Board Staff Interrogatory #224

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

Interrogatory

Reference:
Ref: Exh A1-3-2 page 5
At page 5, OPG states that:

[it] proposes a price-cap index rate-making methodology for the company's regulated hydroelectric generation assets, modeled closely on 4GIRM method set out in the RRFE. Of the three rate-making methods in the RRFE, OPG believes that a price-cap index is best suited to the circumstances of the company's hydroelectric generation facilities.

Is OPG saying that a mechanism like 4GIRM will typically make sense for the Company going forward or is its comment limited to the next five years?

Response

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. If there were significant changes to the hydroelectric business environment such that the hydroelectric business ceased to be in a steady state, it is conceivable that a price-cap index method could cease to be appropriate.

Board Staff Interrogatory #225

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

Interrogatory

Reference:
Ref: Exh A1-3-2 pages 8-9

OPG states that

> With the Niagara Tunnel Project now in service, OPG's regulated hydroelectric generation facilities are in a relatively stable, steady state that is conceptually consistent with a price-cap index form of IR. The company believes that, of the three options set out in the RRFE, the 4GIRM approach is best suited to the state of its regulated hydroelectric generation facilities...
>
> Notwithstanding the negative productivity factor identified by the LEI TFP study, OPG is proposing a productivity factor of zero...
>
> Although LEI's TFP study concludes that a -1% productivity factor is appropriate for OPG's regulated hydroelectric facilities, OPG recognizes that the OEB has declined to accept a negative productivity factor in the context of electricity distribution. OPG therefore proposes a 0% productivity factor for the 2017-2021 IR period. This increase to the productivity factor essentially creates an additional 1% stretch factor for OPG's hydroelectric facilities during each year of the IR period, relative to the industry trend identified in the TFP study.

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?

Response

The following response has been prepared by LEI.

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. NTP has also added approximately $100,000 to annual O&M expenses. Due to the specific nature of this asset in relation to OPG's SAB generating complex, this investment is unlikely to reduce the O&M expenses for the other assets in the fleet.[2] As such, although output is increasing, some inputs (O&M) experienced a step-change. However, it is important to note that the NTP provides a small increment in total production for the regulated hydro fleet - 1.5 TWh would account for less than 5% of OPG's portfolio net generation in 2014.

b) Please see answer to a) above. Also, please take note of the fact that NTP is a single, unique opportunity. LEI is not aware of any similar opportunities for OPG in the coming years. It is not a sustainable ramp-up in capex across OPG's hydroelectric fleet. Therefore, it is unlikely that OPG could experience superior productivity growth for an extended period of time from projects like NTP.

c) LEI's TFP study does capture the results of the Niagara Tunnel Project as it was completed in March 2012 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

[1] Ontario Power Generation. *EB-2013-0321 Exhibit D1 Tab 2 Schedule 1. Page 2* September 27, 2013.
[2] Ontario Power Generation. *EB-2013-0321. Appendix B: Niagara Tunnel Financial Model – Assumptions.* September 27, 2013.

one-year TFP improvement but then revert back to steady state in subsequent years, but for variations in hydrological output.

Board Staff Interrogatory #226

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

Interrogatory

Reference:
Ref: Exh A1-3-2 pages 9, 20-22

At page 9, OPG states:

> Total cost benchmarking is an important component of each rate-setting model in the RRFE and plays an important role in OPG's proposed IR frameworks for both hydroelectric and nuclear assets. Under the 4GIRM method, in which OPG's hydroelectric IR proposal is based upon, an applicant's benchmark performance is used to determine the stretch factor in the distributor's price-cap index. Similarly, OPG proposes that the hydroelectric stretch factor be determined based on the hydroelectric total cost benchmarking study conducted by Navigant Energy Consulting Inc. ("Navigant"), which is filed as Attachment 2 to this schedule.

At page 20, OPG states that "Navigant benchmarked approximately 92% of OPG's 2013 costs attributable to its regulated hydroelectric operations against a peer group".

At pages 21-22, OPG states that:

> Navigant identified Partial Function Cost as the key cost metric for benchmarking purposes to assess OPG's relative performance to its peers... OPG has set the proposed hydroelectric stretch factor based on the company's performance on Partial Function Cost.

a) Please confirm that for 4GIRM the OEB uses an *econometric* model of *total* cost to perform benchmarking exercises. Total cost includes the cost of all plant and not just capital expenditures. Total cost would thus be unusually high in the aftermath of a capex surge.

b) In what sense then can the Navigant study be deemed a total cost benchmarking study? Does the study effectively address OPG's recent hydroelectric capex surge?

c) Please explain the basis for the statement that the Navigant study addressed 92% of OPG's cost.

d) Approximately what percentage of OPG's total hydroelectric cost (excluding water fees) is its proposed stretch factor actually based on?

Response

a) OPG understands that in applying the 4GIRM approach to the distribution industry, the OEB has accepted a quantitative approach involving an econometric model to determine the stretch factor that will apply to each distribution utility for the following year.

OPG further understands that total costs cost includes the cost of all plant and not just capital expenditures. The OEB regulates a large number of distribution utilities and has established requirements ensuring that information is maintained in a specific form. The OEB also requires distributors to report by a specific date to enable the OEB to produce the model results in time for incorporation into the OEB's annual rate setting process. OPG understands that there are very few regulatory jurisdictions with a sufficiently large number of regulated companies in a single industry that would support such an approach.

OPG has proposed to follow the 4GIRM approach reflected in the RRFE with necessary modification to reflect differences between the electric distribution industry and the generation industry. The approach to determining the stretch factor will necessarily differ, as the above circumstances supporting the OEB's electric distribution industry benchmarking do not translate into the regulation of electricity generation.

b) and c)

The Navigant study is a total cost study in that it considered the total of OPG's costs, and identified cost categories that could reasonably be used as for benchmarking against the identified peers, using available data. Navigant determined that 92% of OPG's regulated hydroelectric cost categories were appropriate for benchmarking, the breakdown of which is provided in Ex. A1-3-2, Attachment 2, p. 5.

The Navigant Study provided reasons for not including specific cost categories in its chosen benchmarking metric. OPG understands that the purpose of using benchmarking in the context of assigning a stretch factor is to measure relative performance. In OPG's view, an effective measure balances comprehensiveness and comparability, and the Navigant study benchmarking metric achieves that balance.

Benchmarking studies incorporate results from a variety of companies with various capital spending trends resulting in varying impacts on capacity, production, labour and non-labour costs. As discussed in Ex. L-11.1-1 Staff-225, the Niagara Tunnel project did not impact capacity but does result in an annual increase in O&M costs of $0.1M and an average increase of 1.5TWh in annual production, which would be reflected in the benchmarking analysis.

d) The 2013 costs benchmarked in the Navigant Study represent 69% of the total 2014/2015 annualized hydroelectric revenue requirement, less water fees.

The total costs benchmarked by Navigant were $672.3M, per Ex. A1-3-2 Attachment 2, Page 5. This was a 2013 cost amount.

The stretch factor applies to base rates set for the 2014 to 2015 period. Excluding water fees, the annualized total hydroelectric revenue requirement on which base rates were set was $975.0M. The chart below shows the annualized 2014/2015 amount.

	Revenue Requirement	**GRC (Water fees)**	**Annualized net Amounts**	**Reference EB-2013-0321 Payment Amount Order**
	(a)	(b)	(c) = (a - b) / 2	
Previously Regulated	$1652.8	$548.0	$552.4	Appendix A, Table 1, col. (i)
Newly Regulated	$998.3	$153.1	$422.6	Appendix A, Table 2, col. (i)
Total	$2,651.1	$701.1	$975.0	

$672.3 divided by $975.0 equals 69%.

Board Staff Interrogatory #227

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

Interrogatory

Reference:
Ref: Exh A1-3-2 pages 12-15

In section 2.3.1, OPG documents the methodology for its proposed inflation factor. The inflation measure, or Input Price Index (IPI_{OPG}), uses that same data and formulation as the IPI_{dx} used for the current electricity distributor Price Cap IR and Annual Index IR plans, and only differs in having differing weights for labour (12% for OPG based on hydroelectric generation industry statistics versus 30% for electricity distributors) and non-labour (88% for OPG versus 70% for electricity distributors). OPG has calculated a preliminary IPI_{OPG} (annual percentage change) of 1.8% based on March 2016 StatsCan data. OPG proposes that it would file an annual hydroelectric IRM payment amounts adjustment application in each year and that the "payment amounts adjustment would be based on the values for the GDP-IPI (FDD) and Ontario AWE at the time of those applications."

a) The OEB currently calculates and posts the IPI_{dx} and the derivation of it based on StatsCan's publication of Q2 national account data, as being the most current information available in time for the processing of IRM rate adjustment applications for January 1 of the following year. To ensure consistency of the data on which OPG's inflation index is based with that used for electricity distributors, the OEB could calculate and post the IPI_{OPG} and IPI_{dx} in early September of each year. Please confirm that this timing is acceptable or explain why not.

b) Based on the 2016 Q2 National Accounts data released by Statistics Canada on August 31, 2016, which data are being used by the OEB to calculate the IPI for 2017 electricity distribution IRM rate adjustments, OEB staff has calculated the IPI_{OPG} for 2017, as proposed by OPG, to be 1.7%, This change reflects routine data revisions in the published StatsCan data. Please confirm this updated IPI based on OPG's proposed methodology. In the alternative, please explain.

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	
2015	114.4	114.8	115.6	116.1	115.225	**1.6%**	**88%**	$ 962.73	**2.6%**	**12%**	**105.5**	**1.7%**

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

Response

a) As OPG is using the same indices as the distributors, and is using the same method of calculation as amended to reflect OPG's index weightings, OEB Staff's proposal is both transparent and efficient. In the context of OPG's proposed annual update process, the proposed timing of early September for the publication of the IPI for OPG appears reasonable.

b) The 1.8% I-factor proposed by OPG more accurately reflects the data available from Statistics Canada. OPG used the same data as OEB Staff and the same annual average values, but did not round the result until the last stage of the calculation (calculating the final I-factor value). The annual average values for GDP-IPI-FDD are presented to three decimal places, whereas the annual change in the AWE-All Employees-Ontario is presented to two decimal places.

Applying the weighting proposed by OPG and used by OEB Staff in this example results in an I-factor of 1.75 % or 1.8% when rounded to one decimal, as presented in the following chart:

Index	Value	Weight	I-Factor Value (*rounded to two decimals*)
GDP-IPI-FDD	1.631	0.88	1.44
AWE	2.61	0.12	0.31
I-Factor	n/a	1.00	1.75

Board Staff Interrogatory #228

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

Interrogatory

Reference:
Ref: Exh A1-3-2 page 22
Ref: *Report of the Board: New Policy Options for the Funding of Capital Investments* (EB-2014-0219), issued September 18, 2014
Ref: *Report of the OEB: New Policy Options for the Funding of Capital Investments: Supplemental Report* (EB-2014-0219), issued January 24, 2016.

In section 2.4, OPG states that it would be eligible to apply for an Incremental Capital Module (ICM) for qualifying hydroelectric projects. OPG states that any such request would be prepared in accordance with OEB policy, and refers to the *Report of the Board: New Policy Options for the Funding of Capital Investments* (EB-2014-0219), issued September 18, 2014 (the ACM Report).

On January 24, 2016, the OEB issued its *Report of the OEB: New Policy Options for the Funding of Capital Investments: Supplemental Report* (EB-2014-0219). This Supplemental Report clarified and revised certain matters, including revising the methodology and the formula for the materiality threshold.

Please explain any differences from the current ACM/ICM policy applicable to electricity distributors that OPG proposes for any ICM or ACM treatment for its prescribed hydroelectric generation assets, if its proposal is approved by the OEB.

Response

OPG expects that any future application for ACM or ICM funding for qualifying hydroelectric capital projects would be prepared in accordance with OEB policy, and will therefore reflect the amendments to the policy as reflected in the January 24, 2016 *Report of the OEB; New Policy Options for the Funding of Capital Investments: Supplemental Report (EB-2014-0219)*, except for the two inapplicable elements of the OEB policy identified in the following paragraph.

There are two main differences in the application of an ACM/ICM to a generation utility. First, since OPG does not have a Distribution System Plan, the baseline for an ICM application would be the capital plan underpinning the company's approved payment amounts. In this application, that would be the capital plan underpinning the hydroelectric EB-2013-0321 payment amount application and decision. Second, the growth factor used to calculate the ACM/ICM materiality threshold is not applicable to a generator, since it is based on assumptions and metrics that are only relevant for a distributor (e.g., customer numbers).

Board Staff Interrogatory #229

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

Interrogatory

Reference:
Ref: Exh A1-3-2 pages 20-22

In section 2.3.3.2, OPG documents its proposed stretch factor of 0.3, which corresponds to the middle (median) stretch factor used for electricity distribution rate adjustments under the current 4th Generation IRM (Price Cap IR) plan. OPG states that its proposal is based on the independent benchmarking study conducted by Navigant, which is provided in Exh A1-3-2 Attachment 2.

OPG states that:

> OPG has set the proposed hydroelectric stretch factor based on the company's performance on Partial Function Cost. Navigant found that OPG's regulated hydroelectric facilities are effectively at the median for the hydroelectric generation industry on this measure. Using the range of stretch factors applied in the 4GIRM method, OPG's performance should result in a 0.3% stretch factor.

a) As noted by OPG, the Navigant study uses a Partial Function Cost benchmarking. The LEI study (Exh A1-3-2 Attachment 1) is a Total Factor Productivity study, and the price cap rate adjustment methodology is also inherently to address all costs of production not addressed by deferral and variance accounts. Please explain why the Navigant benchmarking study, being a "partial function cost benchmarking" study, is an appropriate basis for a stretch factor.

b) Chart 6 summarizes the differences between OPG's hydroelectric generation assets versus those of the sample that Navigant benchmarked OPG against, with respect to characteristics such as median age, median group size and median unit size (the latter two in terms of generation size (MW)). Chart 6 demonstrates that OPG's characteristics differ markedly from those of the median for the benchmarking group. Based on these differences, please provide further explanation as to why OPG concludes that the median stretch factor is reasonable.

c) What alternative approaches or analyses did OPG conduct (or have conducted) in considering what would be a reasonable stretch factor or consumer productivity dividend?

Response

a) The Partial Function Cost metric is the appropriate basis for determining the stretch factor because the costs it measures are both controllable and, critically, common to the peers in Navigant's study. Navigant calculated the Partial Function Cost metric by subtracting Public Affairs and Regulatory (PA&R) costs, which are largely not controllable, from Total Function Costs (Ex. A1-3-2 Attachment 2, page 3). OPG's hydroelectric PA&R costs consist almost entirely of GRC, which is not borne by any of the peer utilities in Navigant's study. The Partial Function metric for OPG's regulated hydroelectric facilities is comprised of remaining, controllable costs that pertain to Operations, Plant Maintenance, Waterways and Dams, Buildings and Grounds and Support services. These are the appropriate costs for benchmarking the performance of OPG's regulated hydroelectric facilities relative to the peer group, which is why they form the basis of the proposed hydroelectric stretch factor.

b) Navigant normalized for differences in the peer group (e.g., the types of stations, their capacity or unit size, and age) by segmenting the peer group in accordance with the types of costs being benchmarked (please see Ex. A1-3-2, Attachment 2, page 9 and Appendix B). This normalization addresses the variance between OPG and other members of the peer group and provides for a more meaningful comparison of the costs comprising the Partial Function metric noted in part a) above that underpin OPG's stretch factor.

Navigant benchmarks each functional area separately because each function has different cost drivers, based on a statistical analysis that Navigant performs regularly. The statistical analysis helps to determine the peer groups and the normalizing factors for each function. For example, there is a strong correlation between Operations Cost and the number and size of generating units. Therefore the peer groups for Operations are defined by the Average Unit Size and costs are normalized by the number of generating units (i.e., the primary metric used for benchmarking is $/Unit). Another example is with Plant Maintenance, where there is a strong correlation between costs and energy generated (MWh), station size, and station age. Therefore the peer groups for Plant Maintenance are defined by station size and age and costs are normalized by MWh. The comparisons are meaningful since station groups in the same peer group should have normalized costs in the same range for each function.

c) None.

Board Staff Interrogatory #230

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

Interrogatory

Reference:
Ref: Exh A1-3-2 pages 9, 20-22
Ref: Exh A1-3-2 Attachment 2

OPG describes its rationale for proposing the stretch factor of 0.3%. In large part, it uses the general findings of the Navigant hydroelectric benchmarking study (Exh A1-3-2 Attachment 2) that OPG is generally in the median of its comparator group as supporting the choice of the middle or median, with the 0.3% being the OEB's determined stretch factor for the middle cohort for electricity distributors.

As is noted in footnote 1 on page 3 of the Navigant study, the Navigant benchmarking compared OPG's performance relative to the comparator group for one year (2013) only.

One year's worth of performance data may be volatile, particularly with respect to hydroelectric generation assets, which are more capital-intensive and often longer-lived than even for other capital-intensive industries, including network-based industries such as telecommunications and electricity distribution. Capital investments can be particularly "lumpy", where a major investment in a short period of time may obviate significant capital investments in the future and facilitate significant operating efficiencies in subsequent years. Comparing performance between different utilities may not necessarily be "apples-to-apples" depending on where each utility is on the investment and life cycle of its own assets.

a) What information does OPG have on its performance relative to a comparator group of hydroelectric generators for a longer period? If it has such data, please provide any such studies or, at a minimum, a summary of the results for each such available study.

b) OPG has not proposed that the stretch factor be updated annually, as is done for Ontario's electricity distributors since 3rd Generation IRM was implemented in 2009, but that the stretch factor be fixed for five-year term of the hydroelectric IRM plan.
   i. Please explain why annual benchmarking to update the stretch factor has not been proposed as part of the hydroelectric IRM plan.

ii. If benchmarking were to be done annually to update the stretch factor, certain checks and balances would be needed to ensure the integrity and objectivity of such benchmarking analysis. This could include oversight by the OEB, or external auditability of the methodology and results.

Please provide OPG's views on what changes would be needed in conducting of an annual benchmarking analysis, or in the reporting, oversight and review of any such study, to facilitate the use of such an annual benchmarking study to update the stretch factor for each annual price cap adjustment.

Response

a)

As stated in Ex. A1-3-1, p. 2, OPG has historically made extensive use of benchmarking to help plan and execute the company's nuclear and hydroelectric businesses. Beginning in EB-2010-0008, OPG has provided the OEB and stakeholders with a summary of unit energy cost benchmarking results for 2006 onwards. Please see EB-2010-0008, Ex. F1-1-1, pages 11 - 23; EB-2013-0321, Ex. F1-1-1, pages 11 - 22.

As noted in the evidence referenced in the previous paragraph, OPG participates in Navigant's generation benchmarking program, which includes OM&A unit energy cost. The benchmarking results, both including and excluding the Pump Generating Station, have been strong and consistent, remaining in the first quartile from 2006 to 2011.

OPG also measures EUCG OM&A unit energy cost benchmarking results, which it has filed in prior payment applications. In EB-2013-0321 (Ex. F1-1-1, chart 5b), OPG provided benchmarking results for 20 of the newly regulated plants, covering the period from 2009 to 2011. During the stakeholder consultation session held on December 17, 2015, OPG provided results for 25 plants (combined newly and previously regulated plants) on the same measure for 2010 through 2012[1]. Both sets of EUCG benchmark results show that between 70% and 85% of benchmarked plants are in the top two quartiles.

b) i)

OPG has not proposed annual benchmarking because it is not necessary, given that OPG's benchmarking results have been historically consistent. As noted by LEI in their TFP report at Ex. A1-3-2, Attachment 1, p. 44, hydroelectric generation is a mature

[1] http://www.opg.com/about/regulatory-affairs/stakeholder-information/Documents/Payment_Amounts/Overview_Regulated_Hydroelectric_Stations.pdf

industry with little technological innovation opportunities or cost reduction opportunities through economies of scale. As a result, benchmarked cost results are relatively stable. The implementation of improvement opportunities tends to occur over a number of years typically as part of a program (e.g. runner upgrades), tempering major changes in cost in a short period. In addition, as improvement opportunities are typically widely shared throughout the industry, there may be little if any changes in relative performance in benchmarking results.

In addition, OPG believes that an annual regulatory review of OPG-specific cost benchmarking would not be consistent with a mechanistic incentive rate-setting process. The OEB is able to set the stretch factor for electric distributors mechanistically because it can rely on a single econometric study that applies to all distributors. Since the OEB regulates a sufficiently large number of distributors, it can ensure that the necessary information is available on an acceptable schedule. In such circumstances, annual benchmarking is a relatively efficient and predictable process that provides meaningful performance measures for a large, relatively consistent group of regulated parties. In contrast, annual benchmarking for OPG is a singular exercise that may require the exercise of judgment and adjustments depending on the data available each year; it cannot be updated in the same, purely mechanistic fashion.

b) ii)

The answer to question b) i) notwithstanding, if the OEB decided that annual hydroelectric benchmarking may be required, OPG believes it would be reasonable to monitor benchmarking results over the first generation of IRM and consider whether annual setting of a stretch factor is warranted. Such an approach would be consistent with evolution of the OEB's approach to incentive regulation for electricity distributors. Given the stability of OPG's benchmarking results discussed in part a), and the mature state of the hydroelectric generation industry, OPG believes there is little risk of large swings in costs or revenues during the intervening 2017-2021 IR term.

If the OEB were to decide that the stretch factor should be updated annually based on benchmark performance during the current IR term, OPG believes that the benchmarking should be conducted on the same basis throughout the IR Term. In that circumstance, OPG would propose that the Navigant benchmarking study continue to be used to set the stretch factor, updated annually. OPG believes that Navigant would produce updated reports on the same independent, expert basis as it has produced the report filed in evidence in this proceeding. OPG believes that no more oversight and validation of Navigant’s work would be required in the context of an annual adjustment application than is required in this proceeding. As is the case under 4GIRM, the annual adjustment process should be mechanistic, based on an established range of stretch factors.

Board Staff Interrogatory #231

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

Interrogatory

Reference:
Ref: Exh A1-3-2 pages 6-7, 22-23
Ref: Exh H1-1-1

In section 2.6, OPG indicates that:

> OPG will continue to report the balances in its deferral and variance accounts as directed by the OEB in EB-2010-0008. OPG intends to monitor these balances and may make an application to dispose of these account balances during the 2017-2021 period.

a) What criteria will OPG use to determine whether to make an application to dispose of DVA accounts during the 2017-2021 period?

b) Please identify which DVAs OPG foresees will be reported on, but for which disposition is not expected to occur during the term (2017-2021) of the hydroelectric IRM plan.

Response

a) OPG will determine whether to make an application to dispose of DVA accounts based on the materiality of the outstanding unapproved balances, consumer impacts (including intergenerational equity), and regulatory efficiency.

   As described in Ex. A1-3-3 and H1-1-1, OPG is proposing to file a mid-term production review application in the first quarter of 2019 that would include a request to dispose of applicable audited deferral and variance account balances as at December 31, 2018. Most of the deferral and variance account balances expected to be brought forward as part of that application would reflect amounts accumulated over the period between January 1, 2016 to December 31, 2018 in addition to any unamortized portions, as at December 31, 2018, of previously approved amounts with recovery period extending beyond December 31, 2018.

b) OPG does not expect to dispose of balances in the Mid-term Nuclear Production Variance Account and the Rate Smoothing Deferral Account during the 2017-2021 term. The Mid-term Nuclear Production Variance Account is proposed to begin recording variances after the conclusion of the mid-term review, currently estimated to be in 2019.

The accumulated balances in this account would be put forward for disposition as part of OPG's rate application for payment amounts starting in 2022.

The Rate Smoothing Deferral Account will not be presented for clearance until the recovery period which begins after the Darlington Refurbishment Program ends, which is not expected to be within 2017-2021 term.

Clearance of the Pension & OPEB Cash Versus Accrual Differential Account is subject to the outcome of the OEB's generic proceeding on pension and OPEB costs. As a result, OPG is unsure whether this account will be cleared during the 2017-2021 term.

Board Staff Interrogatory #232

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

Interrogatory

Reference:
Ref: Exh A1-3-2
The current application is the first generation IRM plan for OPG's regulated hydroelectric generation assets. Reviews on how plans have performed have formed a significant part of the development of 2nd generation and subsequent IRM plans for both electricity and natural gas distributors as regulated by the OEB.

a) While it is premature at this point to deal with specifics, does OPG concur with the concept of having a review towards the end of the current plan (i.e., during 2020 or 2021)? Please explain the response.

b) Please provide any views that OPG has at this point regarding the potential or likely issues, nature or scope of any such review.

