity studies has not been as thoroughly vetted as other specifications.

We also have some serious concerns about the way that BV implemented HD.

- BV's calculations of the initial capital stocks start with a utility's net plant value in a certain benchmark year and deflate this value by the assumed average price at which this plant was accumulated. In a geometric decay specification, the service flow from this capital stock then declines at a constant annual rate in subsequent years. *Hyperbolic* decay entails a rate of decay that is slight for many years and gradually increases as the asset ages.

  The specific approach to HD that BV uses treats the capital stock in the benchmark year as *new* and therefore declining very gradually for many years thereafter. However, the initial capital stock was *not* for the most part new and to the contrary included assets of various vintages. BV's treatment underestimates the decline in the service flow from older assets and thereby understates capital and multifactor productivity growth, especially in the early years of the sample period.

- No consensus has been established about the appropriate capital service price index to pair with the capital quantity index when using HD. Explanations of the HD service price index in consultant reports have included undefined terms and substantive typos. Consultants have declined to explain the derivation of their HD service price formulas in their responses to information requests. Dr. Kaufmann over time has reported the use of three different HD service price index formulas. At the technical conference, he voiced concern about Christensen's formula even though he used that formula twice in his own Massachusetts benchmarking studies. In response to an undertaking from PEG in this proceeding, he did not present the derivation of his latest HD service price formula.[54]

[54] Undertaking Response JT1.32 in EGI_Undertakings_Exhibit JT_2024 Rebasing Phase 2_2024801, August 1, 2024.

Pensions and Other Benefits BV included pension and other benefit expenses in their productivity and benchmarking work even though these expenses are accorded variance account treatment in the proposed plan, U.S. utilities tend to have larger pension and benefit obligations, and no labor price index is to our knowledge readily available in Canada that measures trends in the price of total compensation. Pension and other benefit expenses are itemized in the available U.S. operating data, and EGI itemized these expenses in response to a technical conference undertaking.

M&S Prices BV uses the GDPPI as a proxy for the material and service ("M&S") price trend index ("WMS") in their U.S. calculations. We acknowledge that this approach has been widely used in past utility statistical cost research. However, based on recent input price research in a U.S. proceeding,[55] we believe that the GDPPI materially understates the M&S price growth of U.S. gas and electric utilities.[56] One problem is that GDPPI inflation is materially slowed by the typically brisk multifactor productivity growth of the U.S. economy. Another problem is that M&S expenses include a lot of labor-intensive outsourced services, and the price of labor tends to rise more briskly than those of other inputs. In response to Staff-83(j), EGI reported that a substantial 59% of the Company's gross non-labour O&M expenses were outsourced in 2023.[57] By understating WMS growth, BV likely understates TFP and (especially) O&M productivity growth as well.

Itemization of Results Itemized productivity and benchmarking results for O&M and capital cost provide valuable information at modest incremental cost. For example, the O&M revenue of EGI may be the only component of its base revenue that is effectively escalated by indexing due to the proposed incremental capital module. This enhances the relevance of O&M productivity trends.

In response to Staff-62(g), Dr. Kaufmann defended his narrower focus on total cost with the circular argument that "BV did not focus on partial measures because the focus of this work is total cost and total factor productivity measures."[58] In response to Staff-59(d), Dr. Kaufmann refused to calculate

[55] Washington Utilities and Transportation Commission, Docket UE-240004/UG-240005, Exh. MNL-3, Lowry, M.N., Hovde, D., Kavan, R., and Makos, M., "Inflation Research for PSE," January 24, 2024.

[56] See Washington Utilities and Transportation Commission docket UE-240004.

[57] Exhibit I.10.1-Staff-83(j)

[58] Exhibit I.10.1-Staff-62(g)

the O&M and capital productivity trends of U.S. gas distributors on the implausible grounds that the request was "unduly burdensome and extremely time-consuming."[59] However, in the same month (March 2024) in which BV dated its report for EGI, Dr. Kaufmann dated a study for a FortisBC proceeding that focused on gas and electric O&M productivity trends and unit cost benchmarking.

Focus on Distribution Only the cost of EGI's distributor services was benchmarked using US data and only U.S. power distributor productivity trends were calculated even though this proceeding also addresses rates for the Company's extensive transmission and storage services. The focus on distributor services is all the more controversial inasmuch as EGI does not routinely itemize its O&M expenses for these services and resorted to using cost allocations from rebasing proceedings to estimate these expenses.[60]

Lesser But Notable Methodological Concerns

Sample Period Research on the productivity trend and cost performance of EGI should focus on the period since 2011 for several reasons.

- The 1998 benchmark year for the calculation of the capital quantity index is fairly recent. We discuss in Section 2.4 above how a recent benchmark year reduces the accuracy of capital quantity estimates.
- EGD and Union Gas commenced reporting using U.S. GAAP as the primary basis for accounting in January 2012.
- EGI has only provided itemized pension and other benefit data for the 2019-2023 period.

Capital Specification We have several additional concerns as to how BV calculated its capital service prices and quantities.

- In its attachment to its Staff-75 response, BV provided its calculations for a construction cost index for gas distribution using Handy Whitman data. PEG's understanding of these calculations is that, for each region, BV calculated a weighted average of the Handy-Whitman subindexes

[59] Exhibit I.10.1-Staff-59(d)

[60] Exhibit JT1.40

(e.g., those for distribution structures and improvements, cast iron mains, steel mains, meters, meter installations, plastic services). Instead of *cost* share weights, however, the weights for these subindexes were the 2019 Handy Whitman *index values* of each distribution construction cost subindex.

- Dr. Kaufmann acknowledged in his response to Staff-75(a-b) that trends in regional Handy-Whitman indexes were averaged instead of using the applicable regional index to deflate the plant values of each utility. This ignores useful information. BV argued in its response that "It is not straightforward to assign regional Handy-Whitman (HW) indices to individual gas distributors since a significant number of gas distributors have operations that are not contained in a single region. In addition, there is some ambiguity on the exact borders of the North Central vs. South Central regions and the North Atlantic vs. South Atlantic regions, as well as the plateau region." However, the regions consist of groupings of states that are clearly defined on a map that Whitman, Requardt and Associates provides with each edition of their data. Few of the sampled utilities serve multiple regions and those that do typically provide the bulk of their services in one of the regions.[61] In the construction of his Handy-Whitman index for gas distributors nationwide Dr. Kaufmann assumed that each region should have the same weight. This would seem to overweight the indexes for gas distributors in regions where gas distributors serve fewer customers.

- Another concern is that the Handy Whitman Index of Gas Utility Construction Costs requires adjustments to be a reasonably accurate measure of trends in these costs. The problem is that the weights assigned to mains made from different materials have not shifted over time to reflect a change in the mix of materials used. This is discussed further in Appendix A.

- The GDP-IPI-FDD was used as the asset price index for EGI in all years considered. That approach was established many years ago for the OEB's total cost benchmarking program[62] but

[61] For example, Avista serves both the Mountain and Pacific regions but chiefly serves the Pacific region.

