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BY E-MAIL

November 23, 2016

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Dear Ms. Walli:

Re: Ontario Power Generation Inc.
2017-2021 Payment Amounts
Ontario Energy Board File Number EB-2016-0152

In accordance with Procedural Order No. 1 issued on August 12, 2016, and a letter issued by the OEB on November 22, 2016, please find attached the report prepared by Mark Lowry of Pacific Economics Group Research LLC entitled "IRM Design for Ontario Power Generation".

The report was prepared at the request of OEB staff and is being filed for the purpose of assisting the OEB in the current proceeding. The report is marked as Exhibit M2.

OPG and all intervenors have been copied on this filing.

Yours truly,

Original signed by

Violet Binette
Project Advisor, Applications

Attach

IRM Design for

Ontario Power Generation

Mark Newton Lowry, PhD

President, PEG Research LLC

David Hovde

Vice President, PEG Research LLC

23 November 2016

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Executive Summary

Ontario Power Generation ("OPG" or "the Company") filed an application in May 2016 for an incentive rate-setting mechanism ("IRM") for its prescribed hydroelectric generation. The Company proposes a price cap index ("PCI") with an I-X escalation formula. In support of its proposed X factor, OPG retained London Economics Inc. ("LEI") to prepare a study of the recent hydroelectric generation productivity trends of North American utilities.

Staff of the Ontario Energy Board ("OEB") have retained Pacific Economics Group Research LLC ("PEG") to prepare analysis and commentary on LEI's study and the Company's hydroelectric IRM proposal. Our work includes an independent hydroelectric generation productivity study.

An Appraisal of LEI's Research

LEI calculated a multifactor productivity ("MFP") index for an aggregation of OPG and 15 US hydroelectric power generators. The sample period was 2003-2014. Net generation volume was the output measure in the productivity index. Hydroelectric generation capacity was the capital quantity index. LEI reported an average annual MFP decline of 1.01%. Using LEI's methods, PEG has calculated that the MFP growth of OPG averaged a 0.49% annual decline in these years.

Our primary concerns with LEI's study are its output and capital quantity treatments, which are key components of their methodology. Hydroelectric generation volumes are volatile and reflect local weather conditions. Generation capacity is a more important cost driver and is much less sensitive to weather. The volume/capacity trends of sampled generators can differ materially from that expected by OPG prospectively. OPG, in any event, has a variance account for fluctuations in hydrological conditions. With a volume variable, a special smoothing technique may be needed to improve the estimate of the long-run productivity trend. This complicates research but may nonetheless not eliminate the distortion from volume data.

We also believe that monetary methods for measuring capital quantity trends are preferable to LEI's "physical" method, when required data are available. Monetary approaches have to date been much more common in North American productivity research to calibrate X factors. Data required for the monetary method are available for many US utilities. Monetary methods can capture trends in the productivity of utilities in making capacity available. Gradual asset decay matches the stylized facts of hydroelectric generation and is consistent with utility cost accounting. This matters since PCIs are designed to adjust rates between rebasings. The OEB rejected a physical approach to capital quantity measurement in the IRM3 proceeding.

Alternatives to the sample chosen by LEI also merit examination. Longer sample periods are available if only data for US investor-owned utilities are used in the study. Additional utilities can be added to the sample. In our view, OPG should be excluded from the sample used to set X since its inclusion unduly affects results for the peer group and would weaken OPG's performance incentives if done in repeated applications.

PEG's Productivity Research

Given our concerns about LEI's methods and the impracticality of correcting their study to get satisfactory results, we prepared our own study of the hydroelectric generation productivity of 20 US utilities. Generation capacity was the output variable and a monetary method assuming geometric decay was used to measure the capital cost and quantity. Over our featured 1996-2014 sample period, the average annual growth rate in the hydroelectric MFP of our sampled utilities was about **0.29%**.

We also calculated the productivity trends of OPG over LEI's 2003-2014 sample period using our methods. The Company's MFP averaged 0.28% annual growth over the full 2003-2014 sample period. Over the 2003-2013 period that excludes the impact of the Niagara Tunnel Project, OPG's multifactor productivity averaged 1.35% annual growth.

OPG's Proposed Rate-Setting Framework

The incentive rate-setting framework that OPG proposes for its hydroelectric payment is broadly similar to the Fourth Generation Incentive Ratemaking Mechanism ("4GIRM") for power distributors that the Board developed under the Renewed Regulatory Framework. We believe that this general approach to regulation is appropriate for OPG.

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X Factor

OPG proposes a productivity factor of zero. We recommend the **0.29%** MFP growth trend that we calculated for our US utility sample for the 1996-2014 sample period as OPG's productivity factor.

Absent persuasive evidence to the contrary, a 0.3% stretch factor seems appropriate for OPG, as the Company proposes. OPG claims that the difference between its 0% proposal and LEI's -1% MFP trend is, effectively, an additional implicit stretch factor of 1%. Our empirical research shows that a positive MFP trend should be expected of OPG in the medium term. Thus, there is no additional stretch factor implicit in OPG's proposal. Assuming a stretch factor of 0.3%, we recommend a combined X factor of 0.59% for OPG.

Supplemental Capital Revenue

OPG proposes that it retain operation of the Capacity Refurbishment Variance Account ("CRVA") for its prescribed hydroelectric facilities and also have access to an incremental capital module ("ICM"). These proposals raise concerns about performance incentives and overcompensation, and their need is not supported by good capital cost forecasts. We believe that an ICM should be permitted only for capex that is material, hard to anticipate, and not addressed by the Z factor provisions of the plan. If supplemental revenue is granted for kinds of capex that are routinely incurred by utilities in the productivity sample, the IRM should be adjusted to ensure that customers receive the benefit of peer group productivity growth in the longer run. If the CRVA is approved as proposed an increase in the X factor is warranted. The Board should also consider rejecting the CRVA and having the need for supplemental revenue for these costs addressed through the ICM.

Efficiency Carryover Mechanism

We also believe that an efficiency carryover mechanism ("ECM") should be considered for the Company. These mechanisms can materially strengthen performance incentives and help ensure that customers get a fair share of IRM benefits. An ECM for OPG should focus on the benefits customers receive in the next plan. We propose some concrete methods for ECM design.

1. Introduction

OPG filed an application on May 27, 2016 for an IRM for its hydroelectric generation as part of a comprehensive application to set payments for regulated hydroelectric and nuclear generation assets for a five-year period (2017-21). The Company proposes to operate under a price cap index with an I-X escalation formula. In support of its proposed X factor, OPG retained LEI to prepare a study of recent hydroelectric generation productivity trends of a sample of North American utilities. LEI reported an MFP trend of -1.01% for its sample of hydroelectric generators. Navigant prepared a companion cost benchmarking study for OPG in compliance with prior OEB direction.

Staff of the OEB has retained PEG to prepare analysis and commentary on LEI's study and the Company's hydroelectric IRM proposal. Our work includes an independent hydroelectric productivity study.

The plan for our report is as follows. We begin with a discussion of pertinent background information. There follows a general discussion of the use of productivity research in regulation. We critique LEI's research and present results of our own productivity study. There follow a discussion of OPG's hydroelectric IRM proposal and some concluding remarks. An Appendix provides more technical details of our empirical research.

Credentials

PEG is an economic consulting firm in Madison, Wisconsin USA. We are a leading consultancy on incentive regulation and the performance of energy utilities. Our personnel have over fifty man-years of experience in these fields, which share a common foundation in economic statistics. IR plan 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 our practice 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 Research. He has over thirty years of experience as an industry economist, most spent addressing utility issues. Author of dozens of professional publications, he 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.

David Hovde is a Vice President of PEG Research. He has played a key role in numerous productivity studies over a career spanning two decades. Dave holds an MA in economics from the University of Wisconsin.

2. Background

2.1 Overview

OPG is Ontario's largest electric power producer. The Company was established in 1999 to own and operate generating stations of Ontario Hydro after its breakup. OPG is wholly owned by Ontario's government. Its 65 hydroelectric stations have a total capacity exceeding 7,000 MW and are scattered across the province. The Company also owns nuclear, gas-fired, and biofuel generating stations.

Section 78.1 of the Ontario Energy Board Act authorizes the Board to set payment amounts for power produced from prescribed generation assets of OPG. Six large hydroelectric generating stations were prescribed for Board regulation in 2005.[1] The largest of these are located in the Niagara region [e.g., Sir Adam Beck ("SAB") 1 and 2]. Another 48 hydroelectric stations were prescribed for Board regulation effective in 2014.[2] These were smaller stations that accounted for roughly a third of the net generation from OPG's prescribed hydroelectric stations in 2015. In total, more than 6,000 MW of hydroelectric generating capacity was subject to OEB rate regulation in 2015.[3]

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

2.2 Economics of Ontario Hydroelectric Generation

Special features of hydroelectric generation in Ontario should be considered in the design of a regulatory system for OPG.

- Hydroelectric generation is very capital intensive. The required plant includes generating equipment (e.g., turbines, generators, and transformers), extensive civil works (e.g., powerhouses, dams, headworks, and spillways), and buildings to house control rooms, work centers, and offices. In a capital intensive business, containment of capital expenditures

[1] Ontario Regulation 53/05 filed February 2005.

[2] Ontario Regulation 312/13 filed November 2013.

[3] OPG Response to Staff-247, p. 8.

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("capex") is critical to good cost performance. Furthermore, cost and productivity trends are unusually sensitive to the relative costs of older plant (which is gradually depreciating) and replacement capex. High replacement capex can cause costs to surge, especially when capital cost is calculated using traditional regulatory accounting and the average age of assets is high. In the years following a capex surge, however, cost growth can be unusually slow. One manifestation of this phenomenon is that vertically integrated electric utilities ("VIEUs") in the United States have frequently operated without rate cases for several years after major generating plant additions (e.g., new solid-fuel power plants).

- An important reason for the high capital intensiveness of hydroelectric generation is the unusually high cost of civil structures such as dams and waterways that are needed to handle water. These structures have unusually long service lives. High capex to replace such assets have to date been rare. OPG stated in response to an interrogatory that

> Replacement capital in hydro operations is typically limited to mechanical and electrical parts; the majority of the asset base, roughly 75%, consists of civil works that is rarely "replaced".[4]

- Many of OPG's hydroelectric stations are old. Fourteen have operated for over a century. Most of the hydroelectric generation equipment is more than 50 years old. Operation and maintenance ("O&M") expenses of hydro facilities tend to rise as they age. Replacement becomes rational when the net present value of the capital cost that capex gives rise to exceeds the net present value of the O&M cost savings.

  This situation creates a steady stream of opportunities for OPG to repair, refurbish, and replace its facilities. For example, OPG recently replaced several generating units on the Mattagami River.[5] The SAB pumped storage reservoir is scheduled for refurbishment this year (2016). Utilities nonetheless have considerable discretion as to when hydroelectric generating facilities are replaced or refurbished.

- Before its restructuring in 1999, Ontario Hydro's generation assets were valued in historic dollars. Property, plant, and equipment acquired by OPG in 1999 were recorded at a fair value

[4] OPG Response to Staff-233, p. 2.

[5] These units are not prescribed.

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that reflected the present value of estimated future operating results and cash flows of the acquired business in a deregulated market.[6] The net value of OPG's hydroelectric generation assets rose substantially. Plant additions have subsequently been recorded at cost.

- OPG has limited opportunities to increase the scale of its hydroelectric operations. Some modernization projects increase the generating volume or capacity at existing stations. For example, between 1996 and 2005, OPG completed a series of major upgrades at SAB 2 that increased its potential generating capacity by 194 megawatts. More recently, the Niagara Tunnel Project ("NTP") expanded the water flow to SAB 1 and 2.[7] This is expected to increase the generation volume. There are also some opportunities to build new generation capacity but these units may not be prescribed.[8] The limited prospects for growth in OPG's prescribed hydroelectric capacity suggests that opportunities to realize incremental scale economies are limited.
- The revaluation of older plant combined with the large recent NTP plant addition tend to slow OPG's capital cost growth and its need for rate growth by greatly magnifying a cost that is declining gradually due to depreciation. The Company projects its prescribed hydroelectric rate base to grow very little between 2017 and 2021.
- The large number of hydroelectric stations that OPG owns tends to reduce the impact of individual capex projects on the Company's cost and productivity.[9] The impact on total cost tends to be greatest for major capital projects at the largest stations. For example, the NTP increased OPG's hydroelectric rate base by around CAD 1.4 billion between 2012 and 2014.[10] Cost could also, in principle, surge if several smaller stations were refurbished simultaneously.
- Hydroelectric generation volumes (especially those from run of river facilities) vary with water flows. These flows vary in the short run with weather and in the longer term with climate

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

[7] OPG Response to Staff-225. p. 2.

[8] An example is the station OPG is developing on the Abitibi River.

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

[10] OEB, Decision with Reasons in EB-2013-0321, p. iv.

trends. The cost of owning, operating, and maintaining hydroelectric stations does not vary greatly with volume fluctuations.

- The SAB pumped-storage generating station ("GS") is capable of large diurnal swings in generation volumes. Power can be used to pump water to the storage reservoir when prices are low in the bulk power market and produced and sold when these prices are high. Most other OPG hydroelectric stations have some ability to vary generation volumes diurnally, and many operate as baseload units.
- The IESO periodically orders reductions in OPG's hydroelectric generation to manage surplus baseload generation ("SBG"). SBG has been increasingly common in Ontario due to circumstances that include aggressive conservation and demand management, slow growth in provincial manufacturing, unusually large reliance on nuclear and hydroelectric generation, and inflexible power receipts from renewable resources. Wholesale prices have been negative for hundreds of hours in some recent years. When cutbacks are ordered, OPG is sometimes compelled to spill water from its facilities rather than using it for generation.
- OPG earns additional revenue from its hydroelectric operations. Regulation service is offered to control power system frequency and maintain the balance between load and generation. Operating reserve is offered in the form of generation capacity which the IESO can call upon at short notice to replace scheduled energy supply that is unavailable due to an unexpected outage, or to augment scheduled energy as a result of unexpectedly strong demand. Other ancillary services include voltage control and reactive support and certified black start capability. Additional revenue can be realized when units at the Saunders GS on the St. Lawrence River are segregated to serve another control area. Water transactions between OPG and the New York Power Authority permit these parties to use a portion of each other's share of water for power generation.
- The Power Workers' Union and the Society of Energy Professionals together represent roughly 90% of OPG's workforce. In addition, construction work is performed through 19 craft unions with established bargaining rights at OPG facilities.

A Business Transformation initiative has resulted in a reduction of OPG's regular headcount by around 2,700 workers since 2011.

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2.3 OPG's Rate Regulation

O. Reg. 53/05 provides the Board with some discretion as to "the form, methodology, assumptions and calculations used in making an order that determines payment amounts" for OPG's prescribed facilities. However, O. Reg. 53/05 and OEB decisions have authorized variance and deferral accounts for regulated hydroelectric ratemaking that include the following:

- Pension and OPEB Cost Variance Account
- Pension and OPEB Cash Versus Accrual Differential Deferral Account
- Hydroelectric Surplus Baseload Generation Variance Account
- Hydroelectric Water Conditions Variance Account
- Ancillary Services Net Revenue Variance Account-Hydroelectric
- Income and Other Taxes Variance Account
- Hydroelectric Incentive Mechanism Variance Account

The SBG variance account compensates OPG when the company is unable to store water in an SBG situation.

O.Reg 53/05 also provides that the Board shall ensure that OPG recovers capital and non-capital costs and firm financial commitments incurred to increase the output of, refurbish, or add operating capacity to prescribed hydroelectric assets that are prudently incurred. A Capacity Refurbishment Variance Account ("CRVA") was approved in EB-2007-0905 and has been approved in all subsequent OPG applications. This account records variances between actual costs incurred to increase the output of, refurbish, or add operating capacity to prescribed generation facilities and the associated forecasts underpinning revenue requirements approved by the OEB.

The Board considered alternative ways to regulate OPG in EB-2006-0064.[11] They determined that, while IR might be preferable for the Company in the long run, it should be preceded by a period of cost of service regulation. The OEB established a flat rate per MWh sold from prescribed hydroelectric facilities. These rates have been set in a sequence of cost of service proceedings (EB-2007-0905, EB-

[11] OEB, A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation, Inc., November 2006.

2010-0008, and EB-2013-0321), each of which involved two forward test years. OPG has had one stay out year between each of these filings. The current payment rate reflects the expected conditions in 2014-15. In establishing the revenue requirement payable by the IESO in each test year, forecasted other operating revenue (e.g., from ancillary services) is netted off of the forecasted cost of service.

A Hydroelectric Incentive Mechanism ("HIM") was established in EB-2007-0905 that encourages OPG to increase production above monthly averages in hours when the market-clearing price exceeds the regulated payment amount. This was deemed desirable because a flat payment per kWh does not incentivize OPG to tailor its production profile to market needs.

In 2011 the Board retained Power Advisory LLC to prepare a report on IR options for OPG's prescribed generation. Power Advisory recommended an IRM with the following provisions:

- payment amounts escalated by a price cap index featuring a "modest" X factor and a Z factor;
- earnings sharing and off ramp mechanisms;
- retention of the HIM; and
- continuation of after-the-fact reviews of OPG's performance during SBG conditions.[12]

In 2015, the Board issued a letter stating that "it is appropriate to incorporate IR into the rate-setting mechanism for OPG... A long-term, properly designed IR mechanism has the potential to lead to operational efficiencies and innovation, and thus lower electricity costs."[13] Using the parlance of its regulatory system for power distributors, the Board recommended an IRM for OPG's hydroelectric assets and a custom IR framework for its nuclear assets.