Response

a) As it did in the preparation of this application, OPG expects to conduct a stakeholder consultation process in advance of the company's next rate application. That consultation process would include a review of the current hydroelectric IRM framework, and any proposed changes as a result of lessons learned over the course of the IRM term. OPG's hydroelectric incentive rate-setting framework is necessarily specific to the company; it does not apply to other entities regulated by the OEB. As a result, OPG believes that the rate application consultation process is the appropriate mechanism to provide the OEB and other parties with an opportunity to review the 2017-2021 IRM plan.

b) As stated in the preamble to question a), OPG agrees that it is premature to deal with specifics of any issues that may be discussed in the future stakeholder consultation process. OPG expects that the nature or scope of issues in that consultation process will be informed by a number of factors, including the OEB's Decision and Order in the current proceeding, the company's experience operating under IRM in the intervening years, and the needs and preferences of its customers.

Board Staff Interrogatory #233

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

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 1 page 8

The LEI report states: "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."

a) Please provide evidence that the future business conditions of OPG are similar to those experienced by the companies LEI used to calculate the productivity trend over the 2002-2014 period.

b) Are the productivity trends for very-long lived and mature assets sensitive to the replacement capex undertaken during the sample period?

c) Will the large replacement and upgrade investments made by OPG in recent years slow its cost growth in the next ten years? If so, should this affect the choice of a sample period?

d) How much capital replacement must take place for a "mature" asset to no longer be considered "mature" (i.e. if hypothetically everything was repaired/replaced, is the plant now "new" with all the expectations of a new plant)?

e) If it were possible, would a time period that captures a greater portion of the life cycle such as one starting in the 1970s or 1960s be more representative of future expectations?

Response

The following response was provided by LEI.

a) LEI understands that OPG's future business conditions for the regulated hydroelectric fleet will be similar to what they have experienced in the 2002-2014 period given that OPG's operations are in a steady state. Furthermore, given the overall age profile of the peers selected in the hydroelectric industries (ranging from 35 to 74 years) and the maturity of the assets, LEI expects the general trends in total factor productivity experienced by the peer companies over the study period are relevant to OPG going forward.

b) 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”. Productivity trends will show improvement when replacement capital increases production, for example, new blades/new runners will be more efficient and will therefore allow for more energy production as measured in MWh terms.

c) No, not necessarily, as discussed in Ex. L-11.1-1 Staff-244, routine operations and maintenance must continue, even as capital improvements are made to replace aging infrastructure, in order to keep the assets in a satisfactory state of performance.

The choice of sample period in LEI’s industry TFP study adequately captures the dynamics associated with capital improvements and ongoing and routine O&M for mature hydroelectric assets.

d) As noted in the answer to part b) above, large hydroelectric generation facilities are comprised mostly of civil assets which do not get replaced. As such, typical capital replacements would never result in a “mature” asset becoming a “new” asset in this industry.

e) More data is not necessarily better. On page 16 of its report, LEI states *“if the range of data is too long, the estimated trends may be biased and not representative of current dynamics. The time period should ideally incorporate more recent data that captures the latest trends in the industry, while eliminating earlier time periods with differing productivity growth drivers.”* LEI considers the 13-year period used in the study appropriate for capturing the current steady state of the industry and avoids the problems associated with relying on stale inputs.

For a number of the peers, a substantial portion of their assets were constructed in the 1950s and 1960s. For example, 42.7% of Pacific Gas and Electric’s portfolio was constructed during this period. The extension of the study period to as far back as the 1960s would capture an industry undergoing a build out or boom. This is not representative of OPG’s regulated hydroelectric fleet going forward as there are little to no more build out opportunities left for this fleet.

Board Staff Interrogatory #234

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

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 1, pages 7 and 18

This evidence is the updated TFP study conducted by LEI based on OPG and a selected sample of US utilities with significant hydroelectric generation.

Footnote 5 on page 7 of LEI's report states:

> 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.

On page 18, LEI states:

> 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]

Footnote 28 refers to section 9.1.3.1 of Appendix B of the LEI report but insufficient additional information is provided there.

a) Please provide a list of generation TFP studies of which LEI and/or OPG are aware.

b) Please describe how these other studies informed LEI in conducting its documented TFP study for OPG.

c) What are the results, in terms of TFP for hydroelectric generation, from these other studies? How were these results from other studies used to inform LEI and/or OPG regarding the reasonableness of the observed result of about -1% TFP from LEI's study?

Response

The following response was provided by LEI.

a) Please see L-11.2-20 VECC-45 part b).

b) As discussed in Appendix B of its report, these studies supported LEI on choosing the methodology and defining the TFP model specification, such as:

- **TFP Index method** – there were various methodologies used for measuring productivity TFP growth in the empirical studies (DEA, TFP Index, Stochastic, and SPSC); LEI selected the TFP Index method based on its review of these empirical studies and its expert knowledge in this subject area. The TFP Index method is the most popular for regulatory purposes. Furthermore, in Ontario, the OEB has used the TFP index method for incentive regulation of electric and gas distributors.

- **10+ year timeframe** – LEI's study covers a thirteen-year timeframe; all the studies reviewed used a study period of over 10 years.

- **Inputs and outputs** – LEI used two input measures: (i) physical capital measured in MW and (ii) O&M measured in dollars, and generation as the output measure (based on annual MWh of production). This was based on commonly used inputs and outputs seen in the empirical studies.

c) LEI examined these studies for the methodologies they employed rather than the results obtained. The results of these studies are not *per se* informative about OPG's expected productivity trends since they were not specific to an appropriate peer group.

Specifically, in footnote 3 on page 7, LEI states:
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.

Board Staff Interrogatory #235

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

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 1, page 18

LEI states that:

> [it] determined that it would be best to use a single output of generation measured in MWh... after considering 18 productivity studies on generation...LEI found that generation was the most common metric chosen for measuring output. Generation is the appropriate output because it is the essential output being produced by every power generator. Further, generation data is readily available, and is generally measured consistently across power plants and firms.

a) Please provide a table listing the output and capital input quantity specifications and datasets of each of the 18 studies referred to above.

b) Please confirm that generation capacity is also sold in many bulk power markets.

c) Which has a larger impact on generation cost: changes in MWh or changes in capacity? Please explain and support your response.

d) Are pumped storage volumes included in the output measure? If not, why not?

Response

a) LEI does not have the datasets for the empirical studies it reviewed. Tables listing the inputs and outputs used in these studies is available in the report, please see page 56-57.

b) There are only a few deregulated wholesale markets that have a centralized capacity markets, in which capacity is actively being bought and sold. In North America, the following deregulated wholesale markets have a centralized capacity market:
   - New England (ISO-NE),
   - New York-ISO (NYISO), and
   - Pennsylvania-New Jersey-Maryland Interconnection (PJM).

The California Independent System Operator (CAISO) does not have a centralized capacity market, instead there is bilateral requirement for purchase of capacity imposed by the California Public Utilities Commission. Midcontinent Independent System Operator (MISO) operates a voluntary capacity market. Moreover, LEI notes that the majority of peers in the industry, including OPG, do not participate in deregulated wholesale markets that have centralized capacity markets. Specifically, only 11% of the generating capacity (in MW) from the industry peer group participate in the PJM capacity markets, 3% to MISO (Union Electric), and 15% to CAISO.

c) LEI understands that when the question refers to “annual revenue requirement” it means “generation costs”. The annual revenue requirement will be driven both by the capacity rating and annual target production of the facility, in that both metrics impact the design of the plant and therefore the investment costs and the annual revenue requirement. Once the plant is online and operating, most ongoing operating costs at a hydroelectric facility are fixed and invariant to production levels.

d) Pumping volumes for pumped storage units were not included in the output measure for this TFP study; only the generation volumes were included (i.e., when the pumped storage unit is generating electricity). OPG’s hydroelectric portfolio includes only one pumped storage facility, the Sir Adam Beck PGS, which has an installed capacity of 174 MW. This represents less than 1% of the industry as specified in the TFP study.

Board Staff Interrogatory #236

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

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 1 pages 16-17

On pages 16 and 17 of its study, LEI states:

> LEI believes that the thirteen year timeframe of 2002-2014 is appropriate for this study. For OPG, 2002 is also the year the Ontario competitive electricity market opened, a significant event impacting OPG's business environment. US electricity markets also went through reforms and restructuring phases in the late 1990s and early 2000s. The thirteen year study period balances the high variability of year-on-year trends but is also not so long term as to capture "stale" industry trends that would not repeat themselves in the future.

a) In general, as is exemplified by Chart 6 on page 20 of Exh A1-3-2, hydroelectric generation assets have significantly long economic lives, which range into several decades. Some of OPG's hydroelectric generation assets are over a century old, even if they have been refurbished and modernized over time. Is the 12 year study period a sufficiently long slice of the normal useful lives or the business cycle for investment and operations of such-long lived assets so as to give a representative picture?

b) Should the sample period for a TFP study be longer to the extent that output is volatile?

c) What are examples of the '"stale" industry trends that would not repeat themselves in the future' that LEI alludes to in the above quote?

Response

The following response was provided by LEI.

a) LEI believes the 12 year study period sufficiently captures the steady state operations of hydroelectric generation industry. As stated on page 16 of LEI's report, the period is long enough to *"limit exposure to year-on-year productivity changes as well as one-off circumstances with respect to factors like weather, consumption, lumpy capital spending, and fluctuations in labour"* yet short enough to avoid bias and trends *"not representative of current dynamics."* An example of such a trend is the higher cost experienced in the early years in the operations of a new hydroelectric facility, when operating costs are higher than they will eventually be, due to the need to resolve common issues around start-up of a new facility.

b) Not necessarily. The production captured in this study, over this period of time, was representative of long run average trends in production. While more data could reduce the impact of output volatility, LEI cautions that (i) the "start year" problem may still be an issue if it the annual production is far outside the average range of production and (ii) the use of data dating back too far in time may be distortive, for the reasons stated in part a) above.

c) O&M costs for the mechanical and electrical components of hydroelectric generation assets typically follow a 'bathtub curve' in which the failure rate of equipment (and therefore the need to make repairs and additional maintenance) is highest at the beginning of an asset's life and then stabilizes once common start-up issues are resolved and steady state operations begin. O&M costs are likely to creep up again at end of the asset's useful life, in order to maintain operating capability. Such cost trends dating back to the early years of a facility's operations would not be consistent with an industry trend that we are trying to capture for purposes of application in the next five years to OPG's hydroelectric operations.

Board Staff Interrogatory #237

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

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 1, pages 19, 41-42

At page 19 of its report, LEI states that:

> 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 2002-2014 is within 1% of the twenty year average (1994-2013).

At pages 42-42 of its report, LEI states:

> average growth rate for capital inputs measured in MW was 0.15% over the 2002-2014 period, with little year over year fluctuations. This result is to be expected for a mature hydroelectric industry as construction of new generation facilities is infrequent.... For output, net generation growth rate was on average -0.64% for the industry.[67] Note year over year fluctuations were much more visible compared to the average, which is to be expected due to varying hydrology cycles during the 2002-2014 period, as well as other factors such as changes in demand and surplus baseload generation conditions.
>
> [67]A negative generation growth rate does not imply the same capital is producing less over time, but rather is related to the hydrology cycles at the start and end years of the study.

a) Please explain the decline in the MWh generated by sampled utilities relative to their generation capacity during the sample period.

b) What grounds are there to support that this trend will continue?

c) Was the trend in MWh generated adjusted for changes in hydrological conditions during the sample period?

d) What are the expected volume/capacity and water flow trends of OPG in the next five years and the following five years?

e) Is the volume/capacity trend of the sampled utilities pertinent to an X-factor for OPG?

f) Can footnote 67 be taken to mean that hydrological conditions are the cause of declines in capital productivity in the study?

g) If the generation growth rate is not related to production over time, then why was generation selected as the measure of output quantity?

h) For a given unit whose availability and capacity does not change, would the measured capital productivity be zero, by definition, under normal hydrological conditions using the LEI methodology?

Response

The following response was provided by LEI, except for the response to part d) which was prepared by OPG.

a) As stated in footnote 67, LEI believes the decline in MWh is likely related to the hydrology in the chosen start and end year of the study. Section 6.2.2 of LEI's report discusses the trend regression method, which can be useful in establishing average trends in instances where a series exhibits volatility at its endpoints. It was found that the trend regression method produced more negative, but otherwise very similar results to the average growth method.

b) 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 a year, will trend to long term average levels, assuming climatological conditions remain steady.

c) No. LEI used actual reported net generation without any further adjustments.

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

e) The electricity produced is the primary output from OPG's hydroelectric fleet, as has been recognized by the format of the volumetric regulated rate that the OEB has applied to

OPG over the years. As such, LEI believes that the volume of production is a relevant element of determining productivity trends for the industry and the X-factor for OPG. Similarly, the capacity of the hydroelectric assets is a metric that represents the physical quantity of capital deployed and is a relevant element of productivity trends.

f) No, LEI is not suggesting that hydrological conditions drive capital productivity down. The footnote specifically states that "a negative generation growth rate does not imply the same capital is producing less over time". The footnote goes on to state that "hydrology cycles at the start and end years of the study" are driving the trend in generation over the study timeframe. LEI uses a trend-based TFP growth rate to address this type of concern, as described in answer to part a) above. Furthermore, on page 15 of the report, LEI states that "[i]n instances where a series is volatile at its endpoints, it can be argued that the 'trend regression' method may give a better estimate of the underlying TFP growth trend, in that it reduces the weight attached to the first and last years of the study period."

g) Generation is an appropriate metric of output for hydroelectric power plants because it represents the primary output from such facilities; the wholesale power market in Ontario remunerates generation on their MWh of energy; and the OEB has also recognized MWh of production as a key element of the rate for OPG.

h) Conceptually, if there is no change in quantity of capital input, which LEI based on rated capacity of generation facilities, and no change in other inputs and outputs, then overall total factor productivity growth rate would be zero.

Board Staff Interrogatory #238

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

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 1, page 20

LEI states that:

> the most common input observed for generation-related productivity studies was capacity as a physical measure of output. 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.

a) Please confirm that data availability is a major reason why the monetary method for measuring the capital quantity has not been used in other studies.

b) Please confirm that the required capital cost data are available to calculate capital costs and quantities using the monetary method for investor-owned US electric utilities.

c) Please cite examples where the physical assets approach to capital quantity measurement has been used to measure productivity trends by any of the following:
   - U.S. or Canada by National Statistical Agencies such as Statistics Canada, Bureau of Labor Statistics.
   - In productivity studies approved by regulators for the setting of productivity factors used in regulation.

Response

The following response was provided by LEI.

a) While data available did factor into the choice of method, the primary reason was the overarching conceptual issues with using a monetary method for measuring the capital quantity. This consideration led LEI to prefer the physical method. In Appendix C of the report, LEI wrote: *"depreciated asset value methods do suffer from certain analytical subjectivity."* In particular, *"assumptions of declining balance or straight line depreciation are unlikely to properly reflect the true physical depreciation profile of these assets, which are more likely to exhibit a 'one hoss shay' depreciation profile."*

b) The Federal Energy Regulatory Commission (FERC) Form 1 database data is available back to 1994.[1] This may contain some of the inputs that would be necessary for the monetary value approach for estimating capital input quantities. However, for non-FERC jurisdictional entities, such as Seattle City & Light and Southeastern Power Administration, data is not readily available going back that far in time.

c) US and Canadian Statistics Agencies do not explicitly use a physical measure of capital inputs, as that data is not typically available to them. However, many national statistics agencies recognize that traditional geometric depreciation profiles are inadequate and that the fundamental aspects of a "one hoss shay" depreciation profile are more appropriate for some sectors of the economy. The "one hoss shay" profile is the primary reason why LEI used the physical approach. Some national statistics agencies use a hyperbolic assumption for the age-efficiency profile in their multi-factor productivity analysis, which defines the rate at which physical contributions of capital stock decline. US BLS as well as the Australian Bureau of Statistics and Statistics New Zealand use a hyperbolic profile. This profile assigns a lower depreciation rate earlier in an asset's financial life and then increases that depreciation rate in later years, and in doing so, it recognizes that capital assets' physical depreciation and performance are closer to "one hoss shay" than a straight-line assumption.

In addition, studies of TFP growth have been presented before the OEB that have used physical capital measures. And, internationally, the Australian Energy Regulator has used the physical capital proxy approach in electricity and gas network rate determinations since 2014, and it has been used by the Commerce Commission of New Zealand in electricity and gas network rate determinations since 2003.

[1] Federal Energy Regulatory Commission. Form 1 – Electric Utility Annual Report. <https://www.ferc.gov/docs-filing/forms/form-1/data.asp>

Board Staff Interrogatory #239

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

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 1, page 20

On page 20 of its study, regarding measures of output to be used for the TFP analysis, LEI states:

> 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.

There does not appear to be any other discussion in LEI's study of whether or how it considered these other outputs of hydroelectric generation.

Please provide further explanation of how LEI took these outputs, for both OPG and for other generation utilities in the sample, into account, even qualitatively, in conducting the TFP analysis. If these other outputs played no further role, even qualitatively, please explain.

Response

The following response was provided by LEI.

LEI discussed consideration of other services that the hydro generation fleet produces with OPG, for example, water management and recreational value. However, it was not possible to robustly quantify such services (especially across different utilities and jurisdictions) and therefore these services were not considered as a form of output in the empirical study of industry TFP growth. It is worth noting, though, that the performance of such services impose real costs on operation of the hydroelectric resources. And to the extent that compliance requirements and standards for providing these services are becoming more stringent and raising O&M costs and requiring more capital input, such trends over time would create downward pressure on TFP growth. OPG's own experience confirms that some of the standards and requirements for water management, for example, have become more stringent over time and more constraining on hydro operations. New requirements related to water management planning and Dam and Public Safety have been introduced since 2002. OPG does not expect the trend toward more stringent requirements to change in the future.

In consideration of the “reliability” dimension associated with electric generation, LEI also evaluated a two-output model, where a secondary output measure, availability, was included in addition to production (generation). Please see Appendix A on page 49. Although the two-output model was not updated from the 2014 version of the LEI report, the results of the two-output model were generally consistent with the single output model and therefore LEI determined it was not necessary to update the two-output model (see page 19-20 of the LEI report).

Board Staff Interrogatory #240

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

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 1 pages 27-28

LEI states in its study that:

> When selecting peers in order to construct an industry group, LEI used a multi-dimensional criteria set, which focused on comparability across peer hydroelectric operations, while keeping in mind issues related to data availability. As a general rule, LEI looked for firms that have a hydroelectric fleet with a total capacity of between 500-1,000 MW (medium size) or more than 1,000 MW (large size). Additionally, a peer needed to have more than one plant, and ideally the average age of a peer's hydro fleet would be around the average age for OPG's prescribed hydro fleet.

a) Why was operating scale accorded such importance when output growth is so slow for the sampled utilities?

b) What definition of system age was used? Please provide the age data for all utilities considered. What companies were excluded from the sample on the basis of the age criterion?

c) Did LEI gather data and/or calculate productivity results for companies other than those included in the final report? If so, please include these results and data.

Response

The following response was provided by LEI.

a) As discussed in Section 3.1 of LEI's report, common drivers of productivity include technological innovation and improved economies of scale. LEI included both medium and large size hydroelectric fleets, and only excluded small hydroelectric fleets (smaller than 500 MW). This peer restriction in definition of a proper industry given OPG's holdings was intentionally controlling for economies of scale issues. In addition to affecting the relative productivity levels, the size of a firm's hydro fleet can also impact the trends in productivity over time. It is likely that larger utilities have greater opportunities to take advantage of productivity improvements derived from economies of scale, which are not otherwise available to smaller firms. There are also differences in operational practices that can apply to businesses of a different scale. Therefore, choosing utilities which are in a similar size range as OPG was important to choosing comparable peers for an industry productivity growth study. For example, larger utilities might have the ability to use mobile labour teams rather than assigning staff to each facility and to allocate costs over a larger asset base.

b) Age was calculated on the basis of MW-weighted average of a plant's year of construction. It was aggregated to the company level by using a simple weighted average, with weightings based on the MW of capacity. On page 28 of the report, LEI provides a table showing the average age of the hydro fleet. Although LEI examined this criterion for its consideration of companies to include in the industry, no peers were excluded on the basis of age.

d) LEI collected data for Alcoa Power Generating Inc. and Western Area Power Administration. LEI has provided a version of the TFP model including data and results for these companies in response to L-11.1-1 Staff-246.

On page 26 of the report, LEI states:

"Alcoa, which was included in the original TFP study, was excluded in the update due to asset sales resulting in a significant reduction in its portfolio size."

On page 37 of the report, LEI states:

"[A]n abnormal hydrology cycle over the course of the study period (2002-2014) was observed - WAPA annual average hydroelectric generation was below historical average levels for many of the years in the study period… The abnormal generation fluctuations and the size of WAPA's hydroelectric facilities were large enough to potentially skew the final TFP results. For this reason, LEI decided that WAPA should not be included in the final study."

Board Staff Interrogatory #241

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

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 1 page 27

LEI states that:

> The start year of 2002 was chosen because it was the first year that full datasets could be constructed across the peer group.[40] As well, the opening of the Ontario competitive market occurred in 2002 which impacted the business environment for OPG; similarly, market restructurings were occurring across parts of the US in the late 1990s and early 2000s[40]
>
> Footnote 40: Most peers did not have full datasets available before 2002, including OPG, which had revenue data only available starting mid-2002 after market opening

a) Before 2002, did OPG, or its predecessor Ontario Hydro, lack data for hydroelectric generation volume or only for the associated revenue?

b) Please explain how power market restructurings affected the hydroelectric operations of the sampled US electric utilities.

c) What data constraints were encountered for an earlier start date for investor-owned US electric utilities?

d) Is it LEI's view that OPG must be part of the peer group used to calculate its X factor?

Response

The following response was provided by LEI, except for part a), which was prepared by OPG.

a) OPG has data in its records for generation pre-dating 2002, however, revenue data is not available preceding the opening of Ontario's electricity market on May 1, 2002.

b) In the 1990s and early 2000s, a series of state and federal initiatives restructured electric markets in the US, where the vertically integrated utilities were unbundled (separated by business function) and in some cases, certain assets/businesses were divested. In some parts of the US, competitive wholesale markets were formed for the generation sector, and retail competition was legalized. Similarly, the electricity industry was restructured in Ontario. The presence of competitive wholesale markets changed, to some degree, operations of some generation assets.

c) Data from FERC Form 1 for US investor-owned electric utilities is available since 1994; however, not all the peers' data was sourced from FERC Form 1. Even though the data exists, it would need to be tested for hydrology anomalies within each peer. Over the additional period, it is likely that peers could have undergone mergers and acquisitions causing a data constraint.

d) 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 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.

Board Staff Interrogatory #242

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

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 1, page 39

LEI states:

> When estimating individual TFP results, the difference in currencies does not affect results, as a simple scaling up or down of O&M and revenue would result in the exact same outcome. However, in the case of calculating industry TFP trends, Canadian and US figures are compared, and using nonadjusted figures can lead to biases (albeit small) in the TFP results.

Please clarify how the trends for individual utilities were averaged.

Response

First, LEI aggregated plant level data to a peer level.

Second, LEI converted O&M amounts using the 2014 OECD Purchase Power Parity ("PPP") for GDP, at a rate of 1.23 Canadian per 1 US dollar. Please see LEI's response to L-11.2-20 VECC-47 part c, which discusses LEI's use of PPP.

LEI then aggregated the MCR (capacity quantity), deflated O&M costs and net generation of all the peers into a set of industry input and output indices. As noted on page 23 of the report, LEI applied Statistics Canada's industrial average weekly earnings and gross domestic product price index estimate of final domestic demand as labour and non-labour indexes respectively to deflate OPG's O&M. For US peers, labour O&M price index was based on data gathered from US Bureau of Labor Statistics, and non-labour O&M price index was based on the GDP-PI data gathered from the US Bureau of Economic Analysis. The TFP growth rate was estimated from these aggregated values. It is important to note that the aggregation was done for each individual input and output index separately and no additional weighting was applied. LEI's model was also set up as to allow for calculation of TFP trends on a firm by firm basis.

