IRM Framework for the Proposed Merger of Enbridge and Union Gas

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Mark Newton Lowry, Ph.D.
President

PACIFIC ECONOMICS GROUP RESEARCH LLC

44 East Mifflin, Suite 601
Madison, Wisconsin USA 53703
608.257.1522   608.257.1540 Fax

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1. Introduction and Summary

1.1. Introduction

Union Gas Limited ("Union") and Enbridge Gas Distribution Inc. ("Enbridge") (collectively the "Applicants") filed a merger, acquisitions, amalgamations and divestitures ("MAADs") application on November 2, 2017 with the Ontario Energy Board ("OEB").[1] On November 23, 2017 the Applicants proposed a new incentive rate-setting ("IR") mechanism ("IRM") for distribution, transmission, and storage services of the amalgamated company ("Amalco").[2] The proposal follows guidelines in the *OEB Handbook to Electricity Distributor and Transmitter Consolidations* ("MAADs Handbook"), which Enbridge and Union propose to extend to their merger in the natural gas sector.[3]

The filing includes evidence on the productivity trends of North American energy distributors by Dr. Jeff Makholm of NERA Economic Consulting ("NERA"). This study includes some methods for measuring productivity which are uncommon in previous OEB proceedings on IRM design. Most notably, a volumetric index was used to measure output and a one hoss shay ("OHS") approach was used to measure capital quantities.

Enbridge and Union are the two largest gas distributors in Ontario. Assuming approval of the MAADs application, the merged company will become one of North America's largest gas distributors, serving most of Ontario's customers and areas that have gas supply. This increases the importance of a careful appraisal of the Applicants' IRM proposal and supportive productivity research. Controversial technical work and IRM provisions should be highlighted and, where warranted, challenged to avoid undesirable precedents for the Applicants and other Ontario utilities in the future. Staff of the OEB have retained Pacific Economics Group Research LLC ("PEG") to prepare analysis and commentary on NERA's productivity research and testimony and some features of the Applicants' IRM proposal.

This is the report on our work. Following a brief summary of our findings, Section 2 reviews pertinent background information. We discuss in Section 3 the nature of productivity research and its

[1] EB-2017-0306, Exhibit A, Tab 2, November 2, 2017.

[2] EB 2017-0307, Exhibit A, Tab 2.

[3] EB 2017-0307, Exhibit B, Tab 1, p. 2.

role in IRM design, emphasizing the output and capital specifications. There follows in Section 4 our critique of NERA's productivity evidence, and results obtained by PEG using alternative methods. We present results of a study of US gas utility productivity we prepared for this proceeding in Section 5. There follows in Section 6 a discussion of the stretch factor and our X factor recommendations. We conclude in Section 7 with a discussion of other aspects of the Applicants' IRM proposal. Appendices address some of the more technical issues raised in the report in more detail.

1.2. Summary

The Applicants have proposed to operate under a Price Cap IRM for ten years, without rebasing, following the conclusion of their current rate plans this year. The proposed new IRM would have a price cap index and an X factor of zero. NERA provided supportive productivity research and testimony on the total factor productivity ("TFP") trends of Union, Enbridge, and a large sample of American power distributors. Rate growth would be further accelerated for the trend in the Normalized Average Consumption/average use of gas by general service customers. A lost revenue adjustment mechanism ("LRAM") would compensate the Amalco for lost revenue due to conservation and demand management ("CDM") programs for contract customers.

X Factor

Since this filing applies to a gas utility and is being made towards the end of the OEB's 4th generation IRM for Ontario power distributors, PEG understands the Applicants' interest in an updated TFP growth target. The Applicants have hired a well-known TFP practitioner, and the 0% base TFP growth trend that Dr. Makholm proposes is in our view reasonable.

PEG nonetheless has serious concerns about the methods used in NERA's productivity work. We question the appropriateness of submitting a study of US power distribution productivity that excludes customer (e.g., billing and collection) services and administrative and general costs when satisfactory data are available for a gas utility productivity study that includes these costs. Because of the Normalized Average Consumption/average use adjustment and the LRAM, the volumetric output index NERA used is inappropriate for a study intended to calibrate the Applicants' X factor. The OHS method used to measure capital quantities has several disadvantages, including its sensitivity to the assumption made about the average service life of assets. Errors seem to have been made in the measurement of

Enbridge and Union's productivity, and the chosen asset price deflator for this exercise was inappropriate.

We made some corrections for key deficiencies in NERA's productivity research. With improved methods, we find that the TFP trends of U.S. power distributors averaged **0.49%** from 2001 to 2016. Over a similar 2001-2016 sample period, the TFP trend of Enbridge averaged a **-0.76%** annual decline, while the TFP of Union averaged **1.04%** growth.

We also prepared a study of the recent TFP trends of a sample of US natural gas utilities. Over the full 1999-2016 period that we examined, the TFP of sampled utilities averaged a **-0.39%** annual decline. Based on the range of evidence available in this proceeding, we recommend **0.0%** as the base productivity growth target for the Amalco.

We disagree with Dr. Makholm's 0% stretch factor recommendation, which is based on the premise that stretch factors are only appropriate in first generation IRMs. The Board is correct to reconsider stretch factors for all utilities on a regular basis using statistical benchmarking. A utility is no more certain to be efficient after one or even several terms of IR than firms in unregulated markets are certain to be efficient. Several other regulators have approved stretch factors after the first generation of IR.

In the absence of suitable benchmarking evidence, we believe that the Amalco should be assigned a 0.30% stretch factor. Combined with a 0.00% base productivity growth trend, we arrive at a recommendation of a 0.30% X factor. The PCI Formula would then be growth inflation – 0.30%, net of Y and Z factors.

Other Plan Provisions

When a power distributor operating under a price cap IRM consolidates with a distributor operating under Custom IR, the MAADs Handbook permits the distributors to operate for as long as 10 years under price cap IR without rebasing. However, as noted by the OEB in its Decision [on the Issues List] and Procedural Order No. 3, the applicability of the provisions of the MAADs Handbook are an open issue with the exception of the "no harm" test. The proposed IRM for the most part follows *Rates Handbook* 4th GIRM guidelines. It features a price cap index, Y factors, and Z factors. The Applicants have not asked for Y factor treatment of pension and other benefit expenses. An earnings sharing mechanism would be operational for the last five years. An incremental capital module ("ICM") would be available to provide supplemental capital revenue.

We are concerned about some features of the Company's proposal.

- The Board is not obliged to follow MAADs Handbook guidelines. The Applicants' proposed IRM is, in any event, not fully consistent with 4th GIRM.
- Since the Board is free to deviate from MAADs rules, it can require a rebasing of each Applicant's revenue to their recent and normalized historical costs followed by their formulaic escalation to 2019 values. This would sidestep problems of performance incentives and merger-related costs. Since the Applicants are in the last year of their respective IRMs and Custom rate-setting plans, skipping a rebasing in 2019 will do little to spur the Applicants' incentives.
- The proposed ratemaking treatment of capital cost is problematic. The ICM would weaken the Amalco's cost containment incentives and raise regulatory cost. The PCI would effectively apply chiefly to revenue for operation, maintenance, and administrative ("OM&A") expenses and provides only a floor for revenue growth even though it is designed to play neither of these roles. The materiality and dead zone provisions of the ICM merit reconsideration. Alternatively, or in addition, the PCI for operation, maintenance, and administrative cost could reflect the OM&A productivity trend, while the ICM could be calculated using the capital productivity trend.
- An industry price index ("IPI") which averages growth in the GDPIPIFDD and the average weekly earnings in Ontario Industry would likely track gas utility input prices. The IPI also sidesteps the need for a complicated input price differential calculation such as NERA provided.
- The proposed materiality threshold for the Z factor is low. A higher threshold is warranted that is appropriate for the Amalco's large size. The threshold should be escalated for PCI and customer growth.

1.3. PEG Credentials

PEG is an economic consulting firm with headquarters in Madison, Wisconsin USA. We are a leading consultancy on the economics of regulation and statistical research on the performance of gas and electric utilities. Our personnel have over sixty years of experience in these fields, which share a common foundation in economic statistics. IRM design and the measurement of utility productivity trends are company specialties. Work for a mix of utilities, regulators, government agencies, and consumer and environmental organizations has given us a reputation for objectivity and dedication to good research methods. Our practice is international in scope and has included dozens of projects in Canada.

Mark Newton Lowry is the President of PEG. He has over thirty years of experience as an industry economist, most of which have been spent addressing utility issues. He has prepared productivity research and testimony in more than 30 separate proceedings. His most recent study of power distributor productivity was published by Lawrence Berkeley National Laboratory in 2017. Author of dozens of professional publications, Dr. Lowry has chaired numerous conferences on performance measurement and utility regulation. In the last five years, Dr. Lowry has played a prominent role in IR proceedings in Alberta, British Columbia, Maine, Massachusetts, and Quebec as well as Ontario. He holds a PhD in applied economics from the University of Wisconsin. The resume of Dr. Lowry is attached.

2. Background

Under the Applicants' proposal, Enbridge and Union would operate in 2018 under their current rate setting plans (a Custom IR plan for Enbridge and a "price cap" IRM for Union). These plans are scheduled to expire this year. The new IRM would then begin without rebasing revenue to the Amalco's costs (with the exception of certain adjustments proposed to deal with the expiration of certain costs or to reflect certain tax-related or policy-related factors).[4] The new IRM would have the following notable provisions:

- The term would be the ten-year period from January 1, 2019 to December 31, 2028.[5] By 2028, customers of Amalco would therefore have waited from 10 up to 15 years for revenues to be fully rebased to costs.

- The attrition relief mechanism, described as a price cap index ("PCI"), is similar to that in the current Union Gas IRM.[6] This mechanism would not directly escalate rates like those used in the default 4th GIRM. Instead, the revenue requirement would be escalated each year for inflation less an X factor with further Y factor and Z factor adjustments. The updated revenue requirements for volumetric charges of general service customers would be converted to rates using predetermined formulas like

  $$[Revenue_t^{Required}/(Volume_{t-2}^{Normalized}/Customers_{t-2})] \times Customers_t^{Forecasted}.$$

  The term in parentheses is called Normalized Average Consumption ("NAC") and is based on an OEB-approved volume normalization procedure.

  Revenue from general service customers would later be adjusted to yield the amount that would have occurred had normalized average consumption in year *t-1* been used to set rates. Since the number of customers is rising and average use is trending downward, this mechanism

[4] EB 2017-0307, Exhibit B, Tab 1, p. 16.

[5] EB 2017-0307, Exhibit B, Tab 1, p. 4.

[6] EB 2017-0307, Exhibit B, Tab 1, p. 7.

provides additional rate escalation and reduces risk of cost under-recovery for the utility and its shareholders.

- The proposed PCI inflation measure is the gross domestic product implicit price index for final domestic demand for Canada ("GDPIPIFDD^{Canada}").[7]
- The proposed X factor of zero is supported by TFP testimony by Dr. Jeff Makholm of NERA. NERA's research used a monetary "one hoss shay" approach to measuring capital cost that has never to our knowledge been used in Ontario IR proceedings.[8] Dr. Makholm also recommended a 0.0% stretch factor.[9]
- The Applicants propose to maintain most existing deferral and variance accounts.[10] These would include an LRAM to compensate them for lost margins due to conservation programs for contract service customers.
- The plan also features the availability of an ICM for incremental capital funding.[11,12] The capital cost for capex accorded ICM treatment would be eligible for an updated weighted-average cost of capital ("WACC").[13]
- The applicants also propose a Z factor mechanism. The Applicants have indicated the possibility of seeking an increase to the WACC for other capital using the Z factor process.

[7] EB 2017-0307, Exhibit B, Tab 1, p. 8.

[8] However, physical asset capital quantity treatments that are purported to be approximations to the OHS monetary approach have been filed and reviewed in two prior OEB proceedings (EB-2007-0679 and EB-2013-0152).

[9] EB 2017-0307, Exhibit B, Tab 2, pp. 33-34.

[10] EB 2017-0307, Exhibit B, Tab 1, pp. 22-23 and Exhibit B, Tab 1, Attachments 3 and 4.

[11] EB 2017-0307, Exhibit B, Tab 1, pp. 12-16.

[12] While the ICM was designed for IRM rate-setting plans for electricity distributors, the OEB's *Handbook for Utility Rate Applications* (the Rate Handbook) issued October 13, 2016, extends the ICM option to all rate-regulated utilities operating under Price Cap IR plans. Further, the MAADs Handbook also makes the ICM available to an amalgamated utility operating under a Price Cap IR plan prior to rebasing.

[13] EB 2017-0307, Exhibit B, Tab 1, pp. 15-16.

- After five years, an earnings sharing mechanism would come into effect and equally share earnings which are more than 300 basis points above the allowed rate of return on equity (on a regulated basis) between the Amalco and customers.[14]
- The proposal also includes a scorecard with 18 metrics by which various aspects of the Amalco's performance would be measured.[15]

[14] EB 2017-0306, Exhibit B, Tab 1, pp. 43-44.

[15] EB 2017-0307, Exhibit B, Tab 1, pp. 20-22.

3. Principles for X Factor Calibration

3.1. Index Research and its Use in Regulation

Productivity Indexes

The Basic Idea

A productivity index measures the efficiency with which firms use production inputs to achieve certain outputs. The trend in a productivity index is the difference between the trend in an index of outputs ("*Outputs*") and the trend in an input quantity index ("*Inputs*").

trend Productivity = trend Outputs – trend Inputs. [1]

The scope of a productivity index depends on the array of inputs addressed by the input quantity index. *Partial* factor productivity ("*PFP*") indexes measure productivity in the use of a particular input class such as capital or labor. A *multifactor* productivity index measures productivity in the use of multiple kinds of inputs. These are sometimes called *total* factor productivity indexes even though such indexes rarely address the productivity of all inputs.

Output Indexes

The output (quantity) index of a firm summarizes the scale of its operation. If this index is multidimensional, growth in each output dimension which is itemized is measured by a subindex. Growth in the summary output index is a weighted average of the growth in the subindexes.

In designing an output index, choices concerning subindexes and weights should depend on the manner in which the index is to be used. One possible objective is to measure the impact of output growth on *revenue*. In that event, the subindexes should measure trends in *billing determinants* and the weight for each itemized determinant should reflect its share of revenue.[16] A productivity index calculated using a revenue-weighted output index ("$Outputs^R$") will be denoted as $Productivity^R$.

