OPG

EB-2016-0152

OEB Staff Compendium

Panel 2Ai

2017 Input Price Index

Consistent with the policy determinations set out in the Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (EB-2010-0379) (Issued November 21, 2013 and updated December 4, 2013), the Board has calculated the value of the the inflation factor for incentive rate setting under the Price Cap IR and Annual Index plans, for rate changes effective in 2017, to be 1.9%. The derivation of this is shown in the following table. The Board will adjust the price escalator in each applicable distributor's 2017 Incentive Regulation Mechanism model such that this inflationary adjustment is reflected in distribution rate changes resulting from Price Cap IR and Annual Index applications for rates effective in 2017.

Version 1: OEB Staff Calculations as per Electricity Distribution IPI, with OPG's weights. Annual percentage change calculated theough natural logarithmic function. Rounding only for annual percentage change for end result.

	Inputs and Assumptions												
Year	Non-Labour GDP-IPI (FDD) - National							Labour AWE - All Employees - Ontario			Annual Growth for the 2-factor IPI based on OPG's proposed weights		
	Q1	Q2	Q3	Q4	Annual	Annual % Change	Weight	Annual	Annual % Change	Weight	Annual	Annual % Change	
2014	112.5	113.2	113.7	114.1	113.375			$ 938.27			103.7		Annual % change = ln
2015	114.4	114.8	115.6	116.1	115.225	1.61858%	88%	$ 962.73	2.57352%	12%	105.51297	1.7332%	(Current/Previous)
												1.70%	Rounded to three decimals

Sources:
• [GDP-IPI (FDD): Statistics Canada, Table 380-0066 - Price Indexes, gross domestic product, quarterly (2007 = 100 unless otherwise noted) - 2016 Q2, issued August 31, 2016]
• [Average Weekly Earnings (AWE): Statistics Canada, Table 281-0027 - Average weekly earnings (SEPH), by type of employee for selected industries classified using the North American Industry Clasification Classification System (NAICS), annual (current dollars)]
Data accessed August 31, 2016

Version 2: OEB Staff Calculations with OPG's weights. Annual percentage change calculated through arithmetic calculation. Rounding only for annual percentage change for end result.

	Inputs and Assumptions												
Year	Non-Labour GDP-IPI (FDD) - National							Labour AWE - All Employees - Ontario			Resultant Values - Annual Growth for the		
	Q1	Q2	Q3	Q4	Annual	Annual % Change	Weight	Annual	Annual % Change	Weight	Annual	Annual % Change	
2014	112.5	113.2	113.7	114.1	113.375			$ 938.27			103.7		Annual % Change = (Current -
2015	114.4	114.8	115.6	116.1	115.225	1.63175%	88%	$ 962.73	2.60693%	12%	105.51348	1.7488%	Previous) / Previous
												1.70%	Rounded to three decimals

Version 3: OPG's calculations per 11.1-Staff-227, as discussed during Technical Conference (TC, Vol. 2, p. x/l. x to p. x/l.x). Annual percentage change calculated through arithmetic calculation. Rounding only for annual percentage change for end result.

	Inputs and Assumptions												
Year	Non-Labour GDP-IPI (FDD) - National							Labour AWE - All Employees - Ontario			Resultant Values - Annual Growth for the		
	Q1	Q2	Q3	Q4	Annual	Annual % Change	Weight	Annual	Annual % Change	Weight	Annual	Annual % Change	
2014	112.5	113.2	113.7	114.1	113.375			$ 938.27			103.7		Annual % Change = (Current -
2015	114.4	114.8	115.6	116.1	115.225	1.632%	88%	$ 962.73	2.610%	12%	105.5300	1.7494%	Previous) / Previous
							1.440%			0.310%		1.75%	Rounded to four decimals
												1.80%	Rounded to three decimals

1 Executive Summary

On March 28, 2013, the Ontario Energy Board ("OEB") published a report outlining its policy for implementing incentive ratemaking ("IR") for OPG's prescribed assets. With this in mind, London Economics International ("LEI") was engaged by OPG to perform a Total Factor Productivity ("TFP") study of the hydroelectric generation industry. LEI issued a TFP report covering the 2002-2012 timeframe on December 18, 2014. The purpose of this report is to share findings from a data update. LEI has used the same analytical techniques, the same model of TFP, and essentially the same group of peers from the North American hydroelectric generation industry,[1] but has extended the timeframe of analysis to cover an additional two years of operational and financial data. Therefore the industry TFP trends documented in this report cover the 2002 through 2014 period.

This report is structured as follows: Section 2 presents a background into the key events that led to this study. Section 3 presents an overview of the various methods of measuring productivity, and explains why the TFP index method was selected for this study. Section 4 introduces the different inputs and outputs that could be used in the TFP index, and explains LEI's choice. Section 5 goes over the data gathering process for the peers that made up the industry used in the TFP study. Section 6 presents the results of the TFP study, and Section 7 provides concluding remarks.

1.1 What is TFP?

Total factor productivity measures the total quantity of outputs of a firm relative to the quantity of inputs it employs. TFP must cover all material inputs to production, and core outputs of a firm. TFP focuses on quantities, not costs,[2] and measures the year-on-year changes in overall productivity for the firm and its peers. It is important to note that it does not consider efficiency levels, and is therefore not a benchmarking study. An industry TFP study by definition will **not** focus on the regulated firm. The TFP study, by its nature, is also backward looking – reporting historical growth rates or trends in productivity for selected firms or the industry as a whole. A growth rate reflecting multiple years (preferably 10 years or longer) is the primary result reported in an industry TFP study.[3]

[1] Changes to the peer group are discussed in Section 5.1.2.

[2] While costs are not the focus of a TFP study, they are still needed to form input weights; this is described further in Section 4.2.2.

[3] LEI notes that there is no precedent for TFP studies of hydroelectric generation businesses for purposes of regulatory ratemaking. This is not surprising as generation is not typically regulated using IRM. However, TFP based empirical studies do exist for generation in academia.

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1.2 What data was used for the TFP study?

Based on best practices of estimating TFP for generation companies, and after considering issues related to data availability, LEI defined the TFP study output as generation in megawatt hours ("MWh"), and inputs as physical capital measured in megawatts ("MW"), as well as annual operations and maintenance ("O&M") costs measured in dollars and deflated by an appropriate index in order to isolate productivity trends.[4]

The data selection and gathering process was the most significant challenge in conducting the TFP study. Primary data sources include FERC Form 1, EIA, US BEA, US BLS, StatsCan, and company public reports, as well as data provided directly by OPG. The final TFP study includes sixteen (16) firms in total: OPG, thirteen (13) US investor-owned firms that file FERC Form 1 data, and two (2) US federal and municipal operators. Data for this study covered a thirteen year period from 2002 through 2014.[5]

1.3 What are the results of the TFP study?

For the industry consisting of OPG and 15 US peers, using data from 2002-2014, the TFP growth rate was estimated to be -1.01% per annum using the 'average growth' method. Under the 'trend regression' method, the industry TFP growth rate was estimated to be –1.18% per annum.[6] In comparison, the December 18, 2014 study reported a -1.02% industry TFP growth rate using 'average growth' method and -1.00% industry average TFP growth rate using the 'trend regression' method for the 2002-2012 timeframe. As explained further in Section 6.2.1, negative TFP results can be expected for mature hydroelectric businesses, because of fixed production assets, fixed production capabilities, and rising asset maintenance costs over time.

To determine these TFP figures, LEI used a Chained Fisher Ideal index method with a model consisting of two inputs (capital and O&M) and a single output (generation), as described further in Section 6.1.

1.4 How should the results of the TFP study be used for rate setting?

An industry TFP study measures the changes in overall productivity for a particular industry or peer group over a specified time period. Because an industry TFP study reports historical productivity growth rates, care must be applied to ensure that going forward business conditions are similar to those that prevailed historically. An industry TFP is **not** a benchmarking study, as it does not focus on efficiency levels; therefore, it is important that TFP

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[4] See Section 4 for details on how this data is used and Section 4.2.1 for details on the deflation index.

[5] At the time LEI began this study, 2015 data was not yet available.

[6] See Section 3.2.2 for description of the two different methods of measuring TFP growth trends.

4 TFP inputs and outputs

Selecting the appropriate inputs and outputs is a key part of a TFP study. Intuitively, selected inputs and outputs would be those that most accurately represent actual productivity, while also having data that is available and quantifiable. Although there are many dimensions to the hydroelectric industry, and theoretically there are many viable input and output possibilities, not all are measurable. To better understand the appropriate choice of inputs and outputs, LEI reviewed 18 previous academic and regulatory TFP studies. More information on this review can be found in Appendix B (Section 9.1.3), but the general consensus was that inputs to a TFP study should include capital and O&M, while outputs should reflect key products or services.

For the purpose of this TFP study, LEI determined it would be best to use a single output of generation measured in MWh, and two inputs: physical capital measured in MW and O&M measured in dollars. Sections 4.1 and 4.2 below provide more insight into why LEI chose a single output two input model.

Figure 7 below illustrates the TFP model with a single output and two inputs. Note that index methods employ indices that are constructed from ratios of output and input quantities. Where there are multiple outputs or inputs, weights are used to create composite indices (for example, outputs can be weighted by revenue shares and inputs can be weighted by cost shares). In the case of LEI's selected TFP model presented in Figure 7, input weights are represented by α for the O&M share and (1- α) for the capital share. This process is described further in Section 4.2.2.