[62] This particular index was chosen by PEG to be consistent with the OEB's use of the GDP-IPI-FDD as an inflation subindex in the inflation factor formula. It was a replacement for a price index that was no longer being supported by Statistics Canada. This happened during an update of the approved benchmarking model after it had been

current best practice is to use an average of the implicit capital stock deflator for the Ontario utilities sector and the most relevant regional Handy Whitman index x PPP.

- BV used Moody's AAA bond yields to proxy the rate of return on capital whereas the rate of return is usually the average of a bond yield and a rate of return on equity.
- Dr. Kaufmann stated in response to Staff-74(a) that "the real return in the capital price was set at its long-run average to smooth volatility in the capital service price."[63] We believe that this treatment is consistent with research goals that prioritize the calculation of an input price differential such as in the recent Massachusetts proceedings in which Dr. Kaufmann worked with Christensen Associates. That is not an issue in this proceeding and the real return should be time-variant.

Small Errors

- Small errors have been made in many statistical cost research studies submitted in rate proceedings (including some of PEG's). Dr. Kaufmann acknowledged some small errors in BV's responses to Staff-64, Staff-81, and Staff-84. Additional problems were revealed in responses to technical conference undertakings. BV filed an errata to correct many of the items PEG brought to their attention.

Labor Price Indexes BV relied on an unweighted version of the Ontario Average Hourly Earnings metric as its labor price index for EGI. As discussed further in Section 6 below, this index is susceptible to aggregation bias due to its non-fixed weights. EGI has proposed to use the alternative fixed-weighted index of average hourly earnings as a component of the inflation factor formula in its new plan.

established in consultation with industry. PEG viewed the adoption of the GDP-IPI-FDD as the only available index that had implicit OEB approval and therefore did not raise controversy over the choice of a new index. It was not necessarily the index PEG would have recommended had it had all options available.

[63] Exhibit I.10.1-Staff-74a.

ASL

- The 51-year average service life assumed for utilities in BV's productivity and benchmarking work is well above the average service life provided by EGI in response to an undertaking.[64]

4.3. Controversial Statements

BV and EGI have made a number of controversial statements in their evidence. Here are some notable ones.

- Dr. Kaufmann stated in response to Staff-70(c) that he has no recollection of having used a COS approach to capital decay in his work for the OEB when at PEG.[65] In fact, he used the COS approach in a 2008 report in 3rd GIRM and in his 2011 appraisal of the Union Gas and Enbridge Gas Distribution IR plans.[66]

- Dr. Kaufmann controversially likens use of a negative productivity growth target to the OEB choosing a K-bar form of supplemental capital revenue in Staff-54(b).[67] But Alberta distributors must for the most part live with the supplemental revenue that K-bar provides whereas EGI proposes access to an ICM.

- Dr. Kaufmann claimed in his response to Staff-61(b) that capex containment incentives have contributed to *slower* capital growth for EGI.[68] But EGI and predecessor companies have frequently operated under multiyear rate plans with capital revenue supplements that weakened their cost containment incentives.

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[64] Exhibit JT1.31

[65] Exhibit I.10.1-Staff-70(c)

[66] "Assessment of Union Gas Ltd. And Enbridge Gas Distribution Inc. Incentive Regulation Plans," appraising the performance of Enbridge Gas Distribution and Union Gas under IR plans approved in 2008, pp. 75-76, September 2011. The second is from the OEB's IRM3 proceeding EB-2007-0673, "Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario, Report to the Ontario Energy Board, pp. 36-67, February 2008.

[67] Exhibit I.10.1-Staff-54(b)

[68] Exhibit I.10.1-Staff-62(b)

5. New Empirical Research from PEG

5.1. Data

Sampled Utilities

Our research on the cost of U.S. gas utilities used a sample of quality data for 57 utilities. These companies are listed in Table 2. The sample includes most of the larger U.S. gas utilities and most of those that serve urban areas. Some of the sampled utilities (e.g., Southern California Gas) also provided gas transmission and/or storage services but all were involved more extensively in gas distribution. Pacific Gas and Electric was excluded from the sample due to the extraordinary and sustained productivity decline it experienced after the San Bruno explosion.

Sample Period

The sample period for our econometric cost research was the fifteen years from 2008 to 2022. 2022 is the latest year for which all of the requisite data for the study are as yet available. The sample period for our U.S. productivity trend study was the fifteen growth rate years from 2008 to 2022.

Cost Data

The costs addressed in our research encompassed non-fuel O&M expenses and capital costs. These costs are itemized in our calculations.

O&M Expenses

We included in our U.S. cost calculations reported O&M expenses for gas transmission, storage, distribution, customer accounts, and administrative and general activities. We excluded from our U.S. cost calculations expenses for gas production and purchases, gas transmission and compression by others, compressor station fuel, customer services and information ("CS&I"), and pensions and other benefits.

Table 2

Companies in PEG's Gas Utility Sample

Alabama Gas
Atlanta Gas Light
Avista
Baltimore Gas and Electric
Berkshire Gas
Boston Gas
Brooklyn Union
Cascade Natural Gas
Central Hudson Gas & Electric
Citizens Energy Group
Columbia Gas of Kentucky
Columbia Gas of Maryland
Columbia Gas of Ohio
Columbia Gas of Pennsylvania
Columbia Gas of Virginia
Connecticut Natural Gas
Consolidated Edison
Consumers Energy
Corning Natural Gas
DTE Gas
Duke Energy Ohio
East Ohio Gas
Hope Gas
Indiana Gas
Keyspan Gas East
Louisville Gas and Electric
Madison Gas and Electric
Mountaineer Gas
New Jersey Natural Gas
New York State Electric & Gas
Niagara Mohawk Power
North Shore Gas
Northern Illinois Gas
Northern States Power - WI
Northwest Natural Gas
NSTAR Gas
Orange and Rockland Utilities
PECO Energy
Peoples Gas Light and Coke
Public Service Company of Colorado
Public Service Company of North Carolina
Public Service Electric and Gas
Puget Sound Energy
Questar Gas
Rochester Gas and Electric
San Diego Gas & Electric
Sierra Pacific Power
South Carolina Electric & Gas
South Jersey Gas
Southern California Gas
Southern Connecticut Gas
Southern Indiana Gas and Electric
Virginia Natural Gas
Washington Gas Light
Wisconsin Gas
Wisconsin Power and Light
Yankee Gas Services

Notes: The sample comprises data from 57 utilities.
Italicized companies were not included in BV's sample.

The CS&I expenses of many U.S. gas utilities grew briskly during the sample period. This growth was driven mainly by DSM programs. The scale of utility DSM programs varies and is difficult to measure accurately. DSM expenses are not reliably itemized in the U.S. data for easy removal.