$trend\ Productivity^R = trend\ Outputs^R – trend\ Inputs$. [2a]

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[16] This approach to output quantity indexation is due to the French engineer and economist Francois Divisia (1889-1964).

Another possible objective of output research is to measure the impact of growth in scale on *cost.* In that event, the output variable(s) should measure dimensions of "workload" that drive cost.[17] A productivity index calculated using a cost-based output index ("$Outputs^C$") will be denoted as $Productivity^C$.

$$trend\ Productivity^C = trend\ Outputs^C - trend\ Inputs. \qquad [2b]$$

This may fairly be described as a "cost efficiency index."

Sources of Productivity Growth

Economists have considered the drivers of productivity growth using mathematical theory and empirical methods.[18] The research has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

Economies of scale are another important productivity growth driver. These economies are realized in the longer run if cost has a tendency to grow less rapidly than operating scale. Incremental scale economies (and thus productivity growth) will typically be lower the slower is output growth.

A third driver of productivity growth is X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum possible efficiency. Productivity growth will increase to the extent that X inefficiency diminishes. A company's potential for future productivity growth from this source is greater the higher is its current inefficiency level.

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[17] If there is more than one output variable, the weights for these variables should reflect the relative impacts of these drivers on the cost of producing the outputs (the products and services produced by the firm or sector). The sensitivity of cost to a small change in the value of a business condition variable is commonly measured by its cost "elasticity." Cost elasticities can be estimated econometrically using data on the operations of utilities. Such estimates provide the basis for elasticity-weighted output indexes. These have been used on several occasions in PEG's previous research for the OEB. For example, PEG used an elasticity-weighted output index in its research on the TFP growth of Ontario power distributors in the 4th GIRM proceeding. The output variables were delivery volume, peak demand, and the number of customers served. These variables are billing determinants as well as cost drivers.

[18] A classic early discussion of the drivers of productivity growth can be found in Denny, Michael, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

System age can drive productivity growth in the short and medium run. Productivity growth tends to be greater to the extent that the initial capital stock is large relative to the need to refurbish or replace aging plant. If a utility has a need for unusually high replacement capex, capital productivity growth can plunge. On the other hand, productivity growth tends to surge in the aftermath of unusually high capex as the surge capital depreciates.

Productivity growth is also affected by changes in the miscellaneous business conditions, other than input price inflation and output growth, which affect cost. A good example for a gas distributor is a change in safety regulations. This has recently affected the productivity of US gas distributors.

A productivity index with a *revenue*-weighted output index has an important driver that doesn't affect a cost efficiency index. This is true since

$$\begin{aligned} \textit{trend Productivity}^R &= \textit{trend Outputs}^R - \textit{trend Inputs} + (\textit{trend Outputs}^C - \textit{trend Outputs}^C) \\ &= (\textit{trend Outputs}^C - \textit{trend Inputs}) + (\textit{trend Outputs}^R - \textit{trend Outputs}^C) \\ &= \textit{trend Productivity}^C + (\textit{trend Outputs}^R - \textit{trend Outputs}^C). \qquad [3] \end{aligned}$$

Equation [3] shows that growth in $\textit{Productivity}^R$ can be decomposed into the growth in a cost efficiency index and an "output differential" that measures the difference between the impact that growth in operating scale has on revenue and cost.

The output differential is sensitive to changes in external business conditions.[19] For example, the revenue of a gas distributor may depend chiefly on system use due to high usage (e.g., volumetric) charges while cost depends chiefly on system capacity. In that event, increasingly mild winter weather, higher appliance efficiency standards, and/or large, mandated CDM programs can, by slowing growth in system use, reduce the output differential and slow growth in Productivity^R and earnings.

Gas distributors have long considered the number of customers served to be a more pertinent driver of their cost than their delivery volumes. The number of customers served is highly correlated

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[19] Note also that companies can sometimes bolster their output differential and accelerate TFP^R and earnings growth with better marketing. For example, they can try to bolster sales of products that raise revenue more than cost. An example would be the substantial effort of MacDonald's restaurants in recent years to build a breakfast business.

with peak day demand and is an important cost driver in its own right. A declining trend in use per customer (aka "average use") has therefore been highlighted by many distributors as an important source of financial attrition. In the United States, many distributors operate under revenue decoupling systems that escalate allowed revenue each year by the number of customers served and use balancing accounts to ensure that this revenue is ultimately received.[20]

Use of Index Research in Regulation

Price Cap Indexes

Index logic supports the use of index research in price cap index design. We begin our demonstration by considering the growth in the prices charged by an industry that earns, in the long run, a competitive rate of return.[21] In such an industry, the long-run trend in revenue equals the long-run trend in cost.

$$\textit{trend Revenue} = \textit{trend Cost.} \qquad [4]$$

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

$$\textit{trend Revenue} = \textit{trend Outputs}^R + \textit{trend Output Prices}^R. \qquad [5]$$

The trend in cost can be shown to be the sum of the trends in a cost-weighted input price index ("*Input Prices*") and input quantity index.

$$\textit{trend Cost} = \textit{trend Input Prices} + \textit{trend Inputs} \qquad [6]$$

It follows that the trend in output prices that permits revenue to track cost is the difference between the trends in the input price index and a total factor productivity index of *TFP*^{R} form.

$$\begin{aligned}\textit{trend Output Prices}^R &= \textit{trend Input Prices} - (\textit{trend Outputs}^R - \textit{trend Inputs}) \qquad [7]\\ &= \textit{trend Input Prices} - \textit{trend TFP}^R.\end{aligned}$$

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[20] Lowry, M. N., Makos, M., and Waschbusch, G., *Alternative Regulation for Emerging Utility Challenges: 2015 Update*, for Edison Electric Institute, 2015.

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

The result in equation [7] provides a conceptual framework for the design of PCIs of general form

$$\textit{trend Rates} = \textit{trend Inflation} - X. \qquad [8a]$$

Here X, the "X factor," reflects a base productivity growth target ("$\overline{TFP^R}$") that is typically the trend in the *TFP*^{R} of the utility industry or some peer group. A "stretch factor" is often added to the formula which slows PCI growth in a manner that, appropriately designed, shares with customers the financial benefits of performance improvements that are expected under IRMs.[22]

$$X = \overline{TFP^R} + \textit{Stretch} \qquad [8b]$$

Since the X factor often includes a stretch factor it is sometimes said that the index research has the goal of "calibrating" (rather than solely determining) X.

Average Use Adjustment

Equations [3] and [7] imply that

$$\textit{trend Output Prices}^R = \textit{trend Input Prices} - [\textit{trend TFP}^C + (\textit{trend Outputs}^R - \textit{trend Outputs}^C)] \qquad [9]$$

When the X factor is calibrated using a $\overline{TFP^R}$ index (i.e., a TFP index constructed from billing determinants), it follows that it compensates the subject utility for any tendency in the industry for *Outputs*^{R} to grow more slowly than *trend Outputs*^{C}.

Suppose, now, that an IRM with a price cap index includes a *separate* adjustment to rates for the difference between the trends in volumes and the number of customers served by the subject utility. A variant on equation [7] is

$$\textit{trend Output Prices}^R$$

$$= \textit{trend Input Prices} - (\textit{trend Outputs}^R - \textit{trend Inputs}) + (\textit{trend Customers} - \textit{trend Customers})$$

$$= \textit{trend Input Prices} - (\textit{trend Customers - trend Inputs}) - (\textit{trend Outputs}^R - \textit{trend Customers})$$

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[22] Mention here of the stretch factor option is not meant to imply that a positive stretch factor is warranted in all cases.

$$= \textit{trend Input Prices} - \textit{trend } TFP^N - (\textit{trend Outputs}^R - \textit{trend Customers}) \quad [10]$$

This implies that, if a rate plan combines a price cap index with an average use adjustment, the number of customers should be used to measure output in the supportive productivity research.

3.2. Capital Specification

The Monetary Approach to Capital Cost and Quantity Measurement

The capital cost specification is of central importance in research on the productivity trends of energy distributors because their technology is capital intensive. The cost of capital ("*CK*") includes depreciation expenses, a return on investment, and certain taxes. If the price (unit value) of the asset changes over time this cost may also be net of any capital gains or losses.

Monetary approaches to the measurement of capital prices and quantities are conventionally used in North American productivity research. These are so-called because they are based on the value of utility plant. A monetary approach decomposes capital cost into a consistent capital quantity index ("*XK*") and capital service price index ("*WKS*") such that

$$CK = WKS \cdot XK. \quad [11]$$ [23]

In rigorous cost research, it is customary to assume that a capital good provides a stream of services over a period of time that is called the service life of the asset. The capital service price index measures the trend in the price of a unit of capital service. The capital quantity index is constructed by deflating the value of plant additions using an asset price index and subjecting the resultant quantity estimates to a mechanistic decay specification. In research on the productivity of US energy utilities, Handy Whitman utility construction cost indexes have traditionally been used for this purpose. The product of the capital service price index and the capital quantity index is the annual cost of using the flow of services.

[23] The *growth rate* of capital cost is thus the sum of the growth rates of the capital price and quantity indexes.

Benchmark Year Adjustments

Utilities have diverse methods for calculating depreciation expenses that they report to regulators. It is therefore desirable when calculating capital quantities using a monetary method to rely on the reporting companies chiefly for the value of *gross* plant additions and then use a standardized decay specification for all companies. Since some of the plant a utility owns may be 40-60 years old, it is desirable to have gross plant addition data for many years in the past.

For earlier years, the desired gross plant addition data are frequently unavailable. It is then customary to consider the value of all plant at the end of the limited-data period and then estimate the quantity of capital it reflects using construction cost indexes from earlier years and assumptions about the historical capex pattern. The year for which this estimate is undertaken is commonly called the "benchmark year" of the capital quantity index. Since the estimate of the capital quantity in the benchmark year is inexact, it is preferable to base capital and total cost research on a sample period that begins many years after the benchmark year. Research on capital and total cost will be less accurate to the extent that this is impossible.

Alternative Monetary Approaches

Several monetary methods have been established for measuring capital quantity trends. A key issue in the choice of a monetary method is the pattern of decay in the capital service flow. The pattern of decay over time is sometimes called the age-efficiency profile. Another issue is whether plant is valued in historic dollars or replacement dollars.

Three monetary methods have been used in X factor calibration research.

- Under the geometric decay ("GD") specification, the flow of services from investments in a given year declines at a constant rate ("*d*") over time. The quantity of capital at the end of each period t ("XK_t") is related to the quantity at the end of *last* period and the quantity of gross plant *additions* ("XKA_t") by the following "perpetual inventory" equation

$$XK_t = XK_{t-1} \bullet (1-d) + XKA_{t-1}\,. \qquad [12a]$$

$$= XK_{t-1} \bullet (1-d) + \frac{VKA_t}{WKA_t}. \qquad [12b]$$

where *d* is the (constant) rate of decay in the quantity of older capital. In equation [12b], the quantity of capital added each year is measured by dividing the reported value of gross plant additions by the contemporaneous value of a suitable asset price index ("*WKA*"). In research on the productivity of US energy utilities a Handy Whitman Construction Cost Index is conventionally used for this purpose.

The GD method assumes a replacement (i.e., *current* dollar) valuation of plant. Replacement valuation differs from the historical (aka "book") valuation used in North American utility accounting and requires consideration of capital gains.

- Under the one hoss shay specification, the flow of services from a capital asset is assumed to be constant until the end of its service life, when it abruptly falls to zero. This is the pattern that is typical of an incandescent light bulb. The quantity of plant at the end of the year is the sum of the quantity at the end of the prior year plus the quantity of gross plant additions less the quantity of plant retirements ("XKR_t").

$$XK_t = XK_{t-1} + XKA_t - XKR_t. \quad [13a]$$

$$= XK_{t-1} + \frac{VKA_t}{WKA_t} - \frac{VKR_t}{WKA_{t-s}}. \quad [13b]$$

Since utility retirements are valued in historical dollars, the quantity of retirements in year *t* can be calculated by dividing the reported value of retirements by the value of the asset price index for the year when the retired assets retired were added.

Plant is once again valued at replacement cost. The one hoss shay method has nonetheless been used occasionally in research intended to calibrate utility X factors.

- The cost of service ("COS") method is designed to approximate the way that capital cost is calculated in utility regulation. This approach is based on the assumptions of straight line depreciation and historic valuation of plant. The formulae are complicated, making them more difficult to code and review. PEG has used this approach in several X factor calibration studies, including two for the OEB.[24]

Choosing the Right Monetary Approach

The relative merits of alternative monetary approaches to measuring capital cost were discussed at some length in the OEB's recent proceeding on Ontario Power Generation Payments Amounts (EB-2016-0152).[25] Based on our experience as witnesses in that and other recent proceedings we believe that the following considerations are relevant.

1. *The goal of productivity research in X factor calibration is to find a just and reasonable means to adjust rates between rate applications.*

Productivity studies have many uses, and the best methodology for one use may not be best for another. One use of productivity research is to measure the trend in a utility's operating efficiency. Another is to calibrate the X factor in a price-cap or revenue-cap index.

Price-cap indexes in most IRMs for energy utilities, including the IRM proposed by the Applicants, are intended to adjust utility rates between general rate cases that employ a cost of service approach to capital cost measurement. In North America, the calculation of capital cost for ratemaking typically involves an historical valuation of plant and straight-line depreciation. Absent a rise in the target rate of return, the cost of each asset shrinks over time as depreciation reduces net plant value and the return on rate base.

2. *One-hoss shay is not preferable to geometric decay as the foundation for a monetary approach to capital quantity measurement.*

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[24] See Lowry, M., Hovde, D., Getachew, L., and Fenrick, S., *Rate Adjustment Indexes for Ontario's Natural Gas Utilities* in EB-2006-0606/0615, (2007)*;* Kaufmann, L., Hovde, D., Getachew, L., Fenrick, S., Haemig, K., and Moren, A., *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario*, in EB-2007-0673, (2008); and Lowry, M., Hovde, D., and Rebane, K., *X Factor Research for Fortis PBR Plans,* in BCUC Project 3698719, for Commercial Energy Consumers of British Columbia (2013).

[25] See, for example, Exhibit M2, Tab 11.1, Schedule OPG-002, Attachment A of the OEB's EB-2016-0152 proceeding.