Figure 7. Calculating the TFP index

$$\textbf{TFP Index} = \frac{\textbf{Output Quantity}}{\textbf{Input Quantities}} = \frac{\textbf{Net Generation}}{\boldsymbol{\alpha} * \textbf{O\&M} + (\mathbf{1} - \boldsymbol{\alpha}) * \textbf{Capital}}$$

4.1 TFP study outputs

Hydroelectric assets provide a multi-dimensional service, with multiple products such as generation, ancillary services, reliability, firm capability, system support, water management for flood control, and recreational use.

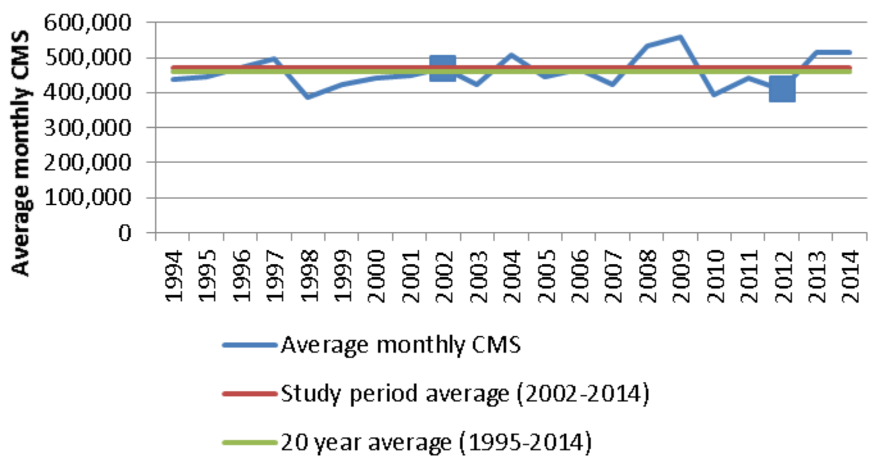
After considering 18 productivity studies on generation, conducted both for academic and regulatory purposes, LEI found that generation was the most common metric chosen for measuring output.[28] Generation is an appropriate output because it is the essential output being produced by every power generator. Furthermore, generation data is readily available, and is generally measured consistently across power plants and firms. Based on this, LEI concluded

[28] See Appendix B Section 9.1.3.1 for more detail.

that annual generation measured in MWh was an essential output measure for a TFP study of this nature.

LEI recognizes that the generation output metric is dependent on hydrology and system operations. However, the longer term nature (thirteen years) of the TFP study compensates for the year-on-year variability in annual generation, and therefore LEI believes variability in annual hydrology should not be an obstacle to this TFP study. Using OPG as an example, the average of water flows during the period of 2002-2014 is within 1% of the twenty year average (1994-2013) as shown in Figure 8; 2013 and 2014 hydroelectric production was also very close to historical norms. Therefore, it is reasonable to conclude the thirteen year study period in general is appropriate and compensates for varying water conditions over the years.[29]

Figure 8. Historical OPG water flow



Source: Based on information provided directly to LEI by OPG

In addition to generation, LEI considered other outputs including measurements of other services that can be provided by hydroelectric plants in the output index. For example, LEI noted that in one particular study, outputs of a hydroelectric industry TFP study included availability (in MWh), energy produced in the driest month, and summer peaking capacity. Availability can be considered an output, as hydroelectric operators (including OPG) spend

[29] LEI understands that in individual cases this statement may not be true. Notable is the case of Western Area Power Administration (described in Section 5.2.3), which shows that historical average and study-period average water flows may not match up. LEI performed an outlier check against individual peers included in the industry TFP study based on their final average TFP growth rates; results from this check can be seen in Section 6.3.

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effort to achieve certain levels of availability (i.e., minimize forced outage rates) for reliability purposes. However, availability data is often not available publically, and the method of measuring availability may vary from individual peer to peer. More generally, availability would already be implied in the annual MWh figure already being used as the primary output. For these reasons, availability was not used as a separate output in the industry TFP study. However, in the December 2014 report, LEI did conduct a sensitivity analysis for a small subgroup of peers where a two output model was evaluated; the results were similar to a single output model and have been included in the Appendix A in Section 8 of this report.

Additional generation measures, such as energy produced in the driest month, or winter and summer peaking capacity, could in theory also be used as outputs. However, data for these outputs is less readily available for all industry peers. As well, compensation for OPG's regulated assets is not geared off such specific production statistics. Other services, such as sales of ancillary services, or water management for flood control and recreational use, are difficult to represent in a TFP study because they lack consistent and easily measurable data; therefore, they should be considered qualitatively only.

To conclude, LEI decided it would be best to use only a single output model consisting of generation measured in MWh. Firstly, this is because this was common practice in reviewed generation TFP studies, and secondly, it is a numerical data point which is both available and consistently measured across firms.

4.2 TFP study inputs

Based on a number of factors discussed below, LEI concluded that a two input model consisting of capital measured in MW of installed hydroelectric generation capacity, and Total O&M costs measured in dollar values, would best capture inputs that are most relevant to hydroelectric operations.

A review of the inputs used in 18 previous productivity studies can be seen in Appendix B in Section 9.1.3.2. The most common input observed for generation related productivity studies was capacity as a physical measure of capital. Capital can also be measured using replacement cost, but this is much less common – in fact, nearly every generation related TFP study used capacity as a measure of capital.[30] Therefore, LEI concluded that capital measured in MW capacity should be used as an input.

The TFP case study review also showed that the second most common input is number of employees, which captures the labour involved in power production. Due to data constraints, LEI could not rely on number of employees or otherwise isolate the labour costs from total

[30] Further discussion on physical as compared to monetary measures of capital can be found in Appendix C Section 10.

O&M costs. However labour costs are already reflected in O&M costs indirectly through the input price indices (which is discussed further in Section 4.2.1).

Fuel consumed and maintenance costs were also often utilized, however, given that this TFP study is for hydroelectric generation rather than thermal or fossil-fuel fired generation, fuel costs are not a relevant input.

4.2.1 O&M input quantities

Input prices are used to derive appropriate quantities of certain inputs for the calculation of TFP. To calculate quantities of "O&M input", total O&M costs are deflated using an appropriate price index.

More specifically, total O&M costs were deflated (i.e., converted into quantity measure) using a total O&M price index which is comprised of a labour price index and non-labour price index, combined together using a labour to non-labour share, as discussed below and in the following Section 4.2.2.

Figure 9. Canadian O&M price indices, 2002-2014

Year	Labour Price Index	Non-Labour Price Index	O&M Price Index
2002	1.00	1.00	1.00
2003	1.02	1.02	1.02
2004	1.05	1.04	1.05
2005	1.09	1.06	1.08
2006	1.11	1.08	1.10
2007	1.15	1.11	1.14
2008	1.18	1.14	1.16
2009	1.19	1.15	1.18
2010	1.24	1.16	1.21
2011	1.26	1.19	1.23
2012	1.27	1.21	1.25
2013	1.29	1.23	1.27
2014	1.32	1.26	1.30

Source: Based on StatsCan data. Weights of Labour and Non-Labour PI as described in Figure 11

For Canadian data, labour O&M price index was based on industrial aggregate average weekly earnings ("AWE") (reported by *Statistics Canada*; in current dollars, for Canadian utilities, including overtime, seasonally adjusted, for all employees), and the non-labour O&M price index was based on the gross domestic product price index estimate of final domestic demand ("GDP-IPI FDD") (reported by *Statistics Canada*; implicit price indexes, gross domestic product, final domestic demand, for Canada). For US data, labour O&M price index was based on data gathered from US Bureau of Labor Statistics ("BLS"), and non-labour O&M price index was based on the GDP-PI data gathered from the US Bureau of Economic Analysis ("BEA").[31] Canadian O&M price indices over the TFP study timeframe are presented in Figure 9, while US O&M price indices over the TFP study timeframe are presented in Figure 10.

Figure 10. US O&M price indices, 2002-2014

Year	Labour Price Index	Non-Labour Price Index	O&M Price Index
2002	1.00	1.00	1.00
2003	1.03	1.02	1.02
2004	1.06	1.05	1.05
2005	1.09	1.08	1.09
2006	1.12	1.11	1.12
2007	1.16	1.14	1.15
2008	1.19	1.17	1.18
2009	1.23	1.18	1.21
2010	1.26	1.19	1.23
2011	1.29	1.21	1.26
2012	1.33	1.23	1.29
2013	1.36	1.25	1.32
2014	1.40	1.28	1.35

Source: Based on data from the US BLS and BEA. Weights of Labour and Non-Labour PI as described in Figure 11

Labour and non-labour O&M price indices for Canada and the US are combined into Canadian and US total O&M price indices using a fixed labour share of total O&M of 63% (Figure 11), as suggested by average trends observed in a confidential EUCG database,[32] that includes hydroelectric generation specific data for 18 companies over the 2004-2014 timeframe.

[31] See Section 5.4 for detailed discussion of how US and Canadian data was treated in order for them to be comparable.

[32] The EUCG dataset containing hydro-specific generation data for 18 companies over 2004-2014 was shared with LEI by EUCG for the purposes of this study. LEI was not able to use this data in the TFP study because thirteen-year datasets (2002-2014) could not be constructed for any of the peers and, 11 of the 18 companies in the EUCG dataset had missing data within the 2004-2014 timeframe.