Board Staff Interrogatory #243

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

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 1, page 40

LEI States: "the Two Inputs are Capital measured as Capacity (MW) and Non-capital costs measured as total O&M inputs in constant prices..." and "the Labour share of O&M is 63% and the Non-labour share of O&M is 37%"

a) What companies in the sample did not have itemized data on labour expenses?

b) Did the O&M expense data include only salaries and wages or did it also include pension and other benefit expenses?

c) Please report the exact labour price indexes employed in the study. Do these indexes address labour price trends inclusive of pension and benefit expenses?

d) Please describe the EUCG dataset and explain how it was used to calculate the 63% labour cost share. What is this percentage for OPG? Why was a fixed weight used instead of a time-varying weight?

e) Please explain the rationale for combining the US and Canadian O&M price indexes into a North American O&M price index. How was it used? Please clarify how the 22% weight for Canada was determined.

Response

The following responses were provided by LEI.

a) FERC Form 1 data did not include public data specific to labour expenses separately from O&M. Federal and municipal peers O&M data was sourced from annual reports/financial filings as well as information obtained directly from the companies and also didn't provide labour data separate from total O&M.

On page 20 of the report, LEI states:

> "Due to data constraints, LEI could not rely on number of employees or otherwise isolate the labour costs from total O&M costs. However, labour costs are already reflected in O&M costs indirectly through the input price indices…"

b) The FERC Form 1 O&M data does not include pension and other benefit expenses; it includes line items from FERC Form 1 as described on Figure 20 on page 34 of LEI's report.[1]

LEI worked with OPG to ensure O&M data consistent between FERC Form 1 and OPG. However, as noted on page 33 of the report, administration costs (including current pension service costs and other benefits) were included in the OPG OM&A data. These administration costs were found by OPG to be relatively flat historically, and were not a major component of the total OM&A, so their inclusion would not measurably impact TFP trends.

c) For a Canadian labour price index, LEI used Statistics Canada's Average Weekly Earnings (AWE) in current dollars, for Ontario, including overtime, seasonally adjusted, for all employees, by selected industries classified using the North American Industry Classification System (NAICS) from CANSIM Table 281-0027.[2] The OEB is familiar with the industrial aggregate AWE in the context of the electric distributor rate-setting.[3] LEI understands that the AWE data is based on gross payroll before source deductions and does not include pension and benefit expenses.

For US companies, LEI used the US Bureau of Labor Statistics: Wages and salaries for Private industry workers in Utilities Index, accessed as of January 5, 2016.[4] It includes wages, salaries and the following benefits: paid leave, supplemental pay, insurance (health benefits), retirement and savings and what is legally required. Note that LEI relied on the best publicly available data regarding hydroelectric O&M and available industry O&M indexes. LEI notes that the US

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[1] Federal Energy Regulatory Commission. *FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report.* Pages 406 and 408. <https://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf

[2] Statistics Canada. Table 281-0027 - Average weekly earnings (SEPH), by type of employee for selected industries classified using the North American Industry Classification System (NAICS), annual (current dollars), CANSIM (database). <http://www5.statcan.gc.ca/cansim/a26?lang=eng&id=2810027>

[3] Ontario Energy Board. *Filing Requirements For Electricity Distribution Rate Applications – 2015 Edition for 2016 Rate Applications. Chapter 3: Incentive Rate-Setting Applications.* July 16, 2015. <http://www.ontarioenergyboard.ca/oeb/_Documents/2016EDR/OEB_Filing%20Requirements_2016Rates_Chapter%203.pdf>

[4] Bureau of Labor Statistics. *Databases, Tables & Calculators by Subject - Wages and salaries for Private industry workers in Utilities, Index (CIU2024400000000I).* <http://data.bls.gov/timeseries/CIU2024400000000I>

BLS and StatsCan indices do not allow for the inclusion or exclusion of pension and benefits.

d) The EUCG's Hydroelectric Productivity Committee (HPC) dataset provides plant level breakdown of hydro-specific generation data for 18 companies over 2004-2014. The database contains information on about 350 hydro plants on areas such as operations, maintenance, environment and regulatory, land and water rental fees, administration, operations and maintenance investments and capital investments.

LEI used the operations and maintenance data which was broken down into labour, contract and other to develop the labour cost share. EUCG labour costs are comprised of:

- All Regular, Permanent Staff;
- All temporary staff, hiring hall, part-time or casual staff, (this will include long term assigned staff or longer term contract staff or where the individual looks and acts like permanent labour);
- All appropriate loadings, such as benefits, concessions, payroll taxes, etc.; and
- Overtime.

For OPG, the labour share of O&M was 63%, consistent with the industry level of 63% from the EUCG data set. LEI used the average labour share versus non-labour share of O&M from 2004 to 2014. A fixed value was used for each of the years in the TFP study, for purposes of simplicity and consistency. It would not have been possible to use specific annual data from the EUCG data on labour shares, as the EUCG data did not cover the full duration of the study period. In addition to not having data for 2002 and 2003, LEI did not use the EUCG data to calculate TFP trends, since company specific data was not consistently represented for the 2004-2014 period.

e) Consistent with LEI's aggregation approach for the industry, LEI combined the US and Canadian O&M price indices into a North American O&M price index in order to capture the relevant price trends of both countries in the industry peer group. As discussed on page 23 of the report, LEI applied a weight of 22% for the Canadian share of the industry based on OPG's share in total O&M for the industry. The resulting weight of US total O&M price index in the North American total O&M price index is 78%. This North American O&M price index was then used to deflate the annual industry aggregate O&M values. LEI could have applied the US and Canadian O&M price indices to the O&M costs for US peers and OPG before aggregating, which would have yielded the same mathematical results.

Board Staff Interrogatory #244

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

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 1 pages 44 and 59

As stated in its report at page 44, 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. As discussed earlier in Section 3.1 of its report, 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).

At page 59, LEI states that:

> The perceived advantage of the monetary method is that it can include capital equipment of all kinds. Some practitioners also argue that the monetary method, with respect to some asset types, produces an estimate that reflects the quality of capital better... 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). As a result, assumptions of declining balance or straight line depreciation are unlikely to properly reflect the true physical depreciation profile of these assets, which are more likely to exhibit a 'one horse shay' depreciation profile.

a) Please confirm that, over the life cycle of a hydroelectric generating station, total cost falls substantially due to depreciation, and such cost reductions can be captured with a monetary method but not the physical assets method.

b) Please confirm that substantial productivity gains are possible when hydroelectric assets are replaced, and that these gains can be captured with a monetary method but not the physical assets method.

c) Please confirm that, in general, when generation capacity is used as the capital quantity index, changes in the productivity (e.g. real cost per unit of capacity) with which the utility provides capacity are ignored in productivity calculations.

d) Please reconcile the statement that an asset provides "a relatively constant flow of services" with the statement that OM&A expenses associated with a hydroelectric generating facility tend to rise as it ages?

e) Please provide three examples of how O&M expenses tend to rise as hydroelectric assets age.

f) Does growth in O&M expenses tend to fall when assets are replaced/modernized?

Response

The following response was provided by LEI, except for part e), which was prepared by OPG.

a) LEI interprets "total costs" in the question to mean the annual revenue requirement, pursuant to historical cost regulatory accounting. As such, as the historical asset value is reduced over time by annual cumulative depreciation, the annual revenue requirement declines with each passing year, unless there is significant capital expenditure that would add to the historical asset value in a given year. Under a monetary approach, the capital input quantity index would be based on the historical asset value plus capital expenditure (if any) less accumulated depreciation expense.

LEI however disagrees with the validity of such an approach for purpose of measuring total factor productivity for hydroelectric assets. The productive capability of a generation asset, and especially a hydroelectric generation asset, should not decline with time (as implied by regulatory accounting and use of depreciation expense), if it is being properly maintained. The physical depreciation of these assets is more appropriately modelled by the "one hoss shay" concept. In this model of depreciation, the asset delivers the same services for each year of operations, regardless of its age, until it eventually fails and has no residual value. LEI believes that the physical asset method is more appropriate for a TFP study of hydroelectric generation assets.

b) As discussed in Ex. L-11.1-1 Staff-233 part b), replacement capex in hydro operations is typically limited to mechanical and electrical parts; however; the majority of the asset base, roughly 75%, consists of civil works and that is rarely "replaced". Productivity trends will show up under the physical asset method when improvements related to replacement capex of a mechanical part (such as a runner) or an electrical part (like a generator) creates a consequential improvement in production. For example, new blades/new runners will be more efficient and will therefore allow for more production. These types of replacements translate to productivity gains in the case where these expenditures result in increased output from the same or similar level of capital input (capital sock). Similarly, a productivity improvement that reduces operating and maintenance costs while maintaining the same output of the power plant will also be captured as a productivity improvement under a physical asset method.

As discussed in Ex. L-11.1-1 Staff-238 part a), hydroelectric assets naturally follow a “one hoss shay” depreciation profile and actual production capability remains largely unchanged over time, as long as the asset is maintained. In contrast, if a depreciation profile is used under the monetary approach that results in a perception of reduced capital quantity, the method could yield an overestimation of TFP trends by under-representing the capital stock being employed.

c) The use of capacity (MW rating) as the proxy for calculating the capital quantity index captures physical changes in the level of productive capital stock being deployed for purposes of a TFP growth rate calculation. It does not measure the investment costs or allow for cost benchmarking. That said, the intended goal of the study was not to calculate cost benchmarks but to estimate an accurate TFP trend.

d) In the excerpt being referred to, the “relatively constant flow of services” refers to the annual generation (i.e., output) of the hydroelectric facilities. The fact that generation is occurring constantly over time (except when an asset is taken completely offline) does not conflict with the fact that OM&A expenses tend to rise with age.

e) The following are three categories of OM&A expenses associated with a hydroelectric generating facility that tend to rise as it ages:

1) Facility maintenance (e.g., repairs become more comprehensive as assets age and require more tool time to repair based on increased wear and tear);
2) Component replacement (including fabricating increasingly obsolete parts, increasing replacement needs for end-of-life parts and basic increases in labour and material costs); and
3) Compliance costs (e.g., increasing dam safety and water management requirements).

f) As noted in the reference, OM&A would likely be increasing over time (in order to maintain asset operational capability as the asset ages). However, for a specific investment at a specific plant, the directional change in O&M expenses after an asset replacement/modernization, if any, will depend on the type of modernization/capex replacement. The maintenance cost (labour and material) associated with equipment that is replaced will decrease for a period of time in real terms, but will escalate with inflation. However, most O&M expenses will continue even when new equipment is installed to replace aging parts because the plant’s capability cannot otherwise be maintained. Most of the capital investment for OPG’s hydroelectric generation is in this broad category of “sustaining” capital investment; therefore a specific investment at a specific plant would not materially reduce O&M expenses which tend to increase over time for the portfolio of plants subject to OEB regulation.

Board Staff Interrogatory #245

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

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 1 page 59

LEI States: "Furthermore, the monetary approach requires data going back many years, which would be difficult to gather for many industries, but is especially difficult in the generation sector of the electric power industry"

If it were possible to overcome these difficulties, would the results of the monetary approach be superior in theory to those obtained by the "straightforward" physical asset approach?

Response

The following response was provided by LEI.

Although the data issues are a practical concern to an empirical TFP study, the theoretical shortcomings of a monetary approach are the critical issue. As discussed in Ex. L-11.1-1 Staff-244, LEI believes that a physical asset approach is superior.

Board Staff Interrogatory #246

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

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 1

LEI describes the methodology, the data selection, data sources and data analysis and manipulation conducted, along with the results of the TFP study. However, the data used and the model are not provided.

Please provide the data set used and the TFP model, and any other model(s) (e.g. for the trend regression analysis referred to in section 6.2.2) used by LEI in its TFP analysis.

The data and model(s) should be provided in working format, such as Microsoft Excel. Where provision of the raw data would reveal confidential or proprietary information, the data may be transformed and provided in an indexed format. Where variables are provided in such a transformed manner, this should be indicated.

Documentation on the data and the model(s) should also be provided to facilitate understanding of the data and model and to link these back to the discussion in LEI's report. Sufficient information should be provided on the design and working of the model, the data used, and the firms used in the data set for the analysis to enable another researcher to replicate the results of LEI's analysis.

Response

Please see the following attached Excel models provided by LEI:

- Attachment 1: Model A: OPG industry TFP model v2016 final
- Attachment 2: Model B: OPG industry TFP model v2016 final (with Alcoa and WAPA, two firms that were excluded from the final TFP model, as described in LEI's report on pages 26 and 27)

As described in Ex. A1-3-2, Attachment 1, the peer data in the LEI data set was sourced from a variety of public and third party commercial databases. Any confidential information used was aggregated as part of the study. Confidential data was aggregated in sufficient quantity and over sufficient time that individual transactions and participants are not disclosed or calculable.

Each model contains a 'READ_ME' tab which provides a stepwise walkthrough of the model.

Total Factor Productivity in North American Hydroelectric Generation

Prepared for:
Ontario Power Generation
in support of incentive rate-making for OPG's prescribed assets

Prepared by:
London Economics International LLC
Julia Frayer, Ian Chow, Barbara Porto, and Jarome Leslie

January 15, 2016

Basic model logic:

Note: Unless otherwise stated, all directions will refer to information contained in the **"TFP_Calcs" worksheet**

Step 1: Select peer from dropdown menu (Cell C2):

The dropdown will show results based on peer or peer group selected. Contains individual information on OPG and 17 peers, as wel
The peer industry includes OPG, 14 US investor owned firms that filed FERC Form 1, 2 federally regulated firms, and 1 municipal

Step 2: Prepare data for the model (Row 5-19):

This contains data including capacity, O&M and net generation. All data here refers back to the full dataset in "TFP_dataset" tab, wit
which refers back to "NA comb O&M price indexes"

Step 3: Calculate quantity sub-indexes and sub-index growth rates (Row 23-38):

The tables illustrate how data from Step 2 is used to calculate the quantity sub-indexes of Input (K), Input (O&M) and Output (MWh
Quantity Sub-indexes Growth rates show the growth rates of the quantity sub-index. Average values for all three are highlighted

Step 4: Calculate implicit price indexes and sub-index growth rates (Row 42-57): This is an implicit calculation step necessary for the calculation o

Step 5: Calculate the year over year changes to Laspeyres, Paasche, and Fisher total Input and total Output indices (Row 61-76)

Step 6: Calculate the Laspeyres, Paasche, and Fisher Ideal total Input, total Output, and Total Factor Productivity Indexes (Row 79-94)

Step 7: Calculate TFP growth rates using 'average growth' and 'trend regression' methods (Row 97-112):

Shows growth rates for all the indexes using both methods. Cell I112 highlights the average TFP index growth rate for 2002-2014, wh

Note: This workbook is colour coded as follows: (i) red for OPG data; (ii) blue for US peer data; (iii) green for other third party data (e.g. EUCG, CA

Worksheets:

TFP_Calcs: Contains the model, provides the method of calculating TFP Index growth

TFP_dataset: Contains all the data relevant to OPG and 17 peers

Note: A PPP of 1.23 Canadian dollars per 1 US dollar was used to convert US peer O&M costs and revenues to Canadian dollars so that tha
compared on an equal basis. PPP was chosen over exchange rates as it better reflects underlying fundamentals (excluding speculatio
Source: OECD (http://stats.oecd.org/Index.aspx?DataSetCode=PPPGDP)

OPG hydro peers: Contains list of all peers and locations (CA or US)

NA comb O&M price indexes: Provides 2002-2014 price indexes for peer group by combining Canadian and US prices indexes

Can O&M price indexes: Provides 2002-2014 price indexes for Canada

US O&M price indexes: Provides 2002-2014 price indexes for U.S.

EUCG L Share: Provides industry level labour share of Operations and Maintenance, based on EUCG data

StatsCan CANSIM tables: Provides the StatsCan data that is used in the 'Canadian O&M price indexes' worksheet

US BLS & BEA tables: Provides the Bureau of Labour Statistics and the Bureau of Economic Analysis data used in the US O&M price indexes work

ll as 'Peer Industry' and 'Peer Industry less OPG'.

h the exception of O&M Price Index,

), with 2002 as base year

f the combined input and output indices

ile cell D117 highlights the TFP growth rate using the 'trend regression' method

NSIM); and (iv) black for calculated values

at different peers can be
n for example) and is less volatile.

sheet

Step 1: Select peers from dropdown in cell C2 (note TFP results for both methods are visible in cells G2 and J2 respectively)

OPG Hydro Group:	Peer Industry	OPG Hydro Peer Industry Total	NA	Average TFP growth (2002-2014)	-1.01%

Step 2: Prepare data, including capacity, O&M, net generation, and O&M price index

Data	I	I	I Price Index	O	I and O shares
Year	MCR (MW)	O&M_total (K$)	O&M Price Index	Net_generation (MWh)	Revenue (K$)
2002	30,597	517,395	1.00	93,101,674	3,580,636
2003	31,285	560,843	1.02	102,685,834	4,511,026
2004	31,331	600,683	1.05	98,966,002	4,375,512
2005	31,309	624,683	1.08	100,606,791	5,379,311
2006	31,374	664,433	1.11	102,422,968	4,612,210
2007	30,701	721,273	1.15	85,570,974	4,096,346
2008	31,027	781,648	1.18	90,123,457	5,034,784
2009	31,080	781,773	1.20	99,004,323	3,516,180
2010	31,085	840,356	1.23	94,503,336	3,422,343
2011	30,704	813,815	1.26	100,040,995	3,339,015
2012	30,802	825,097	1.28	86,640,889	2,470,494
2013	30,962	841,942	1.31	88,883,057	3,327,950
2014	31,168	865,337	1.34	86,259,636	3,620,718

Step 3: Calculate quantity sub-indexes and sub index growth rates

Quantity Sub-indexes			
	Input	Input	Output
Year	K	O&M_total	Net_generation (MWh)
2002	1.00	1.00	1.00
2003	1.02	1.06	1.10
2004	1.02	1.10	1.06
2005	1.02	1.11	1.08
2006	1.03	1.15	1.10
2007	1.00	1.21	0.92
2008	1.01	1.28	0.97
2009	1.02	1.26	1.06
2010	1.02	1.32	1.02
2011	1.00	1.25	1.07
2012	1.01	1.24	0.93
2013	1.01	1.24	0.95
2014	1.02	1.25	0.93

Step 4: Calculate implicit price indexes and sub index growth rates

(Implicit) Price Indexes			
	Input	Input	Output
Year	K	O&M_total	Net_generation (MWh)
2002	3,063,241	517,395	3,580,636
2003	3,863,376	529,720	4,089,991
2004	3,686,393	544,635	4,116,237
2005	4,646,441	560,717	4,978,023
2006	3,850,033	576,538	4,192,463
2007	3,363,684	594,337	4,456,846
2008	4,194,219	610,139	5,201,163
2009	2,691,906	621,579	3,306,545
2010	2,541,484	635,153	3,371,583
2011	2,516,410	649,775	3,107,405
2012	1,634,454	663,025	2,654,718
2013	2,456,728	677,257	3,485,903
2014	2,704,861	693,166	3,907,910

Step 5: Calculate the year over year changes to Laspeyres, Paasche, and Fisher total Input and total Output Indexes

Year to year changes					
	Laspeyres Index	Laspeyres Index	Paasche Index	Paasche Index	Fisher Index
Year	Input	Output	Input	Output	Input
2002					
2003	1.03	1.10	1.03	1.10	1.03
2004	1.01	0.96	1.01	0.96	1.01
2005	1.00	1.02	1.00	1.02	1.00
2006	1.01	1.02	1.01	1.02	1.01
2007	0.99	0.84	0.99	0.84	0.99
2008	1.02	1.05	1.02	1.05	1.02
2009	1.00	1.10	1.00	1.10	1.00
2010	1.01	0.95	1.01	0.95	1.01
2011	0.98	1.06	0.98	1.06	0.98
2012	1.00	0.87	1.00	0.87	1.00
2013	1.00	1.03	1.00	1.03	1.00
2014	1.01	0.97	1.01	0.97	1.01

Step 6: Calculate the Laspeyres, Paasche, and Fisher Ideal total Input, total Output, and Total Factor Productivity Indexes

Index					
	Laspeyres Index	Laspeyres Index	Paasche Index	Paasche Index	Fisher Index
Year	Input	Output	Input	Output	Input
2002	1.00	1.00	1.00	1.00	1.00
2003	1.03	1.10	1.03	1.10	1.03
2004	1.03	1.06	1.03	1.06	1.03

2005	1.04	1.08	1.03	1.08	1.03
2006	1.04	1.10	1.04	1.10	1.04
2007	1.03	0.92	1.03	0.92	1.03
2008	1.05	0.97	1.05	0.97	1.05
2009	1.05	1.06	1.05	1.06	1.05
2010	1.06	1.02	1.06	1.02	1.06
2011	1.04	1.07	1.04	1.07	1.04
2012	1.04	0.93	1.04	0.93	1.04
2013	1.04	0.95	1.04	0.95	1.04
2014	1.05	0.93	1.05	0.93	1.05

Step 7: Calculate TFP growth rates using 'average growth' and 'trend regression' methods

A) Average growth method of measuring TFP

Year	Laspeyres Index Input	Laspeyres Index Output	Paasche Index Input	Paasche Index Output	Fisher Index Input index growth
2002-2003	2.7%	9.8%	2.6%	9.8%	2.7%
2003-2004	0.6%	-3.7%	0.7%	-3.7%	0.7%
2004-2005	0.1%	1.6%	0.1%	1.6%	0.1%
2005-2006	0.6%	1.8%	0.7%	1.8%	0.6%
2006-2007	-1.1%	-18.0%	-0.9%	-18.0%	-1.0%
2007-2008	1.8%	5.2%	1.7%	5.2%	1.8%
2008-2009	-0.1%	9.4%	-0.3%	9.4%	-0.2%
2009-2010	1.2%	-4.7%	1.2%	-4.7%	1.2%
2010-2011	-2.3%	5.7%	-2.3%	5.7%	-2.3%
2011-2012	0.1%	-14.4%	0.0%	-14.4%	0.0%
2012-2013	0.3%	2.6%	0.4%	2.6%	0.3%
2013-2014	0.6%	-3.0%	0.6%	-3.0%	0.6%
AVERAGE	**0.4%**	**-0.6%**	**0.4%**	**-0.6%**	**0.4%**

B) Trend regression method of measuring TFP

T	Natural log of TFP index values	TFP trend growth rate (2002-2014):	Natural log of TFP input values	TFP input index (2002-2014):	Natural log of TFP output values
0	0.00	-1.18%	0.00	0.22%	0.00
1	0.07		0.03		0.10
2	0.03		0.03		0.06
3	0.04		0.03		0.08
4	0.06		0.04		0.10
5	-0.11		0.03		-0.08
6	-0.08		0.05		-0.03
7	0.02		0.05		0.06
8	-0.04		0.06		0.01
9	0.04		0.04		0.07
10	-0.11		0.04		-0.07
11	-0.09		0.04		-0.05
12	-0.12		0.05		-0.08

TFP trend growth rate (2002-2014):	-1.18%

I share Capital (K$)	I share K	I share O&M
3,063,241	0.8555	0.14
3,950,184	0.8757	0.12
3,774,829	0.86	0.14
4,754,628	0.88	0.12
3,947,778	0.86	0.14
3,375,073	0.82	0.18
4,253,136	0.84	0.16
2,734,407	0.78	0.22
2,581,988	0.75	0.25
2,525,200	0.76	0.24
1,645,397	0.67	0.33
2,486,007	0.75	0.25
2,755,381	0.76	0.24

Quantity Sub-indexes Growth rates

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

(Implicit) Price Indexes Growth Rates

Year	Input K	Input O&M_total	Output Net_generation (MWh)
2002			
2003	23.2%	2.4%	13.3%
2004	-4.7%	2.8%	0.6%
2005	23.1%	2.9%	19.0%
2006	-18.8%	2.8%	-17.2%
2007	-13.5%	3.0%	6.1%
2008	22.1%	2.6%	15.4%
2009	-44.3%	1.9%	-45.3%
2010	-5.8%	2.2%	1.9%
2011	-1.0%	2.3%	-8.2%
2012	-43.2%	2.0%	-15.7%
2013	40.8%	2.1%	27.2%
2014	9.6%	2.3%	11.4%
Average	**-1.0%**	**2.4%**	**0.7%**

Fisher Index Output
1.10
0.96
1.02
1.02
0.84
1.05
1.10
0.95
1.06
0.87
1.03
0.97

Fisher Index Output	TFP Index	TFP Growth
1.00	1.00	
1.10	1.07	7.1%
1.06	1.03	-4.4%