The OHS specification is sometimes argued to better fit the service flows of *individual* utility assets. OHS has been used in some productivity studies filed in proceedings to determine X factors. In Alberta, for example, power distribution productivity studies using OHS have been accepted in two proceedings to inform the choice of X factors in rate and revenue-cap indexes for energy distributors. A study with an OHS capital cost specification recently provided the sole basis for the choice of a base productivity trend for Eversource Energy, a large Massachusetts power distributor.

Other evidence suggests that the OHS specification is disadvantageous. Here are some notable problems.

OHS is More Difficult to Implement Accurately than GD. A comparison of equations [12b] and [13b] shows that implementation of GD and OHS both require a deflation of gross plant *additions*. This is straightforward since the years of the additions are known exactly. The challenge with OHS is that it requires, additionally, deflation of plant *retirements.* The vintages of reported retirements are generally unknown to a scholar measuring productivity. OHS practitioners commonly deflate the value of retirements by the value of the construction cost index for a year in the past that reflects the assumed average service life of the assets.

Examining equation [13b], It can be seen that the quantity of capital in a given year will be smaller the larger is the quantity of retirements. The quantity of retirements will be larger the older is the average service life of the assets. Thus, TFP growth will tend to be more rapid under the OHS approach the higher is the average service life.

Our empirical research over the years suggests that productivity results using OHS are also quite sensitive to the average service life assumption. Seemingly reasonable service life estimates can produce negative capital quantities for some utilities. In recent power distribution productivity research for the Consumers' Coalition of Alberta, PEG found results using the OHS capital cost specification to be much more sensitive to the assumed average service life of assets than those using geometric decay.

[26,27] The sensitivity of OHS results to service life assumptions can be reduced by using plant addition and retirement data that are itemized with respect to asset type. Unfortunately, itemizations of FERC Form 1 plant addition and retirement data are not publicly available before 1994.

It should also be noted that the mathematical coding for GD is particularly intuitive and easy to implement and review. The OHS specification involves a complicated capital service price that lacks intuition.

Prices in Many Used Asset Markets are Inconsistent with an OHS Assumption Alternative patterns of *physical* asset decay involve different patterns of asset value *depreciation*. Trends in used asset prices can therefore shed light on asset decay patterns. Several statistical studies of trends in used asset prices have revealed that they are generally not consistent with the OHS assumption.[28] Instead, depreciation patterns like that commensurate with GD appear to be the norm for machinery and are also generally the case for buildings.[29]

An OHS Assumption Does Not Make Sense for Heterogeneous Groups of Assets In real-world productivity studies, capital quantity trends are rarely if ever calculated for *individual* assets. They are instead calculated from data on the value of plant additions (and, in the case of OHS, retirements) which encompass multiple assets of various kinds. Even if each individual asset had an OHS age/efficiency profile, the age/efficiency profile of the *aggregate* plant additions could be poorly approximated by OHS for several reasons.

- Assets of the same kind could end up having different service lives. The light bulbs installed by homeowners in a given year, for example, will burn out at different times.

[26] See, for example, Lowry, M.N. and Hovde, D., *PEG Reply Evidence*, Exhibit 20414-X0468, AUC Proceeding 20414, revised June 22, 2016, pp. 15-18.

[27] See also our discussion in Exhibit M2, Tab 11.1, Schedule OPG-002, Attachment A of the OEB's EB-2016-0152 proceeding for our attempt to implement an established form of OHS for hydroelectric power generation.

[28] For a survey of these studies see Barbara M. Fraumeni, "The Measurement of Depreciation in the U.S. National Income and Product Accounts*," Survey of Current Business*, July 1997, pp. 7-23. A recent Canadian study is John Baldwin, Huju Liu, and Marc Tanguay, "An Update on Depreciation Rates for the Canadian Productivity Accounts," *The Canadian Productivity Review*, Catalogue No. 15-206-X, January 2015.

[29] OECD, *Measuring Capital OECD Manual 2009*, Second Edition, p. 101.

- Different kinds of assets can have markedly different service lives.
- Individual assets, in any event, frequently have components with different service lives. The tires in a motor vehicle, for example, can need replacement before the wheels of the vehicle do.

Alternative capital cost specifications such as GD can provide a better approximation of the service flow of a group of assets that individually have OHS patterns or which are composites of assets with OHS patterns.

Consistent with these remarks, the authors of a capital research manual for the Organization of Economic Cooperation and Development ("OECD") stated in the Executive Summary that

> In practice, cohorts of assets are considered for measurement, not single assets. Also, asset groups are never truly homogenous but combine similar types of assets. When dealing with cohorts, retirement distributions must be invoked because it is implausible that all capital goods of the same cohort retire at the same moment in time. Thus, it is not enough to reason in terms of a single asset but age efficiency and age-price profiles have to be combined with retirement patterns to measure productive and wealth stocks and depreciation for cohorts of asset classes. An important result from the literature, dealt with at some length in the Manual is that, for a cohort of assets, the combined age-efficiency and retirement profile or the combined age-price and retirement profile often resemble a geometric pattern, i.e. a decline at a constant rate. While this may appear to be a technical point, it has major practical advantages for capital measurement. *The Manual therefore recommends the use of geometric patterns for depreciation* because they tend to be empirically supported, conceptually correct and easy to implement.[30] [italics in original]

Gas Distributor Assets Do Not Exhibit a Constant Flow of Services A common sign of decline in the flow of services from an asset is a rise in the expenses to operate and maintain it. Another sign of a diminishing flow of services is a continual stream of "refurbishment" capital expenditures that do not boost volume or capacity. Gas utilities tend to experience rising OM&A expenses and refurbishment capex as their assets age.

The OHS Approach is Rarely Used. These disadvantages of the OHS specification help to explain why alternative specifications are more the rule than the exception in capital quantity research. For

[30] OECD, *op. cit.*, p. 12.

example, GD is used to calculate capital quantities in the National Income and Product Accounts of the US and Canada. Statistics Canada also uses GD in its multifactor productivity studies for sectors of the economy.[31] The U.S. Bureau of Labor Statistics, the Australian Bureau of Statistics, and Statistics New Zealand assume hyperbolic decay, not OHS, in their sectoral TFP studies.

GD has also been the capital cost specification most widely used in productivity studies intended for X factor calibration in the North American energy and telecommunications industries. PEG personnel have used the GD approach in most of their more than 30 productivity studies for the OEB and other clients. PEG's 2017 study of power distributor productivity for Lawrence Berkeley National Laboratory also used GD.[32] Laurits R Christensen, major professor in the PhD committee of Dr. Makholm, and his colleague Dr. Mark Meitzen of Christensen Associates used GD in virtually all of their numerous studies of *telecommunications* utility productivity. Christensen Associates Energy Consulting has to our knowledge also used GD in most of their studies over the years of *energy* utility productivity, including one for Union Gas.[33] The Brattle Group and Concentric Energy Advisors used GD in their gas utility productivity studies for Enbridge.[34] Mr. Steven Fenrick used GD in the recent productivity study he filed in testimony for Hydro One Networks in a proceeding that is currently before the OEB.[35]

The OEB has never to our knowledge appraised a productivity study that used an OHS *monetary* method but has twice expressed skepticism about studies that used a physical asset approximation to an

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[31] For evidence on this see John R. Baldwin, Wulong Gu, and Beiling Yan (2007), "User Guide to Statistics Canada's Annual Multifactor Productivity Program," *Canadian Productivity Review*, Catalogue no. 15-206-XIE – No. 14., p. 41 and Statistics Canada, *The Statistics Canada Productivity Program: Concepts and Methods*, Catalogue no. 15-204, January 2001.

[32] Lowry, M.N., Deason, J., and Makos, M. (2017), "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities,", Lawrence Berkeley National Laboratory, July, p. B.12.

[33] See, for example, Hemphill, R., and Schoech, P. (1999), An Evaluation of the Union Gas Limited Performance-Based Regulation Proposal, p. 25.

[34] James Coyne, James Simpson, and Melissa Bartos, Concentric Energy Advisors, Inc., Incentive Ratemaking Report*, Prepared for Enbridge Gas Distribution*, OEB Proceeding EB-2012-0459, Exhibit A2, Tab 9, Schedule 1, June 28, 2013, p. B-11 and Jeffrey Bernstein and Paul Carpenter, X Factor Guideline and Measurement for Ontario's Natural Gas Distribution Industry, OEB Proceeding EB-2007-0615, Exhibit B, Tab 3, Schedule 6, November 6, 2007.

[35] EB-2017-0049, Exhibit A-3-2, Attachment 1, pp. 22-24.

OHS monetary method. In the recent OPG IRM proceeding to establish an IRM for Ontario Power Generation, for example, the OEB stated that

> Although many hydroelectric generation assets have very long useful lives, the OEB is not convinced that there is no functional depreciation until end of life. In fact, reviews of capital projects to sustain, refurbish and replace hydroelectric stations and assets in OPG's prior payment amount applications confirm that capital expenditures and operating costs are needed to maintain capacity to the end of a station's life. Absent ongoing capital and operating expenditures, hydroelectric generation assets will depreciate over time. In the OEB's view, LEI's physical method, which assumes no depreciation until the end of life, is not a realistic basis for the analysis of productivity of hydroelectric generation facilities.[36]

Conclusions In summary, there are many general arguments against the use of the OHS approach to measure capital quantities in productivity research. The OHS approach seems especially *disadvantageous* in productivity studies of US gas utilities managing mature assets, not especially *advantageous*. That is because the requisite plant value data used in the calculations are insufficiently itemized; depreciation has an important impact on gas distributor cost trends today, and gas utility assets do not in any event seem to have conformed to an OHS service flow pattern in recent years.

The GD approach is preferable based on the data and other information available at this time. Most of these arguments also apply to power distribution. This helps to explain why PEG frequently uses the GD approach in its studies of gas and electric power distribution productivity.

[36] OEB (2017), Decision and Order EB-2016-0152 Ontario Power Generation Inc. Application for payment amounts for the period from January 1, 2017 to December 31, 2021, December 28, p. 127.

4. Critique of NERA's Productivity Research and Testimony

4.1. US Power Distribution

NERA calculated the TFP trend of a large sample of US utilities in the provision of power distribution services over the lengthy 1973-2016 period.[37] This is an update of a study they have undertaken on three prior occasions, including 2010-2012 research and testimony for the Alberta Utilities Commission ("AUC") in its first Alberta generic IRM proceeding.[38] Both their original Alberta study and the updated study filed in this application found a materially *positive* productivity trend before 2000 and a materially *negative* trend since 2000.

Dr. Makholm reported a **0.54**% TFP trend over his full sample period in his work for the Applicants.[39] While in past proceedings he has argued in favor of calibrating X factors using the trend in his index for his *full* sample period, as a witness for the Applicants he is recommending a **0.0%** base TFP growth trend for the Amalco reflecting the slowing growth of his TFP indexes in the latter part of the time period.

PEG was a witness for the Consumers' Coalition of Alberta in the AUC's first generic IRM proceeding, as well as in the second proceeding that concluded in 2016. Although there was no NERA witness in the second proceeding, their methodology was used by two utility witnesses.[40] Based on this experience, and our review of NERA's evidence in this proceeding, we have numerous concerns about their methodology. To facilitate the Board's review, we first discuss our major concerns before detailing other concerns.

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

[38] This proceeding established IRMs for several gas and electric power distributors in Alberta.

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

[40] Written Evidence of Dr. Toby Brown and Dr. Paul R. Carpenter for Altagas Utilities Inc, ATCO Electric, ATCO Gas, Enmax Power Corporation, and FortisAlberta, filed as Exhibit 20414-X0056 in Alberta Utilities Commission Proceeding 20414, pp. 26-32 (Brattle) and filed as Appendix B of Exhibit 20414-X0074 in Alberta Utilities Commission Proceeding 20414, pp. 18-20 (Christensen Associates Energy Consulting).

Major Concerns

Relevance of Research

Our first concern is that the Applicants, who will run one of North America's largest *gas* utilities, would submit a study of *power* distribution industry TFP in this proceeding but not a study of *gas* utility industry productivity. While there are admittedly similarities, power and natural gas distribution have noteworthy differences, and the Amalco IRM would apply to gas transmission and storage services of the Amalco as well as its distributor services. In two previous Ontario rate plan proceedings, Enbridge submitted studies (by the Brattle Group and Concentric Energy Advisors) of US gas utility industry productivity.[41] Studies of gas utility industry productivity have also been presented, usually by utilities, in numerous jurisdictions including Alberta, British Columbia, California, Colorado, Georgia, Massachusetts, New York, Québec, and Australia in IRM applications.

A further concern about the relevance of NERA's power distribution productivity study is that it needlessly excludes customer care and administrative and general ("A&G") costs. These costs will be incurred by the Amalco and are a likely source of merger-related productivity gains. While Dr. Makholm often argues against customizing productivity studies used to calibrate X factors, NERA *did* include these costs in their earlier productivity research and testimony for two power distributors but excluded them from their study for the AUC, presumably because many customer services are provided by independent companies in Alberta.[42]

A related concern is that NERA is not in the habit of reporting trends in the productivity of OM&A inputs and has denied their relevance in IRM design. It follows that, even though the proposed PCI would, due to the ICM, chiefly apply to the *OM&A* expenses of a utility engaged in gas storage, transmission, and distribution, the Applicants have retained a consultant to prepare a study of *power*

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[41] James Coyne, James Simpson, and Melissa Bartos, Concentric Energy Advisors, Inc., *Incentive Ratemaking Report*, Prepared for Enbridge Gas Distribution, OEB Proceeding EB-2012-0459, Exhibit A2, Tab 9, Schedule 1, June 28, 2013 and Jeffrey Bernstein and Paul Carpenter, *X Factor Guideline and Measurement for Ontario's Natural Gas Distribution Industry*, OEB Proceeding EB-2007-0615, Exhibit B, Tab 3, Schedule 6, November 6, 2007.

[42] Jeff Makholm, *Updated and Rebuttal Testimony* on behalf of Central Maine Power Company, June 22, 2000 pp. 6-7; Jeff Makholm, *A Productivity Offset for a Proposed PBR Plan* on behalf of UtiliCorp Networks Canada, Attachment B to EDTI-NERA-1(c), September 1, 2000, pp. 12, 32-33; and Jeff Makholm, *Total Factor Productivity Study for Use in AUC Proceeding 566-Rate Regulation Initiative*, December 30, 2010, p. 6.

distribution productivity which excludes many pertinent OM&A expenses and does not consider OM&A productivity trends.