Figure 11. Labour and Non-labour O&M shares implied by EUCG data

Year	Labour Share based on O&M	Non-Labour Share based on O&M
2004	60%	40%
2005	63%	37%
2006	61%	39%
2007	61%	39%
2008	60%	40%
2009	62%	38%
2010	65%	35%
2011	63%	37%
2012	65%	35%
2013	64%	36%
2014	64%	36%
Average (2002-2014)	**63%**	**37%**

Source: Confidential EUCG database, provided to LEI directly by OPG

The total O&M price indices for US and Canada are blended into a North American O&M price index by applying a weight of 22% for the Canadian share of the industry (i.e., OPG) based on Canadian peer's share in total O&M for the industry; therefore, the weight of US total O&M price index in the North American total O&M price index is 78%. Figure 12 presents the total O&M price index for North America as a whole, while Figure 13 shows the growth trend in these indices in graphical form.[33]

Figure 12. North American combined O&M price indices, 2002-2014

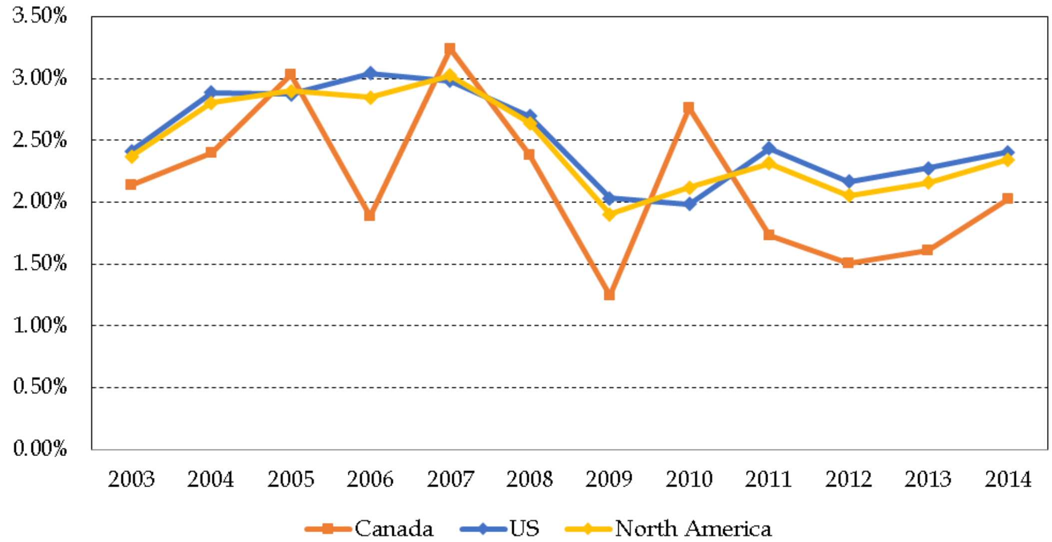
Year	US O&M Price Index	Canadian O&M Price Index	North American O&M Price Index
2002	1.00	1.00	1.00
2003	1.02	1.02	1.02
2004	1.05	1.05	1.05
2005	1.09	1.08	1.08
2006	1.12	1.10	1.12
2007	1.15	1.14	1.15
2008	1.18	1.16	1.18
2009	1.21	1.18	1.20
2010	1.23	1.21	1.23
2011	1.26	1.23	1.26
2012	1.29	1.25	1.28
2013	1.32	1.27	1.31
2014	1.35	1.30	1.34

Source: Based on data from Statistics Canada, US BLS and BEA.[34]

[33] North American index was created in order to create an industry peer set including both US and Canadian peers.

[34] Weights for O&M share of Canadian and US peers were calculated by LEI as the total O&M cost as a fraction of revenues, using data gathered from FERC Form 1, individual firm annual reports, and information provided

Figure 13. O&M price index growth rates (%) for US, Canada, and North America



Source: Based on data from Statistics Canada, US BLS and BEA

4.2.2 Input share weights

Given LEI has determined multiple inputs to the TFP study, capital and O&M costs, weights or cost shares must be used to combine the sub-indices into a composite input quantity index. Capital input shares can be difficult to assess, but LEI believes that the endogenous approach is both appropriate and relatively easy to implement, as discussed in the text box below.

The capital share is determined as the share of the estimated cost of capital to total costs (capital plus total O&M). Based on combined industry business operations data, capital share for the 2002-2014 period averaged 80% for the industry as a whole. These industry-level capital shares, which can be seen in Figure 14, were calculated by LEI using firm-specific data.[35]

directly by firms. Based on internal analysis, Canadian O&M share was calculated to be 22%, and US O&M share was 78%.

[35] See Section 5 for information on the data gathering process for the industry.

Capital input share

Capital cost input shares may be estimated using two methods, an endogenous or an exogenous approach. The endogenous approach is the residual of revenue less operating costs (assumes prices are proportional to marginal costs and revenues are equal to costs); it is appropriate for competitive conditions or if a firm has been regulated for an extended period under a cost of service methodology such that revenues cover costs.

The exogenous approach is calculated by forming a user cost measure based on an estimated depreciation rate, a rate of return on capital, a deduction for the estimated rate of capital gains or addition for capital losses (i.e., annual change in the asset price index), and applied to a starting point asset value (capital stock). It recognizes that there has to be a "return of" capital over the asset's lifetime (i.e., the firm has to recoup its original investment) and a "return on" capital to compensate for holding the asset over its lifetime reflecting the opportunity cost of using the funds in an alternative investment. The exogenous approach must also consider that capital gains resulting from an increase in the price of the asset reduce the cost of holding (and using) the asset over the year. The exogenous approach also requires making a judgment on the firm's true opportunity cost of capital, and usually assumes geometric depreciation of capital.

LEI used the endogenous approach (revenue=costs) to determine capital input shares, as it is easier to implement and is expected to provide a reasonable approximation of capital inputs in the business.

Figure 14. Annual implied Capital to Total O&M shares for hydroelectric generation industry[36]

Year	Capital Share	O&M Share
2002	85%	15%
2003	88%	12%
2004	86%	14%
2005	88%	12%
2006	86%	14%
2007	82%	18%
2008	84%	16%
2009	78%	22%
2010	75%	25%
2011	76%	24%
2012	67%	33%
2013	75%	25%
2014	76%	24%
Average	80%	20%

Source: Based on LEI internal analysis, using data sources described in Section 5.2

[36] In general, changes in capital share were largely driven by year-over-year revenue fluctuations. Specifically, revenue from 2011 to 2012 declined by a rate of -34%, causing capital share for the industry as a whole to drop from 76% in 2011 to 67% in 2012. Lower market revenues are a function of volumes of sales (which may be affected by hydrological conditions) as well as wholesale market price conditions, which can be attributed to external drivers in the regional power markets, such as (but not limited) to gas prices, demand conditions, and aggregate supply. The capital shares have been adjusted from the original study to account for the removal of Alcoa from the peer group.

2 Fundamental characteristics of a TFP study for the hydroelectric generation industry

Three fundamental issues make hydroelectric generation industry different from other industries that are typically regulated under IR schemes:

- Hydroelectric generating assets, if properly maintained, continue to deliver the same productive capability in the long-run. Unlike a battery or distribution poles, the majority of a hydroelectric generator's capital stock does not get "used up" or physically deteriorate in pre-set increments over time.
- The drivers of productivity growth are different than other regulated industries: since output is largely fixed when a facility is designed, productivity gains from output growth are not a driver of hydroelectric industry productivity trends. Generators do not experience demand growth as an electric distributor does. While a distributor may show productivity gains by adding new customers, hydroelectric generators do not. In addition, technology-driven growth is slow in the hydroelectric generation industry.
- Hydroelectric facilities provide a suite of services to consumers, including water management. Ideally, a TFP study should aim to capture these services. To the extent that one or more outputs from hydroelectric power plants are not directly captured, they must be considered in the interpretation of the TFP study results.

The PEG Report does not appear to recognize and reflect these specific characteristics of the hydroelectric generation industry.

2.1 Hydroelectric generation assets experience only minor physical deterioration if properly maintained

An accurate TFP analysis reflects how the actual, physical depreciation of the assets under study (inputs) translate into reduced ability to produce the services (outputs). This is entirely separate from the accounting depreciation used for financial reporting purposes. For hydroelectric generation, the primary input is the asset itself. A hydroelectric plant is composed of civil structures (like the dam, tunnels, and powerhouses) and electrical and mechanical components (like controls, transformers, generators, turbine runners and other turbine components).

Since the actual quantity of capital input used each year is not observable, any measure (physical or monetary) will be a proxy. Therefore, the critical question is the following: which proxy provides the best overall approximation? For hydroelectric generation assets, a "one hoss shay" profile is a close approximation of the physical depreciation of the capital deployed as it assumes that the asset can produce the same level of outputs over its entire service life.

1 Executive Summary

LEI reviewed the PEG Report and the responses to interrogatories filed by OEB Staff regarding the PEG Report, as filed on December 14, 2016. LEI has reached three conclusions regarding PEG's analysis:

1. **The PEG Report is based on assumptions that do not reflect the actual operating properties of hydroelectric generation assets.**

   PEG has employed an accounting standard of depreciation (geometric decay) that is fundamentally inconsistent with the actual, physical performance of hydroelectric generation assets. These assets do not experience physical depreciation in pre-set increments every year of their service life, as estimated by PEG. If they are properly maintained, these assets should operate consistent with their initial design and physical capability year after year. Indeed, OPG has assets that were built more than a hundred years ago, and they are continuing to operate at levels consistent with their design capability.

   The PEG Report also failed to account for other properties of hydroelectric generation assets. These assets do not benefit from fast-paced technology improvements, compared to assets in other infrastructure industries, as only the electrical and mechanical components can be replaced over time to improve productivity, while their civil structures (e.g. dams) remain largely unchanged. In addition, an accurate productivity study should reflect the fact that these assets produce more than electricity and ancillary services. Hydroelectric generators also provide dam safety and watershed management services, balancing energy production requirements with environmental, commercial and recreational needs.