[12] Power Advisory LLC, Incentive Regulation Options for Ontario Power Generation's Prescribed Generation Assets, April 2012, pp. 85-86.
[13] OEB, “Re: Incentive Rate-Setting for Ontario Power Generation’s Prescribed Generation Assets,” Letter to all participants in EB-2012-0340, all participants in EB-2013-0321, and all other interested parties, February 17, 2015, p. 1.

3. Index Research and its Use in Regulation

3.1 Productivity Indexes

The Basic Idea

A productivity index measures the efficiency with which firms use production inputs to achieve a level of operating scale. The trend in a productivity index is the difference between the trend in an index of operating scale (sometimes called an "output" index and here denoted by "Outputs") and the trend in an input quantity index ("Inputs").

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

Productivity grows when the value of the output index rises more rapidly (or falls less rapidly) than that for the input index. Productivity can be volatile but usually has a rising trend in the longer run. The volatility is typically due to fluctuations in outputs and/or the uneven timing of expenditures. The productivity growth rates of individual companies tend to be more volatile than the average productivity growth of a group of companies.

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 ("TFP") indexes even though such indexes rarely address the productivity of all inputs. Because of their capital intensive technologies, the MFP trends of hydroelectric generators tend to be similar to their capital productivity trends.

The output (quantity) index of a firm summarizes the scale of its operation. Growth in each output dimension which is itemized is measured by a subindex. Growth in the 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.[14] A productivity index calculated using a revenue-weighted output index ("*Outputs*^{R}") will be denoted as *Productivity*^{R}.[15]

$$\textit{trend Productivity}^R = \textit{trend Outputs}^R - \textit{trend Inputs.} \qquad [2a]$$

Another possible objective of output research is to measure the impact of growth in scale on *cost.* In that event the subindexes should measure the dimensions of "workload" that drive cost. If there is more than one pertinent scale variable, the weights for these variables should reflect the relative cost impacts of these drivers. 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.[16] These have been used on several occasions in our previous research for the OEB.[17] A productivity index calculated using a cost-based output index ("Outputs^C") will be denoted as *Productivity*^{C}.

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

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

[14] This approach to output quantity indexation is due to the French economist Francois Divisia.

[15] For example, a multifactor productivity index constructed using a revenue-weighted output index would be denoted "MFP^R".

[16] An early discussion of elasticity-weighted output indexes 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.

[17] See, for example, Kaufmann, L., Hovde, D., Kalfayan, J., and Rebane, K., *Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board*, in EB-2010-0379, (2013); Lowry, M., Getachew, L., and Fenrick, S., *Benchmarking the Costs of Ontario Power Distributors* in EB-2006-0268, (2008) and Lowry, M., Hovde, D., Getachew, L., and Fenrick, S., *Rate Adjustment Indexes for Ontario's Natural Gas Utilities* in EB-2006-0606/0615, (2007).

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. Incremental scale economies may also depend on the current scale of an enterprise. For example, there may be diminishing incremental returns to scale as enterprises grow in size.

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

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. Thus, productivity growth tends to surge in the aftermath of unusually high capex as the capital "lump" depreciates, thereby reducing the rate of return component of capital cost. If a utility has a need for unusually high replacement capex, on the other hand, capital productivity growth can plunge.

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 an electric power distributor is the share of distribution lines that are undergrounded. An increase in the share of lines undergrounded will tend to slow multifactor productivity growth but may accelerate O&M productivity growth.

[18] See, for example, Denny, Fuss and Waverman, *op. cit.*

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

$$growth\ MFP^R = growth\ Outputs^R - growth\ Inputs + (growth\ Outputs^C - growth\ Outputs^C)$$

$$= (growth\ Outputs^C - growth\ Inputs) + (growth\ Outputs^R - growth\ Outputs^C)$$

$$= growth\ MFP^C + (growth\ Outputs^R - growth\ Outputs^C) \qquad [3]$$

Relation [3] shows that growth in MFP^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.

Companies can sometimes bolster their output differential with better marketing. For example, they can try to bolster sales of products that raise revenue more than cost. However, the output differential is also sensitive to external business conditions that cause fluctuations in output.[19]

3.2 Use of Index Research in Regulation

Index logic supports the use of index research in price cap index design. We begin our explanation of the supportive index logic by considering the growth in the prices charged by an industry that earns, in the long run, a competitive rate of return.[20] In such an industry, the long-run trend in revenue equals the long-run trend in cost.

$$trend\ Revenue = trend\ Cost. \qquad [4]$$

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}")

[19] For example, the revenue of a power distributor may depend chiefly on system use while cost depends chiefly on system capacity. In that event, mild weather can depress revenue more than cost, reducing the output differential and slowing growth in MFP^R and earnings.

[20] 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.

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

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 ("Inputs").

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

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 multifactor productivity index of MFP^R form.

$$\textit{trend Output Prices}^R = \textit{trend Input Prices} - (\textit{trend Outputs}^R - \textit{trend Inputs}) \quad [7]$$

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

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

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

Here X, the "X factor," reflects a base productivity growth target ("$\overline{MFP^R}$"). A "stretch factor" is often added to the formula which slows PCI growth in a manner that shares with customers the financial benefits of performance improvements that are expected under IRMs.[21]

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

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

3.3 Application to Hydroelectric Power Generation

The productivity trends of hydroelectric power generators can be measured using revenue-based or cost-based output indexes. The generation volume should loom large in a revenue-based

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

output index since volume (MWh) is the chief billing determinant driving revenue growth. A cost-based output index might, in contrast, also place a sizable (and possibly larger) weight on generation *capacity* (MW).

The OEB has a vital interest in OPG's cost efficiency. It is therefore desirable to measure the trend in the Company's cost efficiency using a cost efficiency index. However, the X factor for OPG requires a target for MFP^R growth and we have seen that this depends, additionally, on the output differential. For a hydroelectric generator, the output differential depends on the trend in the volume/capacity ratio, which is the difference between the trends in generation volume and capacity.[22] This difference is sensitive to weather and climate changes.

Given the capital intensiveness of hydroelectric generation, MFP growth is very similar to capital productivity growth. The specification of the capital quantity index is therefore an especially important issue in a research program.

3.4 Research Methods for X Factor Calibration

3.4.1 Capital Cost

Monetary approaches to the measurement of capital costs and quantities have been widely used in multifactor productivity research. These approaches decompose the growth in capital cost into the growth in consistent capital price and quantity indexes such that

$$\textit{growth Cost}^{Capital} = \textit{growth Price}^{Capital} + \textit{growth Quantity}^{Capital}. \qquad [9]$$

The main components of capital cost are depreciation expenses, the return on investment, and taxes.[23]

Several monetary methods are well established for measuring capital quantity trends. A key issue in the choice of a monetary method is whether plant is valued in historic dollars or replacement

[22] The trend in the volume/capacity ratio equals the trend in the capacity factor.

[23] The trends in these costs depends on trends in construction prices, tax rates, and the market rate of return on capital. A capital price index should reflect these trends. The capital price index is sometimes called the "rental" or "service" price index because, in a competitive market, the trend in the price of rentals would tend to reflect the trend in the cost per unit of capital.

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dollars. Another is the pattern of depreciation. Depreciation can result from many factors including wear and tear, casualty loss, increased maintenance requirements, and obsolescence.

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

- The geometric decay ("GD") method assumes a replacement (i.e., *current* dollar) valuation of plant and a constant rate of depreciation. Replacement valuation differs from the historical (aka "book") valuation used in North American utility accounting and requires consideration of capital gains. The GD specification involves formulae for capital price and quantity indexes that are mathematically simple and easy to code and review.

  Academic research has supported use of the GD method to characterize depreciation in many industries, and GD has been widely used in productivity studies, including X factor calibration studies.[24] PEG has used the GD method in most of its productivity research for the Board, including the research for IRM4. The US Bureau of Economic Analysis ("BEA") and Statistics Canada both use geometric decay as the default approach to the measurement of capital stocks in the national income and product accounts.[25]

- The one hoss shay method assumes that plant additions in a given year do not decay gradually but, rather, all at once as the assets reach the end of their service lives. Plant is once again valued at replacement cost. The assumptions underlying the one hoss shay method are thus very different from those used to compute capital cost in utility regulation. We have found that productivity results using the one hoss shay method are unusually sensitive to the choice of a service life. 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

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

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

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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.[26]

3.4.2 Choosing a Productivity Peer Group

Research on the productivity of other utilities can be used in several ways to calculate base productivity growth targets. Using the productivity trend of the entire industry to calibrate X is sometimes likened to simulating the outcome of competitive markets. A competitive market paradigm has broad appeal.

On the other hand, individual firms in competitive markets routinely experience windfall gains and losses. Our discussion in Section 3.1 of the sources of productivity growth implies that differences in the external business conditions that drive productivity growth can cause utilities to have different productivity trends.[27] There is thus considerable interest in methods for customizing base productivity growth targets to reflect local business conditions. The most common approach to customization has been to use the productivity trends of similarly situated utilities.

A variety of potential peer groups are usually available. In choosing among these, the following principles are appropriate. First, the group should either exclude the subject utility or be large enough that the average productivity trend of this utility is substantially insensitive to its actions. This may be called the externality criterion. It is desirable, secondly, for the group to be large enough that the productivity trend is not dominated by the actions of a handful of utilities. This may be called the sample size criterion. A third criterion is that the group should be one in which external business conditions are as propitious to productivity growth as those facing the subject utility. This may be called

[26] See Lowry, et. al., *Rate Adjustment Indexes for Ontario's Natural Gas Utilities, op. cit.;* 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).

[27] Farmers, for example, experience varied weather conditions and varied needs to replace aging structures and equipment. Energy distributors experiencing brisk growth in operating scale are more likely to realize economies of scale (i.e., due to rapid residential and commercial growth in their service territory) than distributors experiencing average growth.

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the "no windfalls" criterion. Relevant conditions for a hydroelectric generator include system age, growth in operating scale, and the volume/capacity trend.

Custom productivity peer groups have frequently been used in X factor calibration research. In New England, for example, a consensus was established that the X factors of price cap indexes should be calibrated using research on the productivity trends of Northeast utilities. The X factors of Ontario power distributors in their current IRM reflect the MFP trends of Ontario distributors.

3.4.3 Data Considerations

The quality of data used in index research has an important bearing on the relevance of results for X factor calibration. Generally speaking, it is desirable to have publicly available data drawn from a standardized collection form such as those developed by government agencies.[28] Unfortunately, the number of utilities for which good data are available and face productivity growth drivers similar to those facing a utility subject to index-based IR is sometimes limited. This is a chronic problem in Canada, where standardized data required to accurately measure the MFP trends of a suitable peer group are generally unavailable.

Data on the operations of US energy utilities are, in contrast, well-suited for X factor calibration studies. Standardized data of good quality have been available from agencies of the federal government for many utilities for many years. The primary source of operating data for electric utilities is the Federal Energy Regulatory Commission ("FERC") Form 1. Major investor-owned electric utilities in the United States are required by law to file this form annually. Cost data reported on the Form 1 must conform to the FERC's Uniform System of Accounts.[29] Detailed plant value data have been available for decades, providing the basis for more accurate capital quantity indexes using monetary methods.

Given the limitations of Canadian data and the advantages of US data, the OEB used estimates of US power distributor productivity trends to choose the base productivity growth target in its third

[28] Data quality also has a temporal dimension. It is customary for statistical cost research used in X factor calibration to include the latest data available.

[29] Details of these accounts can be found in Title 18 of the Code of Federal Regulations.

generation IRM for distributors. Regulators in Alberta and British Columbia have based X factors in their current IRMs for gas and electric power distributors on the productivity trends of US distributors.[30]

[30] Studies of US productivity trends were also submitted in a soon to conclude Alberta generic proceeding to update energy distributor IR plans.

4. LEI's Productivity Evidence

Our discussion of LEI's productivity evidence has three parts. We first summarize and critique the methods that LEI employed, and note where we believe that improvements are warranted. After a review of the results of their research we discuss the reasons for their negative productivity finding and consider the need for appropriate new evidence in this proceeding.

4.1 LEI's Methodology

4.1.1 Sample Selection

Sampled Companies

LEI chose a sample of data from 16 utilities. These included OPG and 15 US utilities. 13 of the US entities are investor-owned utilities that file operating data on the FERC Form 1.[31] The LEI sample also included two publicly held US entities (Seattle City Light and the Southeastern Power Administration) which do not make Form 1 filings. While LEI's substantial efforts to expand the sample should be acknowledged, the resultant sample is nonetheless much smaller than those the OEB has used to calibrate X factors for IRM plans for natural gas and electric power distributors.

LEI echoes our comments in Section 3.4.3 above on the advantages of FERC Form 1 data. They state in their report that "given the reputation of the publisher, using [FERC Form 1] data is both reliable and robust. . . LEI attempted to maximize data consistency by using the same data source (FERC Form 1) as much as possible."[32] LEI also notes that the O&M expense categories on FERC Form 1 match up well with those used by OPG in its cost accounting.

LEI's report provides a helpful discussion of the problems encountered in trying to include Canadian and publicly-held US utilities in a hydroelectric productivity study. We are persuaded by these remarks and our own experience that the inclusion of companies from these sources is quite problematic due chiefly to data comparability and availability issues. The one Canadian company that is

[31] LEI, Frayer, J., Chow, I., Leslie, J., and Porto, B., (2016) *Empirical Analysis of Total Factor Productivity Trends in the North American Hydroelectric Generation Industry*, filed in Ontario Energy Board proceeding EB-2016-0152, Exhibit A1-3-2, Attachment 1, pp. 27-28.

[32] *Ibid*., pp. 32-33.

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worth studying is OPG. The productivity and volume/capacity trends of OPG should be monitored by the Board even if its data are not used to calibrate X. Work undertaken to calculate OPG's productivity trends can also provide the foundation for future statistical benchmarking of OPG's cost.

To choose a peer group from amongst companies with quality, accessible data, LEI used as its criterion the scale of hydroelectric operations. Peers had to have at least a "medium" (500-1,000 MW) level of generating capacity, and multiple generating stations. LEI also deemed system age to be relevant in peer group selection. For each sampled utility they calculated a MW-weighted average of the year of construction of each generating plant. The average age of OPG's plants thus calculated was well above the sample average. However, they did not use their age data in peer group selection.[33]

We have the following concerns about LEI's peer group selection process.

- Since the universe of North American hydroelectric generators with good data is small, the rationale for a custom peer group should be amply demonstrated. We believe that LEI's demonstration is inadequate.
- The peer group selection criteria should include known drivers of productivity *growth*. We noted in Section 3.1 that the level of operating scale and system age can be productivity drivers. However, the level of operating scale doesn't matter much in peer group selection when growth in scale is slow. We therefore believe that the sample should be expanded to include some of the smaller utilities for which data are available.
- We agree that system age may be a pertinent criterion for peer group selection. However, the age measure LEI developed is not the best measure since it considers only when facilities were constructed and not the recentness of their subsequent refurbishments and upgrades.
- LEI ventures the following argument for including OPG in its productivity sample.

> It is LEI's preference to include the regulated company as part of the industry that is being examined for purposes of setting an X factor for that company. The ultimate purpose of the TFP study and the resulting X factor is to simulate the competitive pressures that the regulated company would face if it were to be operating in a competitive environment, free of regulation. As such, since the regulated company would be part of the industry, its experiences should be included in the industry trends. LEI understands that in some instances, data is simply not available for any

[33] OPG Response to Staff-240, p. 2.

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period of time to allow for the regulated company's TFP trends to be considered as part of the industry. In such instances, proxies need to be developed. However, that is not the case in the current situation.[34]

We believe that OPG should be excluded from the sample used to set the Company's X factor. Given its large size relative to the other sampled utilities, the productivity results for the sample are unduly sensitive to its experience, and its performance incentives would be weakened if its results were included in future X factor calibration exercises.

Sample Period

The sample period used by LEI was 2003-2014.[35] The end date is defensible because it was the most recent year for which data were available at the time the study was prepared. With a 2014 end date, a 2003 start date permits a twelve-year sample period. OPG noted in response to an interrogatory that results for earlier start dates were not computed.[36] It was suggested in response to another interrogatory that data were unavailable for Seattle City Light and the Southeastern Power Administration before 2002.[37] There are also some availability and consistency problems with some of OPG's older data.

Twelve years of data are sometimes enough to provide a reasonable estimate of a long-term utility productivity trend. However, there are several reasons why this may not be true for LEI's study.

- A volumetric output measure was chosen by LEI for its study which was volatile, as we discuss further below.
- O&M input quantity growth was also fairly volatile.
- The size of the peer group was fairly small, making summary productivity results for the peer group fairly sensitive to fluctuations in the productivity of individual utilities. The manner of calculating summary results for the peer group made the results especially sensitive to the

[34] OPG Response to Staff-241d, p. 2.

[35] The description of a 2003-2014 period is to highlight the years over which growth rates have been averaged.

[36] OPG Response to EP-030, p. 3.