If NERA's power distribution TFP study were accepted by the OEB as the basis for setting X for the Amalco, it could become a precedent in Ontario power distribution regulation as well, just as the OEB nears commencement of its work to develop the next generation of IRM for power distributors. If it becomes a precedent, some electricity distributors could argue, as they have in recent Alberta, Massachusetts, and Quebec proceedings, that results using NERA's methods and a truncated sample period (producing a materially negative productivity trend) are most appropriate. This increases the importance of reviewing and considering this study carefully.

Reliance on power distribution research might nevertheless be needed to calibrate the Amalco's X factor if abundant data of good quality were unavailable to calculate *gas* utility productivity. In fact, however, good quality and reasonably standardized data are available for numerous US gas distributors since the mid-1990s and can be purchased from commercial vendors.[43] Moreover, the gas data have several advantages (e.g., better data on system age and materials used in line construction) over the analogous power industry data. PEG personnel have done numerous gas utility industry productivity studies over the years for various clients that include the OEB, two Canadian consumer groups, and several US gas utilities.[44] A productivity study we prepared using US data was published in an American Gas Association professional journal.[45]

Methodological Concerns

NERA's methodology for measuring power distribution productivity is, in any event, controversial. To facilitate the Board's review of the numerous and sometimes complicated issues that

[43] Requisite data are available for a smaller group of more than 30 utilities since the mid-1980s, making possible more accurate capital cost and quantity calculations.

[44] See, for example, Lowry, M., Hovde, D., Getachew, L., and Fenrick, S., *Rate Adjustment Indexes for Ontario's Natural Gas Utilities* in EB-2006-0606/0615, (2007). Lowry, M.N. (2016), *Next Generation PBR for Alberta Energy Distributors,* filed in Alberta Utilities Commission Proceeding 20414 as Exhibit 20414-X0082, and Lowry, M., Hovde, D., and Rebane, K., (2013), "X Factor Research for Fortis PBR Plans," in BCUC Project 3698719, for Commercial Energy Consumers of British Columbia.

[45] Lowry, M.N. and Kaufmann, L. (1996) "Forecasting the Productivity Growth of Natural Gas Distributors," *AGA Forecasting Review*, Vol. 5, March.

arise in productivity studies, we begin by highlighting our most important concerns with NERA's methodology.

Output Specification Consider first that NERA measures output growth as a revenue-weighted average of the growth in sales volumes to different service classes. Even though the Applicants propose a price cap index, NERA's volumetric output index is inappropriate for use in the calibration of the Amalco's X factor because of the Normalized Average Consumption adjustment and LRAM that the Applicants have and propose to continue using. The NAC effectively causes customers rather than volumes to drive general services revenue growth. Our analysis in Section 3 showed that the number of customers served is a more appropriate scale variable in the presence of a rate adjustment like the NAC adjustment.

The output specification would matter less if trends in the volumetric index and the number of customers served were similar. However, they are not. Volume growth differs from customer growth by growth in volume *per customer*, and this varied greatly for US electric utilities over NERA's lengthy sample period. The average use of residential and commercial customers is particularly important in a power distributor productivity study.

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

Faced with this challenge, we gathered the necessary customer data for utilities in NERA's sample. Residential and commercial volume and customer trends for these utilities are compared in Table 1 below. It can be seen that residential and commercial average use by customers of the utilities in Dr. Makholm's sample averaged 1.5% annual growth from 1973 to 2000, but averaged a 0.3% annual decline from 2001 to 2016. The decline in average use has accelerated since 2008. This is clearly the main reason for the slowing growth in NERA's TFP indexes after 2000, but has limited relevance to the calibration of an X factor for the proposed IRM of the Applicants.

Capital Specification We also have concerns about the simple one hoss shay approach that NERA used to measure capital cost. We discussed several *general* disadvantages of the OHS approach in Section 3.2

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

	Average Volume Growth			Average Use Growth	
Year	Total Volume [A]	Residential and Commercial Volume [B]	Average Total Customer Growth [C]	Total Volumes [A-C]	Residential and Commerical Volumes [B-C]
1973	7.8%	7.6%	3.0%	4.7%	4.6%
1974	-0.2%	0.4%	2.5%	-2.6%	-2.1%
1975	0.9%	5.3%	1.7%	-0.8%	3.6%
1976	5.6%	3.5%	1.9%	3.7%	1.7%
1977	4.3%	4.8%	2.1%	2.2%	2.7%
1978	3.9%	3.7%	2.4%	1.6%	1.3%
1979	2.8%	2.0%	2.3%	0.5%	-0.3%
1980	1.0%	3.4%	1.8%	-0.8%	1.6%
1981	1.2%	0.4%	1.4%	-0.2%	-1.0%
1982	-1.3%	2.2%	1.2%	-2.5%	1.0%
1983	2.9%	2.9%	1.4%	1.5%	1.5%
1984	4.9%	3.7%	1.5%	3.3%	2.2%
1985	1.6%	2.1%	1.8%	-0.2%	0.3%
1986	2.3%	3.8%	1.8%	0.4%	1.9%
1987	4.2%	4.3%	1.9%	2.3%	2.4%
1988	4.8%	5.7%	1.8%	3.1%	3.9%
1989	2.3%	1.9%	1.6%	0.6%	0.2%
1990	1.6%	2.2%	-0.2%	1.7%	2.4%
1991	2.2%	3.6%	1.3%	0.9%	2.3%
1992	0.0%	-1.2%	1.2%	-1.2%	-2.3%
1993	3.4%	5.0%	1.3%	2.2%	3.7%
1994	2.5%	2.7%	1.4%	1.1%	1.3%
1995	2.4%	4.0%	1.5%	0.9%	2.5%
1996	2.3%	2.6%	-0.1%	2.4%	2.7%
1997	1.0%	0.5%	1.3%	-0.3%	-0.8%
1998	2.7%	3.3%	1.3%	1.3%	2.0%
1999	2.0%	2.9%	3.7%	-1.6%	-0.8%
2000	3.2%	3.5%	1.3%	1.9%	2.2%
2001	-0.8%	0.8%	3.6%	-4.4%	-2.8%
2002	2.1%	4.2%	1.2%	0.8%	3.0%
2003	0.3%	0.6%	0.7%	-0.4%	0.0%
2004	1.7%	0.9%	1.1%	0.6%	-0.3%
2005	2.4%	3.6%	1.4%	1.0%	2.3%
2006	-1.2%	-1.6%	0.3%	-1.5%	-1.9%
2007	3.2%	4.0%	0.9%	2.3%	3.1%
2008	-1.7%	-1.1%	0.7%	-2.3%	-1.8%
2009	-4.9%	-3.5%	0.2%	-5.1%	-3.7%
2010	3.7%	3.5%	0.5%	3.2%	3.0%
2011	-0.8%	-1.0%	0.4%	-1.2%	-1.4%
2012	-2.0%	-1.8%	0.5%	-2.4%	-2.3%
2013	0.6%	0.2%	0.6%	0.1%	-0.3%
2014	-0.4%	0.6%	0.6%	-1.0%	0.0%
2015	-0.7%	-0.6%	0.8%	-1.5%	-1.5%
2016	-0.5%	-0.1%	0.7%	-1.3%	-0.8%
Average Annual Growth Rate					
1973 - 2000	**2.6%**	**3.1%**	**1.6%**	**0.9%**	**1.5%**
1973 - 2016	**1.7%**	**2.2%**	**1.4%**	**0.3%**	**0.8%**
2001 - 2016	**0.1%**	**0.6%**	**0.9%**	**-0.8%**	**-0.3%**
2008 - 2016	**-0.7%**	**-0.4%**	**0.6%**	**-1.3%**	**-1.0%**

Notes
[1]All growth rates are calculated logarithmically. For example, growth rate of V = $\ln(V_t/V_{t-1})$.
[2]Average growth rates in a given year are the mean of the respective annual growth rates for all companies in NERA's sample with plausible customer data available.

above. Our focus in this section is that NERA's particular approach to executing OHS is flawed. Since they do not itemize quantities of different kinds of distributor assets, their OHS approach is particularly sensitive to the choice of an average service life used to estimate the quantity of retirements.

NERA assumes a 33-year average service life.[46] In response to an undertaking, NERA showed that this is the average ratio of power distribution gross plant value to power distribution depreciation expenses for a large sample of US electric utilities from 1988 to 2009.[47] For each company in the sample, PEG divided the end of year gross value of distribution plant by distribution depreciation expenses to replicate NERA's average service life calculations. We removed observations that were zero or negative, and then calculated the mean and standard deviation of average service life for all companies in a given year. We recalculated the mean average service life in each year by filtering out all observations that were more than two standard deviations from the initial mean. By repeating this process for each year, we generated a time series of average service lives. From 1988 to 2009, the period that NERA uses in determining an average service life of 33 years, we found that the mean average service life was 32.7 years. The mean average annual service life grew over this period from 31.1 in 1988 to 35.4 in 2009. Growth continued between 2009 and 2016, from 35.4 to 38.3 for our screened observations.

We demonstrate mathematically in Appendix A.2 that NERA's calculation is appropriate for the analysis of *depreciation expenses*, not for *retirements.* This matters doubly since the 33-year average service life that NERA assumes is on the low end of the range of reasonableness, based on our research and experience. Other research suggests that average service life is higher.

Table 2 summarizes data we have gathered from utility filings on the average service lives of US power distributors today. It can be seen that they typically exceed 40 years. In response to an undertaking, Enbridge and Union report average service lives of about 38 years and 36 years in 2016, respectively.[48] As explained further in Appendix 1, we calculated an alternative average service life that

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

[47] Exhibit JT 2.2, Attachment 1.

[48] Exhibit JT 2.3, Attachments 1 and 2.

Table 2

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

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

Footnotes:
[1] Thousands of dollars
[2] Source: Financial Statistics of Major U.S. Investor-Owned Electric Utilities 1996, EIA. Page 43.
[3] Service life studies that are not consistent with FERC Accounts are excluded from these calculations.

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

is commensurate with retirements using a better formula and detailed retirement data from FERC Form 1. Our alternative estimate was 42 years. We demonstrated in the second Alberta IRM proceeding that, with an average service life of even 37 years, TFP growth using NERA's methodology is much higher.[49]

NERA's capital cost treatment and volumetric index together explain why TFP growth using their index has been materially negative in recent years. They obtain a reasonable TFP trend (e.g., +0.54%) over their lengthy full sample period because brisk (but, in an Application to the Applicants' proposed IRM, irrelevant) growth in average use in the early years offsets the productivity declines in later years. In recent years, their TFP indexes have been declining due to a combination of declining average use and an inappropriate average service life assumption.

The slowdown in TFP growth using NERA's method invites controversy over the appropriate sample period when their methodology is used. In testimony for North American power distributors, the Brattle Group (in Alberta), Christensen Associates Energy Consulting (in Alberta and Massachusetts), and Concentric Energy Advisors (in Quebec) have as utility witnesses embraced most aspects of NERA's methodology but only for recent years of their full sample period when productivity growth was negative.[50] All of these witnesses have, like NERA in this proceeding, cited the AUC's embrace of NERA's work in the first Alberta IRM proceeding. Truncation of the sample period, using NERA's methodology in other respects, was actually never embraced by the AUC but was accepted in a recent decision by the Massachusetts Department of Public Utilities.[51] Note that in the second Alberta generic proceeding, the AUC's chosen 0.3% X factor was informed by utility studies using OHS but also by a study by PEG that used geometric decay.

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[49] Lowry, M.N. and Hovde, D. (2016), *PEG Reply Evidence*, Exhibit 20414-X0468 in AUC Proceeding 20414, pp. 15-19.

[50] Written Evidence of Dr. Toby Brown and Dr. Paul R. Carpenter for Altagas Utilities Inc, ATCO Electric, ATCO Gas, Enmax Power Corporation, and FortisAlberta, filed as Exhibit 20414-X0056 in Alberta Utilities Commission Proceeding 20414, pp. 26-32 (Brattle), Meitzen, M.E. (2016) *Determination of the Second-Generation X Factor for the AUC Price Cap Plan for Alberta Electric Distribution Companies*, filed as Appendix B of Exhibit 20414-X0074 in Alberta Utilities Commission Proceeding 20414, pp. 27-42 (Christensen Associates Energy Consulting), and Concentric Energy Advisors (2018), *Performance Based Regulation: Recommended X Factor*, Report filed as Exhibit B-0178 in Regie de l'Energie file R-4011-2017, pp. 5-9.

[51] See Massachusetts Department of Public Utilities, DPU-17-05, *Order Establishing Eversource's Revenue Requirement*, November 30, 2017, pp. 383-384. PEG did not participate in the Massachusetts proceeding.

Other Concerns

A number of smaller problems with NERA's US power distribution research also merit mention.

- Recall from Section 3 that the computation of a capital quantity index starts with a benchmark year adjustment. We believe NERA's calculations of capital quantity indexes in their initial benchmark year were also incorrect. OHS is sometimes characterized as a method for calculating the quantity associated with gross plant value. Yet NERA deflated *net* plant values by an average of past values of a construction cost index. As a consequence, we believe that the initial quantities of capital for each utility in their sample were understated. Their method effectively removed accumulated depreciation associated with older capital twice. It was first removed when calculating net plant value and then removed again when the original value of plant is retired. When an alternative and higher average service life is used to calculate capital quantities, this can result in negative capital quantities for some utilities. Utility witnesses in Alberta used these negative capital quantities as an argument against a higher average service life.[52]

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

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

  B. Records shall be maintained so that the quantity of electricity sold and the revenue received under each rate schedule shall be readily available.[53]

  It is easy to understand why these instructions might prompt a utility experiencing retail competition to report power *sales* volumes even when its power *delivery* volumes are larger.

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

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

There are, as a consequence, marked declines in the reported volumes of some utilities that lost retail merchant business to competitors.