   Finally, PEG has taken an approach that is inconsistent with how hydroelectric generating assets are paid. The OEB has consistently held that these assets are paid on the basis of their energy production, which implies that electric generation is a good proxy for other services that are produced. Moreover, the design of Ontario's energy market means that if these assets were not regulated, they would also be paid on the basis of energy production. If the TFP model that PEG proposes is used to calibrate the X factor in a price cap index, PEG's approach introduces risk of long-term capital insufficiency.

2. **The PEG Report is based on several methodological errors and omissions.**

   The TFP growth estimate in the PEG Report is biased given the assumptions made. The most important methodological error is the use of the geometric depreciation profile, as also discussed above. By way of the basic math, the use of this assumption in the PEG Report leads to an over-statement of the estimate industry average TFP growth rate.

   Since PEG's model explicitly excludes improvements in generation (MWh), it is unable to account for many productivity improvements that increase energy production but do not impact capacity. For example, PEG's methodology does not recognize any productivity impact from OPG's Niagara Tunnel Project, since that investment increased expected annual generation (MWh) but not capacity (MW) of the Sir Adam Beck generation facility.

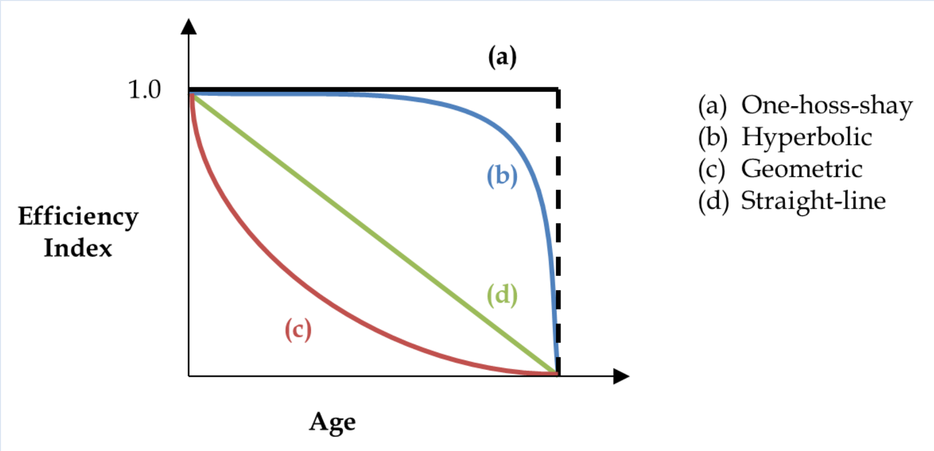
Backgrounder: Efficiency profiles for alternative depreciation profiles

PEG has listed three depreciation profiles used to establish the capital input quantity under the monetary method: geometric decay, "one hoss shay," and cost of service or straight-line.[1] PEG has also noted that regulators consider different capital input methodologies when calibrating X factors.[2] As such, it is important to understand the meaning of each deprecation profile.

1. **Geometric decay** uses a constant depreciation rate every year which creates an effect of a geometric decay in the productive capability of the asset in question.[3]
2. "**One hoss shay**" assumes no depreciation in the asset's physical capabilities until the end of its service life.
3. **Cost of service** or **straight line** depreciation assumes the same depreciation amount in each period.

There is also **hyperbolic depreciation**, which assumes largely no depreciation for the majority of the asset's lifetime, and close to the end of the lifetime, the deterioration is very rapid.[3] The hyperbolic depreciation profile is a current statistical agency practice used by many national statistical agencies (e.g., U.S. Bureau of Labor Statistics ("BLS"), the Australian Bureau of Statistics, and Statistics New Zealand)[4] that recognizes that most assets decay in physical terms closer to "one hoss shay" than geometric depreciation profile.

Figure 1. Illustration of different depreciation profiles for consideration in TFP analysis[5]



Sources:

[1] PEG Report (2016), *op. cit.*, Exhibit M2, Page 21.
[2] PEG's reply to OPG Interrogatory #8. EB-2016-0152, Exhibit M2, Tab 11.1, Schedule OPG-008, filed on December 14, 2016.
[3] Economic Insights (2013). Lawrence, D. and Kain, J. *Inputs to be Used in the Economic Benchmarking of Electricity Network Service Providers.* Briefing notes prepared for Australian Energy Regulator. February 27, 2013.
[4] US BLS. *A Prototype BEA/BLS Industry-Level Production Account for the United States*. November 2012; ABS. *Information paper: Experimental Estimates of Industry Multifactor Productivity*. 2007; Statistics NZ. *Productivity Statistics: Sources and methods*. 2012; PEG is also aware that US BLS assumes hyperbolic depreciation in its multifactor productivity studies. Source: PEG's reply to OPG Interrogatory #9. EB-2016-0152, Exhibit M2, Tab 11.1, Schedule OPG-009, filed on December 14, 2016.
[5] John Baldwin. *Estimating Depreciation Rates for the Productivity Accounts*. 2005.

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Figure 25. Quantity sub-index values for inputs and output

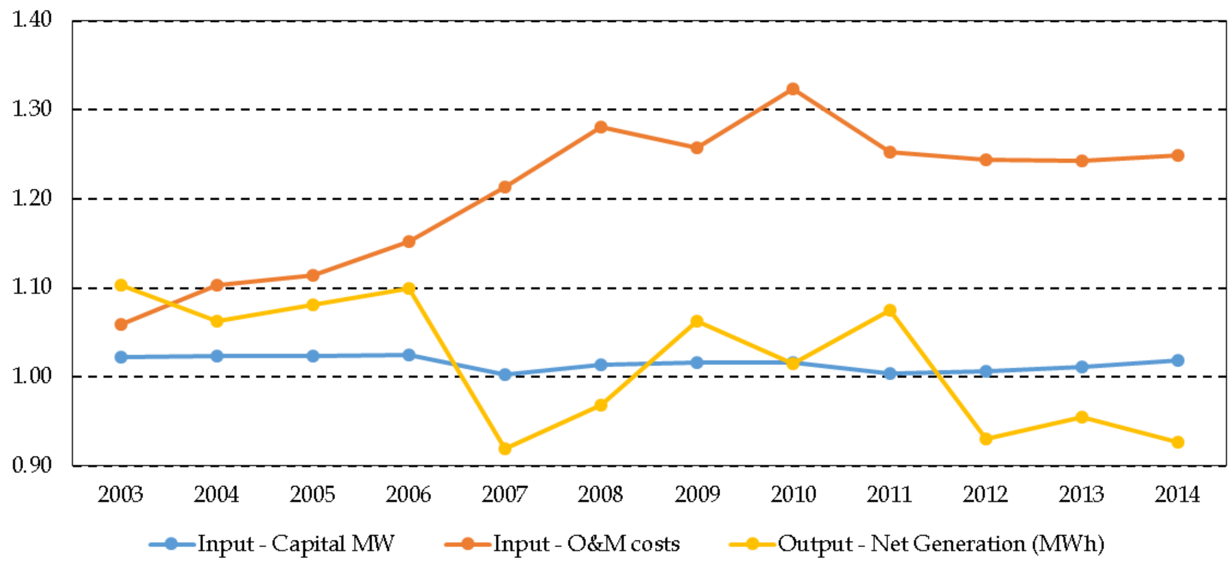


Figure 26. Quantity sub-index growth rates for inputs and output

Year	Quantity Sub-Index Growth Rates: Input (K) weight 80%	Input (O&M) weight 20%	Output (MWh) weight 100%
2002-2003	2.22%	5.71%	9.80%
2003-2004	0.15%	4.09%	-3.69%
2004-2005	-0.07%	1.01%	1.64%
2005-2006	0.21%	3.39%	1.79%
2006-2007	-2.17%	5.17%	-17.98%
2007-2008	1.06%	5.41%	5.18%
2008-2009	0.17%	-1.84%	9.40%
2009-2010	0.01%	5.07%	-4.65%
2010-2011	-1.23%	-5.49%	5.69%
2011-2012	0.32%	-0.64%	-14.38%
2012-2013	0.52%	-0.10%	2.55%
2013-2014	0.67%	0.42%	-3.00%
AVERAGE	**0.15%**	**1.85%**	**-0.64%**

In contrast, negative O&M productivity trends are not typical of electric power distributors in our experience.[10] LEI states on page 9 of its Reply Memo that "OPG's hydroelectric assets are maintained to produce at steady (or improving) levels of expected output (although O&M costs will be rising with time to ensure that productive capability remains at adequate levels)."

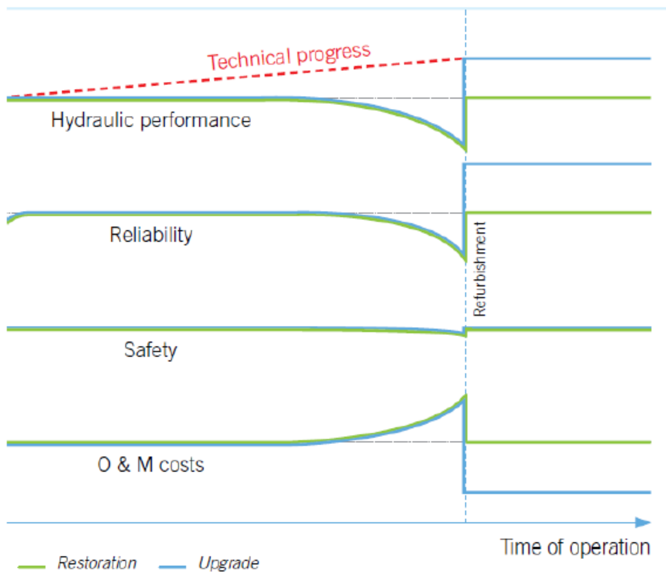
Another sign of a diminishing flow of services is a continual stream of "refurbishment" capital expenditures that do not boost volume or capacity. In this regard, OPG noted in its 2007 *Annual Report* that "Hydro's excellent availability over the years is the result of *ongoing investments and upgrades,* strong equipment performance, and shorter-than expected planned outage durations [italics added]."[11]

Figure 2 on page 7 of LEI's Reply Memo, replicated below, is apparently drawn from a Hydro Equipment Association publication. The figure shows that, after holding steady for many years, the hydraulic performance and reliability of hydroelectric generation assets decline while O&M costs rise. Refurbishments can then restore hydraulic performance and, with technological progress, improve it. This is not an OHS service flow pattern. Since the hydroelectric generation assets in the PEG study were far from new during the featured 1996-2014 sample period and O&M productivity was falling, it seems that the sampled utilities were typically operating in the period of declining capital service flows in LEI's figure. Holding volume and capacity constant required rising O&M expenses and "refurbishments".