[37] OPG Response to EP-031, p. 3.

productivity fluctuations of the largest utilities. Several of these utilities experienced large declines in their volume/capacity ratios during the sample period.

- Due in part to the dwindling number of attractive and politically feasible new hydroelectric generating sites, capacity growth was slow for the sampled utilities during the period examined. This makes productivity results particularly sensitive to the positions of the sampled utilities in their capital replacement cycles. [38] LEI's chosen sample period may not be one in which sampled utilities had the same balance between the initial stock of capital and the need for replacement capex as OPG will have in the foreseeable future.
- Data on the operations of numerous US hydroelectric operators are available for many earlier years.

OPG provides another argument for not choosing a longer sample period.

> OPG has determined that data dating earlier than 2002 would not provide a meaningful basis of comparison over time or with peers. Moreover, pre-2002 data is not reconcilable with more recent information, due to changes within OPG's accounting systems and major changes in the North American hydroelectric generating industry around the turn of the century. The data provided in this response is from 2002 onward, the same start date used in LEI's TFP study. As noted in Ex. A1-3-2, Attachment 1, p. 16, 2002 is the year that the Ontario competitive electricity market opened, a significant event impacting OPG's business environment. The United States' electricity markets also went through reforms and restructuring phases in the late 1990s and early 2000s. As a result of these changes, data prior to 2002 would not be reconcilable with more recent data, nor would it be representative of OPG or the industry's productivity during the period at issue in this application.[39]

PEG personnel have been doing productivity and econometric research using generation data from the 1990s for many years. Based on our experience, we do not believe that use of these older data is problematic for utilities that remained vertically integrated. A spinoff of some generating units could in principle affect the administrative expenses and other general costs assigned to hydroelectric generation. However, these costs are relatively small and their

[38] The capacity growth of US power distributors has, in contrast, been more steady since there is not a pronounced capex "cycle" to contend with in sample period selection.

[39] OPG Response to Staff 247, p. 2.

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itemization on FERC Form 1 makes them easy to remove. LEI in fact excluded the general costs of US investor-owned utilities in its study.

Based on this analysis, we believe that it is appropriate to consider a somewhat lengthier sample period.

4.1.2 Index Specification

Output Quantity

LEI measured output growth using a single scale variable: the volume (in MWh) of net hydroelectric generation ("VG^{Hydro}"). The volume data for US investor-owned electric utilities were drawn from FERC Form 1.[40] This variable has some advantages in a study of hydroelectric productivity.

- A *price* cap plan makes sense for OPG (as discussed further below).
- We noted in Section 3.2 that the calibration of the X factor for a price cap index should consider the trend in billing determinants. The generation volume is by far the most important billing determinant in OPG's hydroelectric generation invoicing.
- Generation volume may also be a significant generation *cost* driver.
- Data on VG^{Hydro} are readily available.
- LEI gathered a number of generation productivity studies and reported that volume data were used as an output variable in numerous generation productivity studies.[41] However, few of these studies considered *hydroelectric* generation. We examined several hydroelectric generation productivity and data envelopment analysis ("DEA") studies and econometric cost studies published in scholarly journals.[42] Volume was used as a scale variable in all of the studies.

On the other hand, VG^{Hydro} is not the only dimension of operating scale that drives the cost or revenue from hydroelectric generation. In particular, it may not even be the principal scale-related driver of generation cost. Moreover, VG^{Hydro} is sensitive to weather fluctuations and climate trends. LEI

[40] LEI, *op. cit.,* p. 32.

[41] See, for example, the survey summarized on p. 56 of LEI's report.

[42] DEA studies also involve input and output variables.

acknowledges, on p. 19 of its evidence, that "the generation output metric is dependent on hydrology and system operation." One company (the Western Area Power Administration) was excluded from its study due to an "abnormal hydrology cycle." Inspection of Figure 23 of LEI's report reveals that the VG^{Hydro} trend in its sample is very sensitive to a downturn in the last eight years of the sample period. This is chiefly due to declines in the volumes of OPG and the two California utilities (Pacific Gas and Electric and Southern California Edison) in the sample. Special smoothing techniques may be required to improve the estimate of the long-run trend. [43] This complicates the research methodology, but may nonetheless not eliminate the potential for distortion resulting from this downturn.

Reliance on VG^{Hydro} as an output variable could therefore make MFP results quite sensitive to the choice of a sample period. Furthermore, the results may reflect output differentials for the sampled companies that are dissimilar to that expected by OPG during the IRM term. This is disadvantageous since OPG was noted above to have a Hydroelectric Water Conditions Variance Account.

Responses by OPG to interrogatories suggests that these are real concerns. For example, when asked what grounds exist for believing that the difference between the volume and capacity trends of sampled utilities was indicative of a long-term productivity trend, OPG responded

> Production from year to year will vary with hydrology and climatological conditions. However, over the longer term, it is expected that production, as represented by MWh generated over the course of the year, will trend to long term average levels, assuming climatological conditions remain steady.[44]

When asked what volume/capacity trend OPG expected during the PBR plan period, OPG responded

> As described in EB-2013-0321 (Ex. E1-1-1), OPG does not perform volume and water flow forecasts for the next five years. For the Niagara Plants, flow forecast information is only available for up to a two-year period, after which flows are assumed to trend back towards historical monthly median flows. For Saunders GS, forecast flows are only available for 6 months, after which flows are projected with trends from the Niagara River flow forecast. For the remaining 48 plants, water flows can change quickly due

[43] LEI states on p. 42 (footnote 68) of its report that "the degree of variability in the output index presents a case for calculating growth rates using a trend regression method rather than the average growth method."

[44] OPG Response to Staff-237b, p. 2.

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significant precipitation events, making them difficult to predict reliably. As a result, OPG uses historical median monthly flows for these plants.[45]

In addition to these concerns, PEG had difficulty matching the volumetric and O&M data provided by LEI with those provided on the FERC Form 1. A review of the hydroelectric generation volume provided on page 401a of the Form 1 versus that provided by LEI indicated that the data do not match in a large number of cases. Small discrepancies were also found between LEI's data and the O&M cost data reported on page 320 of Form 1. The impact of using the PEG version of the generation volumes is to increase the trend in MWh by approximately 0.05% over the LEI sample period.

We speculate that the differences between our data and LEI's are due to their reliance on a *plant-level* database constructed using data provided for large hydroelectric plants on pages 407-408 of Form 1. Data requested on these pages exclude plants under 10 MW and therefore will sometimes not represent the full fleet of hydroelectric plants run by reporting IOUs. In any event, the O&M data reported on page 320 are used to support the financial statements of the companies and should be preferred to page 407-408 expense data, which are supplemental information. The page 401 volumes correspond to the O&M expenses on page 320 and should likewise be preferred to those on pages 407-408.

On balance, we have major concerns with LEI's output specification and believe that it is desirable to consider an alternative scale variable for the productivity research: the MW of hydroelectric capacity ("$Capacity^{Hydro}$"). This variable has several advantages in a study of hydroelectric productivity:

- Our econometric research over the years has shown that capacity is typically the most important scale-related driver of generation cost. Navigant used generating capacity to construct several of the cost performance metrics (e.g., Investment/MW) in its benchmarking study for OPG. The Company stated in response to an interrogatory from Schools Energy Coalition ("SEC") that

[45] OPG Response to Staff-237d, p. 2.

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hydroelectric facility costs are generally invariant to hydroelectric production, as most cost drivers are not related to the volume of electricity produced (except some wear and tear that may arise as a result of utilization of certain equipment).[46]

- We are interested in measuring the trend in the *cost efficiency* of OPG as well as the calibration of the X factor for its price cap index. Generation capacity, as an important generation cost driver, is a useful scale variable in the construction of a generation cost efficiency index.
- *Capacity* growth is much more stable than *volume* growth. This makes a shorter sample period more feasible as a means for estimating long-term productivity trends.
- Generators in some markets are paid for their capacity as well as the volume produced. For example, LEI notes the existence of capacity markets managed by ISO New England, the New York ISO, the Midcontinent ISO, and the PJM interconnection, as well as bilateral capacity contracts.[47]
- Standardized data are obviously available on hydroelectric capacity, since LEI used them to measure the capital quantity trend.
- Capacity has been used as an output variable in several generation productivity and cost studies.

Recall now that our ultimate goal is to establish a *price* cap index for OPG, where price is $/MWh generated. This requires an appropriate target for productivity growth, as measured by a productivity index with formula

$$trend\ Productivity^{R} = trend\ VG^{Hydro} - trend\ Inputs. \qquad [10]$$

However, X factor calibration need not use the trend in this index for a productivity peer group. Instead, we can use relation [7] to decompose [10] into the trend in a cost efficiency index and an *output differential*.

$$trend\ Productivity^{R} = trend\ VG^{Hydro} - trend\ Inputs + (trend\ Outputs^{C} - trend\ Outputs^{C})$$

$$= (trend\ Outputs^{C} - trend\ Inputs) + (trend\ VG^{\mathrm{Hydro}} - trend\ Outputs^{C})$$

[46] OPG Response to SEC-101, p. 1.

[47] LEI, *op. cit.,* p. 27, footnote 39.

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$$= \textit{trend } MFP^{C} + \textit{ Output Differential}. \qquad [11]$$

The output differential will likely be similar to the trend in $VG^{Hydro}/Capacity^{Hydro}$, the volume/capacity ratio. The expected trend in the output differential can be very different for OPG than it was other sampled producers during a particular period. We can then establish an appropriate cost efficiency growth target using US data and adjust this if necessary to reflect the expected output differential of OPG. PEG has used this two-step method in several IR filings around North America, including its work for the OEB in first generation IR for Ontario gas distributors.[48] In the present case, there is no need for the second step since OPG is not forecasting a volume/capacity trend materially different from zero.

Input Quantity Index

Scope The LEI study considers two kinds of costs: hydroelectric capital costs and hydroelectric O&M expenses (less "water for power" expenses). Both of these costs should of course be considered in a productivity study to calibrate X for OPG. For investor-owned US electric utilities in the sample, the O&M expenses that LEI uses do not include those for pensions and benefits or any other administrative and general ("A&G") expenses reported on Form 1.

O&M Quantity Index LEI calculated the trend in O&M input quantities with a "residual" approach that PEG also frequently uses. Effectively,

$$\textit{trend } Inputs^{O\&M} = \textit{ trend } Cost^{O\&M} - \textit{trend Input } Prices^{O\&M}. \qquad [12]$$

To construct the O&M input price index, LEI used the US GDP Price Index and the Employment Cost Index for the wages and salaries of US private industry workers. The analogous price indexes that LEI used for OPG were the Canadian gross domestic product implicit price index for final domestic demand ("GDP-IPI-FDD") and the average weekly earnings ("AWE") of the Ontario industrial aggregate. O&M input price indexes were constructed from these subindexes for the US and Canada. Both of these indexes used a fixed labor cost share of 63% that was "suggested by average trends observed in a

[48] Lowry, et. al, *Rate Adjustment Indexes for Ontario's Natural Gas Utilities*, *op. cit*.

confidential [Electric Utility Cost Group] database that includes hydroelectric generation specific data for 18 companies over the 2004-2014 timeframe."[49] A summary *North American* O&M price index was then calculated. The growth in this index was a weighted average of the growth in the US and Canadian O&M price indexes. The weights for the US and Canada reflected the relative size of the sampled US and Canadian utilities.

This approach falls short of best practice in several respects.

- The 63% labor cost share that LEI employs seems to be out of line with US power generation experience. This appears to be because the labor cost that they used in this calculation includes contract labor and pension and benefit expenses. Pension and benefit expenses should not be considered in this calculation since they are likely to be separately addressed by a Y factor in OPG's IRM.[50]
- PEG regionalizes its labor cost indexes by adjusting them for the difference between regional and national labor price inflation. This practice should modestly improve the accuracy of results. LEI effectively used a regional labor cost index for OPG but not for the US utilities.
- More accurate estimates of the O&M productivity trends of individual utilities in the sample can be obtained using the O&M price index for their country.

Capital Quantity Index The treatment of capital quantity is a second area where we have great concern about LEI's methods. We have explained that the results of a hydroelectric power generation productivity study are very sensitive to the capital quantity treatment. Rather than using a monetary method to construct a capital quantity index based on plant value data, as discussed in Section 3.4.1, LEI uses a "physical" method. Specifically, the trend in the capital quantity is the trend in the megawatts ("MW") of generation capacity. For the investor-owned US electric utilities in its sample, LEI used the nameplate capacity of their hydroelectric generation assets as reported on Form EIA 860. For OPG, LEI used the maximum continuous rating of its hydroelectric generation capacity.

[49] LEI, *op. cit.*, p. 22.

[50] OPG Response to Staff-243d, p. 3.

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

- LEI asserts that "electricity generation assets tend to have long lives and produce a relatively constant flow of services over their useful lives (provided they are properly maintained)."[51] LEI claims that the straight line depreciation and geometric decay assumptions that are sometimes employed when calculating capital quantity indexes using monetary methods are inconsistent with this notion.
- The many years of plant value data required to accurately calculate capital quantity indexes using monetary methods are unavailable for many utilities. Data on generation capacity are more readily available.
- Capacity is used to measure the capital quantity in several of the generation productivity studies that LEI gathered.[52]

Many arguments can be ventured against the physical asset approach that LEI used.

- Capacity is very useful as a scale variable in a generation productivity study, as we noted above.
- LEI claims that individual hydroelectric generation assets provide steady streams of services during their lives, like incandescent light bulbs.[53] One hoss shay is the monetary method for measuring capital quantity trends that matches this assumption, and is sometimes used in utility productivity studies.[54] However, LEI does not use the one hoss shay method, and it is not clear that its chosen physical approach is a reasonable approximation for this method. One reason that the one hoss shay and LEI's physical method can produce different results is that productivity growth can cause the quantity of capital needed to replace aging assets to fall, or can extend the service lives of assets.

[51] LEI, *op. cit.,* p. 59.

[52] LEI, *op. cit.,* p. 57.

[53] OPG Response to Staff-244a.

[54] LEI, *op. cit.,* pp. 57, 59-60 and OPG Response to Staff-238c, 244a.

- More generally, LEI's approach ignores trends in the quantities of inputs that generators need to provide a unit of capacity to the marketplace. This is a potentially significant determinant of productivity growth. The capital quantity could fall while capacity is unchanged.
- Governments routinely use monetary methods to measure capital quantity trends in productivity studies and the national income and product accounts.
- It is not at all clear that generation assets produce a constant flow of services over their useful lives. In contrast to incandescent light bulbs, we have noted that the O&M inputs associated with generating assets tend to rise as they age. Refurbishment capex also increases. Rising expenditures of both kinds can be viewed as a response to a decline in the flow of services from the original plant addition. Very little capacity was added by the utilities LEI sampled during the 2003-2014 period, so their study considers productivity in the management of aging assets. During this period, quantities of O&M inputs rose briskly for most of the utilities.
- The service lives of a cohort of assets (i.e., assets of the same asset class and vintage) vary around the average. Lives of some assets will be shorter than the average while lives of others are longer. As individual assets are removed from production, their contribution to the cohort will also be removed, and the services available from the cohort will gradually fall. Monetary methods other than one hoss shay can model this process.
- The value of an asset tends to decline as it ages due to the fall in its remaining service life. This decline is also simulated by the assumption of depreciation.
- LEI's argument hinges on the notion that the capital quantity index should measure the flow of services from capital assets. This notion does guide the choice of capital quantity treatments in many government studies of productivity in the economy. However, the index logic, detailed in Section 3.2, that supports the use of productivity research in the design of price cap indexes does not require the capital quantity index to measure the stream of capital services. Moreover, capital costs and quantities based on an assumption of straight line depreciation or geometric decay are more consistent with the treatment of capital under COS regulation. The I-X mechanism is intended to adjust rates between conventional rebasings. If depreciation has a major impact on the cost trends of hydroelectric generators between rebasings, it is controversial to ignore this impact.

- Even if a physical asset approach to capital quantity measurement was deemed appropriate, LEI itself concedes that capacity doesn't capture all of the potentially relevant scale dimensions of hydroelectric generation capital.[55]
- The popularity of capacity as a capital quantity variable in their empirical literature on generation productivity reflects the fact that it is easier to obtain capacity data than the plant value data needed to construct capital quantity indexes using monetary methods. However, LEI's sample consists chiefly of investor-owned utilities in the United States which *have* filed the requisite capital cost data for many years in their FERC Form 1 reports. The requisite plant value data are also available for OPG. All of the generation studies that LEI reviewed that used capacity as a capital quantity variable relied in whole or in part on data from countries other than the United States.[56] *All four* of the studies in LEI's survey that were based entirely on US data used a monetary method to calculate capital quantities. All of the DEA and productivity studies of hydroelectric generation that PEG gathered which used capacity as a capital quantity variable used data from other countries (e.g., Portugal, Turkey, and Switzerland). Note also that the vast majority of X factor calibration studies based on US utility data have used one or more monetary approaches to capital quantity measurement.
- The OEB rejected the physical asset approach to capital quantity measurement in the IRM3 proceeding.[57]

Note, finally, that a multifactor input quantity index is a cost-weighted average of the trends in O&M and capital quantities. This requires an estimate of capital cost. The weight LEI assigned to capital in their multifactor input quantity index is based on a crude "endogenous" estimate of capital cost.[58] Specifically, capital cost is calculated as the difference between hydroelectric operating revenue and O&M expenses. Hydroelectric operating revenue is somewhat volatile, and data on the revenue

[55] LEI, *op. cit.,* p. 59.