Moreover, the DSM expenses of EGI may be subject to variance account treatment in the Company's new IRM.[69]

Pension and other benefit expenses incurred by EGI and U.S. gas utilities are non-comparable. A major reason is that more benefits are provided by government agencies in Canada than in the United States. These expenses also vary between utilities with accounting practices and with the extent to which pension services are outsourced and can be sensitive to volatile business conditions, such as equity prices, that are largely beyond utility control. Finally, pension and other benefit expenses incurred by EGI are expected to be subject to variance account treatment in the Company's new IRM.[70]

Capital Costs

We employed a monetary approach to capital cost, price, and quantity measurement which featured a geometric decay specification. Under this specification, capital cost was the sum of depreciation expenses and a return on net plant value less capital gains. Plant was valued in current dollars. Taxes were excluded as these vary greatly between gas distributors and are largely beyond their control.[71]

Capital cost thus calculated is the product of a capital quantity index and a capital service price index. The service price index measures capital cost per unit of capital service. Our capital cost calculations are discussed further in Appendix A.

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[69] EGI is expected to file an application for a new DSM program for the post-2025 period this fall. The ratemaking treatment of their DSM expenses is likely to be determined in this proceeding.

[70] In response to Exhibit I.10.1-Staff-72, part b, EGI stated that

> As part of EB-2022-0200 the OEB also approved of the Post-Retirement True-Up Variance Account. This variance account records the difference between the revenue requirement impact of actual pension and other post-employment benefits (OPEB) costs (accrual and cash-based amounts) and the revenue requirement impact of forecast pension and OPEB costs (accrual and cash-based amounts) included in rates, to the extent the difference is in excess of a $10 million deadband (debit or credit). As a result, Enbridge Gas will collect from or return to customers actual pension and OPEB costs which are significantly higher or lower than the costs reflected in rates.

[71] PEG understands that 50% of the revenue requirement impact of tax rate or rule changes is eligible for variance account treatment.

Ontario

The O&M expenses we included in the study for EGI were based on the expenses BV used and additional data provided by EGI in response to interrogatories and technical conference undertakings. We included in our cost definition the normal expenses for EGI's total regulated operations with the exception of expenses for non-labor DSM, pensions and other benefits, and bad debt. The EGI capital costs that we considered were those for all of EGI's reported regulated plant.

Output Measures

One scale variable was strongly supported by the data in our econometric research: the number of customers served. We expect cost to be higher the higher is a company's operating scale. The parameter of this variable should therefore have a positive sign in our O&M, capital, and total cost econometric models.

Input Prices

Prices that distributors paid for inputs are needed in productivity and cost benchmarking research. These prices change from year to year and differ between utilities in each year. Price differences between utilities at each point in time matter when benchmarking the level of cost but not in the calculation of productivity trends. We used separate but related input price indexes in our benchmarking and productivity *trend* calculations.

For our O&M benchmarking and productivity research we constructed a summary O&M price index. For our total cost benchmarking research we constructed multifactor input price indexes that encompassed prices of capital as well as O&M inputs.

O&M Inputs

Our O&M input price indexes were constructed from price subindexes for labor and materials and services. The estimated shares of salary and wage ("S&W") and M&S expenses in the included O&M expenses of the sampled distributors were used as weights. Most of the sampled gas distributors did not itemize S&W and M&S expenses in their reports to state regulators. For these companies, we used as O&M cost shares the contemporaneous and time-variant averages of those calculated from the data that combined gas and electric utilities in our sample reported on their FERC Form 1 reports.

The labor price subindex for U.S. gas distributors that we used in our benchmarking research was developed from BLS data using a multistep process. Occupational Employment Survey ("OES") data for 2019 were used to construct average wage rates for the service territory of each sampled distributor. These rates were calculated as a weighted average of the survey pay levels for several job categories using weights that correspond to the gas distribution sector of the U.S. economy. For each distributor, we selected a representative city among the available metropolitan statistical areas.

Labor price index values for other years were calculated by adjusting the level in 2019 for the estimated regional inflation in the salaries and wages of utility workers. This inflation was calculated from BLS employment cost indexes ("ECIs"). The growth rate of the labor price index was calculated as the growth rate of the *national* ECI for the salaries and wages of the utility sector plus the difference between the growth rates of multi-sector salary and wage ECIs for workers in the utility's region and in the nation as a whole.

To calculate comparable wage rate index values for EGI in 2019, we compared the average weekly earnings of the U.S. private business sector (as computed by BLS) to the average weekly earnings of the Canadian industrial aggregate (as computed by Statistics Canada). We then compared the average weekly earnings of the industrial aggregate in Ontario to those in Canada.

We note in Section 4.2 above that prices U.S. utilities pay for materials and services are often assumed in statistical cost research to rise over time at the rate of the GDPPI. However, recent research by PEG suggests that the GDPPI tends to materially understate the M&S price inflation of U.S. gas and electric utilities. In this study we use a new proxy M&S price index that is discussed further in Appendix section A.1.

In the price levelization, M&S expenses were assumed to have a 33% local labor content and therefore to be a little higher in regions with higher labor price levels (e.g., M&S prices were especially high in the New York metro area). We used the 2019 labor price levelization just explained to achieve this.

For the M&S price trend of EGI we used Statistics Canada's GDP-IPI-FDD for Canada. This is preferable to the more comprehensive GDP-IPI for this purpose because the latter is unduly sensitive to the volatile and largely irrelevant prices of Canada's sizable commodity exports. There is less concern than in the US about using a macroeconomic inflation measure to proxy M&S input price growth due to the slow multifactor productivity growth of Canada's economy. We did, however, increase the weight assigned to the labor price index to recognize the sizable share of EGI's O&M that is outsourced. M&S prices in the U.S. and Canada were patched using U.S./Canadian purchasing power parity for gross domestic product in the year 2019. PPPs summarize the relative prices of a wide range of products that are included in the gross domestic product.

Capital

Our formulas for the capital service prices are presented in Appendix A.1. The capital costs reflected in these prices are capital gains, depreciation, and the return on net plant value. Market construction costs and the rate of return on plant play key roles in the price formula.

A multistep process was used to construct levelized capital asset prices for the econometric work. We first calculated an index of construction cost levels which varied between the service territories of sampled gas utilities in 2019 in proportion to the relative cost of local construction as measured by total (material and installation) heavy construction cost indexes published by RSMeans.[72] Values of the RSMeans indexes are available for multiple cities in the service territories of utilities in the United States and Canada. We used the value for one city in each service territory. For EGI we used the value for Toronto.

To obtain construction cost index values for other years, we trended the values for 2019 using asset price trend indexes. For the sampled U.S. utilities we used for this purpose the regional Handy Whitman Indexes of Gas Utility Construction Cost Trends for Total Plant. These indexes encompass trends in production, transmission, and storage as well as distribution construction costs. An adjustment was made to these indexes to reflect a change in gas main materials. This adjustment is discussed further in the Appendix.

For EGI we developed an asset price trend index from the average annual growth rates of two indexes. One was the product of the Handy Whitman Index of Gas Utility Construction Costs for Total Gas Plant in the North Atlantic region and the U.S./Canadian PPP for gross domestic product. The other was Statistics Canada's implicit capital stock deflator for engineering construction of the utility sector of

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

Ontario. Statistics Canada includes in the utility sector power generation, transmission, and distribution, gas distribution, and water and sewer utilities. We assigned equal weights to the growth rates in these two indexes. An analogous treatment was used by PEG and the witness for Hydro One Networks, Clearspring Energy Advisors, in a Joint Report on productivity and benchmarking research that was prepared in a recent Hydro One custom IR proceeding.