A OHS Assumption Does Not Make Sense for Heterogeneous Groups of Assets In real-world productivity studies, capital quantity trends are rarely if ever calculated for individual assets. They are instead calculated from data on the value of plant additions (and, in the case of OHS, retirements) which encompass multiple assets of various kinds. Even if each individual asset had an OHS age/efficiency profile, the age/efficiency profile of the *aggregate* plant additions could be poorly approximated by OHS for several reasons. Different kinds of assets can have markedly different service lives. Assets of the same kind could end up having different service lives. Individual assets, in any event, frequently have components with different service lives. The alternator in a motor vehicle, for example, can need replacement before the body of the vehicle does. In this case, OHS doesn't fit the capital service flow of the composite asset. Alternative capital cost specifications such as GD can provide a better approximation of the service flow of a group of assets that individually have OHS patterns or which are composites of assets with OHS patterns.

[10] For example, a 0.76% average annual growth rate in O&M productivity is reported for a large sample of US power distributors from 1997 to 2014 in Mark Newton Lowry and David Hovde, *PEG Reply Evidence,* op. cit., p. 38.
[11] Ontario Hydro, *2007 Annual Report*, p. 9.

Figure 2. Illustration of increasing O&M costs to maintain a hydro plant's performance and reliability



Source: Hydro Equipment Association (HEA 2015). *Global Technology Roadmap*. 2015. Page 30.

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

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

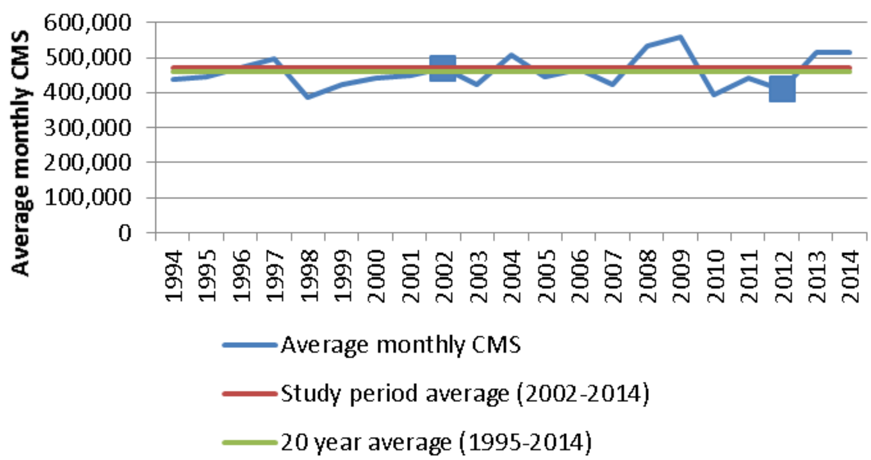
The OHS Approach is Rarely Used These disadvantages of the OHS specification help to explain why alternative specifications are more the rule than the exception in capital quantity research. For

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

that annual generation measured in MWh was an essential output measure for a TFP study of this nature.

LEI recognizes that the generation output metric is dependent on hydrology and system operations. However, the longer term nature (thirteen years) of the TFP study compensates for the year-on-year variability in annual generation, and therefore LEI believes variability in annual hydrology should not be an obstacle to this TFP study. Using OPG as an example, the average of water flows during the period of 2002-2014 is within 1% of the twenty year average (1994-2013) as shown in Figure 8; 2013 and 2014 hydroelectric production was also very close to historical norms. Therefore, it is reasonable to conclude the thirteen year study period in general is appropriate and compensates for varying water conditions over the years.[29]

Figure 8. Historical OPG water flow



Source: Based on information provided directly to LEI by OPG

In addition to generation, LEI considered other outputs including measurements of other services that can be provided by hydroelectric plants in the output index. For example, LEI noted that in one particular study, outputs of a hydroelectric industry TFP study included availability (in MWh), energy produced in the driest month, and summer peaking capacity. Availability can be considered an output, as hydroelectric operators (including OPG) spend

[29] LEI understands that in individual cases this statement may not be true. Notable is the case of Western Area Power Administration (described in Section 5.2.3), which shows that historical average and study-period average water flows may not match up. LEI performed an outlier check against individual peers included in the industry TFP study based on their final average TFP growth rates; results from this check can be seen in Section 6.3.

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included in the original December 2014 TFP study, was excluded in this update as the company sold more than half of its portfolio in mid-2012 (generating capacity decreased to 217 MW) and is no longer aligned with peer selection criteria.[41] The final peer group selected, as summarized in Figure 15, includes sixteen (16) firms: OPG, thirteen (13) US investor owned firms that file FERC Form 1 data, one US federal operator (Southeastern Power Administration), and one US municipal operator (Seattle City & Light).

Figure 15. List of peers included in industry

Company	Average age of hydro fleet (2016)	Sum of hydro plants capacity (MW) 2014
Pacific Gas and Electric	55	3,567
Duke Energy Carolinas, LLC	48	2,859
Virginia Electric and Power	35	2,122
Idaho Power Company	56	1,695
Alabama Power	68	1,668
Southern California Edison Company	74	1,112
Georgia Power Company	64	1,071
PacifiCorp	71	1,016
Avista Corporation	68	921
Portland General Electric Company	62	889
Union Electric	71	904
Appalachian Power Company	58	840
South Carolina Electric & Gas Company	54	750
Ferc Form 1		
Seattle City & Light	61	1,929
Southeastern Power Administration	40	3,392
Federal and Municipal		
OPG	**66**	**6,433**

Source: Source: FF1 dataset, OPG, SEPA and Seattle annual reports, data provided directly by companies

[41] On June 29th 2012, Brookfield Renewable Energy Partners announced its agreement to acquire four of Alcoa Power Generating Inc.'s hydroelectric generating stations in Tennessee and North Carolina. This portfolio change is reflected in Alcoa's 2013 FERC Form 1 filing.

Figure 16. List of peers by capacity and average age of hydro fleet

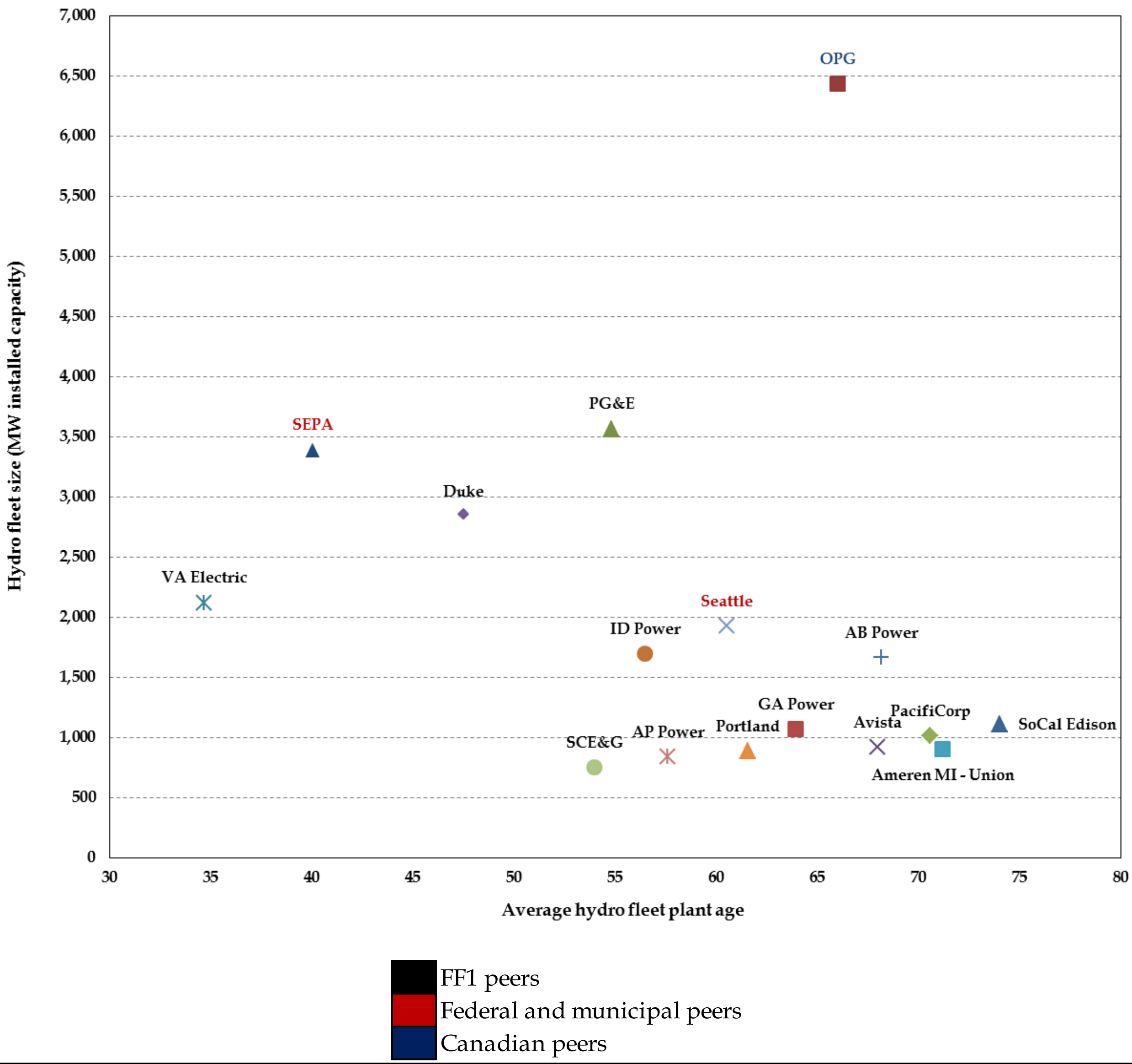

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Table 1

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%**
Source:	TFP _Dataset		TFP _Dataset	TFP _Dataset	Cost / Price	TFP _Dataset	MWH / O&M Quantity		MWH / Capacity			TFP _Dataset	Formula (Tornqvist Index)

[1] Growth rates are calculated logarithmically.