[56] OPG Response to VECC-45b.

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

[58] LEI, *op. cit.,* p. 25.

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specifically received for hydroelectric generation were in many cases unavailable, so that LEI had to estimate this revenue. Thus, the weights for the summary input quantity indexes are based on proxies for capital cost that must be estimated. This is not ideal, but the methodology does produce fairly sensible cost shares.

Index Forms LEI used multifactor input quantity indexes of Chained Fisher Ideal form. This form is known to have good statistical properties, as LEI discusses on page 52 of its report.

Currency Conversions Currency conversions play only a small role in LEI's study. However, it should be noted that conversions using *purchasing power parities* (which compare the prices of goods and services between countries) --- LEI's approach --- are generally considered to be more accurate than conversions using *exchange rates*.

Calculating the Peer Group Trend

To summarize the peer group trends LEI aggregated the generation volume, capacity, and O&M expense data of the sampled utilities.[59] This implicitly weights results for individual companies on the basis of their size and gave substantial weights to results for a few companies that are much larger than the others in the sample. For example, the shares of OPG, Pacific Gas & Electric, Duke Energy, Virginia Electric, Idaho Power, and Alabama Power in 2014 generating capacity were 21%, 11%, 9%, 7%, 5%, and 5%, respectively.[60]

4.2 Results Using LEI's Methodology

LEI reported a -1.01% average annual MFP growth rate over the full 2003-2014 sample period. The input quantity index averaged 0.38% annual growth despite a 0.64% average annual decline in the hydroelectric generation volume. The capital quantity averaged 0.15% growth using LEI's method, while O&M quantities averaged 1.85% growth. Thus, capital productivity averaged a 0.79% annual decline while O&M productivity averaged a steeper 2.49% annual decline.

[59] OPG Response to Staff 242, p. 1.

[60] Calculated using data provided by LEI.

Figure 25 in LEI's report displays the trends in the volume and capacity of LEI's sampled utilities. It is evident that the volume data were much more volatile than the capacity data. The volume and capacity trends were also quite different. Volume growth fell short of capacity growth by an average of 79 basis points.

We used LEI's spreadsheets to compute OPG's productivity trend using their methodology. Results are presented in Table 1. The MFP growth of OPG averaged a 0.49% annual decline using LEI's methods. O&M productivity averaged a substantial 2.59% annual decline while capital productivity averaged a 0.28% decline. Note also that the volume growth fell short of capacity growth by an average of 29 basis points. This is well below the difference for LEI's sample aggregate.

4.3 Sources of Negative Productivity Growth in the LEI Study

The negative productivity trends obtained in the LEI study reflect the methodological choices they made. LEI's choice of an output quantity variable and its physical asset approach to measuring the capital quantity trend are the most important sources of their result.

- The MWh generated by sampled utilities *fell* by an average of 0.64% annually over their sample period despite an average 0.15% *growth* in capacity. Replacing the generation volume with the corresponding capacity would raise MFP growth by 79 basis points. This alone would bring the productivity trend most of the way to zero.
- An upgraded capital quantity methodology also has the potential to increase the productivity trend. By using capacity as the capital quantity metric, the LEI study calculated a positive capital quantity trend. Suppose that a proper capital quantity index had instead been calculated using plant value data. If recent replacement capex were modest on average for sampled utilities, depreciation of plant could exceed the cost of plant additions, leading to a decline in capital quantity.

Other improvements to LEI's study noted above could have a material impact on the results. A longer sample period would be less sensitive to volatility in the generation volume and O&M input quantities. Because the LEI sample is small, including more companies could also materially alter the results. The additional companies available for inclusion have smaller operating scale, but OPG does own and operate many small stations and there were few opportunities for sampled companies to

Table 1

OPG's Productivity Growth Using LEI's Methods[1]

	Generation Volume		O&M	O&M	Input Quantitities		PFP O&M		PFP Capital		Weights		MFP
	MWh	Growth	Cost	Price	O&M	Capacity	O&M	Growth	Capital	Growth	O&M	Capital	growth
2002	33,977,759		117,889	1.000	117,889	6,899	288		4,925		6%	94%	
2003	33,202,786	-2.3%	130,702	1.022	127,933	6,926	260	-10.5%	4,794	-2.7%	6%	94%	-3.2%
2004	35,351,273	6.3%	132,211	1.046	126,340	6,958	280	7.5%	5,081	5.8%	7%	93%	5.9%
2005	33,487,118	-5.4%	142,388	1.079	132,000	6,924	254	-9.8%	4,837	-4.9%	8%	92%	-5.3%
2006	34,329,431	2.5%	156,606	1.099	142,466	6,971	241	-5.1%	4,925	1.8%	11%	89%	1.1%
2007	32,986,718	-4.0%	164,954	1.135	145,276	6,971	227	-5.9%	4,732	-4.0%	12%	88%	-4.2%
2008	37,423,326	12.6%	185,739	1.163	159,731	6,999	234	3.1%	5,347	12.2%	11%	89%	11.1%
2009	36,302,957	-3.0%	185,097	1.177	157,205	6,905	231	-1.4%	5,257	-1.7%	14%	86%	-1.7%
2010	30,568,258	-17.2%	184,693	1.210	152,586	6,906	200	-14.2%	4,427	-17.2%	16%	84%	-16.7%
2011	30,359,921	-0.7%	174,611	1.232	141,787	6,422	214	6.7%	4,727	6.6%	16%	84%	6.6%
2012	28,458,915	-6.5%	178,134	1.250	142,489	6,422	200	-7.0%	4,431	-6.5%	19%	81%	-6.6%
2013	30,347,392	6.4%	182,584	1.270	143,719	6,433	211	5.6%	4,717	6.3%	16%	84%	6.1%
2014	30,625,600	0.9%	188,020	1.296	145,026	6,433	211	0.0%	4,761	0.9%	14%	86%	0.8%
Average Annual Growth Rates													
2003-2014		**-0.87%**	**3.89%**	**2.16%**	**1.73%**	**-0.58%**		**-2.59%**		**-0.28%**	**13%**	**87%**	**-0.49%**
2003-2013		**-1.03%**	**3.98%**	**2.18%**	**1.80%**	**-0.64%**		**-2.83%**		**-0.39%**	**12%**	**88%**	**-0.61%**

[1] Growth rates are calculated logarithmically.

realize scale economies during the sample period. The other upgrades are possible but are unlikely to have major impact on the results.

4.4 Flawed Analysis

LEI's chosen and, in our view, ill-advised approach to capital quantity measurement lead it to proffer flawed analysis at various places in its evidence. Consider first some controversial conclusions it draws from the research results in its report.

> LEI believes that negative TFP trends can be "expected" for mature hydroelectric businesses, because of the fixed production capability, fixed capital stock and rising costs of maintenance through the life cycle of a hydroelectric resource . . . common drivers of productivity include technological innovation and improved economies of scale. However, for a mature hydroelectric business, great leaps forward in technology are extremely rare and economies of scale are generally fixed as soon as the asset is built and put into operation (although occasionally, refurbishments and other capital programs can increase energy production due to advances in new equipment). In general, it should be expected that output levels would be stable over time;[69] capital inputs are constant (once a hydroelectric plant is put into service); and OM&A would likely be increasing over time (in order to maintain asset operational capability as the asset ages).[61]
>
> [69](footnote from LEI quote) Assuming constant water flow levels over the course of the study and given generator design is fixed once the asset is brought into service, unless there are refurbishments that increase output.

OPG stated, relatedly, in response to an interrogatory from SEC that

> As stated in the report, negative TFP trends can be expected for mature hydroelectric businesses, because of the fixed production capability, fixed capital stock and rising costs of maintenance through the life cycle of a hydroelectric resource. The output of the hydroelectric business, generation, is relatively stable over time, despite variations year on year. In terms of capital inputs, as discussed in Ex. L-11.1-1 Staff-233 b), large hydroelectric generation facilities are comprised mostly of civil assets which do not get replaced. However, the other input, O&M costs, keep increasing due to aging of the assets (see discussion regarding bathtub curve in Ex. L-11.1-1 Staff-236 c). Therefore, in equilibrium, when the output (generation) is constant, one input

[61] LEI, *op. cit.,* p. 44.

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(capital) is constant but the other input (O&M) is rising, one would expect to have negative productivity trends.[62]

PEG has the following comments on these discussions.

- Since growth in operating scale was slow during LEI's sample period, it is true that the opportunities to realize economies of scale were negligible (or non-existent).
- It is also true that O&M productivity growth has been negative for many years.
- However, we have shown that it is very debatable whether "capital inputs are constant." They may in fact fall if replacement capex is low relative to the initial capital stock and may rise if replacement capex is high. Technological change can affect the cost and timing of replacement capex. This is an empirical issue that can only be addressed by rigorous capital quantity research.
- LEI's comment that "it should be expected that output levels would be stable over time" stands in contrast to its finding that output trends downward over the sample period in their study.

Flawed analysis can also be found in LEI's responses to some interrogatories. For example, in response to Staff Interrogatory 225:

a) In the aftermath of recent high capex that includes the Niagara Tunnel Project, why shouldn't OPG's hydroelectric operations be poised for unusually slow cost growth?

b) Couldn't this give rise to superior productivity growth and not just industry average growth?

c) Does LEI's physical asset approach to productivity measurement recognize this kind of productivity surge?

d) Is LEI's study designed to capture the productivity trend of a utility that has just concluded capex surge? If not, how can the difference between -1% and 0 be deemed an additional stretch factor?

e) Does LEI employ a method for measuring capital quantity growth that would cause it to slow after a recent capex surge?

LEI responded as follows:

[62] OPG Response to SEC-100.

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a) The Niagara Tunnel Project (NTP) has expanded the volume of water flows at OPG's Sir Adam Beck (SAB) generating stations 1 and 2, resulting in a projected 1.5 TWh average increase in net generation.[1] However, there is no change in the maximum continuous rating (MCR) value for these facilities…

c) LEI's TFP study does capture the results of the Niagara Tunnel Project as it was completed in March 2012 [sic] and LEI's study goes out to 2014. In the context of the TFP framework in LEI's TFP study, a project like Niagara Tunnel Project would show up as an efficiency gain as output, measured in increasing MWh, while inputs are relatively stable (there would be no change in the capital input measure while O&M costs may be increasing - but not nearly as much as production). It is notable that any positive productivity growth would be over-stated using LEI's physical asset approach and modelling specification.

d) Under LEI's approach, the productivity trend associated with a major increase in capex will be reflected in the physical measure of capital if MCR (capacity) values change by a smaller rate than the increase in outputs (MWh).

e) LEI uses a physical method for measuring capital quantity growth. The Niagara Tunnel Project, would not be represented as a change in capital input quantities because it did not increase generating capacity. There are other projects that have been undertaken in the past that have been represented in the capital input quantity index through increases in the MCR. These projects have also been associated with increases in production and would be reflected in the output index. Under LEI's approach, such investments create a one-year TFP improvement but then revert back to steady state in subsequent years, but for variations in hydrological output.[63]

[1] Ontario Power Generation. *EB-2013-0321 Exhibit D1 Tab 2 Schedule 1. Page 2* September 27, 2013.

All of these answers ignore the tendency of OPG's recent capex surge to slow its ongoing cost growth and accelerate its productivity growth.

4.5 Conclusions Regarding LEI's Study

LEI's study should raise serious concerns as the basis for the X factor in OPG's initial hydroelectric IR plan. A correctly calculated MFP trend for LEI's sample may differ considerably from LEI's estimate. Our chief concerns with LEI's methodology are the output specification, the capital quantity specification, and the sample period. The peer group also merits reexamination. Other aspects of LEI's methodology are not best practice but are nonetheless unlikely to affect results greatly.

[63] OPG Response to Staff-225a-e.

It is impractical to “fix” the main problems with LEI’s study by tinkering with their methodology using their working papers, for reasons that include the following.

- LEI did not gather the data required for a more rigorous capital cost treatment.
- Econometric work can be used to consider the appropriate output index.
- Data for a larger universe of companies and/or a longer sample period have not been provided.

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5. PEG Productivity Research

Given our concerns about LEI's methods and the impracticality of correcting their study to get satisfactory results, we prepared an independent study on the productivity trends of hydroelectric generators. This study uses methods that are more commonly used in X factor calibration studies, including PEG's past studies for the Board. Our recommended productivity factor for OPG is based on the trends in the hydroelectric generator MFP of a sample of US electric utilities. We also calculated productivity trends of OPG for years in which the requisite data are available.

5.1 US Hydroelectric Generation

5.1.1 Overview

We gathered historical data on the operations of US investor-owned electric utilities engaged in hydroelectric power generation. We used these data to calculate indexes of trends in the O&M, capital, and multifactor productivity of each utility in the provision of hydroelectric power generation. Size-weighted averages of those trends were then calculated for the full sample and some subsets.

5.1.2 Data Sources

The primary source of the cost data used in our hydroelectric generation research for the Board was the FERC Form 1. Selected Form 1 data were for many years published by the US Energy Information Administration ("EIA").[64] Data for more recent years have been available electronically in raw form from the FERC and in more processed, easy to use forms from commercial vendors. Generation volume data were drawn from the FERC Form 1. Data on the nameplate capacity of hydroelectric generators were drawn from Form EIA 860 (*Annual Electric Generator Report*) and predecessor forms (e.g., Form EIA 767).

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

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

Other sources of data were also accessed in the research. These were used primarily to measure input price trends. We obtained construction cost indexes from Whitman, Requardt & Associates, employment cost indexes from the US Bureau of Labor Statistics, and a macroeconomic price index from the US Bureau of Economic Analysis. The specific data drawn from these and the other sources mentioned are discussed below.

5.1.3 Sample

Data were potentially eligible for inclusion in our sample from major investor-owned US electric utilities engaged in hydroelectric power generation that, together with any important predecessor companies, have filed the FERC Form 1 continuously since 1964. We considered a larger sample of investor-owned US electric utilities than the group featured in LEI's report. All utilities with hydroelectric generating plant exceeding $100 million in 2014 were considered. To be included in the study the data were required, additionally, to be of good quality and plausible.

The 20 utilities in our sample are identified in Table 2. We believe that the data for these companies are the best available for rigorous work on hydroelectric productivity trends to support the development of an X factor for OPG.

The full sample period considered was 1975-2014.[65] Our featured results are for the 1996-2014 period. We also prepared results for the 2003-14 period that is featured in LEI's report.

Data for generation capacity were unavailable from 1976 to 1993. This data issue did not prevent us from accurately calculating productivity trends over the 1975-1995 period. However, we could not calculate the year-to-year productivity growth rates during the "gap" years.

[65] That is to say that the earliest year for growth rate calculations was 1975.

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Table 2

Companies Used in PEG's Productivity Work

Company	Gross Value of Hydroelectric Plant in Service 2014 (USD)	Share of Sample Total
Pacific Gas and Electric[1]	3,411,341,898	22.7%
Duke Energy Carolinas[1]	2,038,980,417	13.6%
Southern California Edison[1]	1,195,311,714	8.0%
Virginia Electric and Power[1]	1,130,236,821	7.5%
Alabama Power[1]	1,061,411,424	7.1%
PacifiCorp[1]	987,478,128	6.6%
Idaho Power[1]	764,142,679	5.1%
Georgia Power[1]	718,177,779	4.8%
Puget Sound Energy	706,912,494	4.7%
South Carolina Electric & Gas[1]	639,869,583	4.3%
Avista[1]	472,146,898	3.1%
Portland General Electric[1]	423,747,272	2.8%
Union Electric[1]	405,371,511	2.7%
Appalachian Power[1]	243,903,604	1.6%
Green Mountain Power	154,117,492	1.0%
Rochester Gas and Electric	150,669,602	1.0%
ALLETE (Minnesota Power)	145,232,692	1.0%
New York State Electric & Gas	131,832,612	0.9%
Public Service Company of Colorado	124,990,507	0.8%
Duke Energy Progress	103,146,444	0.7%
Total	15,009,021,571	100%

[1] These companies were in LEI's sample.

5.1.4 Output Quantity Specification

We considered as output variables the hydroelectric generation volume and capacity. An econometric model of hydroelectric generation cost was developed to consider the relative importance of these variables in a cost efficiency index. We have estimated such models for the Board on numerous occasions.[66] The estimated cost elasticities for the generation capacity and volume were 0.906 and 0.009, respectively. The parameter estimate for the volume variable was not statistically significant. In an elasticity-weighted output quantity index, the resultant weights for capacity and volume trends would be 99% and 1%, respectively. Results for such an index would be virtually identical to those using capacity as the sole output variable. Further details of the econometric cost research can be found in the Appendix.

5.1.5 Input Quantity Specification

Costs Considered

The total cost of hydroelectric power generation considered in the study was the sum of applicable O&M expenses and capital costs. A monetary method assuming geometric decay was used to measure the capital cost and quantity. Applicable capital cost comprised that for hydroelectric generation plant. The capital costs considered were depreciation, a return on rate base, and taxes.

The applicable O&M expenses were those for hydroelectric generation (except "water for power" expenses). Pension and benefit expenses were excluded from the study because they will likely be addressed by variance accounts and are difficult to calculate accurately since those for hydroelectric generation workers are not itemized on FERC Form 1. Other administrative and general expenses were also excluded.