1.08	1.04	1.6%
1.10	1.06	1.2%
0.92	0.89	-17.0%
0.97	0.92	3.4%
1.06	1.02	9.6%
1.02	0.96	-5.8%
1.07	1.04	8.0%
0.93	0.90	-14.4%
0.95	0.92	2.2%
0.93	0.89	-3.6%

Fisher Index Output index growth	TFP Index TFP index Growth
9.8%	7.1%
-3.7%	-4.4%
1.6%	1.6%
1.8%	1.2%
-18.0%	-17.0%
5.2%	3.4%
9.4%	9.6%
-4.7%	-5.8%
5.7%	8.0%
-14.4%	-14.4%
2.6%	2.2%
-3.0%	-3.6%
-0.6%	**-1.01%**

TFP output index (2002-2014):
-0.96%

				I		I	I	I		
				MW	%	K$	K$	K$	%	%
Mod_ID	LEI_ID	Company Name	Year	MCR	Capacity Factor	Labour_O&M	Non-labour_O&M	O&M_total	O&M industry share	Labour_OM&A share
1	0	OPG	2002	6,899	56%	78,723	39,166	117,889	23%	67%
1	0	OPG	2003	6,926	55%	84,147	46,555	130,702	23%	64%
1	0	OPG	2004	6,958	58%	88,414	43,797	132,211	22%	67%
1	0	OPG	2005	6,924	55%	91,483	50,906	142,388	23%	64%
1	0	OPG	2006	6,971	56%	100,682	55,924	156,606	24%	64%
1	0	OPG	2007	6,971	54%	106,220	58,735	164,954	23%	64%
1	0	OPG	2008	6,999	61%	110,503	75,236	185,739	24%	59%
1	0	OPG	2009	6,905	60%	114,132	70,965	185,097	24%	62%
1	0	OPG	2010	6,906	51%	107,412	77,281	184,693	22%	58%
1	0	OPG	2011	6,422	54%	110,456	64,154	174,611	21%	63%
1	0	OPG	2012	6,422	51%	115,567	62,567	178,134	22%	65%
1	0	OPG	2013	6,433	54%	121,789	60,795	182,584	22%	67%
1	0	OPG	2014	6,433	54%	119,907	68,113	188,020	22%	64%
1	1	PG&E	2002	3,578	32%			73,605	14%	
1	1	PG&E	2003	3,578	37%			86,474	15%	
1	1	PG&E	2004	3,578	34%			85,405	14%	
1	1	PG&E	2005	3,578	39%			84,427	14%	
1	1	PG&E	2006	3,578	46%			76,536	12%	
1	1	PG&E	2007	3,578	26%			101,326	14%	
1	1	PG&E	2008	3,578	26%			109,376	14%	
1	1	PG&E	2009	3,578	28%			109,621	14%	
1	1	PG&E	2010	3,578	33%			111,628	13%	
1	1	PG&E	2011	3,578	38%			116,740	14%	
1	1	PG&E	2012	3,578	25%			143,941	17%	
1	1	PG&E	2013	3,567	24%			144,261	17%	
1	1	PG&E	2014	3,567	18%			139,710	16%	
1	2	Duke	2002	2,754	21%			27,024	5%	
1	2	Duke	2003	2,754	26%			29,330	5%	
1	2	Duke	2004	2,754	21%			35,769	6%	
1	2	Duke	2005	2,754	23%			35,120	6%	
1	2	Duke	2006	2,756	19%			27,186	4%	
1	2	Duke	2007	2,756	19%			32,581	5%	
1	2	Duke	2008	2,791	19%			32,180	4%	
1	2	Duke	2009	2,791	20%			35,977	5%	
1	2	Duke	2010	2,795	19%			38,734	5%	
1	2	Duke	2011	2,846	17%			38,866	5%	
1	2	Duke	2012	2,852	16%			39,629	5%	
1	2	Duke	2013	2,858	21%			41,251	5%	
1	2	Duke	2014	2,859	20%			40,395	5%	
1	3	VA Electric	2002	1,718	18%			7,382	1%	
1	3	VA Electric	2003	2,379	17%			7,404	1%	
1	3	VA Electric	2004	2,379	15%			7,900	1%	
1	3	VA Electric	2005	2,379	12%			9,620	2%	

1	3	VA Electric	2006	2,379	14%	10,983	2%
1	3	VA Electric	2007	1,694	19%	11,786	2%
1	3	VA Electric	2008	1,950	12%	12,597	2%
1	3	VA Electric	2009	2,080	15%	12,129	2%
1	3	VA Electric	2010	2,080	18%	10,528	1%
1	3	VA Electric	2011	2,080	16%	11,334	1%
1	3	VA Electric	2012	2,122	24%	10,518	1%
1	3	VA Electric	2013	2,122	16%	10,048	1%
1	3	VA Electric	2014	2,122	17%	13,059	2%
1	4	ID Power	2002	1,695	40%	19,532	4%
1	4	ID Power	2003	1,695	41%	20,580	4%
1	4	ID Power	2004	1,695	40%	24,072	4%
1	4	ID Power	2005	1,695	41%	25,021	4%
1	4	ID Power	2006	1,695	62%	27,153	4%
1	4	ID Power	2007	1,695	41%	28,499	4%
1	4	ID Power	2008	1,695	46%	30,234	4%
1	4	ID Power	2009	1,695	54%	29,841	4%
1	4	ID Power	2010	1,695	49%	30,973	4%
1	4	ID Power	2011	1,695	73%	31,171	4%
1	4	ID Power	2012	1,695	53%	32,385	4%
1	4	ID Power	2013	1,695	38%	33,356	4%
1	4	ID Power	2014	1,695	41%	32,515	4%
1	5	AB Power	2002	1,583	29%	20,800	4%
1	5	AB Power	2003	1,583	42%	22,378	4%
1	5	AB Power	2004	1,583	32%	23,267	4%
1	5	AB Power	2005	1,583	32%	24,858	4%
1	5	AB Power	2006	1,583	22%	27,948	4%
1	5	AB Power	2007	1,583	10%	32,887	5%
1	5	AB Power	2008	1,583	17%	32,894	4%
1	5	AB Power	2009	1,583	43%	28,456	4%
1	5	AB Power	2010	1,583	27%	38,606	5%
1	5	AB Power	2011	1,583	23%	35,774	4%
1	5	AB Power	2012	1,583	19%	37,409	5%
1	5	AB Power	2013	1,668	38%	36,349	4%
1	5	AB Power	2014	1,668	27%	46,029	5%
1	6	SoCal Edison	2002	1,093	35%	23,806	5%
1	6	SoCal Edison	2003	1,093	40%	23,798	4%
1	6	SoCal Edison	2004	1,093	35%	25,166	4%
1	6	SoCal Edison	2005	1,093	50%	24,386	4%
1	6	SoCal Edison	2006	1,093	50%	29,579	4%
1	6	SoCal Edison	2007	1,105	25%	35,054	5%
1	6	SoCal Edison	2008	1,105	25%	32,887	4%
1	6	SoCal Edison	2009	1,105	37%	39,833	5%
1	6	SoCal Edison	2010	1,105	42%	44,793	5%
1	6	SoCal Edison	2011	1,112	47%	48,341	6%
1	6	SoCal Edison	2012	1,112	27%	40,213	5%

1	6	SoCal Edison	2013	1,112	23%	46,790	6%
1	6	SoCal Edison	2014	1,112	16%	34,259	4%
1	7	GA Power	2002	1,058	19%	44,321	9%
1	7	GA Power	2003	1,058	30%	44,236	8%
1	7	GA Power	2004	1,058	24%	54,959	9%
1	7	GA Power	2005	1,071	27%	61,906	10%
1	7	GA Power	2006	1,071	19%	62,726	9%
1	7	GA Power	2007	1,071	15%	62,733	9%
1	7	GA Power	2008	1,071	14%	79,350	10%
1	7	GA Power	2009	1,071	26%	53,906	7%
1	7	GA Power	2010	1,071	24%	63,577	8%
1	7	GA Power	2011	1,071	19%	59,952	7%
1	7	GA Power	2012	1,071	15%	51,646	6%
1	7	GA Power	2013	1,071	25%	47,708	6%
1	7	GA Power	2014	1,071	20%	61,799	7%
1	8	PacifiCorp	2002	980	38%	25,498	5%
1	8	PacifiCorp	2003	989	40%	26,755	5%
1	8	PacifiCorp	2004	1,003	35%	34,820	6%
1	8	PacifiCorp	2005	1,003	34%	34,601	6%
1	8	PacifiCorp	2006	1,011	48%	32,842	5%
1	8	PacifiCorp	2007	1,011	39%	35,559	5%
1	8	PacifiCorp	2008	1,011	39%	36,267	5%
1	8	PacifiCorp	2009	1,011	36%	37,243	5%
1	8	PacifiCorp	2010	1,011	39%	35,591	4%
1	8	PacifiCorp	2011	1,016	49%	38,792	5%
1	8	PacifiCorp	2012	1,016	46%	37,713	5%
1	8	PacifiCorp	2013	1,016	33%	40,175	5%
1	8	PacifiCorp	2014	1,016	40%	38,805	4%
1	9	Avista	2002	879	52%	8,929	2%
1	9	Avista	2003	879	46%	12,271	2%
1	9	Avista	2004	879	49%	13,245	2%
1	9	Avista	2005	899	46%	11,327	2%
1	9	Avista	2006	907	52%	12,126	2%
1	9	Avista	2007	907	46%	12,603	2%
1	9	Avista	2008	914	48%	11,932	2%
1	9	Avista	2009	914	47%	14,021	2%
1	9	Avista	2010	914	44%	13,328	2%
1	9	Avista	2011	914	57%	16,273	2%
1	9	Avista	2012	914	51%	15,768	2%
1	9	Avista	2013	921	45%	18,703	2%
1	9	Avista	2014	921	51%	15,173	2%
1	10	Portland	2002	779	45%	12,790	2%
1	10	Portland	2003	779	44%	12,851	2%
1	10	Portland	2004	779	45%	12,312	2%
1	10	Portland	2005	779	42%	13,573	2%
1	10	Portland	2006	779	53%	15,167	2%

1	10	Portland	2007	779	47%	19,610	3%
1	10	Portland	2008	779	47%	21,110	3%
1	10	Portland	2009	758	48%	25,499	3%
1	10	Portland	2010	758	49%	21,663	3%
1	10	Portland	2011	758	53%	22,383	3%
1	10	Portland	2012	808	49%	25,819	3%
1	10	Portland	2013	808	42%	26,947	3%
1	10	Portland	2014	889	41%	31,103	4%
1	11	Ameren MI - Union	2002	741	27%	13,567	3%
1	11	Ameren MI - Union	2003	741	23%	10,767	2%
1	11	Ameren MI - Union	2004	741	32%	13,208	2%
1	11	Ameren MI - Union	2005	741	32%	10,942	2%
1	11	Ameren MI - Union	2006	741	15%	11,099	2%
1	11	Ameren MI - Union	2007	741	25%	14,224	2%
1	11	Ameren MI - Union	2008	741	27%	17,774	2%
1	11	Ameren MI - Union	2009	779	28%	19,718	3%
1	11	Ameren MI - Union	2010	779	32%	23,106	3%
1	11	Ameren MI - Union	2011	779	26%	14,684	2%
1	11	Ameren MI - Union	2012	779	19%	14,202	2%
1	11	Ameren MI - Union	2013	779	24%	15,495	2%
1	11	Ameren MI - Union	2014	904	18%	15,385	2%
1	12	AP Power	2002	740	15%	21,647	4%
1	12	AP Power	2003	740	23%	19,106	3%
1	12	AP Power	2004	740	20%	22,361	4%
1	12	AP Power	2005	740	20%	32,824	5%
1	12	AP Power	2006	740	19%	34,699	5%
1	12	AP Power	2007	740	18%	35,563	5%
1	12	AP Power	2008	740	16%	37,707	5%
1	12	AP Power	2009	740	19%	34,874	4%
1	12	AP Power	2010	740	18%	38,269	5%
1	12	AP Power	2011	779	15%	33,342	4%
1	12	AP Power	2012	779	14%	28,907	4%
1	12	AP Power	2013	840	14%	27,228	3%
1	12	AP Power	2014	840	12%	33,128	4%
1	13	SCE&G	2002	761	14%	6,274	1%
1	13	SCE&G	2003	751	20%	6,575	1%
1	13	SCE&G	2004	751	17%	6,709	1%
1	13	SCE&G	2005	751	19%	6,810	1%
1	13	SCE&G	2006	751	16%	7,665	1%
1	13	SCE&G	2007	751	15%	6,987	1%
1	13	SCE&G	2008	750	14%	7,494	1%
1	13	SCE&G	2009	750	15%	8,426	1%
1	13	SCE&G	2010	750	13%	7,308	1%
1	13	SCE&G	2011	750	11%	7,017	1%
1	13	SCE&G	2012	750	11%	7,009	1%
1	13	SCE&G	2013	750	12%	7,538	1%

1	13	SCE&G	2014	751	9%	7,830	1%
1	14	SEPA	2002	3,412	18%	71,520	14%
1	14	SEPA	2003	3,412	31%	82,754	15%
1	14	SEPA	2004	3,412	28%	84,330	14%
1	14	SEPA	2005	3,392	31%	83,638	13%
1	14	SEPA	2006	3,392	19%	108,053	16%
1	14	SEPA	2007	3,392	18%	96,188	13%
1	14	SEPA	2008	3,392	15%	99,695	13%
1	14	SEPA	2009	3,392	21%	111,926	14%
1	14	SEPA	2010	3,392	28%	150,046	18%
1	14	SEPA	2011	3,392	22%	128,499	16%
1	14	SEPA	2012	3,392	19%	122,089	15%
1	14	SEPA	2013	3,392	26%	114,310	14%
1	14	SEPA	2014	3,392	25%	124,376	14%
1	15	Seattle	2002	1,929	41%	22,812	4%
1	15	Seattle	2003	1,929	36%	24,860	4%
1	15	Seattle	2004	1,929	36%	24,949	4%
1	15	Seattle	2005	1,929	33%	23,242	4%
1	15	Seattle	2006	1,929	40%	24,064	4%
1	15	Seattle	2007	1,929	39%	30,718	4%
1	15	Seattle	2008	1,929	37%	34,413	4%
1	15	Seattle	2009	1,929	35%	35,205	5%
1	15	Seattle	2010	1,929	33%	27,513	3%
1	15	Seattle	2011	1,929	45%	36,035	4%
1	15	Seattle	2012	1,929	41%	39,715	5%
1	15	Seattle	2013	1,929	36%	49,200	6%
1	15	Seattle	2014	1,929	42%	43,750	5%
1	16	Peer Industry	2002	30,597	35%	517,395	100%
1	16	Peer Industry	2003	31,285	37%	560,843	100%
1	16	Peer Industry	2004	31,331	36%	600,683	100%
1	16	Peer Industry	2005	31,309	37%	624,683	100%
1	16	Peer Industry	2006	31,374	37%	664,433	100%
1	16	Peer Industry	2007	30,701	32%	721,273	100%
1	16	Peer Industry	2008	31,027	33%	781,648	100%
1	16	Peer Industry	2009	31,080	36%	781,773	100%
1	16	Peer Industry	2010	31,085	35%	840,356	100%
1	16	Peer Industry	2011	30,704	37%	813,815	100%
1	16	Peer Industry	2012	30,802	32%	825,097	100%
1	16	Peer Industry	2013	30,962	33%	841,942	100%
1	16	Peer Industry	2014	31,168	32%	865,337	100%
1	17	Peer Industry less OPG	2002	23,698	28%	399,506	77%
1	17	Peer Industry less OPG	2003	24,358	33%	430,140	77%
1	17	Peer Industry less OPG	2004	24,373	30%	468,471	78%
1	17	Peer Industry less OPG	2005	24,386	31%	482,294	77%
1	17	Peer Industry less OPG	2006	24,403	32%	507,827	76%
1	17	Peer Industry less OPG	2007	23,730	25%	556,319	77%

1	17	Peer Industry less OPG	2008	24,028	25%	595,908	76%
1	17	Peer Industry less OPG	2009	24,175	30%	596,677	76%
1	17	Peer Industry less OPG	2010	24,179	30%	655,662	78%
1	17	Peer Industry less OPG	2011	24,282	33%	639,204	79%
1	17	Peer Industry less OPG	2012	24,380	27%	646,962	78%
1	17	Peer Industry less OPG	2013	24,529	27%	659,359	78%
1	17	Peer Industry less OPG	2014	24,735	26%	677,317	78%

O MWh Net_generation	I share K$ Revenue	I share K$ Capital	I share % Capital Share	I share % O&M Share	I share % Labour O&M Share	I share % Non-labour O&M Share	Sub-index unit O&M price index
33,977,759	2,126,290	2,008,401	94%	6%	4%	2%	1.00
33,202,786	2,068,079	1,937,377	94%	6%	4%	2%	1.02
35,351,273	1,851,547	1,719,336	93%	7%	5%	2%	1.05
33,487,118	1,837,930	1,695,542	92%	8%	5%	3%	1.08
34,329,431	1,408,920	1,252,314	89%	11%	7%	4%	1.10
32,986,718	1,378,521	1,213,567	88%	12%	8%	4%	1.14
37,423,326	1,615,589	1,429,849	89%	11%	7%	5%	1.16
36,302,957	1,335,251	1,150,154	86%	14%	9%	5%	1.18
30,568,258	1,125,926	941,233	84%	16%	10%	7%	1.21
30,359,921	1,099,541	924,931	84%	16%	10%	6%	1.23
28,458,915	941,858	763,724	81%	19%	12%	7%	1.25
30,347,392	1,127,001	944,418	84%	16%	11%	5%	1.27
30,625,600	1,310,091	1,122,072	86%	14%	9%	5%	1.30
10,075,261	301,225	227,620	76%	24%	0%	24%	-24%
11,506,124	464,670	378,197	81%	19%	0%	19%	-19%
10,605,018	462,126	376,721	82%	18%	0%	18%	-18%
12,181,585	752,856	668,429	89%	11%	0%	11%	-11%
14,345,679	707,160	630,624	89%	11%	0%	11%	-11%
8,097,547	508,253	406,927	80%	20%	0%	20%	-20%
8,145,244	725,807	616,432	85%	15%	0%	15%	-15%
8,927,398	363,178	253,557	70%	30%	0%	30%	-30%
10,485,910	436,466	324,838	74%	26%	0%	26%	-26%
12,046,693	432,483	315,743	73%	27%	0%	27%	-27%
7,874,464	267,121	123,181	46%	54%	0%	54%	-54%
7,607,401	358,378	214,118	60%	40%	0%	40%	-40%
5,740,008	325,449	185,740	57%	43%	0%	43%	-43%
4,959,185	31,966	4,942	58%	42%	0%	42%	-42%
6,349,659	106,918	77,588	73%	27%	0%	27%	-27%
5,133,383	96,428	60,659	63%	37%	0%	37%	-37%
5,526,417	144,515	109,395	76%	24%	0%	24%	-24%
4,476,743	82,428	55,241	67%	33%	0%	33%	-33%
4,470,974	61,098	28,518	47%	53%	0%	53%	-53%
4,618,792	64,948	32,769	50%	50%	0%	50%	-50%
4,767,989	74,689	38,712	52%	48%	0%	48%	-48%
4,757,841	82,713	43,979	53%	47%	0%	47%	-47%
4,256,244	62,044	23,178	37%	63%	0%	63%	-63%
3,989,993	46,977	7,348	58%	42%	0%	42%	-42%
5,258,826	105,619	64,368	61%	39%	0%	39%	-39%
5,008,985	98,706	58,310	59%	41%	0%	41%	-41%
2,745,908	10,367	2,985	29%	71%	0%	71%	-71%
3,524,075	60,446	53,042	88%	12%	0%	12%	-12%
3,072,059	41,524	33,624	81%	19%	0%	19%	-19%
2,589,093	43,433	33,813	78%	22%	0%	22%	-22%

2,929,977	32,012	21,029	66%	34%	0%	34%	-34%
2,767,601	33,715	21,929	65%	35%	0%	35%	-35%
2,044,218	30,818	18,220	59%	41%	0%	41%	-41%
2,813,461	32,547	20,418	63%	37%	0%	37%	-37%
3,262,836	42,459	31,931	75%	25%	0%	25%	-25%
2,936,357	21,336	10,002	47%	53%	0%	53%	-53%
4,495,195	13,773	3,255	24%	76%	0%	76%	-76%
2,932,193	29,589	19,541	66%	34%	0%	34%	-34%
3,095,734	50,652	37,593	74%	26%	0%	26%	-26%
5,972,445	164,989	145,457	88%	12%	0%	12%	-12%
6,088,883	284,529	263,949	93%	7%	0%	7%	-7%
5,972,148	305,563	281,491	92%	8%	0%	8%	-8%
6,144,823	431,550	406,529	94%	6%	0%	6%	-6%
9,140,420	508,252	481,099	95%	5%	0%	5%	-5%
6,111,406	394,718	366,219	93%	7%	0%	7%	-7%
6,839,696	518,483	488,248	94%	6%	0%	6%	-6%
8,028,082	304,445	274,604	90%	10%	0%	10%	-10%
7,276,822	292,886	261,912	89%	11%	0%	11%	-11%
10,903,116	348,149	316,978	91%	9%	0%	9%	-9%
7,882,921	199,877	167,492	84%	16%	0%	16%	-16%
5,587,871	230,877	197,521	86%	14%	0%	14%	-14%
6,097,434	257,486	224,971	87%	13%	0%	13%	-13%
4,088,810	117,929	97,128	82%	18%	0%	18%	-18%
5,761,736	219,630	197,252	90%	10%	0%	10%	-10%
4,403,651	201,992	178,726	88%	12%	0%	12%	-12%
4,436,797	278,700	253,842	91%	9%	0%	9%	-9%
3,087,416	155,475	127,527	82%	18%	0%	18%	-18%
1,403,518	78,282	45,394	58%	42%	0%	42%	-42%
2,300,449	161,078	128,184	80%	20%	0%	20%	-20%
5,905,956	230,502	202,046	88%	12%	0%	12%	-12%
3,707,310	172,147	133,541	78%	22%	0%	22%	-22%
3,204,062	124,119	88,345	71%	29%	0%	29%	-29%
2,667,009	85,756	48,348	56%	44%	0%	44%	-44%
5,624,823	212,131	175,782	83%	17%	0%	17%	-17%
3,892,917	217,297	171,268	79%	21%	0%	21%	-21%
3,314,010	111,057	87,252	79%	21%	0%	21%	-21%
3,802,857	152,813	129,015	84%	16%	0%	16%	-16%
3,347,422	149,508	124,342	83%	17%	0%	17%	-17%
4,821,918	305,763	281,377	92%	8%	0%	8%	-8%
4,773,110	269,657	240,078	89%	11%	0%	11%	-11%
2,448,324	144,854	109,800	76%	24%	0%	24%	-24%
2,455,275	210,256	177,369	84%	16%	0%	16%	-16%
3,568,086	130,952	91,119	70%	30%	0%	30%	-30%
4,105,320	172,448	127,656	74%	26%	0%	26%	-26%
4,603,429	174,963	126,622	72%	28%	0%	28%	-28%
2,625,534	90,375	50,162	56%	44%	0%	44%	-44%