SEC Interrogatory #95

Issue Number: 11.1
Issue: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

Interrogatory

Reference:
SEC seeks to understand the interplay between the proposed rate-setting mechanism and the Hydroelectric Capacity Refurbishment Variance Account:

a. Please provide a list of all planned capital projects and their costs that are expected to be in-service between 2017 and 2021 that would be subject to the Hydroelectric Capacity Refurbishment Variance Account.

b. For each year between 2017 and 2021, please provide OPG's forecast total hydroelectric in-service additions.

c. Please explain how OPG has taken into account the Hydroelectric Capacity Refurbishment Variance Account in its determination of the appropriate incentive rate-setting adjustment for hydroelectric payment amounts.

Response

a) b) and c)

Incentive regulation decouples revenues and costs. The CRVA retains the link for a specific category of capital costs (i.e., capital and non-capital costs and firm financial commitments incurred to increase the output of, refurbish, or add operating capacity to a generating facility). The CRVA removes any potential economic disincentive to invest in a category of projects. As such, OPG is of the view that in addition to being required to implement O. Reg. 53/05, the CRVA is consistent with incentive regulation. Current approved rates include an amount associated with CRVA projects which will form the reference amount to be used for the CRVA. 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. 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.

Although OPG does not believe it is relevant to this proceeding, OPG has provided the information in requested in parts (a) and (b) in Charts 1 and 2, below.

Chart 1 lists the regulated hydroelectric capital projects currently expected to be fully or partially placed in service between 2017 and 2021 for which incremental revenue requirement is expected to be included in the CRVA. Chart 1 also includes the in-service amounts and total revenue requirement impact (including income tax deductions for Capital Cost Allowance) estimated for each of these projects during the 2017-2021 period.

Chart 1: CRVA-Eligible Projects - Expected In-Service Additions (Regulated Hydroelectric)

Project Name	In-Service Date(s)	Expected In-Service Additions (2017-2021) ($M)	Estimated Revenue Requirement Impact (2017-2021) ($M)
Sir Adam Beck I GS - G10 Major Overhaul & Upgrade	2017	30	10
Sir Adam Beck Pump GS - Reservoir Refurbishment	2017	58	24
DeCew Falls II GS - G2 Overhaul & Upgrade	2018	38	10
Ranney Falls GS Expansion Project	2019	65	-4
Sir Adam Beck I GS - G8 Major Overhaul & Upgrade	2020	27	3
Sir Adam Beck I GS - G2 Frequency Conversion	2020	43	5
Sir Adam Beck I GS - G1 Frequency Conversion	2021	45	2
R.H. Saunders GS - Reinsulate Field Poles	2019, 2020 & 2021	4	0
R.H. Saunders GS - Replace Discharge Rings	2019, 2020 & 2021	7	1
R.H. Saunders GS - Replace Runners	2019, 2020 & 2021	10	1
Stewartville GS - Rewind Generators & Refurbish Field Poles	2020 & 2021	9	1
		335	**52**

*Numbers may not add due to rounding

Chart 2 presents OPG's current expectation of total regulated hydroelectric in-service additions for the 2017-2021 period.

Chart 2: Expected Total In-Service Additions (Regulated Hydroelectric)

($M)	2017	2018	2019	2020	2021
	182	178	186	211	195

Board Findings

OPG has historically over-forecast hydroelectric base and project OM&A. The variance analysis of the base and project OM&A for the historical period 2010 to 2013 clearly indicates that actual spending has been consistently less than OPG had forecast. While OPG argues that the approved OM&A should be based on test period events and the business plan underpinning the application, OPG's forecasting methodology in the current proceeding is similar to that described in previous proceedings. In these prior periods, OPG has managed its hydroelectric operations with a lower than forecast base and project OM&A envelope, with only one year being a minor exception. OPG has confirmed that this trend of under-spending relative to forecast is likely to materialize in 2014 as well.[7] The pre-filed evidence and the testimony of OPG's witnesses confirm that the hydroelectric facilities have been operated safely, reliably and meet environmental standards.

When using a forward test year methodology, historical actuals are informative. In this case, the Board is influenced by OPG's consistent historic under spending but is still mindful of OPG's submissions with respect to the need for its proposed OM&A levels for the 2014 and 2015 period. In considering these factors, the Board finds that a base and project OM&A reduction of 4.2% for the regulated hydroelectric assets is appropriate. The reduction would be $9.5M in 2014 and $9.8M in 2015. As the majority of hydroelectric OM&A expense is related to compensation, this reduction to the hydroelectric OM&A budget for each of the two years will be subsumed into the disallowances for compensation discussed later in this Decision.

The Board finds the hydroelectric benchmarking to be inadequate. The analysis of externally provided OM&A, reliability and safety databases and the reporting is done by OPG, not an independent third party. Further, in the two previous cost of service applications and the current application, OPG has provided OM&A benchmarking information that only considers base OM&A which is only 50% of total OM&A expenses. The Board observes that OPG's nuclear business benchmarking is further advanced than its hydroelectric business benchmarking. The Board notes that OPG responded to Board direction from EB-2007-0905 regarding the benchmarking of the nuclear business. In 2009, ScottMadden Inc., assisted by OPG, identified key performance metrics for benchmarking and identified the peer groups for comparison. The nuclear cost benchmarking includes the allocation for corporate costs. OPG has adopted the

[7] Undertaking J3.13

ScottMadden methodology and format in full for its annual nuclear benchmarking reporting.

The Board orders OPG to have a comparable fully independent benchmarking study undertaken of the hydroelectric operations as soon as possible. The results of this study will be important in developing the incentive regulation methodology for OPG. Data used in the study should be as recent as possible (i.e. not older than 2013), without creating delays in the completion and dissemination of the study.

With respect to the Society's view that little weight should be placed on any benchmarking, the Board reminds the Society that the Act and O. Reg. 53/05 provide the Board with the authority to set payment amounts for OPG's regulated facilities. In addition the Memorandum of Agreement between OPG and the Shareholder requires that OPG's regulated assets be subject to public review and assessment by the Board. The Memorandum of Agreement also requires OPG to establish operating and financial results and measures that will be benchmarked against the performance of the top quartile of electricity generating companies in North America.

2.3 Hydroelectric Capital Expenditure and Rate Base

(Issues 2.1, 4.1, 4.2 and 4.3)

OPG seeks Board review of the capital expenditures proposed for 2014 and 2015. These capital expenditures have no impact on the payment amounts for 2014 and 2015 unless the projects are completed and go into service during this period. Board acceptance of the budget does however provide guidance to OPG with respect to the reasonableness of the budget.

OPG's historical and forecast capital expenditures for the previously regulated and newly regulated hydroelectric facilities are summarized below.

Table 7: Hydroelectric Capital Expenditures (excluding Niagara Tunnel)

$millions	2010 Budget	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Niagara Plant Group	36.2	28.5	30.7	27.2	30.9	27.1	28.8	20.9	24.8	34.3
Saunders GS	17.3	11.8	9.2	8.1	5.9	2.7	5.0	5.8	9.7	3.9
Newly Regulated *	80.2	68.6	76.7	61.4	91.4	80.1	71.4	60.5	91.0	100.0
Total	**133.7**	**108.9**	**116.6**	**96.7**	**128.2**	**109.9**	**105.2**	**87.2**	**125.5**	**138.2**

Source: Exh D1-1-1 table 2 and Exh L-1-Staff-2 Attachment 1 Table 8

* Note: Amounts for Newly Regulated shown under the Board Approved columns are OPG Budget amounts.

Filed: 2016-05-27
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Exhibit A1-3-2
Attachment 2
Page 3 of 43

OPG Regulated Hydro's performance is determined by benchmarking functional areas at each plant with its peer group segment.

Step 1: Identify Key Functions to Benchmark

Operations
Plant Maintenance
Waterways & Dams
Buildings & Grounds
Support
Public Affairs & Regulatory
Investment
Reliability

Step 2: Establish Relevant Peer Group Segments by Plant Size/Type

Micro
Small
Medium
Medium-Large
Large
Pumped Storage

Step 3: Conduct Data Analysis to Define Key Metrics & Quartiles (not OPG specific)

$ per Generating Unit
5 year average investment
Availability Factor
Forced Outage Rate

Step 4: Determine OPG's Benchmarkable Costs and adjust for regional wage and currency differences.