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.[73] For EGI, we employed the same rates of return that we used for US utilities. The construction of capital service prices from these components is discussed further in Appendix A.

5.2. Econometric Cost Research

Real Cost

Before estimating each of our three cost models we divided cost by the corresponding summary input price index. This is commonly done in econometric cost research because it simplifies model estimation and enforces a relationship between cost and input prices that is predicted by economic theory.

Scale Variables

Several scale variables were considered in the econometric research. Of these, only the number of customers served received strong statistical support. We included a quadratic as well as a linear version of this variable in the model to test for the presence of a non-linear relationship that could influence the extent of scale economies.

Other Business Conditions

Twelve other business condition variables were used in one or more of our gas utility cost models. One is the share of the total miles of distribution main that were made of cast iron or bare steel

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

four years prior.[74] This variable is calculated using PHMSA data for the sampled U.S. utilities and data provided by EGI in a technical conference undertaking. Continuing use of cast iron and bare steel mains tends to raise O&M expenses and capex. The sign for this variable's parameter should therefore be positive in all three models. We also included as a variable the cumulative reduction in cast iron and unprotected bare steel ("CIBS") reliance during the sample period. [75] This variable should have a positive sign in the capital cost model since reduced reliance on CIBS is expected to entail replacement capex. Its sign is indeterminate in the O&M and total cost models.

Each model also contains a measure of customer density, calculated as the ratio of miles of Transmission and Distribution ("T&D") main to the number of customers served. The sign of this variable is indeterminate in all three models. We also include a binary business condition variable that indicates whether a utility serves a large and densely settled urban core. This variable was assigned a value of 1 if the company provides gas service to the urban core of a metropolitan area with a population of at least 4 million people. 4 million people is the threshold that had the strongest statistical support.

Another business condition variable is the share of distribution in the gross value of distribution, transmission, and storage plant. This variable picks up the extent to which the utility is involved in gas transmission and storage as well as distribution. Such involvement should raise cost, so the expected sign of this variable's parameter should be negative in all three cost models. The variable % miles transmission x Dummy 2020-2022 captures the effect of the PHMSA Mega Rule on the transmission cost of sampled utilities. This variable should have a positive sign in the O&M cost model since the Mega Rule is believed to have triggered O&M expenses thus far.

An eighth variable considered is the share of residential and commercial ("R&C") deliveries in total gas deliveries. R&C customers contribute disproportionately to costs of customer care and peak day sendout. We therefore expect the parameter for this variable to have a positive sign in all three

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[74] The lagged treatment is intended to reduce concerns about the endogeneity of this variable. Concerns about endogeneity are further reduced by the fact that PHMSA policies have strongly influenced cast iron and bare steel replacements in the States.

[75] An alternative variable that we considered, $\%CIBS^{2007}$ x TREND, produced similar benchmarking results for EGI.

models. Residential average use was considered as a proxy for peak demand. High average use is associated with high peak load due to severe winter weather and reliance on natural gas for space heating. The expected sign of this variable is therefore positive.

The tenth additional business condition is the ratio of the number of customers served in the last and first years of the sample period. This "customer growth" variable is a useful measure of the cost impact of demand growth. Rapid demand growth tends to raise capital cost in the short term even as it may occasion scale economies. In the O&M cost model, this same variable is a proxy for the newness of assets since rapidly growing systems tend to have more new assets and newer assets tend to entail lower O&M expenses.[76] Its sign is therefore indeterminate. The effect of this variable on total cost is also indeterminate.

An electric service binary variable indicates whether a company provides electric as well as gas services. This should reduce the cost of gas service in all three models. The sign of this variable is therefore expected to be negative in all three models.

Each cost model also contains a trend variable. This permits predicted cost to shift over time for reasons other than changes in the specified business conditions. The trend variable captures the net effect on cost of diverse conditions, such as technological change, that are otherwise excluded from the model. Parameters for trend variables often have a negative sign in econometric research on utility cost. However, its sign cannot be predicted.

Other variables were considered for inclusion in the model but ultimately rejected due to a lack of strong statistical support. These included the share of gas customers in the sum of gas and electric customers served and average heating degree days.

5.3. Econometric Research

Using the data we gathered on U.S. gas utility operations we developed econometric models of the impact on gas utility O&M expenses, capital cost, and total cost of an array of external business conditions. Results of this research are reported in Tables 3-5. Each table reports econometric

[76] We did not explore in this project the cost impact of the age of the capital stock at the start of the sample period.

estimates of model parameters and their associated asymptotic t-statistics and p-values. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero can be rejected at a high level of confidence. These significance tests were used in model development. In all three models, all of the parameter estimates for the business condition variables were statistically significant at the ninety-percent confidence level as well as being plausible as to sign and magnitude.

Total Cost

Econometric results for PEG's gas utility total cost model are presented in Table 3. Here are some salient results. Total utility cost was higher the higher was the number of customers served. The quadratic customer term (customers x customers) had a negative and significant parameter estimate. Thus, the relationship between cost and the number of customers served was significantly non-linear.

As predicted, cost was also higher

- the greater was reliance on cast iron and bare steel mains;
- the lower was the share of distribution plant in total plant value;
- the greater was customer growth during the sample period; and
- the greater was line length per customer.

Cost was also higher for utilities that served a large urban core. The trend variable parameter estimate indicates that total cost *increased* each year by 0.60% annually for reasons not otherwise explained in the model. The 0.957 adjusted R^2 statistic suggests that the model had high explanatory power.

Table 3

PEG's Econometric Model of Gas Utility Total Cost

Explanatory Variable	Estimated Cost Elasticity	T-Statistic	P-Value
Number of Customers	0.807***	65.284	0.000
Number of Customers Squared	-0.341***	-10.638	0.000
Miles of Main per Customer	0.182***	12.378	0.000
%CIBS 4 Years Prior	0.0963***	9.929	0.000
Change CIBS07 Cumulative	0.0900***	16.710	0.000
%Dx of Dx+Tx+Storage Plant	-0.583***	-13.976	0.000
Urban 4mil+	0.0267***	40.318	0.000
Customer Growth since 2008	0.613***	8.198	0.000
Trend	0.00602***	7.239	0.000
Constant	7.908***	853.922	0.000

Adjusted R^2	0.957
Sample Period	2008-2022
Number of Observations	859

Notes

***	Statistically significant parameter estimate at 99% confidence
**	Statistically significant parameter estimate at 95% confidence
*	Statistically significant parameter estimate at 90% confidence

Capital Cost

Econometric results for PEG's gas utility capital cost model are presented in Table 4. It can be seen that capital cost was higher the higher was the number of customers served. The quadratic term for the customer variable once again had a negative and highly significant parameter value. This indicates that the relationship of capital cost to customers served was significantly nonlinear.

Capital cost was also higher

- the greater were miles of main per customer, reliance on cast iron and bare steel, residential average use, the share of volume residential and commercial, and customer growth over the sample period; and
- the lower was the share of distribution plant in distribution, transmission, and storage plant.