Index Itemization

In calculating input quantity trends we broke down the applicable costs into those for hydroelectric generation plant and O&M expenses. Expenses for O&M labor and material and service inputs could not be separated.[67] We set the share of labor in O&M expenses at 37%. This was the ratio

[66] See previously cited examples: Lowry, et. al., *Benchmarking the Costs of Ontario Power Distributors, op. cit.;* Lowry, et. al., *Rate Adjustment Indexes for Ontario's Natural Gas Utilities, op. cit.;* and Kaufmann, et. al., *Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board, op. cit*.

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

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of production O&M labor expenses to total non-fuel production O&M expenses for utilities in the sample common to PEG and LEI that had a hydroelectric production volume of 10% or greater. The average share of capital in the applicable total cost of the sampled utilities was 80% in 2014. The growth of the multifactor input quantity index for each company was a cost-weighted average of the growth in quantity subindexes for O&M plant and inputs.

Index Forms

We used chain-weighted Tornqvist forms for the multifactor input quantity indexes. This form has good statistical properties and is widely used in productivity research.[68] It is more intuitively appealing and easier to code and review than the Chained Fisher Form, and should produce similar results.

5.1.6 Research Results

US Productivity Trends

Tables 3 and 4 present key results of our productivity research using US data. Inspecting Table 3 it can be seen that, over the featured 1996-2014 sample period, the average annual growth rate in the MFP of all sampled US hydropower generators was about 0.29%. Output growth averaged a sluggish 0.20% annually while input growth averaged a slight 0.09% annual decline. The capital quantity averaged a 0.48% annual decline while O&M inputs averaged 1.50% annual growth. Capital productivity therefore grew by an average of 0.68% annually while O&M productivity averaged a 1.30% annual decline. Our examination of the hydroelectric O&M expenses of sampled utilities revealed that maintenance expenses rose considerably more rapidly than operating expenses during these years. Note also that volume growth averaged a 2.12% annual decline whereas capacity averaged 0.20% growth. The 232 basis point difference in the trends was much more negative than that of OPG.

[68] LEI, *op. cit.*, p. 52.

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Table 3

Hydroelectric Generation MFP Growth of US Investor-Owned Electric Utilities[1,2]

(Larger Sample)

Year	Outputs		Inputs			Multifactor Productivity	
	Capacity	Volume	Capital	O&M	Multifactor	Capacity	Volume
1996	-1.14%	1.29%	2.96%	6.88%	3.89%	-5.03%	-2.60%
1997	1.04%	-0.76%	-1.77%	-5.08%	-2.31%	3.34%	1.55%
1998	0.14%	6.75%	-1.21%	-4.56%	-1.70%	1.84%	8.45%
1999	-0.60%	-15.88%	-1.77%	8.21%	-0.58%	-0.02%	-15.30%
2000	0.13%	-10.55%	-1.60%	-11.97%	-1.90%	2.02%	-8.66%
2001	0.38%	-13.19%	-1.70%	5.79%	-1.43%	1.82%	-11.76%
2002	-0.67%	10.04%	-1.64%	-0.16%	-1.61%	0.94%	11.65%
2003	0.12%	17.89%	-1.50%	4.65%	-0.66%	0.78%	18.55%
2004	-0.20%	-9.59%	-1.70%	5.09%	-0.70%	0.51%	-8.89%
2005	0.45%	5.17%	-1.25%	1.89%	-0.79%	1.24%	5.96%
2006	0.20%	0.62%	0.62%	-5.78%	-0.25%	0.45%	0.87%
2007	1.48%	-31.85%	-1.34%	11.12%	0.98%	0.50%	-32.83%
2008	-0.12%	3.15%	-0.92%	2.07%	-0.15%	0.03%	3.29%
2009	0.10%	21.86%	-0.67%	4.82%	0.79%	-0.68%	21.08%
2010	-0.01%	-2.06%	-0.78%	3.57%	0.23%	-0.24%	-2.29%
2011	0.08%	2.38%	0.77%	0.79%	1.04%	-0.96%	1.34%
2012	-0.05%	-20.85%	0.50%	0.11%	0.44%	-0.49%	-21.29%
2013	1.77%	8.36%	1.40%	0.64%	1.24%	0.53%	7.12%
2014	0.72%	-13.04%	2.52%	0.46%	1.83%	-1.12%	-14.88%
Averages:							
1975-2014	**1.40%**	**-0.46%**	**0.15%**	**1.96%**	**0.46%**	**0.94%**	**-0.93%**
1975-1995	**2.49%**	**1.04%**	**0.72%**	**2.38%**	**0.96%**	**1.53%**	**0.08%**
1996-2014	**0.20%**	**-2.12%**	**-0.48%**	**1.50%**	**-0.09%**	**0.29%**	**-2.03%**
2003-2014	**0.38%**	**-1.50%**	**-0.20%**	**2.45%**	**0.33%**	**0.05%**	**-1.83%**

[1] Included in LEI but not PEG Sample: Seattle City Light, Southeastern Power Administration.

[2] Growth rates are calculated logarithmically.

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Table 4

Summary of US Hydroelectric Productivity Growth Trends

	Outputs		Inputs			Multifactor Productivity		Partial Factor Productivities[1]	
	Capacity	Volume	Capital	O&M	Multifactor	Capacity	Volume	O&M	Capital
Common Sample[2]									
1975-1995	2.64%	1.11%	0.80%	2.48%	1.04%	1.60%	0.07%	0.16%	1.84%
1975-2014	1.49%	-0.47%	0.11%	2.00%	0.43%	1.06%	-0.90%	-0.51%	1.38%
1996-2014	0.22%	-2.21%	-0.66%	1.47%	-0.25%	0.47%	-1.97%	-1.25%	0.88%
2003-2014	0.39%	-1.64%	-0.49%	2.35%	0.06%	0.33%	-1.70%	-1.96%	0.89%
Larger Sample									
1975-1995	2.49%	1.04%	0.72%	2.38%	0.96%	1.53%	0.08%	0.10%	1.77%
1975-2014	1.40%	-0.46%	0.15%	1.96%	0.46%	0.94%	-0.93%	-0.56%	1.25%
1996-2014	0.20%	-2.12%	-0.48%	1.50%	-0.09%	0.29%	-2.03%	-1.30%	0.68%
2003-2014	0.38%	-1.50%	-0.20%	2.45%	0.33%	0.05%	-1.83%	-2.07%	0.58%

[1] PFP results use capacity as the output measure.

[2] Sample of US utilities used by both LEI and PEG.

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Table 4 shows that over the longer 1975-2014 period the MFP growth was faster, averaging 0.94% annually. Output growth averaged 1.40% while input growth averaged 0.46%. The capital quantity averaged 0.15% annual growth while O&M inputs averaged 1.96% annual growth. Capital productivity therefore averaged 1.25% annual growth while O&M productivity averaged a 0.56% annual decline. Average capacity growth exceeded average volume growth by 186 basis points.

Over the more recent 2003-2014 period featured by LEI in its report, the MFP trend was slower, averaging a slight 0.05% annually. Output growth averaged 0.38% while input growth averaged 0.33%. Capital productivity growth averaged 0.58% annually while O&M productivity fell by 2.07% annually. Average capacity growth exceeded average volume growth by 188 basis points.

Our results suggest that the hydroelectric MFP growth of the sampled US utilities is considerably slower than in the past. Utilities are no longer realizing appreciable scale economies and, as their facilities age, maintenance and replacement capex has loomed larger relative to their depreciating capital stock. However, capital of the sampled utilities is not necessarily continuing to age on balance since there has been considerable replacement capex. The MFP trend is still positive.

Step-by-Step Reconciliation with LEI Results

Table 5 details our work to reconcile the PEG and LEI MFP results. LEI reported an average annual decline of 1.01% for its full sample period. The analogous trend for the somewhat smaller subset of US investor-owned electric utilities that PEG used in its work was -1.38% using LEI's methodology. There is virtually no change to the results using PEG's generation volume data. When we amended LEI's methodology to use capacity rather than volume as the output variable (while still using capacity as the capital quantity variable as well) the MFP trend rose sharply to -0.19%. Consider next that using PEG's GD capital quantity index, the MFP trend for LEI's sample period was 0.33%. A longer 1996-2014 sample period raised the MFP trend modestly to 0.47%. Expanding the sample to include more utilities then lowered the MFP trend modestly to 0.29%.

Table 5

Reconciling LEI and PEG Productivity Results

	Average Annual Growth	
	MFP	Output Quantity
LEI methodology (2003-2014)		
As stated (capacity used as capital input)	-1.01%	-0.64%
With common US sample	-1.38%	-0.99%
Add estimated impact from using PEG Form 1 MWh data (+0.05%)	-1.33%	-0.94%
With capacity used as both output and capital input	-0.19%	0.19%
PEG methodology including a geometric decay (GD) capital quantity index		
With volume as output (2003-2014)	-1.70%	-1.64%
With capacity as output (2003-2014)	0.33%	0.39%
With a longer time periods and capacity as output index		
1996-2014	0.47%	0.22%
1975-2014	1.06%	1.49%
With an expanded sample of US IOUs and capacity as output index		
2003-2014	0.05%	0.38%
1996-2014	0.29%	0.20%
1975-2014	0.94%	1.40%
OPG productivity trends		
Calculated from LEI workpapers	-0.49%	-0.87%
WIth capacity as output and a GD capital quantity index	0.28%	0.06%
1996-2014 trend	1.07%	0.51%
1985-2014 trend	1.24%	0.34%

5.2 Research on OPG Productivity Trends

We have also attempted to calculate the productivity trends of OPG over LEI's 2003-2014 sample period using a GD method to compute capital costs and quantities. The productivity results we present in Table 5 for OPG use the following methodology.

- We calculated the Company's productivity growth over the same 2003-2014 period used by LEI. This is the period over which all data required for our calculations have been furnished by the Company.
- The trend in OPG's operating scale was measured using the Company's maximum continuous capacity rating.
- The O&M input quantity trend was calculated using the residual method. From 2002 to 2014 OPG's expenses were deflated by LEI's Canadian O&M input price index.
- We constructed a capital quantity index using the GD method. This methodology disregarded the revaluation of the Company's older assets. However, the treatment is somewhat similar since the revaluation yielded capital costs similar to those from a replacement valuation.
- Plant value data for the 1972-1999 period were obtained from Ontario Hydro Statistical Yearbooks and Annual Reports. For later years we used data provided by OPG. The benchmark year adjustment was performed for 1972. Plant value data were deflated using the Handy Whitman construction cost index for hydroelectric generation in the US Midwest, adjusted for the difference between US and Canadian inflation.

Results of the calculations can be found in Table 6. It can be seen that the Company's MFP grew by 0.28% annually on average over the full 2003-2014 sample period. The capital quantity index averaged a 0.44% annual decline, while O&M input quantities averaged 2.37% annual growth. OPG's capital productivity thus averaged 0.51% annual growth while its O&M productivity averaged a 2.31% annual decline.

Note also that, using the GD method to measure the capital quantity trend, the capital and multifactor productivity growth of OPG plunged in 2014 due to the large plant additions. This was chiefly

Table 6

OPG's Productivity Growth Using Capacity as Output and a GD Capital Quantity Index[1]

	Generation Capacity (MW)	O&M Cost	O&M Price	Input Quantities		PFP O&M		PFP Capital		Weights		MFP
				O&M	Capital	Index	Growth	Index	Growth	O&M	Capital	Growth
2002	6,384	109,088	1.000	109,088	17,111,981	1.000		1.000		6%	94%	
2003	6,409	120,945	1.022	118,382	16,852,769	0.925	-7.8%	1.019	1.9%	6%	94%	1.3%
2004	6,439	122,341	1.046	116,908	16,488,529	0.941	1.7%	1.047	2.6%	7%	93%	2.6%
2005	6,407	131,759	1.079	122,146	16,285,317	0.896	-4.9%	1.055	0.7%	8%	92%	0.3%
2006	6,451	144,915	1.099	131,830	15,964,144	0.836	-6.9%	1.083	2.7%	11%	89%	1.8%
2007	6,450	152,640	1.135	134,431	15,642,746	0.820	-2.0%	1.105	2.0%	12%	88%	1.6%
2008	6,477	171,873	1.163	147,807	15,371,023	0.749	-9.1%	1.130	2.2%	11%	89%	0.8%
2009	6,390	171,279	1.177	145,469	15,056,221	0.751	0.2%	1.138	0.7%	14%	86%	0.7%
2010	6,390	170,905	1.210	141,195	14,816,586	0.773	3.0%	1.156	1.6%	16%	84%	1.8%
2011	6,422	174,611	1.232	141,787	14,639,427	0.774	0.1%	1.176	1.7%	16%	84%	1.4%
2012	6,422	178,134	1.250	142,489	14,470,826	0.770	-0.5%	1.190	1.2%	19%	81%	0.9%
2013	6,433	182,584	1.270	143,719	14,184,112	0.765	-0.7%	1.216	2.2%	16%	84%	1.7%
2014	6,433	188,020	1.296	145,026	16,222,410	0.758	-0.9%	1.063	-13.4%	14%	86%	-11.5%
Average Annual Growth Rates												
2003-2014	**0.06%**	**4.54%**	**2.16%**	**2.37%**	**-0.44%**		**-2.31%**		**0.51%**	**13%**	**87%**	**0.28%**
2003-2013	**0.07%**	**4.68%**	**2.18%**	**2.51%**	**-1.71%**		**-2.44%**		**1.78%**	**12%**	**88%**	**1.35%**

[1] Growth rates are calculated logarithmically.

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due to the NTP.[69] If we remove 2014 from the sample period and calculate trends over the 2003-2013 period, we find that OPG's multifactor productivity averaged **1.35%** annual *growth*.

[69] The NTP affected the capital quantity index in 2014 using our methodology.

6. OPG's Proposed Rate-Setting Framework

6.1 Overview

The incentive rate-setting framework that OPG proposes for its hydroelectric payment amounts is a multiyear rate plan broadly similar to the Fourth Generation Incentive Ratemaking Mechanism for power distributors that the Board developed under the Renewed Regulatory Framework (for electricity). Salient features of the proposed plan include the following.

Plan Provision	**OPG's Proposal**
Scope	Addresses OPG's compensation for the operation & maintenance expenses and capital cost of prescribed hydroelectric generation assets, including a share of administrative expenses.
Going-In Rates	As determined in EB-2013-0321 for the average of 2014 and 2015, adjusted to remove a one-time allocation of nuclear tax losses
Price Cap or Revenue Cap	Price cap
Attrition Relief Mechanism	Price cap index
Supplemental Capital Revenue	Incremental capital module available on application
Y factors	OPG proposes that numerous costs be addressed by variance accounts.
Plan Termination Provision	5-year term with a stakeholder consultation process preceding a plan update.

In response to an interrogatory, OPG stated that it expects to operate under a regulatory system like this for the foreseeable future.

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> OPG expects that a price-cap index method will continue to be appropriate for setting payment amounts for the company's regulated hydroelectric assets beyond the 2017-2021 IR term.[70]

We discuss some of the provisions in OPG's proposed plan in this section.

6.2 PEG Commentary

6.2.1 Price Cap vs. Revenue Cap

OPG proposes to cap prices rather than revenue. This is the normal approach to power distributor IR in Ontario and has been widely used in IR plans for energy and (especially) telecom utilities around the world. Generally speaking, price caps make more sense than revenue caps (and the revenue decoupling that often accompanies them) when regulators wish to encourage increased system use. This is certainly the case with hydroelectric generation because of its low marginal costs.[71] A price cap reduces the need for a supplemental incentive mechanism to encourage high output.

An example of a rate cap for generation comes from the United States. The California Public Utilities Commission approved a multi-year price cap plan for Pacific Gas and Electric's Diablo Canyon nuclear plant in the late 1980s. PG&E was permitted to charge a preset $/MWh for all power produced. This charge initially compensated PG&E for all capital costs as well as O&M expenses.

6.2.2 Attrition Relief Mechanism

General Form OPG proposes to escalate revenue/kWh with a price cap index. The rate would be escalated by an inflation ("I") factor less an X factor.

Inflation Factor The I factor is the growth of an inflation measure. OPG's proposed inflation measure is a composite index that summarizes inflation in a labor cost index (Average Weekly Earnings for Ontario – Industrial Aggregate) and the Canadian Gross Domestic Product Implicit Price Index for Final Domestic Demand GDP-IPI (FDD). The weights for the subindexes [88% for the GDP-IPI (FDD) and 12% for the Ontario Average Weekly Earnings] were chosen by LEI based on rough estimates of the cost

[70] OPG Response to Staff-224.

[71] Hydroelectric generation has the special advantage of low incremental environmental costs as well as low business costs.

shares of labor and other inputs in LEI's hydroelectric generation productivity study. These weights would be fixed for the plan term.

The inflation measure features the same two subindexes used in the PCIs for 4GIRM. AWEs are also currently used in ICMs in Alberta and Quebec. Compared to the CPI and Canadian GDP-IPI, the GDP-IPI (FDD) places a smaller weight on inflation in the prices of food, energy, and mineral commodities. These prices are volatile and have little impact on the cost of hydroelectric generation.