2,254,662	112,300	65,510	58%	42%	0%	42%	-42%
1,543,032	86,709	52,450	60%	40%	0%	40%	-40%
1,721,153	29,004	(15,317)	34%	66%	0%	66%	-66%
2,780,954	76,607	32,370	42%	58%	0%	58%	-58%
2,215,266	69,634	14,675	21%	79%	0%	79%	-79%
2,553,624	126,549	64,642	51%	49%	0%	49%	-49%
1,776,363	61,708	(1,018)	34%	66%	0%	66%	-66%
1,426,418	41,896	(20,837)	34%	66%	0%	66%	-66%
1,357,464	52,439	(26,910)	34%	66%	0%	66%	-66%
2,441,228	70,078	16,172	23%	77%	0%	77%	-77%
2,208,567	70,814	7,237	34%	66%	0%	66%	-66%
1,761,111	44,494	(15,458)	34%	66%	0%	66%	-66%
1,410,378	25,207	(26,439)	34%	66%	0%	66%	-66%
2,336,744	69,104	21,396	31%	69%	0%	69%	-69%
1,908,307	75,080	13,281	18%	82%	0%	82%	-82%
3,219,922	98,988	73,491	74%	26%	0%	26%	-26%
3,444,668	177,836	151,081	85%	15%	0%	15%	-15%
3,091,170	173,661	138,840	80%	20%	0%	20%	-20%
2,965,117	227,782	193,180	85%	15%	0%	15%	-15%
4,250,197	271,325	238,483	88%	12%	0%	12%	-12%
3,443,624	242,396	206,837	85%	15%	0%	15%	-15%
3,441,159	287,926	251,660	87%	13%	0%	13%	-13%
3,213,992	135,676	98,433	73%	27%	0%	27%	-27%
3,435,392	149,971	114,380	76%	24%	0%	24%	-24%
4,339,268	154,322	115,530	75%	25%	0%	25%	-25%
4,080,847	116,332	78,619	68%	32%	0%	32%	-32%
2,976,700	134,754	94,579	70%	30%	0%	30%	-30%
3,595,400	174,353	135,547	78%	22%	0%	22%	-22%
4,009,637	104,807	95,878	91%	9%	0%	9%	-9%
3,539,611	168,772	156,501	93%	7%	0%	7%	-7%
3,789,043	203,385	190,140	93%	7%	0%	7%	-7%
3,610,823	251,921	240,594	96%	4%	0%	4%	-4%
4,127,672	230,651	218,525	95%	5%	0%	5%	-5%
3,688,791	243,128	230,525	95%	5%	0%	5%	-5%
3,851,251	289,635	277,703	96%	4%	0%	4%	-4%
3,765,761	147,856	133,835	91%	9%	0%	9%	-9%
3,493,588	141,590	128,262	91%	9%	0%	9%	-9%
4,534,293	153,925	137,652	89%	11%	0%	11%	-11%
4,088,289	98,867	83,098	84%	16%	0%	16%	-16%
3,645,832	159,385	140,682	88%	12%	0%	12%	-12%
4,143,307	187,263	172,090	92%	8%	0%	8%	-8%
3,066,765	69,239	56,449	82%	18%	0%	18%	-18%
3,019,577	112,201	99,350	89%	11%	0%	11%	-11%
3,097,850	123,244	110,932	90%	10%	0%	10%	-10%
2,837,546	157,187	143,614	91%	9%	0%	9%	-9%
3,605,566	160,024	144,856	91%	9%	0%	9%	-9%

3,183,332	162,414	142,804	88%	12%	0%	12%	-12%
3,202,085	194,470	173,359	89%	11%	0%	11%	-11%
3,191,546	99,841	74,341	74%	26%	0%	26%	-26%
3,254,776	103,973	82,310	79%	21%	0%	21%	-21%
3,521,657	90,327	67,944	75%	25%	0%	25%	-25%
3,462,116	71,956	46,137	64%	36%	0%	36%	-36%
3,001,760	97,630	70,683	72%	28%	0%	28%	-28%
3,165,690	112,546	81,443	72%	28%	0%	28%	-28%
1,767,529	31,595	18,028	57%	43%	0%	43%	-43%
1,461,441	29,302	18,535	63%	37%	0%	37%	-37%
2,088,127	58,979	45,771	78%	22%	0%	22%	-22%
2,063,631	80,159	69,217	86%	14%	0%	14%	-14%
955,563	49,249	38,150	77%	23%	0%	23%	-23%
1,591,900	92,040	77,816	85%	15%	0%	15%	-15%
1,748,285	105,557	87,783	83%	17%	0%	17%	-17%
1,902,961	57,507	37,789	66%	34%	0%	34%	-34%
2,152,401	82,083	58,977	72%	28%	0%	28%	-28%
1,755,836	47,790	33,105	69%	31%	0%	31%	-31%
1,317,309	29,443	15,241	52%	48%	0%	48%	-48%
1,667,070	48,906	33,411	68%	32%	0%	32%	-32%
1,433,513	41,232	25,847	63%	37%	0%	37%	-37%
976,826	29,571	7,923	27%	73%	0%	73%	-73%
1,503,131	65,870	46,764	71%	29%	0%	29%	-29%
1,312,878	62,736	40,376	64%	36%	0%	36%	-36%
1,307,560	68,665	35,841	52%	48%	0%	48%	-48%
1,235,977	57,309	22,610	39%	61%	0%	61%	-61%
1,169,116	55,461	19,897	36%	64%	0%	64%	-64%
1,056,804	61,110	23,403	38%	62%	0%	62%	-62%
1,201,289	45,532	10,658	23%	77%	0%	77%	-77%
1,190,183	51,515	13,246	26%	74%	0%	74%	-74%
1,037,828	46,709	13,366	29%	71%	0%	71%	-71%
970,063	33,443	4,535	41%	59%	0%	59%	-59%
1,064,469	41,472	14,244	34%	66%	0%	66%	-66%
905,995	25,804	(7,324)	40%	60%	0%	60%	-60%
953,064	6,438	164	45%	55%	0%	55%	-55%
1,285,981	18,541	11,966	65%	35%	0%	35%	-35%
1,133,492	11,193	4,484	40%	60%	0%	60%	-60%
1,273,330	24,820	18,011	73%	27%	0%	27%	-27%
1,019,894	10,817	3,153	29%	71%	0%	71%	-71%
1,018,237	11,101	4,115	37%	63%	0%	63%	-63%
917,768	7,398	(96)	45%	55%	0%	55%	-55%
960,207	12,036	3,609	30%	70%	0%	70%	-70%
870,435	12,041	4,733	39%	61%	0%	61%	-61%
723,578	7,326	310	45%	55%	0%	55%	-55%
752,595	4,825	(2,184)	45%	55%	0%	55%	-55%
809,223	15,566	8,028	52%	48%	0%	48%	-48%

613,520	14,945	7,114	48%	52%	0%	52%	-52%
5,361,741	165,323	93,803	57%	43%	0%	43%	-43%
9,315,598	211,791	129,037	61%	39%	0%	39%	-39%
8,333,515	239,578	155,248	65%	35%	0%	35%	-35%
9,262,617	246,161	162,524	66%	34%	0%	34%	-34%
5,652,920	219,527	111,474	51%	49%	0%	49%	-49%
5,232,989	216,468	120,279	56%	44%	0%	44%	-44%
4,422,917	230,546	130,851	57%	43%	0%	43%	-43%
6,135,029	236,135	124,209	53%	47%	0%	47%	-47%
8,224,506	255,417	105,370	41%	59%	0%	59%	-59%
6,510,698	274,686	146,187	53%	47%	0%	47%	-47%
5,618,173	267,662	145,573	54%	46%	0%	46%	-46%
7,659,184	317,461	193,084	61%	39%	0%	39%	-39%
7,398,826	312,081	197,771	63%	37%	0%	37%	-37%
6,891,659	181,848	159,037	87%	13%	0%	13%	-13%
6,098,753	293,020	268,161	92%	8%	0%	8%	-8%
6,019,707	324,413	299,463	92%	8%	0%	8%	-8%
5,544,793	401,321	378,079	94%	6%	0%	6%	-6%
6,716,041	387,697	363,634	94%	6%	0%	6%	-6%
6,530,479	432,001	401,283	93%	7%	0%	7%	-7%
6,298,724	478,725	444,312	93%	7%	0%	7%	-7%
5,878,382	239,955	204,749	85%	15%	0%	15%	-15%
5,509,191	229,894	202,382	88%	12%	0%	12%	-12%
7,546,905	256,801	220,765	86%	14%	0%	14%	-14%
6,947,088	177,022	137,306	78%	22%	0%	22%	-22%
6,108,908	267,776	218,576	82%	18%	0%	18%	-18%
7,091,368	331,024	287,274	87%	13%	0%	13%	-13%
93,101,674	3,580,636	3,063,241	86%	14%	0%	14%	
102,685,834	4,511,026	3,950,184	88%	12%	0%	12%	
98,966,002	4,375,512	3,774,829	86%	14%	0%	14%	
100,606,791	5,379,311	4,754,628	88%	12%	0%	12%	
102,422,968	4,612,210	3,947,778	86%	14%	0%	14%	
85,570,974	4,096,346	3,375,073	82%	18%	0%	18%	
90,123,457	5,034,784	4,253,136	84%	16%	0%	16%	
99,004,323	3,516,180	2,734,407	78%	22%	0%	22%	
94,503,336	3,422,343	2,581,988	75%	25%	0%	25%	
100,040,995	3,339,015	2,525,200	76%	24%	0%	24%	
86,640,889	2,470,494	1,645,397	67%	33%	0%	33%	
88,883,057	3,327,950	2,486,007	75%	25%	0%	25%	
86,259,636	3,620,718	2,755,381	76%	24%	0%	24%	
59,123,915	1,454,346	1,054,840	73%	27%	0%	27%	-27%
69,483,048	2,442,947	2,012,807	82%	18%	0%	18%	-18%
63,614,729	2,523,965	2,055,493	81%	19%	0%	19%	-19%
67,119,673	3,541,381	3,059,086	86%	14%	0%	14%	-14%
68,093,537	3,203,290	2,695,464	84%	16%	0%	16%	-16%
52,584,256	2,717,825	2,161,506	80%	20%	0%	20%	-20%

52,700,131	3,419,195	2,823,286	83%	17%	0%	17%	-17%
62,701,367	2,180,929	1,584,252	73%	27%	0%	27%	-27%
63,935,078	2,296,417	1,640,755	71%	29%	0%	29%	-29%
69,681,075	2,239,474	1,600,269	71%	29%	0%	29%	-29%
58,181,974	1,528,635	881,673	58%	42%	0%	42%	-42%
58,535,665	2,200,948	1,541,590	70%	30%	0%	30%	-30%
55,634,036	2,310,626	1,633,309	71%	29%	0%	29%	-29%

Is it in the modeling? 1 = yes; 0 = no

Mod_ID	LEI_ID	Short name	Full utility name	
1	0	OPG	OPG Hydro Total	CA
1	1	PG&E	PACIFIC GAS AND ELECTRIC COMPANY	US
1	2	Duke	Duke Energy Carolinas, LLC	US
1	3	VA Electric	VIRGINIA ELECTRIC AND POWER COMPANY	US
1	4	ID Power	Idaho Power Company	US
1	5	AB Power	ALABAMA POWER COMPANY	US
1	6	SoCal Edison	Southern California Edison Company	US
1	7	GA Power	Georgia Power Company	US
1	8	PacifiCorp	PacifiCorp	US
1	9	Avista	Avista Corporation	US
1	10	Portland	Portland General Electric Company	US
1	11	Ameren MI - Union	UNION ELECTRIC COMPANY	US
1	12	AP Power	Appalachian Power Company	US
1	13	SCE&G	South Carolina Electric & Gas Company	US
1	14	Alcoa	Alcoa Power Generating Inc.	US
1	15	SEPA	Southeastern Power Administration	US
1	16	Seattle	Seattle City Light	US
0	17	WAPA	Western Area Power Administration	US
1	18	Peer Industry	OPG Hydro Peer Industry Total	NA
1	19	Peer Industry less OPG	Peer Industry Total (without OPG)	US

Note: combined index for North America (based on O&M share)

O&M share of Canada	23%
O&M share of US	77%

	NA	CA	US
Year	O&M Price Index	O&M Price Index	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	1.08	1.08	1.09
2006	1.11	1.10	1.12
2007	1.15	1.14	1.15
2008	1.18	1.16	1.18
2009	1.20	1.18	1.21
2010	1.23	1.21	1.23
2011	1.26	1.23	1.26
2012	1.28	1.25	1.29
2013	1.31	1.27	1.32
2014	1.34	1.30	1.35
Average G	**2.4%**	**2.2%**	**2.5%**

	NA	NA	NA
	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**	**1.08**
2006	**1.12**	**1.11**	**1.11**
2007	**1.16**	**1.14**	**1.15**
2008	**1.19**	**1.16**	**1.18**
2009	**1.22**	**1.17**	**1.20**
2010	**1.25**	**1.18**	**1.23**
2011	**1.29**	**1.21**	**1.26**
2012	**1.31**	**1.23**	**1.28**
2013	**1.35**	**1.25**	**1.31**
2014	**1.38**	**1.27**	**1.34**

Calculating NA L/NL/C

	NA	NA	NA
	Labour Price Index Growth	Non-Labour Price Index Growth	O&M Price Index Growth
2002	1.00	1.00	1.00
2003	1.03	1.02	1.02
2004	1.03	1.03	1.03
2005	1.03	1.03	1.03
2006	1.03	1.03	1.03
2007	1.03	1.03	1.03
2008	1.03	1.02	1.03
2009	1.02	1.01	1.02
2010	1.03	1.01	1.02
2011	1.02	1.02	1.02
2012	1.02	1.02	1.02
2013	1.02	1.02	1.02
2014	1.03	1.02	1.02

	CA	CA
	(Ontario) Industrial Labour Index Growth	(Canada) GDP-IPI FDD Growth
2002	1.00	1.00
2003	1.02	1.02
2004	1.03	1.02
2005	1.04	1.02
2006	1.02	1.02
2007	1.04	1.02
2008	1.02	1.03
2009	1.01	1.01
2010	1.04	1.01
2011	1.01	1.02
2012	1.01	1.02
2013	1.02	1.02
2014	1.02	1.02

	NA	CA	US
Year	O&M Price Index Growth Rates	O&M Price Index Growth Rates	O&M Price Index Growth Rates
2002			
2003	2.4%	2.1%	2.4%
2004	2.8%	2.4%	2.9%
2005	2.9%	3.0%	2.9%
2006	2.8%	1.9%	3.0%
2007	3.0%	3.2%	3.0%
2008	2.6%	2.4%	2.7%
2009	1.9%	1.2%	2.0%
2010	2.2%	2.8%	2.0%
2011	2.3%	1.7%	2.4%
2012	2.0%	1.5%	2.2%
2013	2.1%	1.6%	2.3%
2014	2.3%	2.0%	2.4%

Average	**2.4%**	**2.2%**	**2.5%**

O&M growths

CA		US	US	US
O&M Price Index Growth		(USA) Labour Index Growth	(USA) GDP-PI Growth	O&M Price Index Growth
1.00	2002	1.00	1.00	1.00
1.02	2003	1.03	1.02	1.02
1.02	2004	1.03	1.03	1.03
1.03	2005	1.03	1.03	1.03
1.02	2006	1.03	1.03	1.03
1.03	2007	1.03	1.03	1.03
1.02	2008	1.03	1.02	1.03
1.01	2009	1.03	1.01	1.02
1.03	2010	1.02	1.01	1.02
1.02	2011	1.03	1.02	1.02
1.02	2012	1.02	1.02	1.02
1.02	2013	1.03	1.02	1.02
1.02	2014	1.03	1.02	1.02

Note: Indices are for Canada
Source: See StatsCan CANSIM Tables

Share of Labour	63%
Share of Non-labour	37%

Year	(Ontario) Average Weekly Earnings, Industrial	(Ontario) Industrial Labour Index Growth	(Canada) GDP-IPI FDD	(Canada) GDP-IPI FDD Growth
2002	710.87	1.00	90.20	1.00
2003	728.38	1.02	91.70	1.02
2004	748.57	1.03	93.40	1.02
2005	775.80	1.04	95.40	1.02
2006	788.25	1.02	97.70	1.02
2007	818.61	1.04	100.00	1.02
2008	837.91	1.02	102.50	1.03
2009	848.85	1.01	103.70	1.01
2010	881.43	1.04	104.80	1.01
2011	893.41	1.01	107.30	1.02
2012	906.09	1.01	109.10	1.02
2013	920.12	1.02	111.00	1.02
2014	938.36	1.02	113.40	1.02

Ontario Industries	Canada GDP-IPI FDD	On+Can O&M	On+Can O&M
(Ind) Labour Price Index	Non-Labour Price Index	O&M Price Index Growth	O&M Price Index
1.00	**1.00**	1.00	**1.00**
1.02	**1.02**	1.02	**1.02**
1.05	**1.04**	1.02	**1.05**
1.09	**1.06**	1.03	**1.08**
1.11	**1.08**	1.02	**1.10**
1.15	**1.11**	1.03	**1.14**
1.18	**1.14**	1.02	**1.16**
1.19	**1.15**	1.01	**1.18**
1.24	**1.16**	1.03	**1.21**
1.26	**1.19**	1.02	**1.23**
1.27	**1.21**	1.02	**1.25**
1.29	**1.23**	1.02	**1.27**
1.32	**1.26**	1.02	**1.30**

On+Can O&M O&M Price Index Growth Rates (%)	Year	EUCG L shares	O&M price index growth	O&M price index	
	2002	0%	1.00	1.00	
2.1%	2003	0%	1.02	1.02	1.6%
2.4%	2004	60%	1.02	1.04	2.1%
3.0%	2005	63%	1.03	1.07	3.0%
1.9%	2006	61%	1.02	1.09	1.9%
3.2%	2007	61%	1.03	1.13	3.2%
2.4%	2008	60%	1.02	1.15	2.4%
1.2%	2009	62%	1.01	1.17	1.2%
2.8%	2010	65%	1.03	1.20	2.8%
1.7%	2011	63%	1.02	1.22	1.7%
1.5%	2012	65%	1.02	1.24	1.5%
1.6%	2013	64%	1.02	1.26	1.6%
2.0%	2014	64%	1.02	1.29	2.0%
2.2%					**2.1%**

Note: Indices are for United States
Source: See US BLS & BEA tables

Share of Labour 63%
Share of Non-labour 37%

Year	(USA) Employment Cost Index, Utilities	(USA) Labour Index Growth	(USA) GDP Price Index	(USA) GDP-PI Growth	USA Utilities Labour Price Index	USA GDP-PI Non-Labour Price Index	USA O&M O&M Price Index Growth
2002	91.30	1.00	85.05	1.00	**1.00**	**1.00**	1.00
2003	93.78	1.03	86.75	1.02	**1.03**	**1.02**	1.02
2004	96.63	1.03	89.13	1.03	**1.06**	**1.05**	1.03
2005	99.28	1.03	91.99	1.03	**1.09**	**1.08**	1.03
2006	102.35	1.03	94.82	1.03	**1.12**	**1.11**	1.03
2007	105.68	1.03	97.34	1.03	**1.16**	**1.14**	1.03
2008	109.05	1.03	99.24	1.02	**1.19**	**1.17**	1.03
2009	112.13	1.03	100.00	1.01	**1.23**	**1.18**	1.02
2010	114.90	1.02	101.21	1.01	**1.26**	**1.19**	1.02
2011	118.08	1.03	103.20	1.02	**1.29**	**1.21**	1.02
2012	120.98	1.02	105.00	1.02	**1.33**	**1.23**	1.02
2013	124.33	1.03	106.59	1.02	**1.36**	**1.25**	1.02
2014	127.70	1.03	108.69	1.02	**1.40**	**1.28**	1.02

USA O&M	USA O&M
O&M Price Index	**O&M Price Index Growth Rates (%)**
1.00	
1.02	2.4%
1.05	2.9%
1.09	2.9%
1.12	3.0%
1.15	3.0%
1.18	2.7%
1.21	2.0%
1.23	2.0%
1.26	2.4%
1.29	2.2%
1.32	2.3%
1.35	2.4%
	2.5%

OPG data only (data from OPG)

	Labour_OM&A share	Capital Share	OM&A Share	Labor OM&A share combined	Other OM&A share combined
2002	67%	93%	7%	5%	2%
2003	64%	94%	6%	4%	2%
2004	67%	93%	7%	5%	2%
2005	64%	92%	8%	5%	3%
2006	64%	89%	11%	7%	4%
2007	64%	88%	12%	8%	4%
2008	59%	89%	11%	7%	5%
2009	62%	86%	14%	8%	5%
2010	58%	84%	16%	9%	7%
2011	62%	84%	16%	10%	6%
2012	64%	81%	19%	12%	7%
2013	67%	84%	16%	11%	5%
2014	64%	86%	14%	9%	5%
average 2002-2014	**63.5%**	**88%**	**12%**	**8%**	**4%**

EUCG data (industry)

	Labour Share based on Total OM&A (Operations+Maintenance+Environment & Regulatory+Land & Water Rental Fees + Administration)	Labour Share based on OM&A, less Water Rentals/Fees and Indirect Admin	Labour Share based on O&M
2002			
2003			
2004	42%	44%	60%
2005	38%	45%	63%
2006	37%	44%	61%
2007	37%	46%	61%
2008	36%	47%	60%
2009	38%	47%	62%
2010	42%	52%	65%
2011	42%	51%	63%
2012	46%	53%	65%
2013	46%	53%	64%
2014	46%	53%	64%
average 2002-2014	**41%**	**49%**	**63%**

Note: LEI derived the above tables from EUCG data

StatsCan Tables: http://www5.statcan.gc.ca/cansim/a29?lang=eng&groupid=All&p2=17

See lower for GDP-IPI FDD

Labour Price Indices

Table 281-0027 [4, 14, 15, 16, 18]

Average weekly earnings (SEPH), by type of employee for selected industries classified using the North American Industry Classification System (NAICS)
annual (current dollars)
Geography = Ontario
Type of employees = All employees
Overtime = Including overtime
Accessed on January 5, 2016

Industrial aggregate excluding unclassified businesses [11-91N] [5, 6]

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	
orig	695.66	710.87	728.38	748.57	775.8	788.25	818.61	837.91	848.85[A]	881.43[A]	893.41[A]	906.09[A]	920.12[A]	938.36[A]	
	695.66	710.87	728.38	748.57	775.8	788.25	818.61	837.91	848.85	881.43	893.41	906.09	920.12	938.36	
		2.16%	2.43%	2.73%	3.57%	1.59%	3.78%	2.33%	1.30%	3.77%	1.35%	1.41%	1.54%	1.96%	1.56%

Utilities [22, 221]

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	
orig	1,306.79	1,385.59	1,441.31	1,420.13	1,449.84	1,488.34	1,577.41	1,544.30	1,672.72[A]	1,680.01[A]	1,714.92[A]	1,707.11[A]	1,758.79[A]	1,915.37[A]	
	1,306.79	1,385.59	1,441.31	1,420.13	1,449.84	1,488.34	1,577.41	1,544.30	1,672.72	1,680.01	1,714.92	1,707.11	1758.79	1915.37	
		5.86%	3.94%	-1.48%	2.07%	2.62%	5.81%	-2.12%	7.99%	0.43%	2.06%	-0.46%	2.98%	8.53%	3.28%

NAICS [1	Industri	Utilities [22, 221]
2001	695.66	1306.79
2002	710.87	1385.59
2003	728.38	1441.31
2004	748.57	1420.13
2005	775.80	1449.84
2006	788.25	1488.34
2007	818.61	1577.41
2008	837.91	1544.30
2009	848.85	1672.72
2010	881.43	1680.01
2011	893.41	1714.92
2012	906.09	1707.11
2013	920.12	1758.79
2014	938.36	1915.37

Footnotes:

1 Although the creation of Nunavut officially took place in April 1999, the Survey of employment, payrolls and hours (SEPH) was only able to begin publishing separ

2 Since January 2001, the Survey of employment, payrolls and hours (SEPH) program no longer combines Northwest Territories and Nunavut.
3 These terminated series are based on the North American Industry Classification System (NAICS) 2002.
4 Data quality indicators are based on the coefficient of variation (CV). Quality indicators indicate the following: A - Excellent (CV from 0% to 4
5 Industrial aggregate covers all industrial sectors except those primarily involved in agriculture, fishing and trapping, private household servi
6 Unclassified businesses (00) are business for which the industrial classification (North American Industry Classification System (NAICS) 201
7 Goods producing industries (11-33N) includes the following sectors: forestry, logging and support (11N), mining, quarrying, and oil and gas
8 Forestry, logging and support (11N) includes the following industries: forestry and logging (113) and support activities to forestry (1153).
9 Non-durable goods (311N) of the manufacturing sector includes the following industries: food manufacturing (311), beverage and tobacco p
10 Durable goods (321N) of the manufacturing sector includes the following industries: wood products manufacturing (321), non-metallic mine
11 Service producing industries (41-91N) includes the following industries: trade (41-45N), transportation and warehousing (48-49), informatio
12 Trade (41-45N) industry includes the following sectors: wholesale (41) and retail trade (44-45).
13 Education special (611N) industry includes the following industries: elementary and secondary schools (6111), community colleges and CEG
14 Source: Labour Statistics Division, Statistics Canada
15 The introduction of administrative data in 2001 and the associated change in methodology resulted in level shifts for some series. This affec
16 Earnings data are based on gross payroll before source deductions.
17 These terminated series are based on the North American Industry Classification System (NAICS) 2007.
18 Industry estimates in this table are based on the 2012 North American Industry Classification System (NAICS).