Capital cost was also higher for distributors serving an urban core.

The trend variable parameter estimate indicates that capital cost increased each year by 1.03% annually for reasons that are not otherwise explained by the model. The 0.946 value of the adjusted R^2 statistic was similar to that for the total cost model.

Table 4

PEG's Econometric Model of Gas Utility Capital Cost

Explanatory Variable	Estimated Cost Elasticity	T-Statistic	P-Value
Number of Customers	0.762***	183.622	0.000
Number of Customers Squared	-0.490***	-11.778	0.000
Miles of Main per Customer	0.260***	10.219	0.000
%CIBS 4 Years Prior	0.0717***	5.365	0.000
Change CIBS07 Cumulative	0.109***	14.957	0.000
%Dx of Dx+Tx+Storage Plant	-0.468***	-12.848	0.000
Urban 4mil+	0.0344***	48.624	0.000
Customer Growth since 2008	1.353***	7.663	0.000
% Throughput Residential & Commercial	0.0795***	7.030	0.000
Residential Average Use	0.191***	5.166	0.000
Trend	0.0103***	6.833	0.000
Constant	9.999***	751.930	0.000

Adjusted R^2	0.946
Sample Period	2008-2022
Number of Observations	859

Notes
*** Statistically significant parameter estimate at 99% confidence
** Statistically significant parameter estimate at 95% confidence
* Statistically significant parameter estimate at 90% confidence

Pacific Economics Group Research, LLC

O&M Expenses

Econometric results of PEG's gas utility O&M cost model are presented in Table 5. It can be seen that O&M cost was once again higher the higher was the number of customers served. A quadratic customer term had a negative and marginally significant parameter estimate. Thus, the relation of cost to the number of customers served was slightly nonlinear.

O&M expenses were also higher the greater was reliance on cast iron and bare steel mains and the share of residential and commercial customers in total volumes delivered, the lower was the share of distribution in distribution, transmission, and storage plant value, and the higher was transmission line length for the period? 2020-2022. O&M expenses were higher for utilities serving a large urban core and lower for utilities that also provided electric service.

The credibility of our econometric results is bolstered by the different estimated impacts of business condition variables on O&M and capital cost. For example, it makes sense that

- the provision of electric service affects O&M cost more than capital cost;
- the recently implemented PHMSA mega rule has initially mattered more to O&M cost than to capital cost;
- residential average use matters more to capital cost (due to higher resultant peak load) than it does to O&M cost;
- the trend variable is less negative for O&M cost than it is for capital cost.

The trend variable parameter estimate suggests that O&M cost decreased by a slight 0.23% annually for reasons that are not otherwise explained in the model. The 0.931 adjusted R^2 statistic was modestly below that of the total cost and capital cost models.

Table 5

PEG's Econometric Model of Gas Utility O&M Expenses

Explanatory Variable	Cost Elasticity	T-Statistic	P-Value
Number of Customers	0.754***	62.96	0.000
Number of Customers Squared	-0.021	-1.91	0.056
%CIBS 4 Years Prior	0.0913***	19.34	0.000
Change CIBS07 Cumulative	0.0556***	7.69	0.000
%Dx of Dx+Tx+Storage Plant	-0.578***	-13.05	0.000
MEGA (%MilesTx x 2020+)	0.00324*	2.47	0.013
Urban 4mil+	0.0236***	9.50	0.000
Customer Growth since 2008	-0.409***	-9.92	0.000
% Throughput Residential & Commercial	0.104***	3.58	0.000
Electric Dummy	-0.0407***	-12.38	0.000
Trend	-0.002	-0.95	0.344
Constant	6.880***	824.17	0.000

Adjusted R^2	0.931
Sample Period	2008-2022
Number of Observations	859

Notes

*** Statistically significant parameter estimate at 99% confidence
** Statistically significant parameter estimate at 95% confidence
* Statistically significant parameter estimate at 90% confidence

5.4. Cost Benchmarking Research

Introduction

We benchmarked the non-fuel O&M expenses, capital cost, and multifactor ("total") cost of EGI using the econometric models detailed in the prior section. In this section we provide some background information about EGI, compare the Company's business conditions to sample norms, and discuss our benchmarking results using productivity indexes and econometric methods.

EGI

Company Background

EGI is the dominant provider of gas distributor services in Ontario. It resulted from the 2019 amalgamation of Enbridge Gas Distribution and Union Gas and is owned by Calgary-based Enbridge Inc. EGI's service territory includes the Toronto metro area (one of North America's largest), Canada's capital city Ottawa, and many smaller cities and towns. Some of these smaller communities have large industrial operations, and some are located in fairly remote areas. Customer growth has historically been brisk by North American standards but has recently slowed to a more normal pace that is expected to continue.

In addition to distributing gas EGI owns, operates, and reads meters and manages customer billing. The Company also owns and operates sizable gas transmission and storage facilities. No electric utility services are provided.

EGI and its legacy companies have operated under three generations of multiyear rate plans since 2008. Details of these plans have varied but typically combine rate or revenue cap indexes with provisions for supplemental capital revenue. The eligibility criteria for supplemental capital funding seem to have loosened over time. In the earlier plans explicit authorization was made for supplemental capital funding of specific kinds of projects through a Y factor or deferral and variance account. For example, legacy EGD's revenue per customer cap index, approved in 2008, allowed the company to seek supplemental funding of system reinforcement capex resulting from connecting natural gas fired generators to its system through a Y factor. A legacy Union Gas plan, approved in the same year, does not appear to have had provisions for supplemental capital funding. The most recently approved plan for EGI in contrast allowed the company to request supplemental funding through an ICM for any capex that met the ICM criteria. Supplemental funding for O&M expenses has typically been limited to Y factor or deferral or variance account treatment for specific kinds of O&M expenses. As a result, PEG believes that EGI's incentives to contain O&M expenses have generally been stronger than those to contain capex.

Econometric Benchmarking Results

Econometric benchmarking results are provided for each year from 2019 to 2022. These are the years for which pension and benefit expenses could be excluded from the analysis. The O&M, capital, and total cost benchmarks were based on the econometric model parameter estimates in Tables 3-5 and values for the business condition variables that are appropriate for EGI. We report results for each year as well as average results for the three-year 2020-2022 period.

Econometric Benchmarking Results

Table 6 and Figure 1 report results of our econometric benchmarking work for EGI. Here are some highlights.

Total Cost On average, EGI's actual total cost for the 2020-2022 period was about 23% above our benchmarks. This is commensurate with a bottom quartile ranking in our U.S. sample. However, the total distributor cost performance score of EGI did tend to improve from 2020 and 2022.

Capital Cost On average, EGI's actual capital cost during the 2020-2022 period was about 25% above our benchmarks. This is also commensurate with a bottom quartile ranking in our U.S. sample.

O&M Expenses On average, EGI's O&M cost during the 2020-2022 period was about 6% above our benchmarks. This is commensurate with a third quartile ranking in our U.S. sample. However, the O&M cost performance of EGI improved substantially from 2019 to 2021. This likely reflected in part the opportunities for amalgamation-related cost savings. An O&M cost performance that is better than capital cost performance is also consistent with our view that EGI's cost containment incentives have been stronger for O&M.