The proposed weight on the labor cost index is more controversial. The share of labor expenses in LEI's productivity study is on the high side because it is calculated including contract labor and pension and benefit expenses in the numerator. Pension and benefit expenses are Y factored in the proposed plan. It is not entirely clear what services contract labor encompasses. Furthermore, the GDP-IPI (FDD) is naturally sensitive to labor price trends since labor costs loom large in the economy as a whole. We believe that the labor cost share should be consistent with the share of O&M salaries and wages in OPG's 2014-2015 revenue requirement.

LEI considered alternative and more accurate price indexes for capital costs but found them to be "historically less stable." More appropriate capital price subindexes can be developed that are more stable using the COS approach to capital cost measurement (or a variant thereof) which we discussed in Section 3.3. These indexes track trends in the cost of capital and an average of past inflation in construction costs. However, the gain in accuracy from such subindexes is offset by their greater complexity.

X Factor Construction OPG's proposed X factor is the sum of a productivity factor and a stretch factor. This is standard IR practice in Ontario and other North American jurisdictions and is reasonable.

Productivity Factor OPG proposes a productivity factor of zero despite the finding of LEI's study that the recent hydroelectric MFP trend of a sample of North American electric utilities is -1%. This proposal is consistent with the inflation-only escalator for the average cost of heritage pool hydroelectric power in Quebec. However, our research suggests that a positive MFP growth target is more appropriate for OPG. We obtained positive hydroelectric productivity trends for all three sample periods we considered.

One criteria for choosing between the sample periods we considered is that it should be one in which drivers of MFP growth for sampled utilities were most similar to those which OPG is expected to experience in the foreseeable future. It is also pertinent that a longer sample period more effectively smooths the effects of volatility in the sample. On the other hand, a more recent sample period reflects more recent business conditions, and the effects of the benchmark year adjustment are further in the past. Taking stock of all these considerations, we recommend that the productivity factor for OPG be based on the 0.29% MFP trend for our large sample during the 1996-2007 period.

Stretch Factor OPG proposes a stretch factor that can range from 0 to 0.6%. The proposed range of possible stretch factor values is the same as that used in IRM4, where a 0.3% stretch factor is assigned to average performers. OPG proposes to fix the stretch factor at 0.3% for the entirety of the IR term based on its performance in the benchmarking study prepared by Navigant.

Navigant's benchmarking methodology differs greatly from that which the Board employs in setting stretch factors for power distributors. One critical difference is that Navigant's study doesn't emphasize *total* cost performance, which includes the cost of older plant. OPG's total cost has been elevated by the revaluation of its older assets and the recent large plant additions. This could lower its measured performance and raise its indicated stretch factor in a total cost benchmarking study. Note also that the Navigant benchmarking study relies on simple unit cost indexes while the Board uses a sophisticated econometric model of total cost. OPG also deviates from the common practice in IRM4 in that it is not proposing to update benchmarking results annually.

We believe that Navigant's study does not by itself provide a satisfactory basis for a stretch factor determination. However, our productivity research suggests that OPG's recent MFP growth trend has been normal even when the NTP is included. In the absence of fully satisfactory benchmarking evidence, we believe that a 0.3% stretch factor is reasonable for OPG's first generation IRM.

OPG claims that the difference between its 0% proposal and LEI's -1% MFP trend is, effectively, an additional implicit stretch factor of 1%. The Company states in this regard that

> OPG believes that this implicit additional stretch factor does not reflect the company's actual productivity growth trends (per the LEI TFP study) and will pose a significant challenge for OPG during the 2017-2021 term.

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Our empirical research shows that a positive MFP trend should be expected of OPG under normal circumstances.[72] Thus, there is no additional stretch factor.

X Factor Adding together the 0.29% productivity factor and the 0.30% stretch factor, we recommend a 0.59% X factor for OPG. However, this recommendation does not take into account the Company's proposed capital cost trackers, as we discuss in the next section.

6.2.3 Supplemental Capital Revenue

When operating under a price cap index OPG may, in this or future plans, occasionally need supplemental revenue to fund capex surges. These surges are sometimes needed, and capex for refurbishment and replacement usually does not produce much supplemental revenue. The proposed Z factor can address capex surges due to force majeure events. However, surges in other and more predictable kinds of capex also occur occasionally, the Niagara Tunnel Project being an example.

Power distributors operating under 4GIRM have two opportunities for securing supplemental capital revenue: the ICM and the advanced capital module ("ACM"). A request for an ACM occurs at the time of rebasing and is supported by the company's Distribution System Plan. This guards against strategic bunching of capex to bolster revenue. The ICM is now mostly reserved for projects that could not be clearly anticipated at the time of rebasing. Projects eligible for both modules must be part of a capital budget that exceeds a formulaically-determined materiality threshold that considers the funding for capex that is yielded by depreciation and the escalation of the price cap index.

OPG does not propose an ACM. However, its plan includes the option to request an ICM. The Company stated in response to an interrogatory that

> OPG has not requested an ACM as part of this application. OPG could apply for an ICM during the 2017-2021 term if it identifies hydroelectric capital work that

[72] From the regulator's standpoint, however, OPG's strategy is preferable to that of Alberta's energy distributors, who are currently advocating negative X factors based on a cherry-picked result from a flawed study of US power distributor productivity trends.

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> qualifies for ICM funding under OEB policy, but it has not currently identified any qualifying capital projects.[73]

OPG also proposes a continue to use the Capacity Refurbishment Variance Account for its prescribed hydroelectric assets. This account would apparently record the difference between the actual capital and non-capital costs that it incurs to increase the output of, refurbish, or add operating capacity to prescribed facilities, and the 2014-15 average forecasted costs underpinning the hydroelectric revenue requirement approved in EB-2013-0321.[74]

We have a number of concerns about OPG's proposed plan provisions for supplemental capital revenue. Consider first that the granting of supplemental capital revenue in an IRM should be based on convincing evidence of need. Unfortunately, OPG is not providing an update in this proceeding to the capital plan for prescribed hydroelectric generation it submitted in support of the EB-2013-0321 payment amount application.[75] This application only addressed capital costs through 2015. Chart 1 in the capital structure section of the Company's IRM application reveals that its hydroelectric generation rate base is expected to grow quite slowly from 2017 to 2021.[76] This projection is drawn from OPG's 2016-2018 Business Plan. If the projection is accurate, there would likely be no need for supplemental capital revenue during this plan. Note also that SEC requested a forecast of OPG's capital projects and costs that would be subject to the hydroelectric CRVA. The Company responded that "OPG's actual costs will be recorded in the CRVA regardless of whether they are included in OPG's current forecasts; therefore forecasts of specific projects or in-service amounts are not relevant."[77]

Another concern is the effect of the proposed trackers on cost containment incentives. In response to an interrogatory from SEC, OPG stated that

> Incentive regulation decouples revenues and costs. The CRVA retains the link for a specific category of capital costs…. The CRVA removes any potential economic disincentive to invest in a category of projects. As such, OPG is of the view that in

[73] OPG Response to CCC-046.

[74] OPG Application, EB-2016-0152, Exhibit H1, Tab 1, Schedule 1, p. 12-13.

[75] EB-2013-0321 Exhibit D1 Tab 1, filed September 2013.

[76] OPG Application, *op. cit.,* Exhibit C1, Tab 1, Schedule 1, p. 1.

[77] OPG Response to SEC-95.

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addition to being required to implement O.Reg 53/05, the CRVA is consistent with incentive regulation.[78]

Actually, capital cost trackers are the opposite of IR because they weaken capex containment incentives and raise regulatory cost. Such trackers are customarily used in IRMs only where and when costs are not easily addressed through the price (or revenue) cap index. The proposed trackers could potentially address a sizable share of OPG's controllable costs. Incentives to contain the tracked costs and other costs would be imbalanced.

Overcompensation is another concern. The PCI is designed to provide a capex budget each year which is sufficient for routine capex in the long run but may not be sufficient in the short run. Revenue grows with inflation and any output growth that capex enables. As for the X factor, some kinds of capex and O&M expenses that these trackers might address were routinely incurred by utilities in the productivity sample and slowed the MFP trend of the peer group. Unusually slow MFP growth in periods of capex surges alternate with unusually rapid MFP growth in other periods. If OPG is provided with supplemental revenue for routine capex whenever there is a material capital revenue shortfall, customers will receive the benefit of peer group productivity growth in some years and substandard productivity growth in others. On average, they will therefore not receive the benefit of peer group productivity growth in the long run, even when it is achievable. The current materiality threshold for an ICM/ACM for the power distribution sector makes sure that the budget for capex offered by inflation and output growth is considered but doesn't ensure customers the benefit of peer group productivity growth in the long run.

Note also that when a capex surge triggers supplemental revenue it tends to overcompensate the utility for the resulting cost over the life of the asset. The utility recovers its cost exactly in the years when it is tracked and in subsequent rate cases. However, revenue corresponding to the asset exceeds its cost between future rate cases due to depreciation and revenue growth. This is part of the rationale for a dead zone in the materiality threshold.

[78] OPG Response to SEC-95.

We recommend that an ICM play the role in OPG's plan that it has in 4GIRM. That means that it would be permitted only for hard-to-foresee, required, and prudently incurred capex that cannot be addressed through the Z factor. The capex should also exceed a reasonable materiality threshold.

If eligible capex is of a kind routinely incurred by utilities in the productivity sample, consideration should be paid to how other IRM provisions can be adjusted to better ensure that customers receive the benefit of industry productivity growth in the longer run. For example, if an ICM is approved to help fund routine capex, the X factor can be raised by the small amount needed over the next (say) 40 years to ensure that customers still receive the benefit of industry productivity growth in the long run. Alternatively, OPG can be permitted to "borrow" rate escalation privileges from future plans. X factors in future plans would then once again be higher. A third option is for the cost of capital (ie depreciation, return on rate base etc.) that is accorded ICM treatment to be subject to *continued* tracking over its service life. Continued tracking would ensure that the capital cost does not generate revenue surpluses in future plans as it gradually declines due to depreciation. This would eliminate overcompensation.

We also have some specific concerns about the CRVA. Since current cost is compared to the revenue requirement established for the 2014-2015 period, no account is taken of the escalation in inflation, generation volume, or capacity. The costs that can potentially be addressed by this account are sizable and include many of those that are rapidly growing. If a high share of OPG's rapidly growing costs are Y factored by this means, the X factor effectively applies only to slower growing costs (like the declining cost of older plant) and is miscalibrated to the detriment of customers if based on the multifactor productivity trend of a peer group.

When asked by SEC how the hydroelectric CRVA affected other provisions of OPG's proposed plan the Company responded that "as the CRVA is consistent with IR, and OPG has followed the price-cap option as defined in the RRFE, no adjustment is necessary and none is proposed."[79] We disagree. Research by PEG in other proceedings has shown that utility productivity growth is substantially higher when a share of plant additions is removed from the calculations. If the CRVA is approved as proposed, an increase in the X factor is indicated which is commensurate with the excluded capex. The OEB should alternatively

[79] *Ibid.*

consider denying approval of the CRVA and permitting the need for supplemental revenue to be addressed through the ACM/ICM process.

6.2.4 Other Deferral and Variance Accounts

OPG proposes to continue its other existing deferral and variance accounts. A new account is proposed to address the revenue impact of OPG's proposed capital structure charge.

The following accounts have previously been approved by the Board.

- Pension and OPEB Cost Variance Account
- Pension and OPEB Cash Versus Accrual Differential Deferral Account
- Hydroelectric Surplus Baseload Generation Variance Account
- Hydroelectric Water Conditions Variance Account
- Income and Other Taxes Variance Account
- Hydroelectric Incentive Mechanism Variance Account

Most are uncontroversial. Some parties may prefer that pension and benefit expenses be addressed by the price cap index. We do not object to the company's proposal to add a variance account to address the impact, if any, of the Board's decision on OPG's request to adjust the common equity ratio.

HIM

We support the basic idea of a HIM to encourage OPG to make its generation pattern more tailored to market need.

Ancillary Services

The ancillary service variance account ensures that customers receive the full benefits of ancillary service revenue. This weakens OPG's incentive to aggressively pursue opportunities to develop other revenue from its assets. We recommend that the current variance mechanism be replaced by a more incentivized partial sharing mechanism. Partial sharing of variances in other operating revenues has precedent in US regulation.

6.2.5 Plan Termination Provisions

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Plan Term

OPG proposes the five-year 2017-2021 period for its IR plan. A five-year term is the norm for IR in Ontario and around the world. OPG has never operated under IR, so a plan of this duration carries some risk. However, the large overhang of depreciating older plant makes OPG's ongoing cost growth slower and more predictable. Furthermore, the Board has a great deal of experience with IR and there are safety valves in the proposed plan to contain risk. We therefore support OPG's proposed five-year term.

Efficiency Carryover Mechanism

We also believe that an efficiency carryover mechanism should be considered for the Company. ECMs can play an important role in strengthening performance incentives and ensuring that customers get a fair share of IRM benefits. Such mechanisms are used in the current IRMs for energy distributors in Alberta and Australia.

The rationale for ECMs is to counteract some of the adverse incentives that result under IRMs from a periodic rebasing of revenue to cost. The following adverse incentives are notable.

- Due to the compression of the period during which benefits of long-term performance gains improve their bottom line, utilities have less incentive in later years of a plan to incur the upfront costs that are often needed to achieve such gains.
- There is also less incentive for utilities to contain cost in the forward test year ("FTY") [or in the historical reference year that provides the foundation for FTY estimates (often plan year 4)] which is the base year for the next IR plan. For example, there would be less incentive to strike a hard bargain with labor unions and other input vendors in the historical reference year. Utilities are also incentivized to defer certain expenditures in the early years of the plan so that they may be higher in the historical reference year and forward test year. Customers may then "pay twice" for some costs.
- When rebasings have forward test years, utilities have an incentive to exaggerate expected costs and understate expected volumes. If successful, these maneuvers can also reduce customer benefits from PBR in the subsequent plan.

To counteract such incentives, ECMs can be designed that reward utilities for offering customers good value in later PBR plans, and that may also penalize them for offering customers poor value. One kind of ECM involves a comparison of the revenue requirement ("RR") in the forward test year to a benchmark. The ECM may take the form of a targeted incentive mechanism. The revenue requirement in the forward test year could, for example, correspond to the following formula.

$$RR_{t+1} = Cost_{t+1} + \alpha \cdot (Benchmark_{j,\, t+} - Cost_{j,\, t+1})$$

where α is a share of the value implied by benchmarking and takes a value between 0 and 1.[80] The variance between benchmark and actual cost can alternatively be used to adjust the X factor. This would typically take the form of a stretch factor adjustment.

This kind of ECM would clearly strengthen OPG's incentive to contain the cost forecasted for the forward test year. Moreover, by making the *test* year the focus of the appraisal rather than the years of the prior plan, this ECM also guards against strategic deferrals and promotes a fair share of plan benefits for customers.

The choice of a benchmark is an important consideration in the design of this kind of ECM. One approach is to escalate the cost established in the forward test year for the previous plan by a suitable escalation index. This could be based on the I-X formula from the expiring plan, with additional escalation for any output growth.

Many variations on this theme are possible. For example, instead of benchmarking *cost*, the *productivity* trend that is implicit in the test year cost since the level approved in the last rate case can be compared to the X factor. This guards against any failure of the inflation measure in the I-X mechanism to accurately track input price inflation.

Cost (or the revenue requirement) may, alternatively, be compared to a benchmark based on statistical cost research that is completely independent of the Company's cost. We have noted that econometric benchmarking is an integral part of IR for Ontario power distributors. The model can be

[80] Note that the formula allows for the possibility that only a subset j of the total cost is benchmarked. This could be the subset that is easier to benchmark.

used to benchmark forward test year cost proposals. Benchmarking is also used extensively in PBR by the Australian Energy Regulator and by Ofgem in Britain. Econometric benchmarking studies have occasionally been filed by US utilities in support of stretch factors or forward test year cost proposals. Public Service of Colorado, for example, has filed econometric benchmarking studies of its forward test year proposals for the cost of its gas and electric operations.

ECMs appropriate for Ontario regulation should address the fact that utilities have access to supplemental capital revenue in every year of a follow-on plan. Capex can then be deferred from one plan to all years of the follow-on plan. Tying the stretch factor to annual total cost benchmarking, as is done in 4GIRM, is one way to address this problem.

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7. Conclusions

Our appraisal of LEI's productivity study showed that it contained significant methodological problems. The output and capital quantity specifications are particular concerns. LEI's capital quantity specification also involves a flawed conceptual framework for discussing X factor and productivity issues.

We have prepared a study for Board Staff that is based on better methods and is more sensitive to the economics of hydroelectric generation and its regulation. Our study takes into account the critically important phenomenon of depreciation when setting X factors. Our research has produced substantially different results and a better framework for future productivity studies in OPG proceedings.

Methodological improvements have been identified in the course of our study that could be worthwhile in future hydroelectric generation productivity studies. Methodological refinements would be particularly welcome in the area of capital cost measurement. For example, costs of generation facilities and civil structures could be itemized. Data could be gathered on US hydroelectric plant additions prior to 1964. More work is worthwhile on the selection of appropriate sample periods and peer groups. We also note that our econometric model of hydroelectric generation cost provides a starting point for econometric benchmarking of OPG's cost.

Our review of OPG's proposed IRM raises several concerns. The X factor should be based on better productivity and benchmarking work. OPG's proposed rules for granting supplemental capital revenue merit close scrutiny. An efficiency carryover mechanism merits consideration.