Source: Statistics Canada. *Table 281-0027 - Average weekly earnings (SEPH), by type of employee for selected industries classified using the North*

GDP-IPI FDD

Table 384-0039 [4]

Implicit price indexes, gross domestic product, provincial and territorial

annual (2007=100)

Geography = Canada 1

Index = Implicit price indexes

Estimates = Final domestic demand

Canada

1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
47.7	52.2	55.1	57.4	59.5	61.8	64.3	66.8	69.7	72.4	74.8	76.3	77.7	79	79.9
	9.02%	5.41%	4.09%	3.59%	3.79%	3.97%	3.81%	4.25%	3.80%	3.26%	1.99%	1.82%	1.66%	1.13%

Ontario

1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
48.1	52.6	55.8	58.3	60.6	63.2	66.4	69.4	72.7	75.1	77.5	78.4	79.9	81	81.9
	8.94%	5.91%	4.38%	3.87%	4.20%	4.94%	4.42%	4.65%	3.25%	3.15%	1.15%	1.90%	1.37%	1.10%

	Canada	*Ontario*
1981	47.70	48.10
1982	52.20	52.60
1983	55.10	55.80
1984	57.40	58.30
1985	59.50	60.60
1986	61.80	63.20
1987	64.30	66.40
1988	66.80	69.40
1989	69.70	72.70
1990	72.40	75.10
1991	74.80	77.50
1992	76.30	78.40
1993	77.70	79.90
1994	79.00	81.00
1995	79.90	81.90
1996	80.80	82.60
1997	82.00	83.90
1998	83.20	85.30
1999	84.40	86.20
2000	86.50	88.20
2001	88.20	90.00
2002	90.20	91.90
2003	91.70	93.40

2004	93.40	95.00
2005	95.40	96.80
2006	97.70	98.30
2007	100.00	100.00
2008	102.50	102.20
2009	103.70	103.30
2010	104.80	104.50
2011	107.30	107.00
2012	109.10	108.70
2013	111.00	110.70
2014	113.40	113.00

Footnotes:

1 Canada totals in the provincial and territorial gross domestic product by income and by expenditure accounts (PTEA) do not correspond to th
2 Terminated with the 1998 data.
3 Prior to 1999, see Northwest Territories including Nunavut.

Source: Statistics Canada. *Table 384-0039 - Implicit price indexes, gross domestic product, provincial and territorial, annual (2007=100 unless othe*

Labour Price Indices

Table 281-0028 [3, 12, 13, 14, 15, 16, 17, 18, 19]

Average weekly earnings (SEPH), including overtime, seasonally adjusted, for all employees, by selected industries classified using the North Americ
monthly (current dollars)
Geography = Ontario
Type of employees = All employees
Overtime = Including overtime
Accessed on April 30, 2014

Industrial aggregate excluding unclassified businesses [11-91N] [4, 5]

	1991	1991	1991	1991	1991	1991	1991	1991	1991	1991	1991	1991	1992	1992
	1	2	3	4	5	6	7	8	9	10	11	12	1	2
orig	560.53(T)	567.77(T)	567.83(T)	570.77(T)	573.76(T)	575.57(T)	576.99(T)	579.08(T)	580.44(T)	584.44(T)	585.23(T)	588.43(T)	589.81(T)	590.87(T)
	560.53	567.77	567.83	570.77	573.76	575.57	576.99	579.08	580.44	584.44	585.23	588.43	589.81	590.87
	560.53	567.77	567.83	570.77	573.76	575.57	576.99	579.08	580.44	584.44	585.23	588.43	589.81	590.87

Utilities [22]

	1991	1991	1991	1991	1991	1991	1991	1991	1991	1991	1991	1991	1992	1992
	1	2	3	4	5	6	7	8	9	10	11	12	1	2
orig	783.05(T)	822.86(T)	864.12(T)	860.22(T)	837.73(T)	842.40(T)	834.83(T)	856.41(T)	856.11(T)	876.23(T)	914.08(T)	901.16(T)	884.58(T)	884.66(T)
	783.05	822.86	864.12	860.22	837.73	842.40	834.83	856.41	856.11	876.23	914.08	901.16	884.58	884.66
	783.05	822.86	864.12	860.22	837.73	842.4	834.83	856.41	856.11	876.23	914.08	901.16	884.58	884.66

NAICS [	Industri	Utilities [22]
1991	575.90	854.10
1992	598.57	892.54
1993	612.11	896.30
1994	627.87	921.55
1995	633.98	936.70
1996	649.29	939.75
1997	663.51	987.87
1998	672.53	1033.23
1999	683.48	1050.11
2000	699.93	1067.98

Footnotes:

ate estimat

3 Industrial aggregate covers all industrial sectors except those primarily involved in agriculture, fishing and trapping, private hous

. They are	**4** Le regroupement « ensemble des industries » comprend tous les secteurs industriels sauf ceux dont les activités relèvent des sec
	5 Unclassified businesses (00) are business for which the industrial classification (North American Industry Classification System (N
4.99%); B	**6** Goods producing industries (11-33N) includes the following sectors: forestry, logging and support (11N), mining, quarrying, and
ces, religi	**7** Forestry, logging and support (11N) includes the following industries: forestry and logging (113) and support activities to forestry
2) has yet	**8** Non-durable goods (311N) of the manufacturing sector includes the following industries: food manufacturing (311), beverage and
extractio	**9** Durable goods (321N) of the manufacturing sector includes the following industries: wood products manufacturing (321), non-me
	10 Service producing industries (41-91N) includes the following industries: trade (41-45N), transportation and warehousing (48-49),
roducts m	**11** Trade (41-45N) industry includes the following sectors: wholesale (41) and retail trade (44-45).
ral produc	**12** Source: Labour Statistics Division, Statistics Canada
on and cul	**13** Some series exhibit no clear seasonal pattern. In such cases the data are not adjusted.
	14 The introduction of administrative data in 2001 and the associated change in methodology resulted in level shifts for some series.
EP (6112)	**15** Estimates for the latest reference month are preliminary.
	16 Earnings data are based on gross payroll before source deductions.
ts the com	**17** Average weekly earnings for the industrial aggregate, excluding unclassified businesses [11-91N] in Alberta; and service producin
	18 Industry estimates in this table are based on the 2012 North American Industry Classification System (NAICS).
	19 Table 281-0028 has been terminated. For more recent estimates, please see table 281-0063.
American	**Source:** Statistics Canada. *Table 281-0028 - Average weekly earnings (SEPH), including overtime, seasonally adjusted, for all employees*

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
80.8	82	83.2	84.4	86.5	88.2	90.2	91.7	93.4	95.4	97.7	100	102.5	103.7	104.8	107.3
1.12%	1.47%	1.45%	1.43%	2.46%	1.95%	2.24%	1.65%	1.84%	2.12%	2.38%	2.33%	2.47%	1.16%	1.06%	2.36%
				1	1.01946	1.04232	1.05951	1.07897	1.10183	1.12808	1.15433	1.18284	1.1966	1.20923	1.23774

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
82.6	83.9	85.3	86.2	88.2	90	91.9	93.4	95	96.8	98.3	100	102.2	103.3	104.5	107
0.85%	1.56%	1.65%	1.05%	2.29%	2.02%	2.09%	1.62%	1.70%	1.88%	1.54%	1.71%	2.18%	1.07%	1.15%	2.36%
				1	1.0202	1.04152	1.05838	1.07636	1.09656	1.11342	1.13251	1.15716	1.16955	1.18305	1.21102

ıe national gross domestic product by income and by expenditure accounts (IEA) estimates at certain times of the year. The two accounts are brought back in li

rwise noted), CANSIM (database). (accessed: 2014-02-26)

can Industry Classification System (NAICS)

1992	1992	1992	1992
3	4	5	6
588.05 (T)	593.11 (T)	598.11 (T)	596.75 (T)
588.05	593.11	598.11	596.75
588.05	593.11	598.11	596.75

1992	1992	1992	1992
3	4	5	6
887.55 (T)	904.94 (T)	895.68 (T)	880.16 (T)
887.55	904.94	895.68	880.16
887.55	904.94	895.68	880.16

ehold services, religious organisations ar

teurs de l'agriculture, de la pêche et du
AICS) 2012) has yet to be determined.
oil and gas extraction (21), utilities (22)
(1153).
d tobacco products manufacturing (312)
etallic mineral products manufacturing (3
, information and cultural industries (51

. This affects the comparability of pre- a

ng industries [41-91N] in Alberta as well

, by selected industries classified using

2012	2013	2014	
109.1	111	113.4	
1.66%	1.73%	2.14%	1.97%
1.25833	1.28005	1.30744	

2012	2013	2014	
108.7	110.7	113	
1.58%	1.82%	2.06%	1.96%
1.23011	1.25254	1.2783	

ne when annual revisions are incorporat

), *Terminated*

1992	**1992**	**1992**	**1992**	**1992**	**1992**	**1993**	**1993**	**1993**	**1993**	**1993**	**1993**	**1993**	**1993**	**1993**	**1993**
7	**8**	**9**	**10**	**11**	**12**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
599.74(T)	603.59(T)	603.43(T)	606.19(T)	606.20(T)	606.98(T)	608.85(T)	608.64(T)	608.37(T)	611.73(T)	610.23(T)	611.22(T)	613.60(T)	612.12(T)	613.91(T)	614.54(T)
599.74	603.59	603.43	606.19	606.20	606.98	608.85	608.64	608.37	611.73	610.23	611.22	613.60	612.12	613.91	614.54
599.74	603.59	603.43	606.19	606.2	606.98	608.85	608.64	608.37	611.73	610.23	611.22	613.6	612.12	613.91	614.54

1992	**1992**	**1992**	**1992**	**1992**	**1992**	**1993**	**1993**	**1993**	**1993**	**1993**	**1993**	**1993**	**1993**	**1993**	**1993**
7	**8**	**9**	**10**	**11**	**12**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
878.41(T)	878.32(T)	905.61(T)	904.58(T)	910.54(T)	895.45(T)	897.15(T)	884.48(T)	884.07(T)	907.93(T)	890.34(T)	895.79(T)	886.23(T)	890.46(T)	906.11(T)	913.13(T)
878.41	878.32	905.61	904.58	910.54	895.45	897.15	884.48	884.07	907.93	890.34	895.79	886.23	890.46	906.11	913.13
878.41	878.32	905.61	904.58	910.54	895.45	897.15	884.48	884.07	907.93	890.34	895.79	886.23	890.46	906.11	913.13

nd the military personnel of the defence services.

piégeage, des services domestiques aux ménages privés, des organismes religieux et du personnel militaire des services de la défense.

, construction (23) and manufacturing (31-33).

, textiles mills (313), textile products mills (314), clothing manufacturing (315), leather and allied products manufacturing (316), paper manufacturing (322), p
327), primary metal manufacturing (331), fabricated metal products manufacturing (332), machinery manufacturing (333), computer and electronic products m
), finance and insurance (52), real estate and rental and leasing (53), professional, scientific and technical services (54), management of companies and enterp

nd post-2001 estimates.

as trade [41-45N] in Quebec for February 2004, 2008 and 2012 have been corrected.

the North American Industry Classification System (NAICS), monthly (current dollars), CANSIM (database). (accessed: 2014-02-26)

:ed.

1993	1993	1994	1994	1994	1994	1994	1994	1994	1994	1994	1994	1994	1994	1995	1995
11	12	1	2	3	4	5	6	7	8	9	10	11	12	1	2
615.18(T)	616.91(T)	617.54(T)	619.45(T)	624.42(T)	627.55(T)	627.47(T)	629.79(T)	631.65(T)	629.75(T)	631.92(T)	631.04(T)	632.04(T)	631.85(T)	632.51(T)	631.71(T)
615.18	616.91	617.54	619.45	624.42	627.55	627.47	629.79	631.65	629.75	631.92	631.04	632.04	631.85	632.51	631.71
615.18	616.91	617.54	619.45	624.42	627.55	627.47	629.79	631.65	629.75	631.92	631.04	632.04	631.85	632.51	631.71

1993	1993	1994	1994	1994	1994	1994	1994	1994	1994	1994	1994	1994	1994	1995	1995
11	12	1	2	3	4	5	6	7	8	9	10	11	12	1	2
912.85(T)	887.11(T)	915.33(T)	915.32(T)	907.78(T)	924.75(T)	921.67(T)	922.05(T)	919.44(T)	920.64(T)	924.74(T)	932.30(T)	945.21(T)	909.36(T)	912.21(T)	927.58(T)
912.85	887.11	915.33	915.32	907.78	924.75	921.67	922.05	919.44	920.64	924.74	932.30	945.21	909.36	912.21	927.58
912.85	887.11	915.33	915.32	907.78	924.75	921.67	922.05	919.44	920.64	924.74	932.3	945.21	909.36	912.21	927.58

rinting and related support activities (323), petroleum and coal products manufacturing (324), chemical manufacturing (325) and plastics and rubber products
anufacturing (334), electrical equipment, appliances and components manufacturing (335), transportation equipment manufacturing (336), furniture and relate
rises (55), administrative and support, waste management and remediation services (56), educational services (61), health care and social assistance (62), arts

1995	1995	1995	1995	1995	1995	1995	1995	1995	1995	1996	1996	1996	1996	1996	1996
3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6
632.52(T)	628.76(T)	627.92(T)	631.46(T)	631.37(T)	636.62(T)	637.87(T)	634.79(T)	636.71(T)	645.52(T)	636.10(T)	638.04(T)	641.65(T)	641.52(T)	647.62(T)	652.29(T)
632.52	628.76	627.92	631.46	631.37	636.62	637.87	634.79	636.71	645.52	636.10	638.04	641.65	641.52	647.62	652.29
632.52	628.76	627.92	631.46	631.37	636.62	637.87	634.79	636.71	645.52	636.1	638.04	641.65	641.52	647.62	652.29

1995	1995	1995	1995	1995	1995	1995	1995	1995	1995	1996	1996	1996	1996	1996	1996
3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6
927.85(T)	935.23(T)	938.58(T)	942.74(T)	936.41(T)	930.31(T)	940.20(T)	955.56(T)	959.10(T)	934.63(T)	919.03(T)	927.40(T)	931.97(T)	940.06(T)	931.98(T)	934.57(T)
927.85	935.23	938.58	942.74	936.41	930.31	940.20	955.56	959.10	934.63	919.03	927.40	931.97	940.06	931.98	934.57
927.85	935.23	938.58	942.74	936.41	930.31	940.2	955.56	959.1	934.63	919.03	927.4	931.97	940.06	931.98	934.57

manufacturing (326).
ed products manufacturing (337) and miscellaneous manufacturing (339).
s, entertainment and recreation (71), accommodation and food services (72), other services (except public administration) (81) and public administration (91).

1996	1996	1996	1996	1996	1996	1997	1997	1997	1997	1997	1997	1997	1997	1997	1997
7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10
652.35(T)	653.31(T)	652.52(T)	658.18(T)	658.80(T)	659.12(T)	661.06(T)	662.16(T)	661.00(T)	661.84(T)	669.30(T)	660.14(T)	660.15(T)	660.78(T)	665.70(T)	663.30(T)
652.35	653.31	652.52	658.18	658.80	659.12	661.06	662.16	661.00	661.84	669.30	660.14	660.15	660.78	665.70	663.30
652.35	653.31	652.52	658.18	658.8	659.12	661.06	662.16	661	661.84	669.3	660.14	660.15	660.78	665.7	663.3

1996	1996	1996	1996	1996	1996	1997	1997	1997	1997	1997	1997	1997	1997	1997	1997
7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10
935.04(T)	935.02(T)	950.50(T)	958.25(T)	970.73(T)	942.46(T)	967.08(T)	969.07(T)	959.15(T)	993.29(T)	999.42(T)	998.34(T)	969.94(T)	974.01(T)	991.88(T)	1,025.73(
935.04	935.02	950.50	958.25	970.73	942.46	967.08	969.07	959.15	993.29	999.42	998.34	969.94	974.01	991.88	1,025.73
935.04	935.02	950.5	958.25	970.73	942.46	967.08	969.07	959.15	993.29	999.42	998.34	969.94	974.01	991.88	1,025.73

1997	**1997**	**1998**	**1998**	**1998**	**1998**	**1998**	**1998**	**1998**	**1998**	**1998**	**1998**	**1998**	**1998**	**1999**	**1999**
11	**12**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**1**	**2**
669.77(T)	666.89(T)	673.03(T)	675.61(T)	672.84(T)	674.36(T)	669.97(T)	670.05(T)	667.01(T)	670.41(T)	670.32(T)	675.97(T)	674.08(T)	676.71(T)	675.36(T)	675.70(T)
669.77	666.89	673.03	675.61	672.84	674.36	669.97	670.05	667.01	670.41	670.32	675.97	674.08	676.71	675.36	675.70
669.77	666.89	673.03	675.61	672.84	674.36	669.97	670.05	667.01	670.41	670.32	675.97	674.08	676.71	675.36	675.7

1997	**1997**	**1998**	**1998**	**1998**	**1998**	**1998**	**1998**	**1998**	**1998**	**1998**	**1998**	**1998**	**1998**	**1999**	**1999**
11	**12**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**1**	**2**
1,016.63(	989.92(T)	1,064.65(	1,011.82(	1,007.16(	1,011.04(	1,013.18(	1,031.88(	1,041.62(	1,039.00(	1,039.92(	1,044.75(	1,044.54(	1,049.20(	1,043.23(	1,039.50(
1,016.63	989.92	1,064.65	1,011.82	1,007.16	1,011.04	1,013.18	1,031.88	1,041.62	1,039.00	1,039.92	1,044.75	1,044.54	1,049.20	1,043.23	1,039.50
1,016.63	989.92	1,064.65	1,011.82	1,007.16	1,011.04	1,013.18	1,031.88	1,041.62	1,039.00	1,039.92	1,044.75	1,044.54	1,049.20	1,043.23	1,039.50

1999	1999	1999	1999	1999	1999	1999	1999	1999	1999	2000	2000	2000	2000	2000	2000
3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6
677.45(T)	679.60(T)	684.35(T)	684.20(T)	687.87(T)	686.56(T)	686.46(T)	687.02(T)	686.22(T)	691.02(T)	692.50(T)	694.79(T)	695.61(T)	697.48(T)	698.65(T)	699.54(T)
677.45	679.60	684.35	684.20	687.87	686.56	686.46	687.02	686.22	691.02	692.50	694.79	695.61	697.48	698.65	699.54
677.45	679.6	684.35	684.2	687.87	686.56	686.46	687.02	686.22	691.02	692.5	694.79	695.61	697.48	698.65	699.54

1999	1999	1999	1999	1999	1999	1999	1999	1999	1999	2000	2000	2000	2000	2000	2000
3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6
1,042.05(	1,062.64(	1,054.36(	1,023.22(	1,049.26(	1,053.32(	1,050.77(	1,057.80(	1,060.68(	1,064.49(	1,064.39(	1,069.17(	1,067.63(	1,065.73(	1,064.43(	1,064.89(
1,042.05	1,062.64	1,054.36	1,023.22	1,049.26	1,053.32	1,050.77	1,057.80	1,060.68	1,064.49	1,064.39	1,069.17	1,067.63	1,065.73	1,064.43	1,064.89
1,042.05	1,062.64	1,054.36	1,023.22	1,049.26	1,053.32	1,050.77	1,057.80	1,060.68	1,064.49	1,064.39	1,069.17	1,067.63	1,065.73	1,064.43	1,064.89

2000	2000	2000	2000	2000	2000
7	8	9	10	11	12
701.24[T]	703.40[T]	703.73[T]	702.90[T]	704.07[T]	705.23[T]
701.24	703.40	703.73	702.90	704.07	705.23
701.24	703.4	703.73	702.9	704.07	705.23

2000	2000	2000	2000	2000	2000
7	8	9	10	11	12
1,067.55(	1,067.93(	1,069.10(	1,071.52(	1,070.48(	1,072.96[T]
1,067.55	1,067.93	1,069.10	1,071.52	1,070.48	1,072.96
1,067.55	1,067.93	1,069.10	1,071.52	1,070.48	1,072.96

Employment Cost Index
Original Data Value

Series Id: CIU2024400000000I
Series Title: Wages and salaries for Private industry workers in Utilities, Index
Ownership: Private industry workers
Component: Wages and salaries
Occupation: All workers
Industry: Utilities
Subcategory: All workers
Area: United States (National)
Periodicity: Index number
Years: 2001 to 2015
Source: http://data.bls.gov/timeseries/CIU2024400000000I

Year	Qtr1	Qtr2	Qtr3	Qtr4	Annual	*Growth*
2001	87.0	88.1	88.3	89.1	**88.1**	
2002	89.8	91.4	91.8	92.2	**91.3**	*3.5%*
2003	93.0	93.6	94.0	94.5	**93.8**	*2.7%*
2004	95.4	96.6	97.1	97.4	**96.6**	*3.0%*
2005	98.4	99.2	99.5	100.0	**99.3**	*2.7%*
2006	100.8	102.1	103.0	103.5	**102.4**	*3.1%*
2007	104.3	105.5	106.1	106.8	**105.7**	*3.2%*
2008	108.0	109.3	109.3	109.6	**109.1**	*3.1%*
2009	111.0	112.0	112.2	113.3	**112.1**	*2.8%*
2010	113.9	114.7	115.4	115.6	**114.9**	*2.4%*
2011	116.9	118.1	118.5	118.8	**118.1**	*2.7%*
2012	119.6	121.3	121.3	121.7	**121.0**	*2.4%*
2013	123.0	124.2	124.9	125.2	**124.3**	*2.7%*
2014	126.6	127.6	128.3	128.3	**127.7**	*2.7%*
2015	129.9	130.8	131.4		**130.7**	
						2.9%

Table 1.1.9. Implicit Price Deflators for Gross Domestic Product

[Index numbers, 2009=100]

Bureau of Economic Analysis

Last Revised on: April 30, 2014 - Next Release Date May 29, 2014

accessed on May 22, 2014 source: http://www.bea.gov/iTable/iTable.cfm?ReqID=9&step=1#reqid=9&step=3&isuri=

product	
2000	81.89
2001	83.77
2002	85.05
2003	86.75
2004	89.13
2005	91.99
2006	94.82
2007	97.34
2008	99.24
2009	100.00
2010	101.21
2011	103.20
2012	105.00
2013	106.59
2014	108.69

1&910=x&911=0&903=13&904=2000&905=2013&906=a

Total Factor Productivity in North American Hydroelectric Generation

Prepared for:
Ontario Power Generation
in support of incentive rate-making for OPG's prescribed assets

Prepared by:
London Economics International LLC
Julia Frayer, Ian Chow, Barbara Porto, and Jarome Leslie

LE
LONDON ECONOMICS

January 15, 2016

Basic model logic:

Note: Unless otherwise stated, all directions will refer to information contained in the **"TFP_Calcs" worksheet**

Step 1: Select peer from dropdown menu (Cell C2):

The dropdown will show results based on peer or peer group selected. Contains individual information on OPG a

The peer industry includes OPG, 14 US investor owned firms that filed FERC Form 1, 2 federally regulated firms,

Step 2: Prepare data for the model (Row 5-19):

This contains data including capacity, O&M and net generation. All data here refers back to the full dataset in "TF
which refers back to "NA comb O&M price indexes"

Step 3: Calculate quantity sub-indexes and sub-index growth rates (Row 23-38):

The tables illustrate how data from Step 2 is used to calculate the quantity sub-indexes of Input (K), Input (O&M) a
Quantity Sub-indexes Growth rates show the growth rates of the quantity sub-index. Average values for all three a

Step 4: Calculate implicit price indexes and sub-index growth rates (Row 42-57): This is an implicit calculation step necessary fo

Step 5: Calculate the year over year changes to Laspeyres, Paasche, and Fisher total Input and total Output indices (Row 61-76)

Step 6: Calculate the Laspeyres, Paasche, and Fisher Ideal total Input, total Output, and Total Factor Productivity Indexes (Ro

Step 7: Calculate TFP growth rates using 'average growth' and 'trend regression' methods (Row 97-112):

Shows growth rates for all the indexes using both methods. Cell I112 highlights the average TFP index growth rate

Note: This workbook is colour coded as follows: (i) red for OPG data; (ii) blue for US peer data; (iii) green for other third party da

Worksheets:

TFP_Calcs: Contains the model, provides the method of calculating TFP Index growth

TFP_dataset: Contains all the data relevant to OPG and 17 peers

Note: A PPP of 1.23 Canadian dollars per 1 US dollar was used to convert US peer O&M costs and revenues to Canadia
compared on an equal basis. PPP was chosen over exchange rates as it better reflects underlying fundamentals (ex
Source OECD (http://stats.oecd.org/Index.aspx?DataSetCode=PPPGDP)

OPG hydro peers: Contains list of all peers and locations (CA or US)

NA comb O&M price indexes: Provides 2002-2014 price indexes for peer group by combining Canadian and US prices indexes

Can O&M price indexes: Provides 2002-2014 price indexes for Canada

US O&M price indexes: Provides 2002-2014 price indexes for U.S.