Table 6

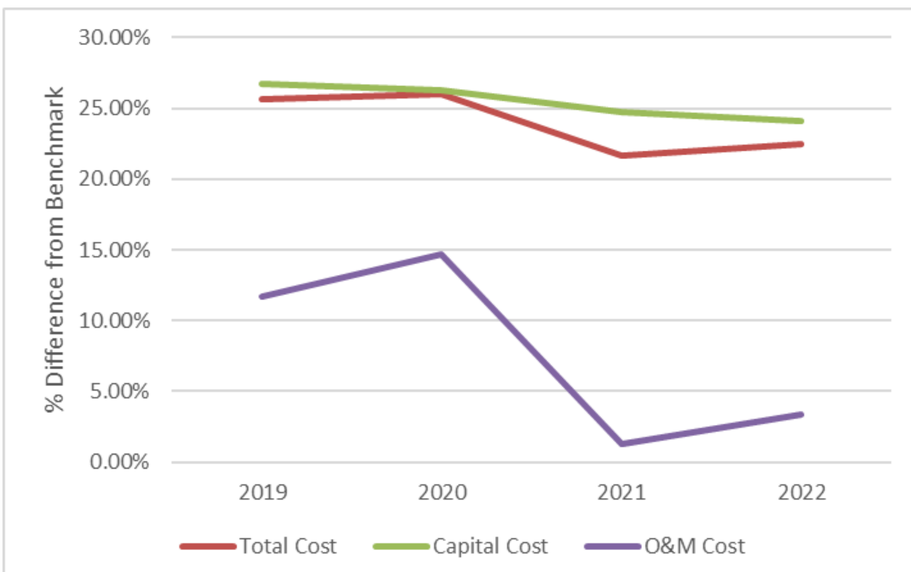
Econometric Cost Level Benchmarking Scores

[Actual – Predicted Cost]

Period	Total Cost	Capital Cost	O&M Cost
2019	25.66%	26.74%	11.70%
2020	26.00%	26.29%	14.66%
2021	21.66%	24.72%	1.24%
2022	22.46%	24.09%	3.33%
Annual Averages			
2020-2022	**23.37%**	**25.03%**	**6.41%**

Figure 1

Econometric Cost Level Benchmarking Scores



5.5. U.S. Productivity Trends

Index Details

Scope

We calculated indexes of trends in the O&M, capital, and total factor productivity of each sampled utility in the provision of gas distributor, transmission, and storage services. The costs that we considered did not include taxes or expenses for customer service and information, uncollectible accounts, pensions and other benefits, gas supply, transmission and compression of gas by others, compressor station fuel or the electric services of combined gas and electric utilities.

The applicable total cost was calculated as the sum of applicable O&M expenses and the costs of gas plant ownership. The index calculations required the breakdown of cost into two input categories: capital and O&M inputs. O&M inputs comprised labor, materials, and services.

Output Measure

The choice of an output measure for a productivity study designed to calibrate the X factor for EGI in this proceeding is complicated. EGI proposes a *price* cap index, and we showed in Section 2.2 above that these indexes in theory require a productivity study in which output is based on trends in billing determinants (e.g., delivery volumes) rather than cost drivers. Trends in billing determinants of U.S. gas distributors (e.g., residential deliveries) can differ markedly from the trends in their cost drivers. To avoid the complications for ratemaking of declining average use, several North American distributors (including Alberta Gas and legacy Enbridge Gas Distribution) have operated under revenue cap indexes with customer growth escalators. In the absence of multiyear rate plans, many more have operated under revenue per customer decoupling.

We have used the number of customers to measure output growth in our study for EGI for several reasons.

- EGI's proposed lost revenue adjustment mechanism and normalized average use adjustment reduce the relevance of industry billing determinant trends.
- Our econometric cost research found the number of customers to be the main output-related cost driver.

- The Company is likely to propose new rate designs in Phase 3 that increase reliance on fixed charges.
- EGI's own witness BV has used customers to measure output in their benchmarking and productivity research.

Input Quantity Index

The growth rate in the input quantity index of each sampled distributor was a weighted average of quantity subindexes for capital and O&M inputs.

Sample Period

In choosing a sample period for an indexing study used in X factor calibration, it is generally desirable that the period include the latest year for which all of the requisite data are available. In the present case this year is 2022. It is also desirable for the sample period to reflect the long-run productivity trend. We generally desire a sample period of at least 10 years to fulfill this goal. A long sample period, however, may not be indicative of the latest trends in external productivity growth drivers. Moreover, the accuracy of the measured capital quantity trend is enhanced by having a start date for the indexing period that is several years after the first year that good capital cost data are available. We attempt to balance all of these considerations by presenting productivity results for the fifteen growth rate years from 2008 to 2022.

Index Results and Analysis

Table 7 reports annual growth rates in the O&M, capital, and multifactor productivities of all sampled U.S. gas utilities for each year of the full sample period. Even-weighted and size-weighted averages are both presented. Examining the even-weighted averages we find that total factor productivity averaged a 1.26% annual decline.[77] O&M productivity growth averaged a slight 0.01% annual decline while capital productivity growth averaged a more substantial 2.17% annual decline. As for the cost-weighted averages, total factor productivity averaged a 1.54% annual decline. O&M productivity growth averaged a 0.49% annual decline while capital productivity growth averaged a more

[77] All growth trends in this report were included logarithmically.

Table 7

Productivity Results for All Sampled Gas Distributors Using Geometric Decay

	Simple Average			Cost-Weighted Average		
	Total Factor Productivity	**O&M Productivity**	**Capital Productivity**	**Total Factor Productivity**	**O&M Productivity**	**Capital Productivity**
2005	-1.0%	-1.4%	-0.5%	-0.78%	-1.16%	-0.35%
2006	2.0%	4.5%	-0.4%	2.08%	4.32%	-0.33%
2007	-1.7%	-2.7%	-0.9%	-0.24%	0.01%	-0.24%
2008	-0.3%	0.4%	-0.8%	0.28%	0.78%	-0.71%
2009	-1.3%	-1.8%	-1.0%	-1.05%	-1.04%	-1.16%
2010	-1.1%	-1.1%	-1.3%	-0.70%	-0.78%	-1.24%
2011	-0.6%	0.3%	-1.4%	-0.05%	1.50%	-1.22%
2012	0.7%	2.6%	-0.9%	0.14%	1.15%	-0.79%
2013	-2.3%	-2.8%	-1.7%	-2.58%	-3.71%	-1.83%
2014	-1.6%	-1.6%	-1.6%	-1.85%	-2.40%	-1.59%
2015	-0.7%	1.7%	-2.5%	-0.11%	3.54%	-2.51%
2016	-1.1%	0.7%	-2.5%	-2.01%	-1.28%	-2.87%
2017	-2.0%	-0.1%	-3.2%	-2.49%	-0.64%	-3.60%
2018	-0.9%	1.8%	-2.8%	-3.83%	-3.69%	-3.36%
2019	-2.4%	-0.5%	-3.4%	-1.61%	1.61%	-3.96%
2020	-0.8%	3.2%	-3.3%	-2.63%	0.27%	-3.79%
2021	-3.0%	-2.6%	-3.0%	-8.22%	-10.90%	-3.49%
2022	-1.5%	-0.3%	-3.1%	3.58%	8.19%	-3.73%
Average Annual Growth Rates						
2008-2022	**-1.26%**	**-0.01%**	**-2.17%**	**-1.54%**	**-0.49%**	**-2.39%**
2013-2022	**-1.63%**	**-0.05%**	**-2.71%**	**-2.17%**	**-0.90%**	**-3.07%**

substantial 2.39% annual decline. Thus, productivity growth was modestly more negative using size-weighted averages.