Approx 92% of OPG Regulated Hydro Costs are benchmarkable.

Step 5: Develop Comparative Reference Costs

Reference Cost is the amount that OPG would have spent if its Key Metric (e.g., $/Unit) was the same as the median for the segment

Step 6: Compare OPG's Regulated Hydro Performance to Peer Group

OPG Regulated Hydro's performance is determined by benchmarking functional areas at each plant against its peer group segment.

NAVIGANT ENERGY

OPG Regulated Hydro benchmarks at the second quartile(1) on the key cost metric and the key reliability metrics.

- » OPG's cost performance by functional area and reliability metric are shown in the table below.
- » The Partial Function(2) metric is considered by Navigant to be the key cost metric for benchmarking purposes because it includes the functions that are regularly performed at all hydro plants.
- » The Partial Function metric is calculated as Total Function Cost(3) less Public Affairs and Regulatory (PA&R, which is largely not controllable, and in OPG's case is dominated by Gross Revenue Charges In lieu of Property Tax ($204M) and the Gross Revenue Charges for water rental fees ($121M)).

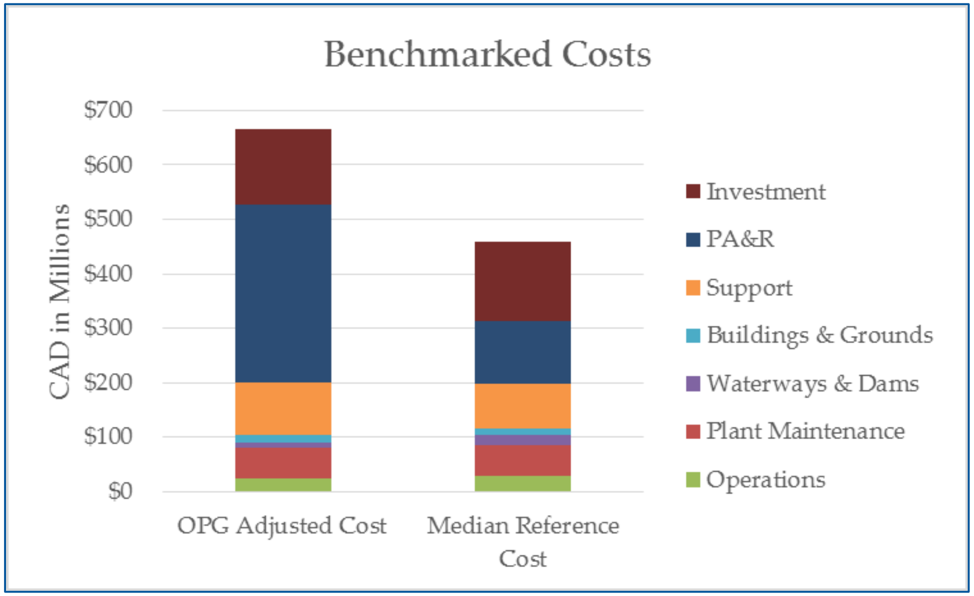
	Cost Performance Metrics (USD)									Reliability Metrics	
	Operations (K$/Unit)	Plant Maint. ($/MWh)	WW&D Maint. (K$/MW)	B&G Maint. (K$/MW)	Support (K$/MW)	Partial Function ($/MWh)	PA&R (K$/MW)	Total Function ($/MWh)	Invest-ment (K$/MW)	Avail-ability Factor (%)	Forced Outage Rate (%)
OPG Reg. Hydro	$87	$1.41	$1.2	$1.9	$11.8	$5.01	$40	$13.19	$17	92.8	1.3

Top Quartile
Second Quartile
Third Quartile
Bottom Quartile

(1) Quartiles are determined by comparing OPG's 2013 performance to the peer group values in each functional area.
(2) Partial Function Cost is the sum of Operations, Plant Maintenance, WW&D Maintenance, B&G Maintenance, and Support (all functions except for Investment and PA&R).
(3) Total Function Cost is the sum of Operations, Plant Maintenance, WW&D Maintenance, B&G Maintenance, Support, and PA&R (all functions except for Investment). OPG's Total Function Costs are bottom quartile on average primarily due to high PA&R Costs (Gross Revenue Charges)
(4) Costs on pages 3 and 13-20 are in USD; all other pages are in CAD.
(5) All costs in this report are for 2013.

NAVIGANT ENERGY

On the key Partial Function cost metric, benchmarked costs were lower than the Reference Cost.



Cost Category	OPG Actual (M$)	% of Total
Total Costs Benchmarked (4)	672.3	91.7%
Total Costs Not Benchmarked (5)	59.3	8.3%
Total Costs	***733.4***	***100%***

(1) Costs adjusted for regional wage differences
(2) The Reference Cost is the amount that OPG would have spent if its Key Metric in each function was the same as the segment median. See page 37 for details.
(3) Gap to Median Reference = OPG Adjusted Cost – Median Reference Cost
(4) Unadjusted costs
(5) Some cost categories are not benchmarked because they are not available and/or don't apply for the peer group and are not part of the benchmarking program design. See page 10 for details.

CAD in Millions	OPG Adjusted Cost	1st Quartile Reference Cost	Median Reference Cost	3rd Quartile Reference Cost	Gap to Median Reference (3)	% of Total Gap
Operations	23	21	28	47	(5)	-3%
Plant Maintenance	56	43	62	98	(5)	-3%
Waterways & Dams	9	10	18	39	(8)	-4%
Buildings & Grounds	16	6	13	35	3	1%
Support	97	35	83	189	14	7%
Partial Function	***201***	***114***	***203***	***408***	***(2)***	***-1%***
PA&R	326	28	115	218	211	104%
Total Function	***527***	***142***	***318***	***625***	***209***	***103%***
Investment	140	64	146	444	(6)	-3%
Total Costs Benchmarked (1)	***666***	***206***	***463***	***1,069***	***203***	***100%***

Top Quartile
Second Quartile
Third Quartile
Bottom Quartile

2013 Hydroelectric Operating Costs and Navigant Benchmarking

$million

1	454.7	Total PrevReg HE Operating Cost (EB-2013-0321 L-1-Staff-2 Attachment 1 Table 15)
2	331.3	Total NewReg HE Operating Cost (EB-2013-0321 L-1-Staff-2 Attachment 1 Table 16)
3	786.0	
4	733.4	Navigant Total Cost Starting Point (EB-2016-0152 Exh A1-3-2 Attachment 2 page 5 of 43)
5	59.3	Costs not benchmarked, Navigant report page 5 and 11
6	672.3	Unadjusted costs benchmarked by Navigant - Note that mathematical difference is $674.1M
		Note that the 672.3M vs 733.4M is the reference to 92% of costs benchmarked
7	666.0	Adjusted costs benchmarked by Navigant (regional wage differences) page 5 of 43
8	140.0	Investment - Navigant page 5 of 43 - Note - essentially depreciation cost from references for lines 1 and 2
9	526.0	TOTAL FUNCTION COST benchmarked by Navigant
10	326.0	PA&R - Public Affairs and Regulatory costs, large majority is GRC - Note consistent with GRC from references for lines 1 and 2
11	200.0	PARTIAL FUNCTION COST benchmarked by Navigant (recommended as key cost metric for benchmarking)
12	103.5	Base OM&A PrevReg HE (EB-2013-0321 L-1-Staff-2 Attachment 1 Table 15)
13	61.6	Base OM&A NewReg HE (EB-2013-0321 L-1-Staff-2 Attachment 1 Table 16)
14	165.1	Majority of OM&A consisdered for previous benchmarking
15	124.7	Total OM&A PrevReg HE (EB-2013-0321 L-1-Staff-2 Attachment 1 Table 15)
16	196.6	Total OM&A NewReg HE (EB-2013-0321 L-1-Staff-2 Attachment 1 Table 16)
17	321.3	Lines 15+16
18	59.3	Costs not benchmarked by Navigant (line 5 above)
19	262.0	
20	259.5	Adjust by 666/672.3 regional wage difference

Partial Function Cost

$5.01/MWh Navigant page 4 of 43, Second Quartile
Line 11 - $200M CF to USD @0.8011 (L-11.1-Staff-250) = $160.22
To calculate $5.01/MWh, HE generation would be 31.98 TWh
From EB-2013-0321 L-1-Staff-2 Attachment 1 Table 13, actual 2013 production was 31.3 TWh - $5.19/MWh
Line 20 - $259.5M - $6.64/MWh

Total Function Cost

$13.19/MWh Navigant page 4 of 43, Third Quartile
Line 9 - $526M CF to USD @0.8011 (L-11.1-Staff-25) = $421.38
To calculate $13.19/MWh, HE generation would be 31.95 TWh
From EB-2013-0321 L-1-Staff-2 Attachment 1 Table 13, actual 2013 production was 31.3 TWh - $13.46/MWh

Table 15

Operating Costs Summary - Previously Regulated Hydroelectric ($M)

Line No.	Cost Item	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	OM&A:						
1	**Base OM&A[1]**	59.4	50.1	60.2	61.6	74.6	68.6
2	**Project OM&A**	5.4	6.6	13.6	14.7	13.5	17.9
3	**Allocation of Corporate Costs**	22.4	22.0	24.5	26.1	29.8	26.9
4	**Allocation of Centrally Held Costs**	19.6	15.9	19.6	20.7	26.1	26.0
5	**Asset Service Fee**	2.1	1.6	1.8	1.6	1.5	1.7
6	**Total OM&A**	108.8	96.3	119.7	124.7	145.5	141.1
7	**Gross Revenue Charge**	252.2	259.4	244.5	249.5	253.3	269.5
	Other Operating Cost Items:						
8	**Depreciation and Amortization[2]**	63.5	65.6	70.0	80.5	82.1	81.9
9	**Income Tax**	29.9	33.4	32.3	(0.1)	48.5	61.5
10	**Capital Tax**	2.8	N/A	N/A	N/A	N/A	N/A
11	**Property Tax**	0.1	0.2	0.2	0.2	0.3	0.3
12	**Total Operating Costs**	457.4	454.9	466.6	454.7	529.5	554.4

Notes:

1 2011 Actual Base OM&A cost includes an extraordinary credit of $19.0M in Niagara Plant Group related to the reversal of a provision for the environmental cleanup of Lake Gibson (DeCew Falls GS).