EUCG L Share: Provides industry level labour share of Operations and Maintenance, based on EUCG data

StatsCan CANSIM tables: Provides the StatsCan data that is used in the 'Canadian O&M price indexes' worksheet

US BLS & BEA tables: Provides the Bureau of Labour Statistics and the Bureau of Economic Analysis data used in the US O&M p

nd 17 peers, as well as 'Peer Industry' and 'Peer Industry less OPG'.
and 1 municipal

P_dataset" tab, with the exception of O&M Price Index,

and Output (MWh), with 2002 as base year
are highlighted
or the calculation of the combined input and output indices
)
w 79-94)

e for 2002-2014, while cell D117 highlights the TFP growth rate using the 'trend regression' method

ta (e.g. EUCG, CANSIM); and (iv) black for calculated values

n dollars so that that different peers can be
cluding speculation for example) and is less volatile.

ɔrice indexes worksheet

Step 1: Select peers from dropdown in cell C2 (note TFP results for both methods are visible in cells G2 and J2 respectively)

OPG Hydro Group:	**Peer Industry**	**OPG Hydro Peer Industry Total**	**NA**	**Average TFP growth (2002-2014)**

Step 2: Prepare data, including capacity, O&M, net generation, and O&M price index

Data	I	I	I Price Index	O
Year	MCR (MW)	O&M_total (K$)	O&M Price Index	Net_generation (MWh)
2002	40,990	711,765	1.00	94,808,476
2003	41,535	796,805	1.02	105,715,095
2004	41,559	821,320	1.05	101,232,949
2005	41,609	867,346	1.08	102,903,142
2006	41,735	913,380	1.12	104,117,150
2007	41,166	994,736	1.15	86,806,588
2008	41,525	1,083,503	1.18	91,466,658
2009	41,536	1,073,367	1.20	101,304,275
2010	41,530	1,152,773	1.23	96,564,012
2011	41,202	1,150,456	1.26	101,773,095
2012	41,246	1,186,816	1.28	88,107,289
2013	41,110	1,173,364	1.31	89,919,225
2014	41,316	1,203,719	1.34	87,044,181

Step 3: Calculate quantity sub-indexes and sub index growth rates

Quantity Sub-indexes			
	Input	Input	Output
Year	K	O&M_total	Net_generation (MWh)
2002	1.00	1.00	1.00
2003	1.01	1.09	1.12
2004	1.01	1.10	1.07
2005	1.02	1.12	1.09
2006	1.02	1.15	1.10
2007	1.00	1.22	0.92
2008	1.01	1.29	0.96
2009	1.01	1.25	1.07
2010	1.01	1.32	1.02
2011	1.01	1.28	1.07
2012	1.01	1.30	0.93
2013	1.00	1.26	0.95

2014	1.01	1.26	0.92

Step 4: Calculate implicit price indexes and sub index growth rates

(Implicit) Price Indexes

Year	Input K	Input O&M_total	Output Net_generation (MWh)
2002	2,920,287	711,765	3,632,052
2003	3,780,044	728,846	4,149,689
2004	3,607,290	749,597	4,194,418
2005	4,599,338	771,654	5,100,694
2006	3,725,935	794,005	4,286,223
2007	3,160,395	818,383	4,552,983
2008	3,990,812	840,308	5,313,721
2009	2,502,732	856,489	3,377,969
2010	2,334,648	874,760	3,454,223
2011	2,256,684	895,298	3,184,860
2012	1,333,845	913,938	2,721,353
2013	2,191,413	933,949	3,554,477
2014	2,438,416	956,116	3,988,166

Step 5: Calculate the year over year changes to Laspeyres, Paasche, and Fisher total Input and total Output Indexes

Year to year changes

Year	Laspeyres Index Input	Laspeyres Index Output	Paasche Index Input	Paasche Index Output
2002				
2003	1.03	1.12	1.03	1.12
2004	1.00	0.96	1.00	0.96
2005	1.01	1.02	1.01	1.02
2006	1.01	1.01	1.01	1.01
2007	1.00	0.83	1.00	0.83
2008	1.02	1.05	1.02	1.05
2009	0.99	1.11	0.99	1.11
2010	1.02	0.95	1.02	0.95
2011	0.99	1.05	0.99	1.05
2012	1.00	0.87	1.01	0.87
2013	0.98	1.02	0.99	1.02
2014	1.00	0.97	1.00	0.97

Step 6: Calculate the Laspeyres, Paasche, and Fisher Ideal total Input, total Output, and Total Factor Productivity Indexes

Index

Year	Laspeyres Index Input	Laspeyres Index Output	Paasche Index Input	Paasche Index Output
2002	1.00	1.00	1.00	1.00
2003	1.03	1.12	1.03	1.12
2004	1.03	1.07	1.03	1.07
2005	1.04	1.09	1.03	1.09
2006	1.04	1.10	1.04	1.10
2007	1.04	0.92	1.04	0.92
2008	1.06	0.96	1.06	0.96
2009	1.06	1.07	1.05	1.07
2010	1.07	1.02	1.07	1.02
2011	1.06	1.07	1.06	1.07
2012	1.06	0.93	1.06	0.93
2013	1.05	0.95	1.05	0.95
2014	1.05	0.92	1.05	0.92

Step 7: Calculate TFP growth rates using 'average growth' and 'trend regression' methods

A) Average growth method of measuring TFP

Year	Laspeyres Index Input	Laspeyres Index Output	Paasche Index Input	Paasche Index Output
2002-2003	2.9%	10.9%	2.6%	10.9%
2003-2004	0.1%	-4.3%	0.1%	-4.3%
2004-2005	0.6%	1.6%	0.5%	1.6%
2005-2006	0.6%	1.2%	0.7%	1.2%
2006-2007	0.0%	-18.2%	0.2%	-18.2%
2007-2008	2.1%	5.2%	1.9%	5.2%
2008-2009	-0.6%	10.2%	-0.8%	10.2%
2009-2010	1.5%	-4.8%	1.6%	-4.8%
2010-2011	-1.4%	5.3%	-1.4%	5.3%
2011-2012	0.4%	-14.4%	0.5%	-14.4%
2012-2013	-1.7%	2.0%	-1.4%	2.0%
2013-2014	0.4%	-3.2%	0.4%	-3.2%
AVERAGE	**0.4%**	**-0.7%**	**0.4%**	**-0.7%**

B) Trend regression method of measuring TFP

T	Natural log of TFP index values	TFP trend growth rate (2002-2014):	Natural log of TFP input values	TFP input index (2002-2014):
0	0.00	-1.41%	0.00	0.36%
1	0.08		0.03	
2	0.04		0.03	
3	0.05		0.03	
4	0.05		0.04	
5	-0.13		0.04	
6	-0.10		0.06	
7	0.01		0.05	
8	-0.05		0.07	
9	0.01		0.06	
10	-0.13		0.06	
11	-0.10		0.05	
12	-0.13		0.05	

-1.12%		TFP trend growth rate (2002-2014):	-1.41%	

I and O shares	I share	I share	I share
Revenue (K$)	Capital (K$)	K	O&M
3,632,052	2,920,287	0.8040	0.20
4,627,062	3,830,257	0.8278	0.17
4,478,642	3,657,322	0.82	0.18
5,536,187	4,668,840	0.84	0.16
4,707,062	3,793,682	0.81	0.19
4,168,709	3,173,972	0.76	0.24
5,126,423	4,042,920	0.79	0.21
3,609,410	2,536,043	0.70	0.30
3,518,184	2,365,411	0.67	0.33
3,418,819	2,268,363	0.66	0.34
2,529,004	1,342,188	0.53	0.47
3,371,174	2,197,810	0.65	0.35
3,661,557	2,457,837	0.67	0.33

Quantity Sub-indexes Growth rates			
	Input	Input	Output
Year	K	O&M_total	Net_generation (MWh)
2002			
2003	1.32%	8.91%	10.89%
2004	0.06%	0.22%	-4.33%
2005	0.12%	2.55%	1.64%
2006	0.30%	2.32%	1.17%
2007	-1.37%	5.51%	-18.18%
2008	0.87%	5.90%	5.23%
2009	0.02%	-2.85%	10.22%
2010	-0.01%	5.03%	-4.79%
2011	-0.79%	-2.52%	5.25%
2012	0.11%	1.05%	-14.42%
2013	-0.33%	-3.31%	2.04%

2014	0.50%	0.21%	-3.25%
Average	**0.07%**	**1.92%**	**-0.71%**

(Implicit) Price Indexes Growth Rates

Year	Input K	Input O&M_total	Output Net_generation (MWh)
2002			
2003	25.8%	2.4%	13.3%
2004	-4.7%	2.8%	1.1%
2005	24.3%	2.9%	19.6%
2006	-21.1%	2.9%	-17.4%
2007	-16.5%	3.0%	6.0%
2008	23.3%	2.6%	15.5%
2009	-46.7%	1.9%	-45.3%
2010	-7.0%	2.1%	2.2%
2011	-3.4%	2.3%	-8.1%
2012	-52.6%	2.1%	-15.7%
2013	49.6%	2.2%	26.7%
2014	10.7%	2.3%	11.5%
Average	**-1.5%**	**2.5%**	**0.8%**

Fisher Index Input	Fisher Index Output
1.03	1.12
1.00	0.96
1.01	1.02
1.01	1.01
1.00	0.83
1.02	1.05
0.99	1.11
1.02	0.95
0.99	1.05
1.00	0.87
0.98	1.02
1.00	0.97

Fisher Index Input	Fisher Index Output	TFP Index	TFP Growth
1.00	1.00	1.00	
1.03	1.12	1.09	8.2%
1.03	1.07	1.04	-4.4%
1.03	1.09	1.05	1.1%
1.04	1.10	1.06	0.5%
1.04	0.92	0.88	-18.3%
1.06	0.96	0.91	3.2%
1.06	1.07	1.01	10.9%
1.07	1.02	0.95	-6.4%
1.06	1.07	1.01	6.6%
1.06	0.93	0.87	-14.9%
1.05	0.95	0.91	3.6%
1.05	0.92	0.87	-3.7%

Fisher Index Input index growth	Fisher Index Output index growth	TFP Index TFP index Growth
2.7%	10.9%	8.2%
0.1%	-4.3%	-4.4%
0.5%	1.6%	1.1%
0.7%	1.2%	0.5%
0.1%	-18.2%	-18.3%
2.0%	5.2%	3.2%
-0.7%	10.2%	10.9%
1.6%	-4.8%	-6.4%
-1.4%	5.3%	6.6%
0.5%	-14.4%	-14.9%
-1.5%	2.0%	3.6%
0.4%	-3.2%	-3.7%
0.4%	**-0.7%**	**-1.12%**

Natural log of TFP output values	TFP output index (2002-2014):
0.00	-1.05%
0.11	
0.07	
0.08	
0.09	
-0.09	
-0.04	
0.07	
0.02	
0.07	
-0.07	
-0.05	
-0.09	

Mod_ID	LEI_ID	Company Name	Year	I MW MCR	% Capacity Factor	I K$ Labour_O&M	I K$ Non-labour_O&M	I K$ O&M_total
1	0	OPG	2002	6,899	56%	78,723	39,166	117,889
1	0	OPG	2003	6,926	55%	84,147	46,555	130,702
1	0	OPG	2004	6,958	58%	88,414	43,797	132,211
1	0	OPG	2005	6,924	55%	91,483	50,906	142,388
1	0	OPG	2006	6,971	56%	100,682	55,924	156,606
1	0	OPG	2007	6,971	54%	106,220	58,735	164,954
1	0	OPG	2008	6,999	61%	110,503	75,236	185,739
1	0	OPG	2009	6,905	60%	114,132	70,965	185,097
1	0	OPG	2010	6,906	51%	107,412	77,281	184,693
1	0	OPG	2011	6,422	54%	110,456	64,154	174,611
1	0	OPG	2012	6,422	51%	115,567	62,567	178,134
1	0	OPG	2013	6,433	54%	121,789	60,795	182,584
1	0	OPG	2014	6,433	54%	119,907	68,113	188,020
1	1	PG&E	2002	3,578	32%			73,605
1	1	PG&E	2003	3,578	37%			86,474
1	1	PG&E	2004	3,578	34%			85,405
1	1	PG&E	2005	3,578	39%			84,427
1	1	PG&E	2006	3,578	46%			76,536
1	1	PG&E	2007	3,578	26%			101,326
1	1	PG&E	2008	3,578	26%			109,376
1	1	PG&E	2009	3,578	28%			109,621
1	1	PG&E	2010	3,578	33%			111,628
1	1	PG&E	2011	3,578	38%			116,740
1	1	PG&E	2012	3,578	25%			143,941
1	1	PG&E	2013	3,567	24%			144,261
1	1	PG&E	2014	3,567	18%			139,710
1	2	Duke	2002	2,754	21%			27,024
1	2	Duke	2003	2,754	26%			29,330
1	2	Duke	2004	2,754	21%			35,769
1	2	Duke	2005	2,754	23%			35,120
1	2	Duke	2006	2,756	19%			27,186
1	2	Duke	2007	2,756	19%			32,581
1	2	Duke	2008	2,791	19%			32,180
1	2	Duke	2009	2,791	20%			35,977

1	2	Duke	2010	2,795	19%	38,734
1	2	Duke	2011	2,846	17%	38,866
1	2	Duke	2012	2,852	16%	39,629
1	2	Duke	2013	2,858	21%	41,251
1	2	Duke	2014	2,859	20%	40,395
1	3	VA Electric	2002	1,718	18%	7,382
1	3	VA Electric	2003	2,379	17%	7,404
1	3	VA Electric	2004	2,379	15%	7,900
1	3	VA Electric	2005	2,379	12%	9,620
1	3	VA Electric	2006	2,379	14%	10,983
1	3	VA Electric	2007	1,694	19%	11,786
1	3	VA Electric	2008	1,950	12%	12,597
1	3	VA Electric	2009	2,080	15%	12,129
1	3	VA Electric	2010	2,080	18%	10,528
1	3	VA Electric	2011	2,080	16%	11,334
1	3	VA Electric	2012	2,122	24%	10,518
1	3	VA Electric	2013	2,122	16%	10,048
1	3	VA Electric	2014	2,122	17%	13,059
1	4	ID Power	2002	1,695	40%	19,532
1	4	ID Power	2003	1,695	41%	20,580
1	4	ID Power	2004	1,695	40%	24,072
1	4	ID Power	2005	1,695	41%	25,021
1	4	ID Power	2006	1,695	62%	27,153
1	4	ID Power	2007	1,695	41%	28,499
1	4	ID Power	2008	1,695	46%	30,234
1	4	ID Power	2009	1,695	54%	29,841
1	4	ID Power	2010	1,695	49%	30,973
1	4	ID Power	2011	1,695	73%	31,171
1	4	ID Power	2012	1,695	53%	32,385
1	4	ID Power	2013	1,695	38%	33,356
1	4	ID Power	2014	1,695	41%	32,515
1	5	AB Power	2002	1,583	29%	20,800
1	5	AB Power	2003	1,583	42%	22,378
1	5	AB Power	2004	1,583	32%	23,267
1	5	AB Power	2005	1,583	32%	24,858
1	5	AB Power	2006	1,583	22%	27,948
1	5	AB Power	2007	1,583	10%	32,887
1	5	AB Power	2008	1,583	17%	32,894

1	5	AB Power	2009	1,583	43%	28,456
1	5	AB Power	2010	1,583	27%	38,606
1	5	AB Power	2011	1,583	23%	35,774
1	5	AB Power	2012	1,583	19%	37,409
1	5	AB Power	2013	1,668	38%	36,349
1	5	AB Power	2014	1,668	27%	46,029
1	6	SoCal Edison	2002	1,093	35%	23,806
1	6	SoCal Edison	2003	1,093	40%	23,798
1	6	SoCal Edison	2004	1,093	35%	25,166
1	6	SoCal Edison	2005	1,093	50%	24,386
1	6	SoCal Edison	2006	1,093	50%	29,579
1	6	SoCal Edison	2007	1,105	25%	35,054
1	6	SoCal Edison	2008	1,105	25%	32,887
1	6	SoCal Edison	2009	1,105	37%	39,833
1	6	SoCal Edison	2010	1,105	42%	44,793
1	6	SoCal Edison	2011	1,112	47%	48,341
1	6	SoCal Edison	2012	1,112	27%	40,213
1	6	SoCal Edison	2013	1,112	23%	46,790
1	6	SoCal Edison	2014	1,112	16%	34,259
1	7	GA Power	2002	1,058	19%	44,321
1	7	GA Power	2003	1,058	30%	44,236
1	7	GA Power	2004	1,058	24%	54,959
1	7	GA Power	2005	1,071	27%	61,906
1	7	GA Power	2006	1,071	19%	62,726
1	7	GA Power	2007	1,071	15%	62,733
1	7	GA Power	2008	1,071	14%	79,350
1	7	GA Power	2009	1,071	26%	53,906
1	7	GA Power	2010	1,071	24%	63,577
1	7	GA Power	2011	1,071	19%	59,952
1	7	GA Power	2012	1,071	15%	51,646
1	7	GA Power	2013	1,071	25%	47,708
1	7	GA Power	2014	1,071	20%	61,799
1	8	PacifiCorp	2002	980	38%	25,498
1	8	PacifiCorp	2003	989	40%	26,755
1	8	PacifiCorp	2004	1,003	35%	34,820
1	8	PacifiCorp	2005	1,003	34%	34,601
1	8	PacifiCorp	2006	1,011	48%	32,842
1	8	PacifiCorp	2007	1,011	39%	35,559

1	8	PacifiCorp	2008	1,011	39%	36,267
1	8	PacifiCorp	2009	1,011	36%	37,243
1	8	PacifiCorp	2010	1,011	39%	35,591
1	8	PacifiCorp	2011	1,016	49%	38,792
1	8	PacifiCorp	2012	1,016	46%	37,713
1	8	PacifiCorp	2013	1,016	33%	40,175
1	8	PacifiCorp	2014	1,016	40%	38,805
1	9	Avista	2002	879	52%	8,929
1	9	Avista	2003	879	46%	12,271
1	9	Avista	2004	879	49%	13,245
1	9	Avista	2005	899	46%	11,327
1	9	Avista	2006	907	52%	12,126
1	9	Avista	2007	907	46%	12,603
1	9	Avista	2008	914	48%	11,932
1	9	Avista	2009	914	47%	14,021
1	9	Avista	2010	914	44%	13,328
1	9	Avista	2011	914	57%	16,273
1	9	Avista	2012	914	51%	15,768
1	9	Avista	2013	921	45%	18,703
1	9	Avista	2014	921	51%	15,173
1	10	Portland	2002	779	45%	12,790
1	10	Portland	2003	779	44%	12,851
1	10	Portland	2004	779	45%	12,312
1	10	Portland	2005	779	42%	13,573
1	10	Portland	2006	779	53%	15,167
1	10	Portland	2007	779	47%	19,610
1	10	Portland	2008	779	47%	21,110
1	10	Portland	2009	758	48%	25,499
1	10	Portland	2010	758	49%	21,663
1	10	Portland	2011	758	53%	22,383
1	10	Portland	2012	808	49%	25,819
1	10	Portland	2013	808	42%	26,947
1	10	Portland	2014	889	41%	31,103
1	11	Ameren MI - Union	2002	741	27%	13,567
1	11	Ameren MI - Union	2003	741	23%	10,767
1	11	Ameren MI - Union	2004	741	32%	13,208
1	11	Ameren MI - Union	2005	741	32%	10,942
1	11	Ameren MI - Union	2006	741	15%	11,099

1	11	Ameren MI - Union	2007	741	25%	14,224
1	11	Ameren MI - Union	2008	741	27%	17,774
1	11	Ameren MI - Union	2009	779	28%	19,718
1	11	Ameren MI - Union	2010	779	32%	23,106
1	11	Ameren MI - Union	2011	779	26%	14,684
1	11	Ameren MI - Union	2012	779	19%	14,202
1	11	Ameren MI - Union	2013	779	24%	15,495
1	11	Ameren MI - Union	2014	904	18%	15,385
1	12	AP Power	2002	740	15%	21,647
1	12	AP Power	2003	740	23%	19,106
1	12	AP Power	2004	740	20%	22,361
1	12	AP Power	2005	740	20%	32,824
1	12	AP Power	2006	740	19%	34,699
1	12	AP Power	2007	740	18%	35,563
1	12	AP Power	2008	740	16%	37,707
1	12	AP Power	2009	740	19%	34,874
1	12	AP Power	2010	740	18%	38,269
1	12	AP Power	2011	779	15%	33,342
1	12	AP Power	2012	779	14%	28,907
1	12	AP Power	2013	840	14%	27,228
1	12	AP Power	2014	840	12%	33,128
1	13	SCE&G	2002	761	14%	6,274
1	13	SCE&G	2003	751	20%	6,575
1	13	SCE&G	2004	751	17%	6,709
1	13	SCE&G	2005	751	19%	6,810
1	13	SCE&G	2006	751	16%	7,665
1	13	SCE&G	2007	751	15%	6,987
1	13	SCE&G	2008	750	14%	7,494
1	13	SCE&G	2009	750	15%	8,426
1	13	SCE&G	2010	750	13%	7,308
1	13	SCE&G	2011	750	11%	7,017
1	13	SCE&G	2012	750	11%	7,009
1	13	SCE&G	2013	750	12%	7,538
1	13	SCE&G	2014	751	9%	7,830
0	13	Alcoa	2002	546	36%	10,504
0	13	Alcoa	2003	556	62%	11,200
0	13	Alcoa	2004	514	50%	8,133
0	13	Alcoa	2005	554	47%	9,029

0	13	Alcoa	2006	514	38%	8,076
0	13	Alcoa	2007	514	27%	8,161
0	13	Alcoa	2008	563	27%	8,846
0	13	Alcoa	2009	514	51%	10,414
0	13	Alcoa	2010	514	46%	8,767
0	13	Alcoa	2011	567	35%	19,181
0	13	Alcoa	2012	514	33%	15,423
0	13	Alcoa	2013	217	55%	7,954
0	13	Alcoa	2014	217	41%	9,683
1	14	SEPA	2002	3,412	18%	71,520
1	14	SEPA	2003	3,412	31%	82,754
1	14	SEPA	2004	3,412	28%	84,330
1	14	SEPA	2005	3,392	31%	83,638
1	14	SEPA	2006	3,392	19%	108,053
1	14	SEPA	2007	3,392	18%	96,188
1	14	SEPA	2008	3,392	15%	99,695
1	14	SEPA	2009	3,392	21%	111,926
1	14	SEPA	2010	3,392	28%	150,046
1	14	SEPA	2011	3,392	22%	128,499
1	14	SEPA	2012	3,392	19%	122,089
1	14	SEPA	2013	3,392	26%	114,310
1	14	SEPA	2014	3,392	25%	124,376
1	15	Seattle	2002	1,929	41%	22,812
1	15	Seattle	2003	1,929	36%	24,860
1	15	Seattle	2004	1,929	36%	24,949
1	15	Seattle	2005	1,929	33%	23,242
1	15	Seattle	2006	1,929	40%	24,064
1	15	Seattle	2007	1,929	39%	30,718
1	15	Seattle	2008	1,929	37%	34,413
1	15	Seattle	2009	1,929	35%	35,205
1	15	Seattle	2010	1,929	33%	27,513
1	15	Seattle	2011	1,929	45%	36,035
1	15	Seattle	2012	1,929	41%	39,715
1	15	Seattle	2013	1,929	36%	49,200
1	15	Seattle	2014	1,929	42%	43,750
0	15	WAPA	2002	9,847	28%	183,866
0	15	WAPA	2003	9,694	29%	224,763
0	15	WAPA	2004	9,714	28%	212,504