National average TFP trends from the United States do not provide a suitable basis for establishing an X factor for EGI. The principal reasons for this are as follows.

- The productivity factor should reflect to the extent practicable the business conditions that EGI will face going forward.
- Casual empiricism supported by our econometric cost research suggests that some of the biggest drivers of declines in US gas utility productivity in the last 15 years are not relevant to EGI's situation going forward. In particular, EGI has few cast iron and bare steel mains and is not

likely to face the costly transmission safety mandates that many gas transmission providers in the States contended with during the sample period. EGI's early replacement of its cast iron and bare steel mains should prospectively slow its cost growth due to the depreciation of replacement plant.

A more reasonable productivity growth peer group for Enbridge would accordingly be U.S. utilities that started the sample period with little CIBS, did not own much transmission capacity, and had a fairly normal rate of customer growth on average. We have developed a peer group consisting of all sampled utilities that, specifically,

- had distribution plant exceeding 80% of total gross plant value
- relied on CIBS mains for less than 5% of their distribution line length in 2007.

We then removed the two utilities with the most rapid customer growth during the sample period to better reflect EGI's customer growth prospects going forward.[78]

Eleven utilities satisfied these criteria. Their customer growth averaged 0.95% annually during the sample period. Table 8 identifies these peers and provides details of their productivity growth during the sample period. It can be seen that their TFP growth averaged a slight 0.20% annual decline. O&M productivity averaged 1.10% growth while capital productivity averaged a 0.84% annual decline.

5.6. Recommended Productivity Factor and Stretch Factor

Productivity Factor

PEG believes that the productivity factor for EGI should reflect the Company's forward-looking business suggestions. We accordingly recommend that the productivity factor should equal the -0.20% average annual decline in the TFP trend of our custom peer group.

[78] These utilities (South Carolina Electric and Gas and Questar Gas) also had above-average productivity growth.

Table 8

Productivity Trends for a Custom EGI Peer Group

	Productivity Trend (15 Years)		
	Total Cost	**O&M**	**Capital**
Avista	-0.84%	0.41%	-1.61%
Cascade Natural Gas	-0.12%	0.85%	-0.74%
Citizens Energy Group	1.76%	2.89%	1.27%
Madison Gas and Electric	0.05%	0.19%	-0.13%
New York State Electric & Gas	-1.08%	-1.86%	-0.02%
North Shore Gas	-0.56%	0.65%	-1.23%
Northern States Power - WI	-0.94%	1.40%	-2.33%
Puget Sound Energy	-0.13%	1.16%	-0.62%
Sierra Pacific Power	1.87%	4.11%	0.56%
Wisconsin Gas	-0.81%	2.77%	-2.64%
Wisconsin Power and Light	-1.39%	-0.50%	-1.79%
Custom Peer Group Average	**-0.20%**	**1.10%**	**-0.84%**

Stretch Factor

Our econometric total cost benchmarking model found the total cost of EGI to be about 23% above our total cost model's forecast for the Company on average during the 2020-2022 period. This is commensurate with a stretch factor of 0.45% in Ontario. We recommend this value for EGI.

X Factor

Insofar as the X factor is the sum of a productivity factor and a stretch factor, PEG recommends an X factor of 0.25% for EGI.

6. Calculating the Revenue Cap Index Inflation Factor

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

The advantage of the FWI AHE is illustrated in Table 9. This table compares the inflation in the AWEs and FWI AHEs of Canada and Ontario from 2002 to 2023. Recession years are shaded in pink.

During a recession, lower paid workers are more likely to be laid off while during a recovery they are more likely to be added. This causes an AWE to grow too rapidly during a recession and too slowly during a recovery. The table shows that results using the FWI AHE tend to be more reasonable during recessions and recoveries. Note also that the standard deviations of growth rates are lower for FWI AHEs than for AWEs. The use of an FWI AHE reduces needless noise in rate adjustments and involves a trivial transition cost.

In its recent PBR3 decision, the Alberta Utilities Commission replaced an AWE with the FWI AHE in its inflation factor formula.[79] PEG has also supported use of the FWI AHE in the new Custom IR plan of Toronto Hydro.

We do not object to EGI's proposed alternative cost-share weights for the two inflation factor subindexes in the inflation factor formula. However, we recognize that the OEB may for simplicity prefer the same weights for gas and electric distributor services.

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

Table 9

Historical Labour Price Trend Indicators for Canada and Ontario

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

Notes

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

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

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

Pink shading indicates recession years in Canada.
Yellow shading emphasizes points made in the text

Appendix A

A.1 Details of the U.S. Gas Utility Productivity Research

This Appendix contains more technical details of our gas productivity research. We first discuss our input quantity and productivity indexes, respectively. We then address our method for calculating input price inflation and capital cost.

Input Price and Quantity Indexes

The trend in the O&M input quantity of EGI was calculated as the difference between the trend in its applicable O&M expenses and an O&M input price index.

$$ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right)$$

$$= ln\left(\frac{Cost_t}{Cost_{t-1}}\right) - ln\left(\frac{Input\ Prices_t}{Input\ Prices_{t-1}}\right) \qquad [A1]$$

The growth rate of an input price index is defined by a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and price subindexes.

The summary input price trend indexes used in this study were of Törnqvist form. This means that the annual growth rate of each index was determined by the following general formula. For any asset category *j*,

$$\ln\left(\frac{Input\ Prices_t}{Input\ Prices_{t-1}}\right) = \sum_j \frac{1}{2}\cdot\left(sc_{j,t} + sc_{j,t-1}\right)\cdot \ln\left(\frac{W_{j,t}}{W_{j,t-1}}\right). \qquad [A2]$$

Here in each year *t*,

$Input\ Prices_t$ = Input price index

$W_{j,t}$ = Price subindex for input category *j*

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

The growth rate of the index is a weighted average of the growth rates of input price subindexes. Each growth rate is calculated as the logarithm of the ratio of the subindex values in successive years. The average shares of each input group in the applicable cost of each utility during the two years are the weights.

Capital Cost and Quantity Specification

A monetary approach was chosen to measure the capital cost of EGI and the sampled U.S. utilities. Recall from Section 2.4 that under this approach capital cost is the product of a capital quantity index and a capital (service) price index.

$$CK = WKS \cdot XK. \qquad [A3]$$

Geometric decay was assumed. We began computing the capital quantity index in 1994. The value for each capital quantity index in this "benchmark" year was based on the net value of plant that the utility reported to its state commission. We estimated the benchmark year quantity (inflation adjusted value) of net plant by dividing this book value by a triangularized-weighted average of the 41 values of a regional index of utility construction cost for a period ending in the benchmark year. 41 years is the assumed average service life of the assets.