2 From Ex. L-01.0.1 Staff-002, Attachment 1, Table 27, line 5.

Numbers may not add due to rounding.

Table 16

Operating Costs Summary - Newly Regulated Hydroelectric ($M)

Line No.	Cost Item	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	OM&A:						
1	**Base OM&A**	100.0	106.0	102.9	103.5	113.4	113.7
2	**Project OM&A**	39.8	21.6	20.3	23.1	24.5	32.1
3	**Allocation of Corporate Costs**	31.4	32.3	36.6	35.2	42.1	39.6
4	**Allocation of Centrally Held Costs**	19.0	25.1	33.1	31.8	49.6	48.7
5	**Asset Service Fee**	3.6	3.4	3.3	3.0	2.9	3.0
6	**Total OM&A**	193.8	188.4	196.2	196.6	232.5	237.2
7	**Gross Revenue Charge**	54.9	67.7	65.6	75.4	75.6	77.5
	Other Operating Cost Items:						
8	**Depreciation and Amortization**[1]	58.3	58.0	58.6	59.0	62.2	63.1
9	**Income Tax**	N/A	N/A	N/A	N/A	31.4	43.2
10	**Capital Tax**	N/A	N/A	N/A	N/A	N/A	N/A
11	**Property Tax**	0.2	0.2	0.2	0.2	0.2	0.2
12	**Total Operating Costs**	307.2	314.3	320.6	331.3	401.9	421.2

Notes:

1 From Ex. L-01.0.1 Staff-002, Attachment 1, Table 27, line 11.

Board Staff Interrogatory #25

Issue Number: 4.2
Issue: Are the proposed nuclear capital expenditures and/or financial commitments (excluding those for the Darlington Refurbishment Program) reasonable?

Interrogatory

Reference:
Ref: Exh D2-1-3, Attachment 1, Tab 1

The referenced evidence is a request for approval of $9.7M (over the approved execution-full Business Case Summary (BCS)) for the Darlington Operations Support Building Refurbishment. The original project cost was forecasted to be $46.7M[5]. The Engineering, Procurement, Construction (EPC) contract is identified as being $14.4M over the original budget.

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[5] EB-2013-0321, Exh. D2-2-1, Attachment 8-4

a) Please explain the root causes for the cost variance and what actions OPG has taken to better manage projects in future to prevent such over-variances.

b) What was the final project cost?

c) Please confirm whether the OPG Project Management cost for project oversight was $3.7M. If not, what was the final OPG Project Management cost?

d) Please summarize the role of OPG Project Management in project oversight for the Darlington Operation Support Building Refurbishment.

e) What is the typical cost as per cent and/or dollars for OPG Project Management?

Response

a) The root causes of the cost variance are as follows:

    i) The estimate at the time of the full release approval was inadequate. The full release for the project was approved prior to the completion of detailed engineering, which was not in accordance with established practices. OPG has updated the project approval process to ensure that the required deliverables for each approval gate are completed and that the project has an appropriate class of estimate for the approval gate.

ii) Engineering assumptions were not validated prior to the full BCS approval. The main assumption was that the building rehabilitation would be executed to commercial standards. However, due to the building being inside the nuclear power plant, that was not entirely feasible. There was insufficient contingency allocated for invalidated design assumptions. Collaborative front-end planning and the Gated process as described in Ex. L-4.4-15 SEC-43 will address the validation inadequacy and engineering assumptions on future projects.

iii) Changes from the preliminary engineering requirements were identified during detailed engineering to meet code requirement and reduce future maintenance costs for the heating, ventilation, and air condition systems.

iv) The amount of power available from the station was limited without costly upgrades to the power supplies, which necessitated modifications to use lower power consumption LED lighting. While this increased project costs, it will result in lower OM&A costs in the future.

v) There were some required scope additions to address discovery issues such as mold and asbestos.

b) The project, which is still completing close-out activities, is currently projected to cost $62.0M by the project team.

c) A final OPG project management cost is not available until all close-out activities have occurred.

d) OPG Project Management conducted project oversight for the Darlington Operation Support Building Refurbishment in accordance with N-STD-AS-0030 Project Oversight Standard. Oversight activities include:

i) Regular progress meetings to review risks as well as schedule and cost performance
ii) Monitoring of project metrics (safety, quality, schedule and cost)
iii) Meets with vendor
iv) Perform observations, and review documentation
v) Regular walk downs of the jobsite for safety compliance to the applicable safety management program, workmanship and to assess progress.

e) The typical OPG Project Management cost is 10% of the total cost.

4.1. Proposed Performance Measures

OPG proposes to report the company's annual benchmarking performance measures. The hydroelectric performance measures set out in Chart 11 are the same as the key performance areas filed in OPG's prior payment amounts application (EB-2013-0321, Ex. F1-1-1, Appendix B). The nuclear performance measures in Chart 12 are the benchmarks used in the company's annual nuclear benchmarking report.

Chart 11: Annual Hydroelectric Performance Measures

Hydroelectric Performance Measures	
Category	**Measure**
Safety	All Injury Rate (per 200k hours)
	Environmental Performance Index (%)
Reliability	Availability Factor (%)
	Equivalent Forced Outage Rates (%)
Cost Effectiveness	OM&A Unit Energy Cost ($/MWh)

Total Generating Cost* ($/MWh)	Forecast 2016	Business Plan 2017	Business Plan 2018	Business Plan 2019	Projection 2020	Projection 2021
Enterprise	[redacted]					
Nuclear	63.2	75.6	74.6	74.5	77.1	77.3
Hydroelectric	[redacted]					

* Total Generating Cost is calculated as: (OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures) divided by OPG generation adjusted for surplus baseload generation losses

The business plan builds on efficiencies achieved to date, with a focus on pursuing further opportunities for cost effectiveness improvement across the generating business units and support services. In 2016, OPG adopted Total Generating Cost (TGC) per MWh as an enterprise-wide measure of operational cost effectiveness, in addition to TGC per MWh metrics for each of the Nuclear and Hydroelectric operations. Enterprise-wide targets for TGC per MWh range from approximately [redacted] over the 2017-2021 period. The [redacted] in the TGC over the planning period reflects [redacted] the Darlington refurbishment outages, as well as [redacted] large hydroelectric project [redacted] the Sir Adam Beck I GS power canal liner rehabilitation. The TGC targets are adjusted for hydroelectric generation losses due to surplus baseload generation conditions.

A prominent feature of the OEB's incentive regulation framework is to encourage productivity savings. In particular, for the hydroelectric business, OPG's application requests regulated rates that reflect annual increases of less than inflation. For the nuclear business, OPG's application includes a stretch factor that reduces recoverable OM&A expenses below planned levels. This will challenge OPG to find additional cost savings within its operations, beyond those already reflected in planned cost levels. In order to improve profitability, OPG must identify and implement such additional efficiency improvements starting as early as 2017, with cost savings growing over time.

Benchmarking studies have indicated that OPG has reduced the gap to the average nuclear staffing benchmark from 17% in 2011 to 4% in 2014. With further sustained headcount reductions since 2014, OPG is confident that its current and planned nuclear staffing levels are at the benchmark level. OPG also benchmarks the costs of the Pickering and Darlington stations against other nuclear stations. On a per unit, basis, OPG's all-in operating and capital expenditures for the stations continue to be amongst the lowest in the industry. OPG's nuclear stations will continue to target strong reliability performance, including a top-quartile forced loss rate performance of 1.0% for the Darlington station and a 5.0% forced loss rate for the Pickering station consistent with planned investment levels, for the 2017-2019 period. The operational targets and associated initiatives for the Nuclear business unit are found in Appendix 4, with OPG's Nuclear strategic planning framework included in Appendix 5.

The hydroelectric stations continue to exhibit strong cost effectiveness performance, with regulated fleet operating costs, excluding Gross Revenue Charge (GRC) payable to the Province, benchmarking in the second quartile relative to peers. Operating targets for 2017-2019 include strong fleet-wide hydroelectric availability factors averaging [redacted] per year. The operational targets and associated initiatives for the Renewable Generation & Power Marketing (RG&PM) business unit are found in Appendix 6.

The operational targets and associated initiatives for OPG's centre-led Business and Administrative Services organization, which is focused on providing cost effective information technology, supply chain and real estate services in support of business priorities, are found in Appendix 7.

Production

Total planned OPG production ranges from [redacted] per year over the 2017-2019 period, [redacted] forecast in 2016 and [redacted] in 2021. This reflects a declining trend in the Darlington production due to refurbishment outages starting in October 2016, including a partial overlap starting in 2021 between the second and third unit refurbishments.

The following other main factors affect the variability in the planned nuclear production over the period:
- Incremental planned outage days at the Pickering station to enable continued operations in line with the business case approved by the Board in November 2015;
- Single Fuel Channel Replacement outage work at the Pickering station in 2019 and at the Darlington station in 2017 and 2020;