- There is too much weight on the trend in industrial volumes in NERA's volumetric index. NERA acknowledged in response to an information request that many large industrial customers of US electric utilities take service directly from the transmission system.[54]
- NERA failed to correct for some mergers.
- There were no controls for transfers of costs of assets and other inputs between the transmission and distribution operations of utilities.
- A Törnqvist/Thiel multilateral form was used for the productivity indexes. This form is not the best available for measuring productivity *trends.* Chain-weighted Törnqvist and Fisher Ideal forms are preferable for trend studies. PEG conventionally uses chain-weighted Törnqvist forms for input price and productivity indexes used in productivity trend studies.
- We are also concerned that NERA's documentation of their research for the Applicants in his direct evidence is substandard for an IRM filing in Ontario. For example, he did not discuss his methods for calculating the TFP trends of Enbridge and Union. To describe NERA's US power distribution productivity research, Enbridge attached his *first* report in the 2012 Alberta proceeding even though NERA revised their methodology during the proceeding and presented new results.[55] For example, Dr. Makholm acknowledged at the technical conference that he revised his labor cost specification during this Alberta proceeding at the recommendation of Dr. Lowry.[56]

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

[55] The second report filed in AUC proceeding 566 was filed in response to an interrogatory response Exhibit C/Staff-34 b), Attachment 2.

[56] Technical Conference Transcript March 29, 2018, pp. 7-9.

Alternative Results

To illustrate the problems with NERA's power distributor productivity research, PEG has undertaken several alternative runs. Results of this exercise are presented in Table 3. We focus here on results for the 2001-2016 part of the sample period. The table also presents results for the full sample period.

- We first revised the benchmark year capital quantity calculation to deflate *gross* plant value by a 33-year average of past construction cost index values. This raised the estimated TFP trend for the sample by about 30 basis points, from -1.21% to -0.91%.
- We next corrected for a small problem with NERA's labor quantity calculation. This raised the estimated TFP trend by about 8 basis points, to -0.83%.
- We next removed some merged companies from the sample. This lowered the estimated TFP trend by 3 basis points, to -0.86%.
- We next raised the average service life from 33 to 37 years. This raised the estimated TFP trend by a remarkable 68 basis points, to -0.18%.
- Finally, we replaced NERA's volumetric output index with the number of customers served. This raised the estimated TFP trend by another 67 basis points, to **+0.49%.** With all of these upgrades and corrections, the estimated TFP trend using OHS for the *full* (1973-2016) sample period was **+0.85%.**

4.2. Enbridge and Union

NERA also calculated the TFP trend of Enbridge over the 1993-2016 period and that of Union over the 2001-2016 period. NERA reported a **-0.21%** average annual growth rate for Enbridge and a **-0.23%** trend for Union.[57] Our review of his work revealed several concerns. Here are the major ones.

[57] EB 2017-0307, Exhibit B, Tab 2, pp. 26-27.

Table 3

Summary of Corrections and Modifications to NERA's Productivity Calculations

	1973-2016			1973-2000			2001-2016		
	TFP Trend	**Incremental Change**	**Cumulative Change**	**TFP Trend**	**Incremental Change**	**Cumulative Change**	**TFP Trend**	**Incremental Change**	**Cumulative Change**
As Reported	0.54%			1.53%			-1.21%		
Modifications									
33 year TWA	0.55%	0.02%	0.02%	1.55%	0.02%	0.02%	-1.19%	0.02%	0.02%
Gross Plant 20 Year TWA	0.67%	0.12%	0.13%	1.65%	0.10%	0.11%	-1.04%	0.15%	0.16%
Gross Plant 33 Year TWA	0.78%	0.11%	0.24%	1.75%	0.10%	0.21%	-0.91%	0.13%	0.30%
Labor Quantity Calculation	0.81%	0.03%	0.27%	1.75%	0.00%	0.21%	-0.83%	0.08%	0.38%
Remove Merged Companies	0.79%	-0.03%	0.25%	1.73%	-0.02%	0.19%	-0.86%	-0.03%	0.35%
Average Service Life = 37 Years	1.23%	0.45%	0.69%	2.04%	0.29%	0.50%	-0.18%	0.73%	1.03%
Customers as Output	**0.85%**	**0.06%**	**0.31%**	**1.06%**	**-0.67%**	**-0.48%**	**0.49%**	**1.34%**	**1.69%**

- The Handy Whitman Index for *electric power distribution* construction costs in the Northeast US was used to deflate the asset values of these two *natural gas* utilities. We believe that the Statistics Canada's implicit price index for the capital stock of the utility sector is a more appropriate asset price deflator for the Applicants.
- NERA's benchmark year adjustment deflated the plant values of each applicant by an average of construction cost index values for a period ending in *1964* when the average should end in a year around the turn of the 21st century, when plant additions for each applicant become available. This is an apparent error in NERA's research.
- The number of customers served should be the output variable if the goal is to calibrate the X factor of the Applicants.

We recalculated these indexes using the number of customers served, our preferred asset value deflator, and benchmark year adjustments that are appropriate for Union in 1992 and Enbridge in 2000.

The OHS approach to measuring capital quantity and the 33-year average service life assumed by NERA were not changed.

Results of our calculations are presented in Tables 4a and 4b. Over the full 1993-2016 sample period for which data were gathered for Enbridge, its TFP growth averaged 0.31% annually while its OM&A productivity averaged 1.95% growth and its capital productivity averaged a 1.70% annual decline. Over the full 2001-2016 period for which data were gathered for both companies, Enbridge averaged a 0.76% annual TFP decline while Union averaged 1.04% annual growth. Both companies experienced brisk OM&A productivity growth.

Table 4a
Corrected Union TFP Results

Yearly Estimates:	TFP: NERA Results	TFP: Corrected Benchmark Year Adjustment	TFP: Plus Canadian Asset Price Index	TFP: Plus Customers as Output	O&M Productivity: NERA Results*	O&M Productivity: Plus Customers as Output	Capital Productivity: NERA Results*	Capital Productivity: Corrected Benchmark Year Adjustment	Capital Productivity: Plus Canadian Asset Price Index	Capital Productivity: Plus Customers as Output
2001	-6.89%	-6.80%	-6.64%	2.30%	-6.41%	2.53%	-7.00%	-7.37%	-7.02%	1.92%
2002	7.08%	7.82%	7.85%	3.26%	3.41%	-1.19%	7.81%	12.80%	13.60%	9.00%
2003	5.43%	8.73%	9.10%	7.30%	11.67%	9.87%	3.82%	3.83%	4.09%	2.28%
2004	-4.91%	-6.29%	-6.35%	0.30%	-9.77%	-3.12%	-3.94%	-2.43%	-1.92%	4.73%
2005	0.83%	2.11%	2.21%	3.95%	2.25%	3.99%	0.49%	1.87%	2.07%	3.81%
2006	-8.23%	-8.28%	-8.46%	1.27%	-8.11%	1.63%	-8.24%	-8.48%	-9.10%	0.63%
2007	6.96%	6.97%	6.62%	1.33%	6.40%	1.12%	7.08%	7.71%	6.96%	1.67%
2008	2.33%	2.04%	1.65%	0.69%	3.19%	2.24%	2.20%	0.67%	-0.99%	-1.95%
2009	-4.00%	-3.70%	-4.45%	0.84%	-4.12%	1.17%	-3.95%	-3.16%	-4.87%	0.41%
2010	-4.06%	-5.50%	-6.37%	-1.50%	-8.60%	-3.73%	-3.25%	-2.11%	-3.33%	1.54%
2011	6.34%	6.14%	5.33%	0.11%	6.10%	0.88%	6.38%	6.18%	4.17%	-1.05%
2012	-8.29%	-8.49%	-9.38%	0.21%	-9.51%	0.08%	-8.07%	-7.40%	-9.25%	0.33%
2013	12.52%	13.08%	11.99%	1.12%	13.39%	2.52%	12.35%	12.66%	9.78%	-1.08%
2014	6.62%	7.03%	6.32%	1.36%	8.72%	3.76%	6.17%	4.78%	2.52%	-2.44%
2015	-8.30%	-9.65%	-10.80%	-1.84%	-9.66%	-0.71%	-8.06%	-9.75%	-12.05%	-3.10%
2016	-7.13%	-10.26%	-11.36%	-4.04%	-9.94%	-2.62%	-6.64%	-10.81%	-13.42%	-6.10%
Average Annual Growth Rates										
2001-2016	**-0.23%**	**-0.31%**	**-0.80%**	**1.04%**	**-0.69%**	**1.15%**	**-0.18%**	**-0.06%**	**-1.17%**	**0.66%**

*PEG calculated O&M and capital productivity based on summary results calculated by NERA.

Table 4b
Corrected Enbridge TFP Results

Yearly Estimates:	TFP: NERA Results	TFP: Corrected Benchmark Year Adjustment	TFP: Plus Canadian Asset Price Index	TFP: Plus Customers as Output	O&M Productivity: NERA Results*	O&M Productivity: Plus Customers as Output	Capital Productivity: NERA Results*	Capital Productivity: Corrected Benchmark Year Adjustment	Capital Productivity: Plus Canadian Asset Price Index	Capital Productivity: Plus Customers as Output
1993	1.22%	-2.85%	-3.05%	-3.67%	-2.16%	-2.78%	2.38%	-4.40%	-4.86%	-5.48%
1994	1.87%	0.25%	0.19%	0.64%	0.82%	1.27%	2.29%	-0.58%	-0.51%	-0.06%
1995	-4.21%	-5.63%	-5.55%	1.17%	-4.87%	1.85%	-3.88%	-6.59%	-6.55%	0.16%
1996	7.04%	4.90%	4.88%	-0.81%	3.33%	-2.35%	8.24%	6.03%	6.18%	0.50%
1997	-3.65%	-4.69%	-4.43%	2.14%	-4.35%	2.23%	-3.63%	-6.17%	-5.83%	0.75%
1998	-4.68%	-3.13%	-2.68%	7.23%	2.22%	12.13%	-7.36%	-11.07%	-10.94%	-1.03%
1999	3.35%	2.88%	3.05%	2.92%	4.17%	4.04%	3.04%	1.11%	1.24%	1.11%
2000	8.10%	11.33%	11.73%	9.83%	18.22%	16.31%	4.57%	2.49%	2.58%	0.67%
2001	-0.18%	-2.16%	-2.09%	0.12%	-2.25%	-0.04%	0.38%	-2.30%	-2.16%	0.05%
2002	-0.93%	-2.08%	-2.05%	1.03%	0.18%	3.26%	-1.28%	-4.44%	-4.58%	-1.50%
2003	6.78%	3.63%	3.39%	-2.71%	0.66%	-5.44%	8.56%	6.21%	6.07%	-0.03%
2004	-2.85%	-3.11%	-3.07%	2.82%	-2.47%	3.43%	-2.98%	-3.83%	-3.75%	2.14%
2005	0.08%	-0.69%	-0.87%	1.83%	2.08%	4.78%	-0.62%	-3.77%	-4.65%	-1.95%
2006	-9.30%	-10.37%	-10.72%	0.29%	-8.57%	2.44%	-9.50%	-11.96%	-13.13%	-2.12%
2007	8.39%	7.44%	6.94%	0.04%	7.63%	0.73%	8.59%	7.30%	6.03%	-0.86%
2008	0.03%	-0.24%	-0.59%	1.50%	2.04%	4.14%	-0.50%	-1.69%	-2.98%	-0.88%
2009	-2.78%	-2.65%	-3.02%	1.15%	0.10%	4.27%	-3.46%	-4.45%	-5.66%	-1.49%
2010	-3.08%	-3.23%	-3.86%	1.05%	-2.11%	2.81%	-3.39%	-4.37%	-5.80%	-0.89%
2011	3.56%	2.87%	2.20%	-0.23%	3.99%	1.56%	3.38%	1.82%	0.22%	-2.21%
2012	-10.33%	-12.31%	-13.42%	-3.18%	-14.65%	-4.41%	-9.23%	-10.60%	-12.53%	-2.29%
2013	9.33%	7.29%	6.42%	-3.10%	7.19%	-2.33%	9.89%	7.36%	5.60%	-3.92%
2014	6.16%	5.73%	5.07%	0.13%	10.08%	5.15%	5.00%	2.19%	0.33%	-4.60%
2015	-7.94%	-9.92%	-11.05%	-3.24%	-11.91%	-4.10%	-6.79%	-7.59%	-9.04%	-1.24%
2016	-11.07%	-15.62%	-17.49%	-9.58%	-10.02%	-2.11%	-11.36%	-19.52%	-23.44%	-15.53%
Average Annual Growth Rates										
1993-2016	**-0.21%**	**-1.35%**	**-1.67%**	**0.31%**	**-0.03%**	**1.95%**	**-0.32%**	**-2.87%**	**-3.67%**	**-1.70%**
2001-2016	**-0.88%**	**-2.21%**	**-2.76%**	**-0.76%**	**-1.13%**	**0.88%**	**-0.83%**	**-3.10%**	**-4.34%**	**-2.33%**

*PEG calculated O&M and capital productivity based on summary results calculated by NERA.

5. New Research on U.S. Gas Utility Productivity

PEG has prepared a study of the recent OM&A, capital, and total factor productivity trends of a sizable sample of US gas distributors. This study uses productivity research methods which are more appropriate for calculating the Amalco's X factor than some of the methods that NERA used. We describe the research at a high level in this section. Some additional details of the research can be found in Appendix A.2.

5.1. Productivity Trends of US Gas Distributors

Data

US Gas Distributors

The chief source of our data on the costs of US gas utilities was reports to state regulators. These reports are fairly standardized since they often use as templates the Form 2 that interstate gas pipeline companies file with the FERC. A Uniform System of Accounts is available for this form. The chief source for our data on gas utility customers was Form EIA 176. Data from both of these sources are compiled by respected commercial venders. We obtained most of the gas operating data used in this study from SNL Financial.[58]

Other data sources were also employed in our productivity research. These were used primarily to measure input price trends. The supplemental sources of price data were Whitman, Requardt & Associates, the Regulatory Research Associates unit of SNL Financial, the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor, and the U.S. Department of Commerce.

Our calculations of the productivity trends of US gas distributors are based on quality data for 58 utilities. The sample includes most of the larger distributors in the United States. Some of the sampled distributors (e.g., Southern California Gas) also provided gas transmission and/or storage services but all were involved more extensively in gas distribution. The sampled distributors are listed in Table 5.

[58] For a few of the sampled companies, the SNL data were deemed insufficient in some of the earliest years of the sample period. In such cases, we used data from sources we have used in the past such as the GasDat service of Platts.