The construction cost indexes (WKA_t) were developed from the regional Handy Whitman Index of Cost Trends of Gas Utility Construction of Total Plant.[80] We adjusted these indexes to better reflect how the composition of gas main materials changed over the years.

The following formula was used to compute values of the capital quantity index in subsequent years. For any asset category *j*,

$$XK_{j,t} = (1-d) \cdot XK_{j,t-1} + \frac{VKA_{j,t}}{WKA_{j,t}}. \qquad [A4]$$

Here, the parameter *d* is the economic depreciation rate and VKA_t is the value of gross additions to utility plant.

The formula for the corresponding GD capital service price indexes used in the research was

$$WKS_{j,t} = [d \cdot WKA_{j,t} + WKA_{j,t-1} \cdot \left[r_t - \frac{(WKA_{j,t} - WKA_{j,t-1})}{WKA_{j,t-1}}\right]. \qquad [A5]$$

[80] These data are reported in the Handy-Whitman Index of Public Utility Construction Costs, a publication of Whitman, Requardt and Associates.

The first term in the expression corresponds to the cost of depreciation. The second term corresponds to the real rate of return on capital. The second term was smoothed to reduce the volatility of capital costs and prices.

Composition of Handy Whitman Construction Cost Indexes for Gas

Stylized Facts

The Handy Whitman indexes for gas construction cost use fixed weights set in 1973. For many types of plant this is not a concern. However, the dominant cost for plant construction is for mains and the material used in mains has significantly changed over time. Because the cost trends in plastic and steel have differed significantly since 1973, a measurement issue exists. The index assumes the same proportions of steel and plastic are used as they were in 1973 which is known to be false.

Solution

Fortunately, Handy Whitman provides separate subindexes for steel, plastic, and cast iron main. PEG used this information to adjust the reported Handy Whitman index data to reflect a gradual change in the weight given to steel vs. plastic mains since 1973. The additions to miles of main by type of material is known from data published by the PHMSA. These provide the basis for weights used to combine the steel and plastic cost indexes into a single index. Plant in service data from 2003 provided the basis for combining the other published indexes and the custom steel/plastic index into a single modified index.

Productivity Growth Rates and Trends

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

$$\ln\left(Productivity_t / Productivity_{t-1} \right)$$
$$= \ln\left(Output\ Quantities_t / Output\ Quantities_{t-1} \right) - \ln\left(Input\ Quantities_t / Input\ Quantities_{t-1} \right). \quad [A6]$$

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

Material and Service Price Index

Stylized Facts

In research and testimony for Puget Sound Energy in a recent Washington state proceeding, PEG found the following results for twenty (growth rate) years ending in 2022.[81]

- An M&S price index ("WMS") for gas distribution calculated by Standard and Poor's Power Planner service averaged **2.71%** annual growth.
- Our examination of Standard and Poor's methodology revealed that this index is really a measure of material prices and does not track service prices well.
- The ECI for salaries and wages of all private industries averaged **2.62%** annual growth.
- A "corrected" WMS for U.S. gas distribution that took better account of the labor intensiveness of services might assume that 50% of M&S cost was for services and 50% of service cost was for labor. Then 2/3 of M&S inflation is driven by materials prices, one third is driven by labor prices, and (2/3) x 2.71% + (1/3) x 2.62% = 1.81% + 0.87% = **2.68%**. We will call this the corrected M&S price index.
- The gross domestic product price index averaged **2.23%** annual growth and therefore materially understated WMS growth. The inflation differential using Standard and Poor's WMS was 2.71-2.23 = **0.48%.** The inflation differential using the corrected WMS was 2.68% - 2.23% = **0.45%.**

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

- The Power Planner WMS for gas distribution averaged **2.47%** annual growth.
- The ECI for salaries and wages of all private industry workers averaged **2.56%** annual growth.
- A "corrected" WMS for U.S. gas distribution averaged (2/3) 2.47% + (1/3) x 2.56% = 1.65% + 0.85% = **2.50%.**

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

- The GDPPI averaged **2.08%** growth and therefore once again substantially understated WMS growth. The inflation differential using WMS was 2.47% - 2.08% = 0.39%. The inflation differential using corrected WMS was 2.50% - 2.08% = 0.42%.

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

- The Power Planner WMS for gas distribution averaged **2.03%** annual growth.
- The ECI for salaries and wages of all private industry workers averaged **2.34%** annual growth.
- A "corrected" WMS for U.S. gas distribution averaged (2/3) x 2.03% + (1/3) x 2.34% = 1.36% + 0.78 = **2.13%.**
- The GDPPI averaged **1.83%** growth. The inflation differential using WMS was 2.03-1.83% = 0.21%. The inflation differential using *corrected* WMS was 2.13 – 1.83 = 0.31%.

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

Solution

A conservative means of improving the accuracy of the WMS proxy without purchasing the WMS index from Power Planner at considerable cost is to base it 2/3 on GDPPI inflation and 1/3 on inflation in the salary and wage ECI for all private industries. If we instead swap out the regionalized ECI for the utility sector for the ECI for all private industries we obtain a further simplification.

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

Appendix B

PEG Credentials

PEG is an economic consulting firm with headquarters on Capitol Square in Madison, Wisconsin USA. We are the leading North American consultancy on IR and statistical research on energy utility productivity trends and cost performance. Our personnel have over sixty years of experience in these fields, which share a common foundation in economic statistics. In addition to statistical cost research, PEG personnel have for many years routinely monitored the progress of PBR, preparing surveys and white papers on various plan design topics.

Work for a mix of utilities, regulators, government agencies, and consumer and environmental groups has given us an unusual reputation for objective empirical research and commitment to good regulation. We have had a notable impact on the evolution of energy utility IR in the United States and Canada.

Mark Newton Lowry, the author of this report and principal investigator for this project, is the President of PEG. He has over forty years of experience as an applied economist, most of which have been spent addressing energy utility issues. We have submitted over forty energy utility productivity studies in IR proceedings in at least thirteen jurisdictions, from Québec to Bolivia. We have submitted statistical benchmarking studies in more than thirty proceedings. The first OEB project that he led for the OEB was the second generation IR for energy distributors and he has done numerous projects in the years since.

Author of dozens of professional publications, he has also spoken at numerous conferences on utility regulation and statistical performance measurement. He recently coauthored two influential white papers on IR for Lawrence Berkeley National Laboratory. An advisor on IR to the British Columbia and Ontario regulatory commissions, he has in the last seven years alone testified or provided commentary in IR proceedings in Alberta, British Columbia, Colorado, Hawaii, Massachusetts, Minnesota, North Carolina, Québec, and Washington state as well as Ontario. He holds a PhD in applied economics from the University of Wisconsin and lives in Shorewood Hills, Wisconsin near Madison.

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