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8. Appendix: Further Details of the PEG Productivity Research

This section contains more technical details of our hydroelectric productivity research. We first detail the construction of input quantity and productivity indexes. We then turn to the calculation of capital cost. There follows a discussion of our econometric cost research.

8.1 Input Quantity Indexes

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

The growth rate of the labor price index was calculated for later years of the sample period as the growth rate of the national employment cost index ("ECI") for the salaries and wages of the utility sector of the US economy plus the difference between the growth rates of the *multi-sector* ECI for workers in each utility's service territory and the multisector ECI for the nation as a whole.[81] In the early years we used the ECI for the electric, gas, and sanitary sector in this formula. We used the gross domestic product price index ("GDPPI") as a proxy for the M&S price index.

The summary input quantity index for each company was of chain-weighted Törnqvist form.[82] This means that its annual growth rate was determined by the following general formula:

$$\ln\left(\frac{Inputs_t}{Inputs_{t-1}}\right) = \sum_j \frac{1}{2}\cdot\left(sc_{j,t} + sc_{j,t-1}\right)\cdot\ln\left(\frac{X_{j,t}}{X_{j,t-1}}\right). \qquad [A1]$$

Here in each year *t*,

$Inputs_t$ = Summary input quantity index

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

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

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$X_{j,t}$ = 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.[83]

8.2 Productivity Growth Rates and Trends

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

$$\begin{aligned} & ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right) \\ & = ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}}\right) - ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right). \end{aligned} \qquad [A2]$$

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

8.3 Capital Cost and Quantity Measurement

A monetary approach was chosen to measure capital costs and quantities. In the application of the general method used in this study, the cost of utility plant in a given year *t* (CK_t) is the product of a capital price index (WKS_t) and an index of the capital quantity at the end of the prior year (XK_{t-1}).

$$CK_t = WKS_t \bullet XK_{t-1} \qquad [A3a]$$

Then

$$growth\ CK_t = growth\ WKS_t + growth\ XK_{t-1} \qquad [A3b]$$

[83] To calculate the input quantity growth between 1974 and 1995 we assumed that the cost share for 1974 was the same as that in 1995.

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Utilities have diverse procedures for calculating depreciation and retirements, and the procedures of individual utilities change over time. When calculating capital costs and quantities using a monetary approach, it is therefore customary to rely on the reporting companies chiefly for the value of *gross* plant additions and then use standardized depreciation methods. Since the quantity of capital on hand may involve plant added thirty to fifty years ago, it is desirable to have gross plant addition data for many years in the past.

There is typically a previous period for which plant addition data are unavailable. This challenge is customarily addressed by considering the aggregate of plant value at the end of this period and then estimating the quantity of capital that it reflects using indexes of construction cost inflation from earlier years and assumptions about the pattern of gross plant additions in these years. The year for which this exercise is undertaken is sometimes called the “benchmark year.” Since this exercise is inexact, it is desirable to measure MFP growth for a sample period many years after the benchmark year.

In constructing capital quantity indexes for the sampled utilities we took 1964 as the benchmark year. The values for these indexes in the benchmark year are based on the net value of plant as reported in the FERC Form 1. We estimated the benchmark year quantity of net plant by dividing the net book value of plant by a weighted average of the past values of a utility construction cost index in years when hydroelectric generating stations were completed. Index numbers received heavier weights to the extent that the stations to which they correspond were larger and more recent. The construction cost index (WKA_t) was the applicable regional Handy-Whitman construction cost index for total hydraulic production plant.[84]

The following formula was used to compute values for the capital quantity index for years after the benchmark year.

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

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

In this "perpetual inventory equation," the parameter *d* is the economic depreciation rate and $VKA_{j,t}$ is the value of gross plant additions. For hydroelectric generation, the economic depreciation rate was set at 2.63%. It was based on the assumption of a 100-year average service life for structures and a 52-year average service life for equipment. The declining balance parameters specified were 0.938 for structures and 1.65 for equipment.

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

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

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

The calculation of [A5] requires an estimate of the rate of return on capital.[85] We employed a 50/50 average of rates of return for debt and equity. For debt we calculated the average embedded cost of debt for a large sample of electric utilities, using data from FERC Form 1. For each distributor we calculated the ratio of interest expenses on long-term debt to the value of long-term debt outstanding. The rate of return on equity was the average approved each year for electric utilities in rate cases as reported by the Edison Electric Institute.

8.4 Econometric Cost Research

We developed a model of the applicable total cost of hydroelectric power generation. Cost is a function of external business conditions. We also developed a consistent cost share equation. Parameters of both equations were estimated econometrically.

[85] This calculation was made solely for the purpose of measuring input price and productivity *trends* and does not prescribe appropriate rate of return *levels* for OPG.

Total cost was the sum of hydroelectric generation capital cost and applicable hydroelectric O&M expenses. Total cost was normalized by an O&M price index. Capital cost was calculated using the geometric decay method.

Explanatory Variables

A fundamental result of economic theory is that the minimum cost of an enterprise increases with input prices and the operating scale. There can in principle be multiple scale variables. The theory also permits the existence of other business condition variables. This theory provides the basis for a cost model in which cost is a function of input prices, operating scale variables, and miscellaneous other quantifiable business conditions.

Our model had two scale variables: the hydroelectric generation volume and capacity. There were price indexes for O&M inputs and capital. The capital price index was consistent with the geometric decay assumption. The data for the scale variables were the same as those used in our productivity work.

The econometric model also contains a trend variable. This permits predicted cost to shift over time for reasons other than changes in the specified business conditions. The trend variable captures the net effect on cost of diverse conditions, such as technological change, that are otherwise excluded from the model. Parameters for such variables often have a negative sign in statistical cost research.

Functional Form

The model had a translogarithmic ("translog") functional form. This means that in addition to "first order" terms for the right hand side variables there are interaction terms and quadratic terms for these variables. Data were mean-scaled. The parameter for each first-order term therefore equals the long-run elasticity of cost with respect to the variable at sample mean values of the business conditions.

Sample

Data for 20 utilities were included over the 1995-2014 sample period. The sample contained 400 observations.

Estimation Procedure

Model parameters were estimated using a seemingly unrelated regression procedure implemented in the R statistical software package. This procedure accounted for autocorrelation and group-wise heteroscedasticity in the error terms.

Results

Results of the econometric work for the cost model are reported in Table 7. The table also reports the values of the *t* statistic that correspond to each parameter estimate. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. This statistical test requires the selection of a critical value for the test statistic.

In this study, we employed critical values appropriate for a 90% confidence level in a large sample. The critical value of the *t* statistic corresponding to this confidence level is about 1.645. The corresponding critical value for the p value is 0.10. An estimate with a *t* statistic exceeding 1.645 or a *p* value less than 0.10 is statistically significant at a confidence level of 90% or greater.

Examining the results in Table 7 it can be seen that all of the parameter estimates for the first-order terms were plausible. Cost was found to be higher the higher were the two output quantities. At the sample mean values of the variables we found that a 1% increase in generation capacity raised cost by 0.906% in the long run. 1% growth in generation volume raised cost by about 0.009%. The estimate of the capacity variable parameter was highly significant whereas the estimate of the volume variable parameter was not. These results strongly support the notion that capacity is the dominant scale-related driver of hydroelectric generation cost.

The estimates of the parameters of the other business conditions were also sensible.

- Cost was higher the higher was the capital price.
- Apart from the impact of other business conditions included in the model, cost trended downward over time by about 0.20% per annum.

Table 7

Econometric Cost Model For Hydroelectric Generation

VARIABLE KEY

WK = Capital Price Index
YCH = Net Generation Volume (MWh)
YVH = Generation Capacity (MW)
Trend = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
WK	0.862	123.659*
YCH	0.906	36.854*
YVH	0.009	0.851
(WKxWK)/2	0.107	15.565*
(YCHxYCH)/2	0.211	5.641*
(YVHxYVH)/2	-0.013	-0.515
WKxYCH	0.008	1.171
WKxYVH	0.004	0.930
YCHxYVH	-0.014	-0.548
Trend	-0.002	-1.433
Constant	18.541	725.471*

***Variable is significant at 90% confidence level**

OTHER INFORMATION	
System Rbar-Squared	0.944
Sample Period	1995-2014
Number of Observations	400

The table also reports a system-adjusted R^2 statistic for the system. This measures the ability of the model to explain variation in the sampled costs of distributors. Its value was 0.944, suggesting that the explanatory power of the model was high.

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Relevant Work Experience, Primary Positions

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

Chief executive and sole proprietor of the research unit of the Pacific Economics Group consortium. Leads internationally recognized practice in alternative regulation ("Altreg") and utility statistical 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.

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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. Research on Gas Market Competition for a Western Electric Utility. 1981.
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4. Research on Load Relief from Interruptible Services for a Northeast Electric Utility. 1989.
5. Design of Time-of-Use Rates for a Midwest Electric Utility. 1989.
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151. Research and Testimony on Forward Test Years and the cost performance of a large Western Gas Distributor. 2010-2011.
152. Research and Testimony in Support of Revenue Decoupling for a Midwestern Power Distributor. 2010-2011.
153. Benchmarking Research and Report on the Generation Maintenance Performance of a Midwestern Electric Utility. 2010-2011.
154. Research and Testimony on the Design of an Incentivized Formula Rate for a Canadian Gas Distributor. 2010-2011.
155. White Paper for a National Trade Association on Remedies for Regulatory Lag. 2010-2011.
156. Benchmarking Research and Report on the Performance of a Midwestern Electric Utility. 2011.
157. Assistance with an Alternative Regulation Settlement Conference for a Northeastern Power Distributor. 2011.
158. Research and Testimony on Remedies for Regulatory Lag for Three Northeastern Power Distributors. 2011-2012.
159. Research and Testimony on the Design of Performance Based Ratemaking Mechanisms for a Canadian Consumer Group. 2011-2012.
160. Research and Testimony on Projected Attrition for a Northwest Electric Utility. 2011-2012.
161. Research and Testimony on the Design of a Performance Based Ratemaking Plan for a Canadian Gas Utility. 2012-2013.
162. Testimony for US Coal Shippers on the Treatment of Cross Traffic in US Surface Transportation Board Stand Alone Cost Tests. 2012.
163. Survey of Gas and Electric Altreg Precedents for a US Trade Association. 2012-2013.
164. Research and Testimony on the Design of an Attrition Relief Mechanism for a Northeast Electric Utility. 2013.
165. Research and Testimony on Issues in PBR Plan Implementation for a Canadian Consumer Group. 2013.
166. Consultation on an Altreg Strategy for a Southeast Electric Utility. 2013.
167. Consultation on an Altreg Strategy for a Midwestern Electric Utility. 2013.
168. Research and Testimony on the Design of a PBR Plan for a Northeast Electric Utility. 2013.
169. Research and Testimony on the Design of a PBR Plan for a Massachusetts Electric Utility. 2013
170. Consultation on Altreg Strategy for a California Electric Utility. 2013.
171. Research on Drivers of O&M expenses for a Canadian Gas Utility. 2013.
172. Research on the Design of an Attrition Relief Mechanism for a Midwest Electric & Gas Distributor. 2013.
173. PBR Strategy for a Southeast Electric Utility. 2013
174. Research on the Design of an Attrition Relief Mechanism for a Southeast Electric Utility. 2013.
175. Research and Testimony on Productivity Trends of Gas and Electric Power Distributors for a Canadian Consumer Group, 2013-2014.
176. Research and Testimony on Productivity Trends of Vertically Integrated Electric Utilities, 2014.
177. Research and Testimony on Statistical Benchmarking and O&M Expense Escalation for a Western Electric Utility, 2014.
178. Transnational Benchmarking of Power Distributor O&M Expenses for an Australian Regulator, 2014.
179. Research and Testimony on Statistical Benchmarking and O&M Cost Escalation for an Ontario Power Distributor, 2014-2015.
180. Assessment of Statistical Benchmarking for Australian Power Distributors, 2014-2015.
181. Research and Testimony on Merger of Two Midwestern Utility Holding Companies, 2014-2015.
182. White Paper on PBR for a Midwest Electric Utility, 2015.
183. Research and Support in the Development of Regulatory Frameworks for the Utility of the Future, 2015.
184. Survey of Gas and Electric Alternative Regulation Precedents for a US Trade Association. 2015.

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185. White Paper on Multiyear Rate Plans for a US Trade Association and a consortium of Electric Utilities, 2015.
186. White Paper on Performance-Based Regulation in a High Distributed Energy Resources Future, 2016.
187. White Paper on Performance Metrics for the Utility of the Future for a US Trade Association and a consortium of electric utilities, 2016.
188. Research and Testimony on PBR for Power Transmission and Distribution, 2015 to present.
189. Testimony on Revenue Decoupling for Pennsylvania Energy Distributors, 2016.
190. Research and Testimony on PBR Plan Design and US Power Distribution Productivity Trends, 2016.
191. Development of a Revenue Decoupling Mechanism and Supporting Testimony on behalf of a Midwest Environmental Advocate, 2016.
192. Research and Testimony on PBR Plan Design and Hydroelectric Generator Productivity Trends for a Canadian Regulator. 2016.
193. White Paper on Utility Experience and Lessons Learned from Performance-Based Regulation Plans, 2016-2017.
194. Workshop on PBR for Regulators in a New England state, 2016.

Publications

1. Public vs. Private Management of Mineral Inventories: A Statement of the Issues. <u>Earth and Mineral Sciences</u> 53, (3) Spring 1984.
2. Review of <u>Energy, Foresight, and Strategy</u>, Thomas Sargent, ed. (Baltimore: Resources for the Future, 1985). <u>Energy Journal</u> 6 (4), 1986.
3. The Changing Role of the United States in World Mineral Trade in W.R. Bush, editor, <u>The Economics of Internationally Traded Minerals.</u> (Littleton, CO: Society of Mining Engineers, 1986).
4. Assessing Metals Demand in Less Developed Countries: Another Look at the Leapfrog Effect. <u>Materials and Society</u> 10 (3), 1986.
5. Modeling the Convenience Yield from Precautionary Storage of Refined Oil Products (with junior author Bok Jae Lee) in John Rowse, ed. <u>World Energy Markets: Coping with Instability</u> (Calgary, AL: Friesen Printers, 1987).
6. Pricing and Storage of Field Crops: A Quarterly Model Applied to Soybeans (with junior authors Joseph Glauber, Mario Miranda, and Peter Helmberger). <u>American Journal of Agricultural Economics</u> 69 (4), November, 1987.
7. Storage, Monopoly Power, and Sticky Prices. les Cahiers du CETAI no. 87-03 March 1987.
8. Monopoly Power, Rigid Prices, and the Management of Inventories by Metals Producers. <u>Materials and Society</u> 12 (1) 1988.
9. Review of Oil Prices, Market Response, and Contingency Planning, by George Horwich and David Leo Weimer, (Washington, American Enterprise Institute, 1984), <u>Energy Journal</u> 8 (3) 1988.
10. A Competitive Model of Primary Sector Storage of Refined Oil Products. July 1987, <u>Resources and Energy</u> 10 (2) 1988.
11. Modeling the Convenience Yield from Precautionary Storage: The Case of Distillate Fuel Oil. <u>Energy Economics</u> 10 (4) 1988.
12. Speculative Stocks and Working Stocks. <u>Economic Letters</u> 28 1988.
13. Theory of Pricing and Storage of Field Crops With an Application to Soybeans [with Joseph Glauber (senior author), Mario Miranda, and Peter Helmberger]. University of Wisconsin-Madison College of Agricultural and Life Sciences Research Report no. R3421, 1988.
14. Competitive Speculative Storage and the Cost of Petroleum Supply. <u>The Energy Journal</u> 10 (1) 1989.

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15. Evaluating Alternative Measures of Credited Load Relief: Results From a Recent Study For New England Electric. In Demand Side Management: Partnerships in Planning for the Next Decade (Palo Alto: Electric Power Research Institute, 1991).
16. Futures Prices and Hidden Stocks of Refined Oil Products. In O. Guvanen, W.C. Labys, and J.B. Lesourd, editors, International Commodity Market Models: Advances in Methodology and Applications (London: Chapman and Hall, 1991).
17. Indexed Price Caps for U.S. Electric Utilities. The Electricity Journal, September-October 1991.
18. Gas Supply Cost Incentive Plans for Local Distribution Companies. Proceedings of the Eight NARUC Biennial Regulatory Information Conference (Columbus: National Regulatory Research Institute, 1993).
19. TFP Trends of U.S. Electric Utilities, 1975-92 (with Herb Thompson). Proceedings of the Ninth NARUC Biennial Regulatory Information Conference, (Columbus: National Regulatory Research Institute, 1994).
20. A Price Cap Designers Handbook (with Lawrence Kaufmann). (Washington: Edison Electric Institute, 1995.)
21. The Treatment of Z Factors in Price Cap Plans (with Lawrence Kaufmann), Applied Economics Letters 2 1995.
22. Performance-Based Regulation of U.S. Electric Utilities: The State of the Art and Directions for Further Research (with Lawrence Kaufmann). Palo Alto: Electric Power Research Institute, December 1995.
23. Forecasting the Productivity Growth of Natural Gas Distributors (with Lawrence Kaufmann). AGA Forecasting Review, Vol. 5, March 1996.
24. Branding Electric Utility Products: Analysis and Experience in Regulated Industries (with Lawrence Kaufmann), Washington: Edison Electric Institute, 1997.
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.