Table 5
Companies in PEG's Gas Utility Indexing Sample

Avista	Northwest Natural Gas
Baltimore Gas and Electric	NSTAR Gas
Berkshire Gas	Ohio Gas
Cascade Natural Gas	Ohio Valley Gas
Central Hudson Gas & Electric	Orange and Rockland Utilities
Citizens Energy Group	Pacific Gas and Electric
Columbia Gas of Kentucky	PECO Energy
Columbia Gas of Maryland	Peoples Gas Light and Coke
Columbia Gas of Ohio	Peoples Gas System
Columbia Gas of Pennsylvania	Public Service of Colorado
Columbia Gas of Virginia	Public Service Electric and Gas
Connecticut Natural Gas	Puget Sound Energy
Consumers Energy	Questar Gas
Corning Natural Gas	Rochester Gas and Electric
Duke Energy Ohio	San Diego Gas & Electric
East Ohio Gas	Sierra Pacific Power
Hope Gas	South Carolina Electric & Gas
Indiana Gas Company	South Jersey Gas
Louisville Gas and Electric	Southern California Gas
Madison Gas and Electric	Southern Connecticut Gas
Mountaineer Gas	Southern Indiana Gas and Electric
National Fuel Gas Distribution	Spire Alabama
New Jersey Natural Gas	St. Joe Natural Gas
New York State Electric & Gas	St. Lawrence Gas
Niagara Mohawk Power	Vermont Gas Systems
North Shore Gas	Virginia Natural Gas
Northern Illinois Gas	Washington Gas Light
Northern Indiana Public Service	Wisconsin Gas
Northern States Power - Wisconsin	Yankee Gas Services

Note: Sample comprises 58 utilities

Index Details

Scope

We calculated indexes of trends in the OM&A, capital, and total factor productivity of each sampled utility in the provision of gas transmission, storage, and distributor services. Costs of administrative and general functions and many customer services (e.g., billing and collection) were included in the study. The costs considered also encompassed taxes and pension and other benefit expenses.

Itemized costs attributed to electric services provided by combined gas and electric utilities in the sample were excluded from the analysis. We also excluded certain costs that are itemized on U.S. data forms and are unlikely to be subject to indexing in the IRM of the Applicants. The costs excluded for this reason included expenses for gas supply, gas transmission by others, and compressor station fuel.

We also excluded customer service and information expenses. These costs grew briskly during the sample period for many utilities due to the growth in utility CDM programs. The cost of these programs is not itemized in the U.S. data for easy removal. CDM programs are not covered by the indexing provisions of the Applicants' proposed IRM.

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 OM&A inputs. OM&A inputs comprised labor, materials, and services. Material and service ("M&S") inputs is a residual input category that includes the OM&A services of contractors, insurance, real estate rents, equipment leases, materials, and miscellaneous other goods and services. The calculation of capital cost is discussed further in Appendix Section A.2.

Output Measure

The number of customers served was the output metric in our gas productivity study. We show in Section 3.1 above that this is the output specification that is relevant to the calibration of an X factor for the Applicants.

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 OM&A 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 2016. 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 technology trend. 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 eighteen-year 1999 to 2016 period.

Index Results and Analysis

Table 6 reports annual growth rates in the total and partial factor productivities of US gas utilities for each year of the full sample period. Inspecting the results, it can be seen that the sampled distributors averaged **-0.39%** annual TFP growth.[59] Output growth averaging **1.03**% annually was outpaced by multifactor input quantity growth averaging **1.42**% annually. OM&A productivity growth averaged **0.33**% annually whereas capital productivity growth averaged a **0.87%** annual decline.

Table 6 also shows that, in the last 5-6 years of the sample period, there was a decline in OM&A, capital, and total factor productivity growth. Increased OM&A expenses and capex seem to have partly resulted from the distributors' response to regulations that were enacted by the US Pipeline and Hazardous Materials Safety Administration ("PHMSA") and by a high-profile gas transmission pipeline explosion in San Bruno, California. The new regulations mandated that distributors have and implement a Distribution Integrity Management Program ("DIMP") with a written integrity management plan by August 2, 2011.[60]

OM&A expenses of gas utilities increased due in part to the cost of developing and implementing the DIMP and addressing the findings of major incident investigations. Some of the increased OM&A expenses would be temporary. For example, in the aftermath of the San Bruno incident, Pacific Gas and Electric requested nearly $400 million for various activities related to upgrading

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

[60] Gas transmitters already operated under a requirement that they implement a Transmission Integrity Management Program ("TIMP") for many of the pipelines they operate by December 17, 2004.

Table 6

Productivity Results for Sampled Gas Distributors[1]

	Output	Input Quantities			Productivity		
Year	Customers [A]	OM&A [B]	Capital [C]	Total [D]	OM&A [A-B]	Capital [A-C]	TFP [A-D]
1999	2.12%	0.75%	2.11%	1.83%	1.37%	0.02%	0.29%
2000	2.67%	3.62%	2.44%	2.82%	-0.96%	0.23%	-0.15%
2001	1.30%	-5.02%	2.79%	-0.12%	6.33%	-1.49%	1.42%
2002	0.82%	-3.89%	1.80%	-0.31%	4.72%	-0.98%	1.14%
2003	2.21%	2.42%	1.71%	1.82%	-0.21%	0.50%	0.39%
2004	0.94%	2.93%	1.96%	2.22%	-1.98%	-1.02%	-1.28%
2005	1.39%	1.77%	1.40%	1.54%	-0.38%	-0.01%	-0.15%
2006	0.77%	-3.92%	0.99%	-1.19%	4.69%	-0.22%	1.96%
2007	0.62%	3.18%	1.07%	1.91%	-2.57%	-0.45%	-1.29%
2008	0.33%	0.32%	0.92%	0.69%	0.01%	-0.59%	-0.36%
2009	0.29%	3.26%	1.05%	2.09%	-2.97%	-0.76%	-1.80%
2010	0.34%	1.81%	1.34%	1.52%	-1.47%	-1.00%	-1.18%
2011	0.56%	1.02%	1.54%	1.35%	-0.46%	-0.98%	-0.79%
2012	0.87%	2.05%	1.34%	2.11%	-1.19%	-0.47%	-1.24%
2013	0.66%	2.46%	2.14%	2.03%	-1.80%	-1.49%	-1.37%
2014	0.85%	5.55%	2.71%	3.74%	-4.70%	-1.86%	-2.89%
2015	0.94%	-2.14%	3.36%	1.11%	3.08%	-2.42%	-0.17%
2016	0.88%	-3.55%	3.60%	0.39%	4.43%	-2.71%	0.49%
Average Annual Growth Rates							
1999-2016	**1.03%**	**0.70%**	**1.90%**	**1.42%**	**0.33%**	**-0.87%**	**-0.39%**

Notes

[1]Research used geometric decay and a 1994 benchmark year for capital quantity.

their transmission pipeline records.[61] OM&A 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 increased in subsequent years, as distributors relied on the data compiled from implementing the DIMP and addressing the findings of major incident investigations to identify assets needing replacement due to a high risk of failure. To help ensure that DIMP and TIMP costs would be funded, regulators in several states (e.g., Colorado, Connecticut, and Michigan) have approved trackers to address some, if not all, of these costs.

Surges in capex that result from these programs slow TFP growth in the short run. Once a surge ends, however, TFP growth can accelerate as these assets depreciate.

[61] The regulator disallowed the costs not due to concerns about their level but rather because it believed that Pacific Gas & Electric had followed deficient document management procedures that required this work to be undertaken. California Public Utilities Commission (2012), *Decision Mandating Pipeline Safety Implementation Plan, Disallowing Costs, Allocating Risk of Inefficient Construction Management to Shareholders and Requiring Ongoing Improvement in Safety Engineering*, Decision 12-12-030, December 20, pp. 89-97.

6. Stretch Factor and X Factor Recommendations

6.1 Stretch Factor

The Applicants adopted NERA's recommendation of a 0% stretch factor.[62] No benchmarking evidence was presented by the Applicants to substantiate this proposal. The evidence in hand is that Enbridge had a TFP growth trend well below the U.S. norm, while Union's TFP growth was above the norm.[63] Both companies have been operating for several years under rate plans that provide supplemental capital revenue.

Dr. Makholm maintained in his direct evidence that stretch factors are appropriate only for first generation IRMs. The AUC embraced this principle in its decision in its first generic IRM proceeding.[64] However, the AUC in in its second generation IRM decision seemed to include a stretch factor in its 0.30% X factor decision.[65] Stretch factors have been included explicitly in some other second generation or later IRMs.[66] For example, *three* generations of IRMs for power distributors in Ontario have included a stretch factor, including the current plan. The OEB explained why it continues to include stretch factors in IRMs in a decision on 4th GIRM, stating that:

> The Board believes that stretch factors continue to be required and is not persuaded by arguments that stretch factors are only warranted immediately after distributors switch from years of cost of service regulation to IR. Stretch factors promote, recognize and reward distributors for efficiency improvements relative to the expected sector productivity trend. Consequently, stretch factors continue to have an important role in IR plans after distributors move from cost of service regulation.[67]

[62] EB 2017-0307, Exhibit B, Tab 1, pp. 8-9.

[63] However, better methods for measuring the MFP trends of the Applicants may yield faster TFP growth.

[64] EB 2017-0307, Exhibit B, Tab 2, p. 14.

[65] Alberta Utilities Commission (2017), *Errata to Decision 20414 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities*, pp. 38-40.

[66] Numerous IRMs, including most established through settlements, do not itemize the components of the X factor and thus do not indicate whether a stretch factor is included. This likely includes some second generation or later IRMs which had previously included an explicit stretch factor.

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

This logic applies to investor-owned utilities as well as publicly-owned utilities. Stretch factor assignments in the 3rd and 4th generation Ontario power distribution IR plans have been updated annually to reflect company performance in cost benchmarking studies. Utilities that have operated under one or even several IRMs have not necessarily eliminated all inefficiencies. Moreover, operation under an IRM will typically generate stronger performance incentives than the regulatory systems of the typical utility in the productivity sample. Consider also that the Ontario stretch factor and benchmarking system works as an efficiency carryover mechanism that rewards distributors for sustained reductions in cost and penalizes them for sustained increases.

Similarly, after several generations of IRMs, the British Columbia Utilities Commission approved stretch factors of 0.2% for FortisBC Energy Inc. (formerly Terasen Gas) and 0.1% for FortisBC (formerly West Kootenay Power) for their current plans. The BC Commission also endorsed the possibility of including stretch factors in future generations of IR plans that are based on benchmarking evidence. The Commission believed that there was

> a lack of evidence as to the efficiency of Fortis' operations relative to other utilities. This information would be helpful in making a determination on a stretch factor. A benchmarking study would provide the Commission with information on the utilities' efficiency relative to other utilities. While there is no such study available at this time, the Panel considers that it would be useful to have one completed prior to the application for the next phase of the PBR. **Accordingly, the Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018.**[68] [Emphasis in original]

Telecommunications precedents are also of interest. The US Federal Communications Commission approved stretch factors in second-generation IRMs for AT&T and the interstate services of incumbent local exchange carriers.[69] Dr. Lowry has advocated for the inclusion of stretch factors in

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

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

second generation or later IR plans in testimony for several utility clients.[70] Hydro One Networks, Ontario's largest power distributor, is proposing a 0.45% stretch factor in its current IRM proposal.[71]

Since the Applicants have not submitted benchmarking evidence, a 0.30% stretch factor seems in order for the Amalco. In the 4th GIRM this is the standard stretch factor for Ontario power distributors with average cost performance. Also, in EB-2016-0152, OPG proposed, and the OEB approved, a 0.30% X factor for the hydroelectric generation payment amounts Price Cap plan, on the basis of cost benchmarking evidence of how OPG compared with a sample of other hydroelectric generators filed in that proceeding.

6.2 X Factor

Our review of the assembled productivity evidence reveals the following facts.

- The TFP trends of sampled U.S. gas utilities over the 1999-2016 sample averaged **-0.39%.**
- When Dr. Makholm's research was corrected and upgraded to be more pertinent to the Applicants' IRM proposal, the TFP trends of sampled U.S. power distributors averaged **+ 0.49%** from 2001-2016.
- PEG obtained a similar **+0.23%** average trend in the TFP of U.S. power distributors from 2001 to 2014.[72] OM&A productivity growth averaged **0.40%** while capital productivity growth averaged **0.18%.**
- The IRM favors the Applicants in many respects. For example, the company will be compensated for a substantial portion of its capital revenue shortfalls.

Based on the assembled evidence, we recommend a **0.0%** base TFP trend for the Amalco. Adding this to a 0.30% X factor, we recommend a **0.30%** X factor.

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[70] See, for example, his X factor recommendations for Central Maine Power in 2007 and Gaz Metro in 2012. A full listing of Dr. Lowry's X factor recommendations for clients during the 2006-2015 period were detailed in Alberta Utilities Commission Proceeding 20414, Exhibit 20414-X0205 (CCA-EDTI Attachment 1b).

[71] EB-2017-0049, Exhibit A, Tab 3, Schedule 1, p. 21.

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

7. Other IRM Provisions

When a power distributor operating under a price cap IRM consolidates with a distributor operating under Custom IR, the MAADs Handbook permits the distributors to operate for as long as 10 years under a price cap IRM without rebasing. However, as noted by the OEB in its Decision [on the Issues List] and Procedural Order No. 3, the applicability of the provisions of the MAADs Handbook are an open issue with the exception of the "no harm" test. The proposed IRM for the most part follows *Rates Handbook* guidelines. It features a price cap index, Y factors, and Z factors. The Applicants have not asked for Y factor treatment of pension and other benefit expenses. An earnings sharing mechanism would be operational for the last five years. An incremental capital module ("ICM") would address the need for supplemental capital revenue.

We have concerns about some features of the Applicants' proposed plan. Here are the most notable.

7.1. Adherence to MAADs

The Applicants propose to use MAADs provisions that the OEB designed to encourage consolidation of Ontario's power distributors, with their balkanized power distribution service territories. Consolidation of smaller power distributors can streamline OEB regulation and produce economies of scale and contiguity that can be passed on to customers. The regulatory and efficiency benefits of merging the Applicants is less obvious. Thus, the OEB should not feel obliged to apply all MAADs provisions to the Applicants' proposal. The panel in this proceeding has agreed that the applicability of the MAADs Handbook to gas utilities, and the Enbridge-Union merger specifically, is an unresolved issue in this proceeding. This means that the IRM for the Amalco does not need to closely resemble 4th GIRM.

The proposed IRM, in any event, deviates from the OEB's 4th GIRM in several ways. In addition to a 0% stretch factor proposal that lacks empirical substantiation, for instance, the inflation measure is GDPIPIFDD^{Canada} and not an industry price index that more accurately tracks a utility's cost by averaging the inflation of the GDPIPIFDD^{Canada} and the average weekly earnings of workers in Ontario industry. The Normalized Average Consumption/average use adjustments are also not part of 4th GIRM.

7.2. Rebasing

Since the Board is free to deviate from MAADs rules, it can require a rebasing of each Applicant's revenue to their recent and normalized historical costs followed by their formulaic escalation to 2019 values. This would sidestep problems of performance incentives and merger-related costs. Since the Applicants are in the last year of their respective IRMs and Custom rate-setting plans, skipping a rebasing in 2019 will do little to spur the Applicants' incentives. In the extra time that the rebasing requires, the Applicants can prepare a more appropriate asset management plan for use in ICM applications.[73]

7.3. Capital Cost Treatment

The Applicants' proposed ratemaking treatment of capital cost is in line with 4th GIRM but nonetheless raises several concerns. The ICM would weaken the Amalco's capex containment incentives. Incentives to contain capex and OM&A expenses are imbalanced, creating perverse incentives to incur excessive capex to reduce OM&A costs. The Applicants would also be incentivized to "bunch" their capex so that it maximizes revenue. The Applicants would have some incentive to exaggerate capex needs since this helps to legitimize the need for an ICM and reduces pressure for capex containment.

Exaggeration of capex needs may reduce the credibility of the Applicants' forecasts in future proceedings. However, utilities can always claim that they "discovered" ways to economize under the force of stronger incentives. British distributors operating under several generations of IR have repeatedly spent less on capex than they forecasted.

Another problem with the ICM is that customers must compensate the Amalco for most of the expected capital revenue shortfalls when capex is high even though most of the capex in question is likely to be similar in kind to that made by distributors in the productivity research sample.[74] Utilities can then be compensated twice for the same capex: once via the ICM and then again by a low X factor.

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[73] Alternatively, the Applicants could use the rebasing to request an Advanced Capital Module in potentially repeated ICM filings.

[74] Hydro One would not, however, be compensated for unexpected capex overruns.

A similar concern about "double dipping" arises concerning distribution capex costs that are Z factored due to exogenous events such as severe storms and highway construction programs. These costs are also incurred by distributors in the productivity sample and slow their productivity growth.

PEG has shown in other proceedings that the TFP growth of gas and electric power distributors alike rises considerably if a portion of their capex is removed from the calculations. In 2016 Alberta testimony, for instance, PEG showed that excluding 10% of capex from a study of the productivity of US power distributors raised their estimated TFP trend over the full 1997-2014 sample period by 23 basis points, from 0.48% to 0.71%.[75]

Consider also that the Company is asking for supplemental revenue now, when its TFP growth is slowed by high capex, but could in the future operate under a standard IRM in which its price growth is limited by the industry's *long run* productivity trend. The trend in I-X mechanism thus effectively provides only a *floor* for the escalation of allowed revenue, and arguably applies chiefly to OM&A revenue, when the X factor was not designed to play either of these roles. Customers are not ensured the benefit of industry productivity growth even in the long run and even when it is achievable.

Given the inherent unfairness to customers of asymmetrically funding capital revenue shortfalls, and Applicants' incentives to exaggerate capex requirements, stakeholders and the Board must be especially vigilant about the Applicants' capex proposal. This raises regulatory cost. The need for the OEB to sign off on multiyear total capex proposals complicates price cap IR proceedings and is one of the reasons why the Board must review asset management plans --- a major expansion of its workload and that of stakeholders. Despite the extra regulatory cost, OEB Staff and stakeholders are sometimes hard-pressed to effectively challenge capex proposals.

Following an unhappy experience with capital cost trackers, a number of possible reforms to the ratemaking treatment of capital were discussed in the recent Alberta generic proceeding on second generation IR for energy distributors in that province. Based on the record, the Alberta Utilities Commission eventually chose a means for providing supplemental capital revenue that was less

[75] Lowry, Mark N., Pacific Economics Group Research, *Next Generation PBR for Alberta Energy Distributors*, Exhibit 20414-X0082 in Alberta Utilities Commission Proceeding 20414, March 23, 2016, pp. 63-66.

dependent on distributor capex forecasts. Regulatory cost was reduced thereby, and capex containment incentives were strengthened.[76]

A number of possible reforms to the capital cost tracker process were proposed by PEG in the Alberta proceeding which could also make sense in Ontario.

- The capex eligible for supplemental revenue could be subject to materiality thresholds and dead zones. Dead zones could also be added to materiality thresholds for Z-factored capex.
- The X factor could be raised in this and future plans to reduce expected double dipping and give customers a better chance of receiving the benefits of industry productivity growth in the long run. Knowledge that there is a price to be paid in the long run from asking for extra revenue now would strengthen the Amalco's capex containment incentives.
- Eligibility of capex for ICM treatment could be scaled back. For example, capex in the last year of the plan term could be declared ineligible because this involves only one year of underfunding.
- The ICM threshold can be escalated using the productivity trend of capital, while the X factor for OM&A revenue can reflect the productivity trend of OM&A. This could reduce the need for supplemental ICM revenue and make escalation of OM&A revenue more reflective of industry OM&A cost trends.

The OEB already embraces one of these strategies, since the ICM has a materiality threshold and dead zone. However, it is not clear whether the 10% threshold is appropriate, and under current ICM policy the Amalco would be funded for 100% of its marginal capex once it exceeds the threshold. An alternative is to disallow a fixed share of the total capex excess once capex exceeds the ICM threshold. Separate X factors for OM&A and capital revenue is another idea meriting consideration. If the OEB does not wish to deviate from the ratemaking treatment of capital in the 4th GIRM, the favorable treatment of capital should be kept in mind when considering other plan provisions.

[76] PEG nonetheless does not endorse the AUC's chosen approach.

7.4. Other Recommendations

Here are some other recommended modifications to the Applicants' proposal.

- An IPI is consistent with 4Th GIRM and sidesteps the need for a complicated input price differential calculation such as NERA provided. The OHS and GD capital cost specifications that NERA and PEG have used in this proceeding are very different from the methodology the Board uses to calculate capital costs in rate applications. This reduces the relevance of input price differential calculations that might be made using GD or OHS.
- If the OEB approves the Normalized Average Consumption/average use adjustments and LRAMs, the number of customers should be used in supportive TFP calculations to calibrate the X factor.
- The materiality threshold for Z factors plays an important role in IR. It reduces regulatory cost and can increase cost containment incentives.
- The proposed materiality threshold for the Z factor is low. A higher threshold is warranted that is appropriate for the Amalco's large size. The threshold should be escalated for PCI and customer growth.

Appendix

A.1 Calculating the Average Service Life

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

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

Please note the following:

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

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

where

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

- ASL^R may change over time.

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

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

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

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

$$= ASL_t^D. \qquad \text{[A3]}$$

Please note the following.

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

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

A.2 Details of the US 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 Quantity Indexes

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

Index Form

The growth of the gas distribution O&M quantity input index was the difference between the growth in applicable total cost and the growth of an O&M input price index. Each summary input quantity index was of chain-weighted Törnqvist form.[77] This means that its annual growth rate was determined by the following general formula:

$$\ln\left(\frac{Inputs_t}{Inputs_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1} \right) \cdot \ln\left(\frac{X_{j,t}}{X_{j,t-1}} \right). \qquad [A4]$$

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

Here in each year *t*,

$Inputs_t$ = Summary input quantity index

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

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

It can be seen that the growth rate of the index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable cost of each utility in the current and prior years served as weights.

Productivity Growth Rates and Trends

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

$$\ln\left(Productivity_t \big/ Productivity_{t-1} \right)$$
$$= \ln\left(Output\ Quantities_t \big/ Output\ Quantities_{t-1} \right) - \ln\left(Input\ Quantities_t \big/ Input\ Quantities_{t-1} \right). \quad [A5]$$

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

Input Price Indexes

The trend in the OM&A input quantity of each sampled distributor was calculated as the difference between the trend in its applicable OM&A expenses and an OM&A input price index. The growth rate of an input price index is defined by a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and price subindexes.

Price Index Formulas

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

$$\ln\left(\frac{Input\ Prices_t}{Input\ Prices_{t-1}} \right) = \sum_j \ \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1} \right) \cdot \ln\left(\frac{W_{j,t}}{W_{j,t-1}} \right). \qquad [A6]$$

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.

Input Price Subindexes

The OM&A input price indexes summarized trends in the prices of labor and M&S inputs. Regionalized employment cost indexes from the BLS were used to measure labor quantity trends. The gross domestic product price index ("GDPPI") was used to measure the trend in material and service prices. A price subindex for capital was required to calculate the capital quantity and is discussed further below.

Capital Cost and Quantity Specification

A monetary approach was chosen to measure the capital cost of each utility. Recall from Section 3.2 that under this approach capital cost is the product of a capital quantity index and a capital (service) price index.

$CK = WKS \cdot XK.$

Geometric decay was assumed. We took 1964 as the benchmark year for the capital quantity index. The values for the capital quantity indexes in the benchmark year were based on the net value of plant as reported in the FERC Form 1. We estimated the benchmark year (inflation adjusted) value of net plant by dividing this book value by an average of the values of an index of utility construction cost for a period ending in the benchmark year.

The construction cost indexes (WKA_t) were developed from the applicable regional Handy-Whitman Index of Cost Trends of Gas Utility Construction.[78] We adjusted these indexes to better reflect the changing composition of materials.

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

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

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

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

$$WKS_{j,t} = [CK_{j,t}^{Taxes} / XK_{j,t-1}] + d \cdot WKA_{j,t} + WKA_{j,t-1}\left[r_t - \frac{(WKA_{j,t} - WKA_{j,t-1})}{WKA_{j,t-1}}\right]. \qquad \text{[A8]}$$

The first term in the expression corresponds to taxes and franchise fees. The second term corresponds to the cost of depreciation. The third term corresponds to the real rate of return on capital. This term was smoothed to reduce capital cost volatility.

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

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RESUME OF MARK NEWTON LOWRY

April 2018

Home Address 1511 Sumac Drive
Madison, WI 53705
(608) 233-4822

Business Address 44 E. Mifflin St., Suite 601
Madison, WI 53703
(608) 257-1522 Ext. 23

Date of Birth August 7, 1952

Education High School: Hawken School, Gates Mills, Ohio, 1970
BA: Ibero-American Studies, University of Wisconsin-Madison, May 1977
Ph.D.: Applied Economics, University of Wisconsin-Madison, May 1984

Relevant Work Experience, Primary Positions

Present Position **President, Pacific Economics Group Research LLC, Madison WI**

Chief executive and sole proprietor of a consulting firm in the field of utility economics. Leads internationally recognized practice performance-based regulation and utility performance research. Other research specialties include: utility industry restructuring, codes of competitive conduct, markets for oil and gas, and commodity storage. Duties include project management and expert witness testimony.

October 1998-February 2009 **Partner, Pacific Economics Group, Madison, WI**

Managed PEG's Madison office. Developed internationally recognized practice in the field of statistical cost research for energy utility benchmarking and Altreg. Principal investigator and expert witness on numerous projects.

January 1993-October 1998 **Vice President**
January 1989-December 1992 **Senior Economist, Christensen Associates, Madison, WI**

Directed the company's Regulatory Strategy group. Participated in all Christensen Associates testimony on energy utility Altreg and benchmarking.

Aug. 1984-Dec. 1988 **Assistant Professor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Responsibilities included research and graduate and undergraduate teaching and advising. Courses taught: Min Ec 387 (Introduction to Mineral Economics); 390 (Mineral Market Modeling); 484 (Political

Economy of Energy and the Environment) and 506 (Applied Econometrics). Research specialty: role of storage in commodity markets.

August 1983-July 1984 **Instructor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Taught courses in Mineral Economics (noted above) while completing Ph.D. thesis.

April 1982-August 1983 **Research Assistant to Dr. Peter Helmberger, Department of Agricultural and Resource Economics, University of Wisconsin-Madison**

Dissertation research on the role of speculative storage in markets for field crops. Work included the development of a quarterly econometric model of the U.S. soybean market.

March 1981-March 1982 **Natural Gas Industry Analyst, Madison Consulting Group, Madison, Wisconsin**

Research under Dr. Charles Cicchetti in two areas:

- Impact of the Natural Gas Policy Act on the production and average wellhead price of natural gas in the United States. An original model was developed for forecasting these variables through 1985.

- Research supporting litigation testimony in an antitrust suit involving natural gas producers and pipelines in the San Juan Basin of New Mexico.

Relevant Work Experience, Visiting Positions:

May-August 1985 **Professeur Visiteur, Centre for International Business Studies, Ecole des Hautes Etudes Commerciales, Montreal, Quebec.**

Research on the behavior of inventories in metal markets.

Major Consulting Projects

1. Competition in the Natural Gas Market of the San Juan Basin. Public Service of New Mexico, 1981.
2. Impact of the Natural Gas Policy Act on U.S. Production and Wellhead Prices. New England Fuel Institute, 1981
3. Modeling Customer Response to Curtailable Service Programs. Electric Power Research Institute, 1989.
4. Customer Response to Interruptible Service Programs. Southern California Edison, 1989.
5. Measuring Load Relief from Interruptible Services. New England Electric Power Service, 1989.
6. Design of Time-of-Use Rates for Residential Customers. Iowa Power, 1989.
7. Incentive Regulation: Can it Pay for Interstate Gas Companies? Southern Natural Gas, 1989.