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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, Synapse Energy Economics), Lawrence Berkeley National Laboratory, January 2016.
50. "Comprehensive PBR for US Electric Utilities," (With Matthew Makos and Jeff Deason), Lawrence Berkeley National Laboratory, forthcoming.

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

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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]

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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. Great Plains Institute, Minneapolis, MN, February 2016
96. National Regulatory Research Institute, Teleseminar, March 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, August 2016

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 Economists
Wisconsin Public Utilities Institute

RESUME OF
DAVID ALAN HOVDE

November 2016

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Education: MS: Economics, University of Wisconsin - Madison, May 1990
BA: Majors in Economics, Political Science, and International Relations, University of Wisconsin-Madison, August 1988
High School: Waukesha North High School, Waukesha, WI, 1984

Relevant Work Experience, Primary Positions:

March 2009 – Present	Vice President, Pacific Economics Group Research, LLC
December 2005 – March 2009	Vice President, Pacific Economics Group, LLC
November 1998 - December 2005	Senior Economist, Pacific Economics Group, LLC

Responsible for database services in support of PEG research. Other responsibilities include management of projects, the training and supervision of staff and the preparation of testimony, studies, analyses and other research for clients in the electric power, natural gas, and other industries.

April 1998-October 1998	Senior Economist
April 1990-April 1998	Economist
	Christensen Associates, Madison, WI

Member of the regulatory strategy group. Responsibilities included the preparation and analysis of electric and gas utility productivity and cost performance studies.

Teaching Experience:

Madison College (2007-2012): Instructor of Economics

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Duties include teaching introductory economics and obtaining advanced training as required. Experience includes teaching accelerated and distance learning versions of the class.

Carroll University (2009): Adjunct Faculty Member
Duties include teaching an undergraduate course in Microeconomics.

University of Wisconsin – Madison (1989-1990): Teaching assistant
Duties included holding weekly discussion sections to reinforce material delivered via lecture.

Pro Bono Work:

Woodside Farms Neighborhood Association (2/2009-2/2012): Board Member and Board Secretary. The board is responsible for the maintenance and improvement of common areas. Members are responsible for drafting a budget and assessing an appropriate levy on lot owners. Secretarial responsibilities include neighborhood communications such as meeting notifications, minutes, and other communications as required.

West Madison Senior Coalition (6/2005-6/2007): Board Member, Chair of Personnel Committee
The WMSC serves older adults in Madison by providing resources, programs, and advocacy that allow seniors to live more active and creative lives. As a board member, I advised the board on strategic planning, budgeting, personnel, fundraising feasibility, and led a search committee that successfully hired a new executive director.

Publications:

1. Gas Supply Cost Incentive Plans for Local Distribution Companies (with Mark Lowry). Proceedings of the Eight NARUC Biennial Regulatory Information Conference (Columbus: National Regulatory Research Institute, 1993).
2. TFP Trends of U.S. Electric Utilities, 1975-92 (with Herb Thompson and Mark Lowry). Proceedings of the Ninth NARUC Biennial Regulatory Information Conference, (Columbus: National Regulatory Research Institute, 1994).
3. Economies of Scale and Vertical Integration in the Investor-Owned Electric Utility Industry (with Herb Thompson). The National Regulatory Research Institute, January 1996.
4. Branding Electric Utility Products: Analysis and Experience in Regulated Industries (with Lawrence Kaufmann), Washington: Edison Electric Institute, 1997.
5. Econometric Benchmarking of Cost Performance: The Case of U.S. Power Distributors (with Mark Lowry and Lullit Getachew), The Energy Journal, Volume 26. No. 3, 2005.
6. AltReg Rate Designs Address Declining Average Gas Use (with Mark Lowry, Lullit Getachew, and Steve Fenrick), Natural Gas & Electricity, April 2008.

Major Research Projects:

1. Development of Comprehensive Performance Indexes for a Northeastern Combined Electric and Gas Utility, 1990-1991.
2. Measuring Productivity Trends in the Local Gas Distribution Industry for a Northeastern Gas Distributor, 1990.
3. Measurement of Productivity Trends for the U.S. Electric Power Industry for a Northeastern Vertically Integrated Electric Utility, 1990-91.
4. Productivity Growth Estimates for U.S. Gas Distributors and Their Use in Incentive Regulation for a Western Gas Distributor, 1991.
5. Development of Cost Performance Indexes for a Northeastern Combined Electric and Gas Utility, 1991.
6. Efficient Rate Design for Interstate Gas Transporters for a Western Vertically Integrated Electric Utility, 1991.
7. Gas Transportation Strategy for a Western Electric Utility, 1992.
8. Design of a Comprehensive Benchmark Incentive Plan for a Northeastern Electric Utility, 1992.
9. Design of a Comprehensive Benchmark Incentive Plan for a Northeastern Gas Distributor, 1992.
10. TFP Measurement for a Western Electric Utility, 1993-96.
11. Development of and Regulatory Support for a Price Cap Plan for a Northeastern Electric Utility, 1993.
12. Productivity Research in Support of a Price Cap Plan for a Northeastern Electric Utility, 1994.
13. Productivity Research in Support of a Price Cap Plan for a Western Gas Distributor, 1994.
14. Statistical Benchmarking for Bundled Power Services of a Western Electric Utility, 1994.
15. Development of Price Cap Plans for a Northeastern Combined Gas & Electric Utility, 1995.
16. Productivity Research for a Price Cap Filing for a Northeastern Gas Distributor, 1996.
17. Stranded Cost Recovery and Power Distribution Regulation for a Restructuring U.S. Electric Utility, 1996.
18. Power Distribution Benchmarking for a Northeast Electric Utility, 1996.
19. Comprehensive Benchmarking for a Northeast Electric Utility, 1996.
20. Comprehensive Benchmarking for a Tropical Island Electric Utility, 1996.

21. White Paper on Utility Brand Name Policy for a Trade Association, 1997.
22. Generation and Power Transmission PBR for a Restructuring Canadian Electric Utility, 1997.
23. Statistical Benchmarking for a Western Electric Utility, 1997-98.
24. Analysis of a Purchased Power Agreement for a Midwestern Municipality, 1997.
25. Statistical Benchmarking and Stranded Cost Recovery for a Trade Association, 1997.
26. Inflation and Productivity Trends of U.S. Power Distributors for a Northeastern Electric Utility, 1997.
27. Statistical Benchmarking and Productivity Trends for a Southeast Gas Distributor, 1997-98.
28. PBR Research and Testimony for a Western Energy Utility, 1997-98.
29. Research into the Vintage of Electric Utility Plant in the United States for a Western Electric Utility, 1998.
30. Productivity Research for two Midwestern Electric Utilities, 1998.
31. Statistical Benchmarking for two Midwestern Electric Utilities, 1998-99.
32. Design of an Incentive Fuel Clause for two Midwestern Electric Utilities, 1998.
33. Benchmarking Study of T&D Capital Input for a Western Electric Utility, 1998.
34. Economies of Scale for an Island Electric Utility, 1998.
35. Litigation Support in a Price Fixing Case Involving Agricultural Products, 1998.
36. Comprehensive Benchmarking for a Midwestern Electric Utility, 1999.
37. Cost Benchmarking of Power Transmission and Distribution, 1999.
38. Distribution Benchmarking for Multiple Australian Power Distributors, 1999.
39. Comprehensive National TFP Trends for an Island Electric Utility, 1999.
40. Transmission and Distribution Benchmarking for a Northeast Utility, 1999-2000.
41. Prepare Evidence for Rebuttal of a Benchmarking Study on Behalf of Multiple Australian Power Distributors, 2000.
42. Litigation Support on Benchmarking Issues to an Australia Gas Distributor, 2000.
43. Transmission Benchmarking for an Australian Power Transmission Utility, 2000.
44. Cost Benchmarking for Power Transmission and Distribution for a Northeastern Electric Utility, 2000.
45. Benchmarking Evaluation of Power Distribution Costs, 2000.

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46. Economies of Scale and Scope in Power Delivery and Metering Services for a Group of Northeastern Electric Utilities, 2000.
47. Estimate Scale Economies in Power Generation, Scope Economies Between Power Transmission and Power Generation, and Implications for Public Policy in Western Australia, 2000.
48. Service Quality Benchmarking and Construction of Appropriate Deadbands for a Group of Northeastern Electric Utilities, 2001.
49. Gas Distribution TFP Trends and Benchmarking for two Western Gas Distributors, 2001.
50. Power Distribution TFP Trends and Benchmarking for a Western Power Utility, 2001.
51. Power Distribution TFP Trends for a Northeastern Power Distributor, 2001.
52. Statistical Benchmarking for three Australian Gas Utilities, 2001.
53. Research on Productivity and Benchmarking for a Western Power Distributor, 2002.
54. Research on Productivity and Benchmarking for two Western Natural Gas Distributors, 2002.
55. Statistical Benchmarking for an Australian Electric Power Transmission Utility, 2002.
56. Research on Benchmarking for a Western Bundled Power Service Utility, 2002.
57. Research on Productivity and Benchmarking for a Northeastern Natural Gas Distributor, 2002-3.
58. Research on Productivity for a Power Distributor, 2002-3.
59. Research on Productivity and Benchmarking for a Canadian Natural Gas Distributor, 2002-3.
60. Research on Productivity and Benchmarking for a Canadian Power Transmission Company, 2002.
61. Cost Analysis Research and Benchmarking for a South American Power Regulator, 2003.
62. Assemble a Power Transmission Database for a Japanese Regulator, 2003.
63. Benchmarking of Power Distribution Performance of New Zealand, 2003.
64. Benchmarking and Total Factor Productivity for an Island Electric Utility, 2003-2004.
65. Research on Productivity and Benchmarking for a Canadian Gas Distributor, 2004.
66. Benchmarking Power Distribution Performance for two Australian Power Distributors, 2004.
67. Statistical Benchmarking, Productivity, and Incentive Power Research for a Northeastern Combined Gas and Electric Company, 2003.

68. Benchmark Comprehensive Power and Water Utility Operations for an Island Electric & Water Utility, 2004.
69. Assemble a U.S. Gas Transmission Database for a Mexican Regulator, 2004.
70. Benchmarking Gas Distribution Operations for three New Zealand Gas Distributors, 2004.
71. Research on Productivity Trends for the National Power Distribution and Natural Gas Industries for two Gas Distributors and one Power Distributor, 2004.
72. Research on Productivity Trends for the Power Distribution Industry of Victoria, Australia for an Australian Regulator, 2004.
73. Statistical Benchmarking for a Northeastern U.S. Natural Gas Distributor, 2004-2005.
74. Statistical Benchmarking for a Canadian Power Distributor, 2005.
75. Statistical Benchmarking for Total Electric Utility Operations for a Southeastern Vertically Integrated Electric Utility, 2005.
76. Statistical Benchmarking of the Nuclear Operations of Regulated Utilities for a Western Electric Utility, 2005.
77. Research on Productivity Trends for the U.S. Power Distribution Industry for a Northeastern Power Distributor, 2005.
78. Calculation of Adjusted Refund Liability as a Result of the Western Power Crisis for two Western Vertically Integrated Electric Utilities, 2005-2006.
79. Research on Abnormal Bidding Patterns for a Western Power Generation Utility, 2005.
80. Statistical Benchmarking for a Northeastern Power Distributor, 2005-2006.
81. Statistical Benchmarking for a Northeastern Gas Distributor, 2006.
82. Research on Productivity Trends for the Power Distribution Industry of Victoria, Australia for an Australian Regulator, 2005-2007.
83. Research on Productivity Trends for the U.S. Natural Gas Distribution Industry for two Western Gas Distributors, 2006-2007.
84. Statistical Benchmarking for a Northeastern Gas Distributor, 2006-2007.
85. Measurement of Gas Distribution TFP of Australia, 2006-2007.
86. Research on Productivity Trends for Natural Gas Distribution for a Canadian Regulator, 2006 – 2007.
87. Litigation Support for a Northwestern U.S. Power Company, 2007.
88. Generation Benchmarking for a Southwestern Power Company, 2007.
89. Gas Distribution Productivity Research for a Canadian Regulator, 2007-2008.

90. Power Distribution Productivity Research for a Canadian Regulator, 2007-2008.
91. Power Distribution Productivity Research of Victoria, Australia for an Australian Regulator, 2007-2008.
92. Natural Gas Distribution Productivity of Victoria, Australia for an Australian Regulator, 2008.
93. Unit Cost Research for a large Midwestern Natural Gas Distributor, 2008.
94. Power Distribution Productivity Research for an Island Electric Utility, 2008.
95. Input Price and Productivity Research in Support of a Decoupling Mechanism for an Island Electric Utility, 2009.
96. Benchmarking the Base Rate Cost of a Midwestern Vertically Integrated Electric Utility, 2009.
97. Productivity and O&M Benchmarking for a Northeastern Natural Gas Distributor, 2009.
98. TFP Research for New Zealand Power Distributors for a New Zealand Trade Association, 2009.
99. Research and Testimony in Support of a Forward Test Year Rate Filing by a Vertically Integrated Western Electric Utility, 2009.
100. Simulation of Productivity within a Building Block Model for an Australian Regulator, 2009.
101. Research and Report on the Importance of Forward Test Years for U.S. Electric Utilities for a U.S. Trade Association, 2009-2010.
102. Research and Testimony on Altreg for Western Gas and Electric Utilities Operating under Decoupling, 2009-2010.
103. Research and Report on Revenue Decoupling for Ontario's Gas and Electric Utilities for a Canadian Regulator, 2009-2010.
104. Research and Report on the Performance of a Western Electric Utility, 2009-2010.
105. Research and Report on the Effectiveness of Decoupling for a Western Gas Distributor, 2009-2010.
106. Statistical Cost Benchmarking for a Midwestern Electric Utility, 2010.
107. Research and Testimony in Support of a Forward Test Year Rate Filing by a Western Gas Distributor, 2010.
108. Partial Factor Productivity Measurement for a Northeastern Gas Distributor, 2010.
109. Productivity Trends of Victoria, Australia's Power Distribution Companies for an Australian Regulator, 2010.

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110. Research and Testimony in Support of Revenue Decoupling for a Midwestern Power Distributor, 2010-2011.

111. Research and Report on the Design of an Incentivized Formula Rate for a Canadian Gas Distributor, 2010-2011.

112. Productivity Trends for New Zealand Gas Distributors for a New Zealand Gas Distributor, 2011.

113. Benchmarking Research and Report on the Performance of a Midwestern Electric Utility, 2011.

114. Research on Approaches to Reduce Regulatory Lag for a Northeastern Power Distributor, 2011.

115. Assistance with an Alternative Regulation Settlement Conference for a Northeastern Power Distributor, 2011.

116. Research on Remedies for Regulatory Lag for two Northeastern Power Distributors, 2011-2012.

117. Research on Projected Attrition for a Northwestern Electric Utility, 2011-2012.

118. Natural Gas Productivity Research and Evaluation of Productivity Research of Other Parties on Behalf of a Canadian Consumer Group, 2012-2013.

119. Productivity and Plan Design Research and Testimony in Support of a PBR Plan for a Canadian Gas Distributor, 2012-2013.

120. Power Distribution Productivity and Cost Benchmarking Research for a Canadian Regulator, 2012-2013.

121. Research Measuring the O&M Productivity of Northeast U.S. Power Distributors, 2013-14.

122. Evaluation of company sponsored productivity evidence for a Canadian Consumer Group, 2013.

123. Productivity research of U.S. Gas and Electric distributors for a Canadian Consumer Group, 2013.

124. Productivity research of vertically integrated U.S. electric utilities, electric utility client name withheld, 2013-2014.

125. Total Factor Productivity research for the New Zealand power distribution industry, 2014.

126. Total cost benchmarking research for a multi-state utility holding company, 2014.

127. Total cost benchmarking research for a Western Utility, 2014.

128. Assemble a power distribution benchmarking database for an Australian Regulator, 2014.

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129. Benchmarking research and report in support of updated stretch factors for a Canadian Regulator, 2014.

130. Evaluation of company sponsored cost and reliability benchmarking evidence for a Canadian Regulator, 2014.

131. Total cost benchmarking research for an Ontario, Canada power distributor, 2014-2015.

132. Evaluation of an alternative regulation proposal by a Canadian utility, 2014-2015.

133. Development of a spreadsheet model for the calculation and forecasting of power distribution cost performance for a Canadian Regulator, 2015.

134. Total cost benchmarking of Ontario power distributors for a Canadian Regulator, 2015.

135. Research in support of an incentive ratemaking proposal for a Canadian utility, 2015

136. Training Ontario LDC personnel on the calculation of benchmarking performance, 2016

137. Develop a cost performance forecast model for Ontario power distributors for a Canadian Regulator, 2016.

138. Total cost benchmarking of Ontario power distributors for a Canadian Regulator, 2016.

139. Total Factor Productivity of U.S. Power Distributors for an Alberta consumer advocate, 2016

140. Calculation of the Total Factor Productivity of Hydroelectric operations for a Canadian Regulator, 2016

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FORM A

Proceeding: EB-2016-0152

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 November 21, 2016

Signature

FORM A

Proceeding: EB-2016-0152

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is David Hovde (*name*). I live at Oconomowoc (*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 November 21, 2016

Signature