8. Measuring the Productivity Growth of Gas Transmission Companies. Interstate Natural Gas Association of America, 1990.
9. Measuring Productivity Trends in the Local Gas Distribution Industry. Niagara Mohawk Power, 1990.
10. Measurement of Productivity Trends for the U.S. Electric Power Industry. Niagara Mohawk Power, 1990-91.
11. Comprehensive Performance Indexes for Electric and Gas Distribution Utilities. Niagara Mohawk Power, 1990-1991.
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35. Productivity Research and Testimony for a Natural Gas Distributor. NMGas, 1995.
36. Speech on PBR for Electric Utilities. Hawaiian Electric, 1995.
37. Development of a Price Cap Plan for a Midwest Gas Distributor. Illinois Power, 1996.
38. Stranded Cost Recovery and Power Distribution PBR for a Restructuring U.S. Electric Utility. Delmarva Power, 1996.
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40. Consultation on the Design and Implementation of Price Cap Plans for Natural Gas Production, Transmission, and Distribution. Comision Reguladora de Energia (Mexico), 1996.
41. Power Distribution Benchmarking for a PJM Utility. Delmarva Power, 1996.
42. Testimony on PBR for Power Distribution. Commonwealth Energy System, 1996.

43. PBR Plan Design for Bundled Power Services. Hawaiian Electric, 1996
44. Design of Geographic Zones for Privatized Natural Gas Distributors. Comision Reguladora de Energia (Mexico), 1996.
45. Statistical Benchmarking for Bundled Power Service. Pennsylvania Power & Light, 1996.
46. Presentation on Performance-Based Regulation for a Natural Gas Distributor, Northwestern Utilities, 1996.
47. Productivity Research and PBR Plan Design (including Service Quality) and Testimony for a Gas Distributor under Decoupling. BC Gas, 1997.
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49. White Paper on Utility Brand Name Policy. Edison Electric Institute, 1997.
50. Generation and Power Transmission PBR for a Restructuring Canadian Electric Utility, EPCOR, 1997.
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90. Statistical Benchmarking for Power Distribution, Queensland Competition Authority, 2001.
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105. Advice on Performance Goals for a U.S. Transmission Company. American Transmission, 2003.
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111. Advice on Statistical Benchmarking for Two British Power Distributors. Northern Electric and Yorkshire Electricity Distribution, 2003.
112. Testimony on Distributor Cost Benchmarking. Hydro One Networks. 2004.
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135. Research and Testimony on the Cost Performance of a New England Power Distributor, Central Vermont Public Service, 2006.
136. White Paper on Alternative Regulation for Major Plant Additions for a U.S. Trade Association. EEI. 2006.
137. Consultation on Price Cap Regulation for Provincial Power Distributors. Ontario Energy Board. 2006.
138. Statistical Benchmarking of A&G Expenses. Michigan Public Service Commission. 2006.
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171. Research and Testimony on Approaches to Reduce Regulatory Lag for a Northeastern Power Distributor, Potomac Electric Power. 2011.
172. Assistance with an Alternative Regulation Settlement Conference for a Northeastern Power Distributor, Delmarva Power & Light. 2011.
173. Research and Testimony on the Design of a Attrition Relief Mechanisms for power and gas distributors on behalf of a Canadian Consumer Group, Consumers' Coalition of Alberta. 2011-2012.
174. Research and Testimony on Remedies for Regulatory Lag for 2 Northeastern Power Distributors, Atlantic City Electric & Delmarva Power & Light. 2011-2012.
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176. Productivity and Plan Design Research and Testimony in Support of a PBR plan for Canadian Gas Distributor, Gaz Metro. 2012-2013.
177. Testimony for US Coal Shippers on the Treatment of Cross Traffic in US Surface Transportation Board Stand Alone Cost Tests. 2012
178. Survey of Gas and Electric Altreg Precedents. Edison Electric Institute. 2012-2013.
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180. Research and Testimony on Issues in PBR Plan Implementation for a Canadian Consumer Group, Consumers' Coalition of Alberta. 2013.
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25. Price Cap Regulation for Power Distribution (with Larry Kaufmann), Washington: Edison Electric Institute, 1998.
26. Controlling for Cross-Subsidization in Electric Utility Regulation (with Lawrence Kaufmann), Washington: Edison Electric Institute, 1998.
27. The Cost Structure of Power Distribution with Implications for Public Policy (with Lawrence Kaufmann), Washington: Edison Electric Institute 1999.
28. Price Caps for Distribution Service: Do They Make Sense? (with Eric Ackerman and Lawrence Kaufmann), Edison Times, 1999.
29. "Performance-Based Regulation for Energy Utilities (with Lawrence Kaufmann)," Energy Law Journal, Fall 2002.
30. "Performance-Based Regulation and Business Strategy" (with Lawrence Kaufmann), Natural Gas and Electricity, February 2003
31. "Performance-Based Regulation and Energy Utility Business Strategy (With Lawrence Kaufmann), in Natural Gas and Electric Power Industries Analysis 2003, Houston: Financial Communications, Forthcoming.
32. "Performance-Based Regulation Developments for Gas Utilities (with Lawrence Kaufmann), Natural Gas and Electricity, April 2004.
33. "Alternative Regulation, Benchmarking, and Efficient Diversification" (with Lullit Getachew), PEG Working Paper, November 2004.
34. "Econometric Cost Benchmarking of Power Distribution Cost" (with Lullit Getachew and David Hovde), Energy Journal, July 2005.
35. "Assessing Rate Trends of U.S. Electric Utilities", Edison Electric Institute, January 2006.
36. "Alternative Regulation for North American Electric Utilities" (With Lawrence Kaufmann), Electricity Journal, July 2006.
37. "Regulation of Gas Distributors with Declining Use Per Customer" USAEE Dialogue August 2006.
38. "Alternative Regulation for Infrastructure Cost Recovery", Edison Electric Institute, January 2007.
39. "AltReg Rate Designs Address Declining Average Gas Use" (with Lullit Getachew, David Hovde, and Steve Fenrick), Natural Gas and Electricity, 2008.
40. "Price Control Regulation in North America: Role of Indexing and Benchmarking", Electricity Journal, January 2009
41. "Statistical Benchmarking in Utility Regulation: Role, Standards and Methods," (with Lullit Getachew), Energy Policy, 2009.
42. "Alternative Regulation, Benchmarking, and Efficient Diversification", USAEE Dialogue, August 2009.

43. "The Economics and Regulation of Power Transmission and Distribution: The Developed World Case" (with Lullit Getachew), in Lester C. Hunt and Joanne Evans, eds., International Handbook on the Economics of Energy, 2009.
44. "Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry" (With Lullit Getachew), Review of Network Economics, December 2009
45. "Forward Test Years for US Electric Utilities" (With David Hovde, Lullit Getachew, and Matt Makos),
Edison Electric Institute, August 2010.
46. "Innovative Regulation: A Survey of Remedies for Regulatory Lag" (With Matt Makos and Gentry Johnson), Edison Electric Institute, April 2011.
47. "Alternative Regulation for Evolving Utility Challenges: An Updated Survey" (With Matthew Makos and Gretchen Waschbusch), Edison Electric Institute, 2013.
48. "Alternative Regulation for Emerging Utility Challenges: 2015 Update" (With Matthew Makos and Gretchen Waschbusch), Edison Electric Institute, November 2015.
49. "Performance-Based Regulation in a High Distributed Energy Resources Future," (With Tim Woolf), Lawrence Berkeley National Laboratory, January 2016.
50. "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," (With Jeff Deason), Lawrence Berkeley National Laboratory, July 2017.

Conference Presentations

1. American Institute of Mining Engineering, New Orleans LA, March 1986
2. International Association of Energy Economists, Calgary AL, July 1987
3. American Agricultural Economics Association, Knoxville TN, August 1988
4. Association d'Econometrie Appliqué, Washington DC, October 1988
5. Electric Council of New England, Boston MA, November 1989
6. Electric Power Research Institute, Milwaukee WI, May 1990
7. New York State Energy Office, Saratoga Springs NY, October 1990
8. National Association of Regulatory Utility Commissioners, Columbus OH, September 1992
9. Midwest Gas Association, Aspen, CO, October 1993
10. National Association of Regulatory Utility Commissioners, Williamsburg VA, January 1994
11. National Association of Regulatory Utility Commissioners, Kalispell MT, May 1994
12. Edison Electric Institute, Washington DC, March 1995
13. National Association of Regulatory Utility Commissioners, Orlando FL, March 1995
14. Illinois Commerce Commission, St. Charles IL, June 1995
15. Michigan State University Public Utilities Institute, Williamsburg VA, December 1996
16. Edison Electric Institute, Washington DC, December 1995
17. IBC Conferences, San Francisco CA, April 1996
18. AIC Conferences, Orlando FL, April 1996
19. IBC Conferences, San Antonio TX, June 1996
20. American Gas Association, Arlington VA, July 1996
21. IBC Conferences, Washington DC, October 1996
22. Center for Regulatory Studies, Springfield IL, December 1996
23. Michigan State University Public Utilities Institute, Williamsburg VA, December 1996
24. IBC Conferences, Houston TX, January 1997
25. Michigan State University Public Utilities Institute, Edmonton AL, July 1997
26. American Gas Association, Edison Electric Institute, Advanced Public Utility Accounting School, Irving TX, Sept. 1997

27. American Gas Association, Washington DC [national telecast], September 1997
28. Infocast, Miami Beach FL, Oct. 1997
29. Edison Electric Institute, Arlington VA, March 1998
30. Electric Utility Consultants, Denver CO, April 1998
31. University of Indiana, Indianapolis IN, August 1998
32. Edison Electric Institute, Newport RI, September 1998
33. University of Southern California, Los Angeles CA, April 1999
34. Edison Electric Institute, Indianapolis, IN, August 1999
35. IBC Conferences, Washington, DC, February 2000
36. Center for Business Intelligence, Miami, FL, March 2000
37. Edison Electric Institute, San Antonio TX, April 2000
38. Infocast, Chicago IL, July 2000 [Conference chair]
39. Edison Electric Institute, July 2000
40. IOU-EDA, Brewster MA, July 2000
41. Infocast, Washington DC, October 2000
42. Wisconsin Public Utility Institute, Madison WI, November 2000
43. Infocast, Boston MA, March 2001 [Conference chair]
44. Florida 2000 Commission, Tampa FL, August 2001
45. Infocast, Washington DC, December 2001 [Conference chair]
46. Canadian Gas Association, Toronto ON, March 2002
47. Canadian Electricity Association, Whistler BC, May 2002
48. Canadian Electricity Association, Montreal PQ, September 2002
49. Ontario Energy Association, Toronto ON, November 2002
50. Canadian Gas Association, Toronto ON, February 2003
51. Louisiana Public Service Commission, Baton Rouge LA, February 2003
52. CAMPUT, Banff, ALTA, May 2003
53. Elforsk, Stockholm, Sweden, June 2003
54. Eurelectric, Brussels, Belgium, October 2003
55. CAMPUT, Halifax NS, May 2004
56. Edison Electric Institute, eforum, March 2005
57. EUCI, Seattle, May 2006 [Conference chair]
58. Ontario Energy Board, Toronto ON, June 2006
59. Edison Electric Institute, Madison WI, August 2006
60. EUCI, Arlington VA, September 2006 [Conference chair]
61. EUCI, Arlington VA September 2006
62. Law Seminars, Las Vegas, February 2007
63. Edison Electric Institute, Madison WI, August 2007
64. Edison Electric Institute, national eforum, 2007
65. EUCI, Seattle WA, 2007 [Conference chair]
66. Massachusetts Energy Distribution Companies, Waltham MA, July 2007.
67. Edison Electric Institute, Madison WI, July-August 2007.
68. Institute of Public Utilities, Lansing MI, 2007
69. EUCI, Denver, 2008 [Conference chair]
70. EUCI, Chicago, July 2008 [Conference chair]
71. EUCI, Toronto, March 2008 [Conference chair]
72. Edison Electric Institute, Madison WI, August 2008
73. EUCI, Cambridge MA, March 2009 [Conference chair]
74. Edison Electric Institute, national eforum, May 2009

75. Edison Electric Institute, Madison WI, July 2009
76. EUCI, Cambridge MA, March 2010 [Conference chair]
77. Edison Electric Institute, Madison WI, July 2010
78. EUCI, Toronto, November 2010 [Conference chair]
79. Edison Electric Institute, Madison WI, July 2011
80. EUCI, Philadelphia PA, November 2011 [Conference chair]
81. SURFA, Washington DC, April 2012
82. Edison Electric Institute, Madison WI, July 2012
83. EUCI, Chicago IL, November 2012 [Conference chair]
84. Law Seminars, Las Vegas NV, March 2013
85. Edison Electric Institute Washington DC, April 2013
86. Edison Electric Institute, Washington DC, May 2013
87. Edison Electric Institute, Madison WI, July 2013
88. National Regulatory Research Institute, Teleseminar, August 2013
89. EUCI, Chicago IL April 2014 [Conference chair]
90. Edison Electric Institute, Madison WI, July 2014
91. Financial Research Institute, Columbia MO, September 2014
92. Great Plains Institute, St. Paul MN, September 2014
93. Law Seminars, Las Vegas NV, March 2015
94. Edison Electric Institute, Madison WI, July 2015
95. Lawrence Berkeley National Laboratory, Vermont Future of Electric Utility Regulation Workshop January 2016
96. Great Plains Institute, Minneapolis MN, February 2016
97. Wisconsin Public Service Commission, Madison WI, March 2016
98. Society of Utility Regulatory Financial Analysts (SURFA), Indianapolis IN, April 2016
99. Edison Electric Institute, Madison WI, July 2016
100. Lawrence Berkeley National Laboratory, Webinar, November 2016
101. Washington State House of Representatives, Technology and Economic Development Committee, January 2017
102. National Regulatory Research Institute, Webinar, May 2017
103. National Conference of Regulatory Attorneys, Portland OR, May 2017
104. Edison Electric Institute, Madison WI, July 2017
105. Lawrence Berkeley National Laboratory, Webinar, August 2017
106. New England Conference of Public Utilities Commissioners, Hallowell ME, September 2017
107. Wisconsin Public Utilities Institute, Madison WI, October 2017
108. University of Wisconsin Department of Applied Economics, October 2017
109. NARUC, St Paul MN, January 2018

Journal Referee

Agribusiness
American Journal of Agricultural Economics
Energy Journal
Journal of Economic Dynamics and Control
Materials and Society

Association Memberships (active)

International Association of Energy Economist
Wisconsin Public Utilities Institute

FORM A

Proceeding:...EB 2017-0307.........

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is ...Mark Newton Lowry..................(*name*). I live at ..Madison.......... (*city*), in the ...State................. (*province/state*) of ..Wisconsin............... .

2. I have been engaged by or on behalf of .Ontario Energy Board... (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date ...April 11, 2018.........................

M. Newton Lowry

Signature