0	15	WAPA	2005	9,746	25%	233,634
0	15	WAPA	2006	9,848	30%	240,871
0	15	WAPA	2007	9,952	25%	265,302
0	15	WAPA	2008	9,935	25%	293,009
0	15	WAPA	2009	9,942	26%	281,180
0	15	WAPA	2010	9,932	28%	303,651
0	15	WAPA	2011	9,931	38%	317,460
0	15	WAPA	2012	9,931	34%	346,297
0	15	WAPA	2013	9,931	29%	323,468
0	15	WAPA	2014	9,931	28%	328,700
1	16	Peer Industry	2002	40,990	26%	711,765
1	16	Peer Industry	2003	41,535	29%	796,805
1	16	Peer Industry	2004	41,559	28%	821,320
1	16	Peer Industry	2005	41,609	28%	867,346
1	16	Peer Industry	2006	41,735	28%	913,380
1	16	Peer Industry	2007	41,166	24%	994,736
1	16	Peer Industry	2008	41,525	25%	1,083,503
1	16	Peer Industry	2009	41,536	28%	1,073,367
1	16	Peer Industry	2010	41,530	27%	1,152,773
1	16	Peer Industry	2011	41,202	28%	1,150,456
1	16	Peer Industry	2012	41,246	24%	1,186,816
1	16	Peer Industry	2013	41,110	25%	1,173,364
1	16	Peer Industry	2014	41,316	24%	1,203,719
1	17	Peer Industry less OPG	2002	34,091	20%	410,010
1	17	Peer Industry less OPG	2003	34,608	24%	441,341
1	17	Peer Industry less OPG	2004	34,601	22%	476,605
1	17	Peer Industry less OPG	2005	34,686	23%	491,324
1	17	Peer Industry less OPG	2006	34,764	23%	515,903
1	17	Peer Industry less OPG	2007	34,195	18%	564,480
1	17	Peer Industry less OPG	2008	34,526	18%	604,755
1	17	Peer Industry less OPG	2009	34,630	21%	607,090
1	17	Peer Industry less OPG	2010	34,625	22%	664,429
1	17	Peer Industry less OPG	2011	34,780	23%	658,385
1	17	Peer Industry less OPG	2012	34,824	20%	662,385
1	17	Peer Industry less OPG	2013	34,677	20%	667,312
1	17	Peer Industry less OPG	2014	34,883	18%	687,000

16.2%	62.7%						
		O	I share	I share	I share	I share	I share
%	%	MWh	K$	K$	%	%	%
O&M industry share	**Labour_OM&A share**	**Net_generation**	**Revenue**	**Capital**	**Capital Share**	**O&M Share**	**Labour O&M Share**
17%	67%	33,977,759	2,126,290	2,008,401	94%	6%	4%
16%	64%	33,202,786	2,068,079	1,937,377	94%	6%	4%
16%	67%	35,351,273	1,851,547	1,719,336	93%	7%	5%
16%	64%	33,487,118	1,837,930	1,695,542	92%	8%	5%
17%	64%	34,329,431	1,408,920	1,252,314	89%	11%	7%
17%	64%	32,986,718	1,378,521	1,213,567	88%	12%	8%
17%	59%	37,423,326	1,615,589	1,429,849	89%	11%	7%
17%	62%	36,302,957	1,335,251	1,150,154	86%	14%	9%
16%	58%	30,568,258	1,125,926	941,233	84%	16%	10%
15%	63%	30,359,921	1,099,541	924,931	84%	16%	10%
15%	65%	28,458,915	941,858	763,724	81%	19%	12%
16%	67%	30,347,392	1,127,001	944,418	84%	16%	11%
16%	64%	30,625,600	1,310,091	1,122,072	86%	14%	9%
10%		10,075,261	301,225	227,620	76%	24%	0%
11%		11,506,124	464,670	378,197	81%	19%	0%
10%		10,605,018	462,126	376,721	82%	18%	0%
10%		12,181,585	752,856	668,429	89%	11%	0%
8%		14,345,679	707,160	630,624	89%	11%	0%
10%		8,097,547	508,253	406,927	80%	20%	0%
10%		8,145,244	725,807	616,432	85%	15%	0%
10%		8,927,398	363,178	253,557	70%	30%	0%
10%		10,485,910	436,466	324,838	74%	26%	0%
10%		12,046,693	432,483	315,743	73%	27%	0%
12%		7,874,464	267,121	123,181	46%	54%	0%
12%		7,607,401	358,378	214,118	60%	40%	0%
12%		5,740,008	325,449	185,740	57%	43%	0%
4%		4,959,185	31,966	4,942	58%	42%	0%
4%		6,349,659	106,918	77,588	73%	27%	0%
4%		5,133,383	96,428	60,659	63%	37%	0%
4%		5,526,417	144,515	109,395	76%	24%	0%
3%		4,476,743	82,428	55,241	67%	33%	0%
3%		4,470,974	61,098	28,518	47%	53%	0%
3%		4,618,792	64,948	32,769	50%	50%	0%
3%		4,767,989	74,689	38,712	52%	48%	0%

3%	4,757,841	82,713	43,979	53%	47%	0%
3%	4,256,244	62,044	23,178	37%	63%	0%
3%	3,989,993	46,977	7,348	58%	42%	0%
4%	5,258,826	105,619	64,368	61%	39%	0%
3%	5,008,985	98,706	58,310	59%	41%	0%
1%	2,745,908	10,367	2,985	29%	71%	0%
1%	3,524,075	60,446	53,042	88%	12%	0%
1%	3,072,059	41,524	33,624	81%	19%	0%
1%	2,589,093	43,433	33,813	78%	22%	0%
1%	2,929,977	32,012	21,029	66%	34%	0%
1%	2,767,601	33,715	21,929	65%	35%	0%
1%	2,044,218	30,818	18,220	59%	41%	0%
1%	2,813,461	32,547	20,418	63%	37%	0%
1%	3,262,836	42,459	31,931	75%	25%	0%
1%	2,936,357	21,336	10,002	47%	53%	0%
1%	4,495,195	13,773	3,255	24%	76%	0%
1%	2,932,193	29,589	19,541	66%	34%	0%
1%	3,095,734	50,652	37,593	74%	26%	0%
3%	5,972,445	164,989	145,457	88%	12%	0%
3%	6,088,883	284,529	263,949	93%	7%	0%
3%	5,972,148	305,563	281,491	92%	8%	0%
3%	6,144,823	431,550	406,529	94%	6%	0%
3%	9,140,420	508,252	481,099	95%	5%	0%
3%	6,111,406	394,718	366,219	93%	7%	0%
3%	6,839,696	518,483	488,248	94%	6%	0%
3%	8,028,082	304,445	274,604	90%	10%	0%
3%	7,276,822	292,886	261,912	89%	11%	0%
3%	10,903,116	348,149	316,978	91%	9%	0%
3%	7,882,921	199,877	167,492	84%	16%	0%
3%	5,587,871	230,877	197,521	86%	14%	0%
3%	6,097,434	257,486	224,971	87%	13%	0%
3%	4,088,810	117,929	97,128	82%	18%	0%
3%	5,761,736	219,630	197,252	90%	10%	0%
3%	4,403,651	201,992	178,726	88%	12%	0%
3%	4,436,797	278,700	253,842	91%	9%	0%
3%	3,087,416	155,475	127,527	82%	18%	0%
3%	1,403,518	78,282	45,394	58%	42%	0%
3%	2,300,449	161,078	128,184	80%	20%	0%

3%	5,905,956	230,502	202,046	88%	12%	0%
3%	3,707,310	172,147	133,541	78%	22%	0%
3%	3,204,062	124,119	88,345	71%	29%	0%
3%	2,667,009	85,756	48,348	56%	44%	0%
3%	5,624,823	212,131	175,782	83%	17%	0%
4%	3,892,917	217,297	171,268	79%	21%	0%
3%	3,314,010	111,057	87,252	79%	21%	0%
3%	3,802,857	152,813	129,015	84%	16%	0%
3%	3,347,422	149,508	124,342	83%	17%	0%
3%	4,821,918	305,763	281,377	92%	8%	0%
3%	4,773,110	269,657	240,078	89%	11%	0%
4%	2,448,324	144,854	109,800	76%	24%	0%
3%	2,455,275	210,256	177,369	84%	16%	0%
4%	3,568,086	130,952	91,119	70%	30%	0%
4%	4,105,320	172,448	127,656	74%	26%	0%
4%	4,603,429	174,963	126,622	72%	28%	0%
3%	2,625,534	90,375	50,162	56%	44%	0%
4%	2,254,662	112,300	65,510	58%	42%	0%
3%	1,543,032	86,709	52,450	60%	40%	0%
6%	1,721,153	29,004	(15,317)	34%	66%	0%
6%	2,780,954	76,607	32,370	42%	58%	0%
7%	2,215,266	69,634	14,675	21%	79%	0%
7%	2,553,624	126,549	64,642	51%	49%	0%
7%	1,776,363	61,708	(1,018)	34%	66%	0%
6%	1,426,418	41,896	(20,837)	34%	66%	0%
7%	1,357,464	52,439	(26,910)	34%	66%	0%
5%	2,441,228	70,078	16,172	23%	77%	0%
6%	2,208,567	70,814	7,237	34%	66%	0%
5%	1,761,111	44,494	(15,458)	34%	66%	0%
4%	1,410,378	25,207	(26,439)	34%	66%	0%
4%	2,336,744	69,104	21,396	31%	69%	0%
5%	1,908,307	75,080	13,281	18%	82%	0%
4%	3,219,922	98,988	73,491	74%	26%	0%
3%	3,444,668	177,836	151,081	85%	15%	0%
4%	3,091,170	173,661	138,840	80%	20%	0%
4%	2,965,117	227,782	193,180	85%	15%	0%
4%	4,250,197	271,325	238,483	88%	12%	0%
4%	3,443,624	242,396	206,837	85%	15%	0%

3%	3,441,159	287,926	251,660	87%	13%	0%
3%	3,213,992	135,676	98,433	73%	27%	0%
3%	3,435,392	149,971	114,380	76%	24%	0%
3%	4,339,268	154,322	115,530	75%	25%	0%
3%	4,080,847	116,332	78,619	68%	32%	0%
3%	2,976,700	134,754	94,579	70%	30%	0%
3%	3,595,400	174,353	135,547	78%	22%	0%
1%	4,009,637	104,807	95,878	91%	9%	0%
2%	3,539,611	168,772	156,501	93%	7%	0%
2%	3,789,043	203,385	190,140	93%	7%	0%
1%	3,610,823	251,921	240,594	96%	4%	0%
1%	4,127,672	230,651	218,525	95%	5%	0%
1%	3,688,791	243,128	230,525	95%	5%	0%
1%	3,851,251	289,635	277,703	96%	4%	0%
1%	3,765,761	147,856	133,835	91%	9%	0%
1%	3,493,588	141,590	128,262	91%	9%	0%
1%	4,534,293	153,925	137,652	89%	11%	0%
1%	4,088,289	98,867	83,098	84%	16%	0%
2%	3,645,832	159,385	140,682	88%	12%	0%
1%	4,143,307	187,263	172,090	92%	8%	0%
2%	3,066,765	69,239	56,449	82%	18%	0%
2%	3,019,577	112,201	99,350	89%	11%	0%
1%	3,097,850	123,244	110,932	90%	10%	0%
2%	2,837,546	157,187	143,614	91%	9%	0%
2%	3,605,566	160,024	144,856	91%	9%	0%
2%	3,183,332	162,414	142,804	88%	12%	0%
2%	3,202,085	194,470	173,359	89%	11%	0%
2%	3,191,546	99,841	74,341	74%	26%	0%
2%	3,254,776	103,973	82,310	79%	21%	0%
2%	3,521,657	90,327	67,944	75%	25%	0%
2%	3,462,116	71,956	46,137	64%	36%	0%
2%	3,001,760	97,630	70,683	72%	28%	0%
3%	3,165,690	112,546	81,443	72%	28%	0%
2%	1,767,529	31,595	18,028	57%	43%	0%
1%	1,461,441	29,302	18,535	63%	37%	0%
2%	2,088,127	58,979	45,771	78%	22%	0%
1%	2,063,631	80,159	69,217	86%	14%	0%
1%	955,563	49,249	38,150	77%	23%	0%

1%	1,591,900	92,040	77,816	85%	15%	0%
2%	1,748,285	105,557	87,783	83%	17%	0%
2%	1,902,961	57,507	37,789	66%	34%	0%
2%	2,152,401	82,083	58,977	72%	28%	0%
1%	1,755,836	47,790	33,105	69%	31%	0%
1%	1,317,309	29,443	15,241	52%	48%	0%
1%	1,667,070	48,906	33,411	68%	32%	0%
1%	1,433,513	41,232	25,847	63%	37%	0%
3%	976,826	29,571	7,923	27%	73%	0%
2%	1,503,131	65,870	46,764	71%	29%	0%
3%	1,312,878	62,736	40,376	64%	36%	0%
4%	1,307,560	68,665	35,841	52%	48%	0%
4%	1,235,977	57,309	22,610	39%	61%	0%
4%	1,169,116	55,461	19,897	36%	64%	0%
3%	1,056,804	61,110	23,403	38%	62%	0%
3%	1,201,289	45,532	10,658	23%	77%	0%
3%	1,190,183	51,515	13,246	26%	74%	0%
3%	1,037,828	46,709	13,366	29%	71%	0%
2%	970,063	33,443	4,535	41%	59%	0%
2%	1,064,469	41,472	14,244	34%	66%	0%
3%	905,995	25,804	(7,324)	40%	60%	0%
1%	953,064	6,438	164	45%	55%	0%
1%	1,285,981	18,541	11,966	65%	35%	0%
1%	1,133,492	11,193	4,484	40%	60%	0%
1%	1,273,330	24,820	18,011	73%	27%	0%
1%	1,019,894	10,817	3,153	29%	71%	0%
1%	1,018,237	11,101	4,115	37%	63%	0%
1%	917,768	7,398	(96)	45%	55%	0%
1%	960,207	12,036	3,609	30%	70%	0%
1%	870,435	12,041	4,733	39%	61%	0%
1%	723,578	7,326	310	45%	55%	0%
1%	752,595	4,825	(2,184)	45%	55%	0%
1%	809,223	15,566	8,028	52%	48%	0%
1%	613,520	14,945	7,114	48%	52%	0%
1%	1,706,803	51,416	40,912	80%	20%	0%
1%	3,029,261	116,036	104,836	90%	10%	0%
1%	2,266,947	103,131	94,997	92%	8%	0%
1%	2,296,351	156,876	147,846	94%	6%	0%

1%	1,694,182	94,851	86,775	91%	9%	0%
1%	1,235,614	72,363	64,202	89%	11%	0%
1%	1,343,201	91,639	82,793	90%	10%	0%
1%	2,299,952	93,230	82,816	89%	11%	0%
1%	2,060,676	95,841	87,074	91%	9%	0%
2%	1,732,100	79,804	60,623	76%	24%	0%
1%	1,466,400	58,510	43,088	74%	26%	0%
1%	1,036,168	43,224	35,270	82%	18%	0%
1%	784,545	40,839	31,156	76%	24%	0%
10%	5,361,741	165,323	93,803	57%	43%	0%
10%	9,315,598	211,791	129,037	61%	39%	0%
10%	8,333,515	239,578	155,248	65%	35%	0%
10%	9,262,617	246,161	162,524	66%	34%	0%
12%	5,652,920	219,527	111,474	51%	49%	0%
10%	5,232,989	216,468	120,279	56%	44%	0%
9%	4,422,917	230,546	130,851	57%	43%	0%
10%	6,135,029	236,135	124,209	53%	47%	0%
13%	8,224,506	255,417	105,370	41%	59%	0%
11%	6,510,698	274,686	146,187	53%	47%	0%
10%	5,618,173	267,662	145,573	54%	46%	0%
10%	7,659,184	317,461	193,084	61%	39%	0%
10%	7,398,826	312,081	197,771	63%	37%	0%
3%	6,891,659	181,848	159,037	87%	13%	0%
3%	6,098,753	293,020	268,161	92%	8%	0%
3%	6,019,707	324,413	299,463	92%	8%	0%
3%	5,544,793	401,321	378,079	94%	6%	0%
3%	6,716,041	387,697	363,634	94%	6%	0%
3%	6,530,479	432,001	401,283	93%	7%	0%
3%	6,298,724	478,725	444,312	93%	7%	0%
3%	5,878,382	239,955	204,749	85%	15%	0%
2%	5,509,191	229,894	202,382	88%	12%	0%
3%	7,546,905	256,801	220,765	86%	14%	0%
3%	6,947,088	177,022	137,306	78%	22%	0%
4%	6,108,908	267,776	218,576	82%	18%	0%
4%	7,091,368	331,024	287,274	87%	13%	0%
26%	24,574,000	744,498	560,632	75%	25%	0%
28%	24,740,000	851,413	626,650	74%	26%	0%
26%	23,926,000	915,860	703,356	77%	23%	0%

27%	20,970,000	889,494	655,860	74%	26%	0%
26%	26,245,000	985,550	744,679	76%	24%	0%
27%	21,971,000	992,306	727,004	73%	27%	0%
27%	21,842,000	994,268	701,259	71%	29%	0%
26%	23,002,000	1,025,475	744,295	73%	27%	0%
26%	24,159,000	1,076,720	773,069	72%	28%	0%
28%	33,154,000	1,175,186	857,726	73%	27%	0%
29%	29,549,000	1,095,590	749,293	68%	32%	0%
28%	25,067,000	1,098,103	774,635	71%	29%	0%
27%	24,407,180	1,106,286	777,587	70%	30%	0%
100%	94,808,476	3,632,052	2,920,287	80%	20%	0%
100%	105,715,095	4,627,062	3,830,257	83%	17%	0%
100%	101,232,949	4,478,642	3,657,322	82%	18%	0%
100%	102,903,142	5,536,187	4,668,840	84%	16%	0%
100%	104,117,150	4,707,062	3,793,682	81%	19%	0%
100%	86,806,588	4,168,709	3,173,972	76%	24%	0%
100%	91,466,658	5,126,423	4,042,920	79%	21%	0%
100%	101,304,275	3,609,410	2,536,043	70%	30%	0%
100%	96,564,012	3,518,184	2,365,411	67%	33%	0%
100%	101,773,095	3,418,819	2,268,363	66%	34%	0%
100%	88,107,289	2,529,004	1,342,188	53%	47%	0%
100%	89,919,225	3,371,174	2,197,810	65%	35%	0%
100%	87,044,181	3,661,557	2,457,837	67%	33%	0%
58%	60,830,717	1,505,763	1,095,752	73%	27%	0%
55%	72,512,309	2,558,983	2,117,643	83%	17%	0%
58%	65,881,676	2,627,095	2,150,490	82%	18%	0%
57%	69,416,024	3,698,256	3,206,932	87%	13%	0%
56%	69,787,719	3,298,142	2,782,239	84%	16%	0%
57%	53,819,870	2,790,188	2,225,708	80%	20%	0%
56%	54,043,332	3,510,834	2,906,079	83%	17%	0%
57%	65,001,319	2,274,159	1,667,069	73%	27%	0%
58%	65,995,754	2,392,258	1,727,829	72%	28%	0%
57%	71,413,175	2,319,278	1,660,893	72%	28%	0%
56%	59,648,374	1,587,146	924,761	58%	42%	0%
57%	59,571,833	2,244,172	1,576,860	70%	30%	0%
57%	56,418,581	2,351,465	1,664,465	71%	29%	0%

I share %	Sub-index unit
Non-labour O&M Share	**O&M price index**
2%	1.00
2%	1.02
2%	1.05
3%	1.08
4%	1.10
4%	1.14
5%	1.16
5%	1.18
7%	1.21
6%	1.23
7%	1.25
5%	1.27
5%	1.30
24%	-24%
19%	-19%
18%	-18%
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20%	-20%
15%	-15%
30%	-30%
26%	-26%
27%	-27%
54%	-54%
40%	-40%
43%	-43%
42%	-42%
27%	-27%
37%	-37%
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33%	-33%
53%	-53%
50%	-50%
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17%	-17%
27%	-27%
28%	-28%
28%	-28%
42%	-42%
30%	-30%
29%	-29%

Is it in the modeling? 1 = yes; 0 = no		
Mod_ID	**LEI_ID**	**Short name**
1	0	OPG
1	1	PG&E
1	2	Duke
1	3	VA Electric
1	4	ID Power
1	5	AB Power
1	6	SoCal Edison
1	7	GA Power
1	8	PacifiCorp
1	9	Avista
1	10	Portland
1	11	Ameren MI - Union
1	12	AP Power
1	13	SCE&G
0	14	Alcoa
1	15	SEPA
1	16	Seattle
0	17	WAPA
1	18	Peer Industry
1	19	Peer Industry less OPG

Full utility name	
OPG Hydro Total	CA
PACIFIC GAS AND ELECTRIC COMPANY	US
Duke Energy Carolinas, LLC	US
VIRGINIA ELECTRIC AND POWER COMPANY	US
Idaho Power Company	US
ALABAMA POWER COMPANY	US
Southern California Edison Company	US
Georgia Power Company	US
PacifiCorp	US
Avista Corporation	US
Portland General Electric Company	US
UNION ELECTRIC COMPANY	US
Appalachian Power Company	US
South Carolina Electric & Gas Company	US
Alcoa Power Generating Inc.	US
Southeastern Power Administration	US
Seattle City Light	US
Western Area Power Administration	US
OPG Hydro Peer Industry Total	NA
Peer Industry Total (without OPG)	US

Note: combined index for North America (based on O&M share)

O&M share of Canada	16%
O&M share of US	84%

	NA	CA	US
Year	O&M Price Index	O&M Price Index	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	1.08	1.08	1.09
2006	1.12	1.10	1.12
2007	1.15	1.14	1.15
2008	1.18	1.16	1.18
2009	1.20	1.18	1.21
2010	1.23	1.21	1.23
2011	1.26	1.23	1.26
2012	1.28	1.25	1.29
2013	1.31	1.27	1.32
2014	1.34	1.30	1.35
Average G	**2.5%**	**2.2%**	**2.5%**

	NA	NA	NA	
	Labour Price Index	Non-Labour Price Index	O&M Price Index	
2002	**1.00**	**1.00**	**1.00**	2002
2003	**1.03**	**1.02**	**1.02**	2003
2004	**1.06**	**1.05**	**1.05**	2004
2005	**1.09**	**1.08**	**1.08**	2005
2006	**1.12**	**1.11**	**1.12**	2006
2007	**1.16**	**1.14**	**1.15**	2007
2008	**1.19**	**1.16**	**1.18**	2008
2009	**1.22**	**1.17**	**1.20**	2009
2010	**1.26**	**1.19**	**1.23**	2010
2011	**1.29**	**1.21**	**1.26**	2011
2012	**1.32**	**1.23**	**1.28**	2012
2013	**1.35**	**1.25**	**1.31**	2013
2014	**1.39**	**1.27**	**1.34**	2014

	NA	CA	US
Year	O&M Price Index Growth Rates	O&M Price Index Growth Rates	O&M Price Index Growth Rates
2002			
2003	2.4%	2.1%	2.4%
2004	2.8%	2.4%	2.9%
2005	2.9%	3.0%	2.9%
2006	2.9%	1.9%	3.0%
2007	3.0%	3.2%	3.0%
2008	2.6%	2.4%	2.7%
2009	1.9%	1.2%	2.0%
2010	2.1%	2.8%	2.0%
2011	2.3%	1.7%	2.4%
2012	2.1%	1.5%	2.2%
2013	2.2%	1.6%	2.3%
2014	2.3%	2.0%	2.4%
Average	**2.5%**	**2.2%**	**2.5%**

Calculating NA L/NL/O&M growths

NA	NA	NA
Labour Price Index Growth	Non-Labour Price Index Growth	O&M Price Index Growth
1.00	1.00	1.00
1.03	1.02	1.02
1.03	1.03	1.03
1.03	1.03	1.03
1.03	1.03	1.03
1.03	1.03	1.03
1.03	1.02	1.03
1.03	1.01	1.02
1.03	1.01	1.02
1.03	1.02	1.02
1.02	1.02	1.02
1.03	1.02	1.02
1.03	1.02	1.02

	CA	CA	CA
	(Ontario) Industrial Labour Index Growth	(Canada) GDP-IPI FDD Growth	O&M Price Index Growth
2002	1.00	1.00	1.00
2003	1.02	1.02	1.02
2004	1.03	1.02	1.02
2005	1.04	1.02	1.03
2006	1.02	1.02	1.02
2007	1.04	1.02	1.03
2008	1.02	1.03	1.02
2009	1.01	1.01	1.01
2010	1.04	1.01	1.03
2011	1.01	1.02	1.02
2012	1.01	1.02	1.02
2013	1.02	1.02	1.02
2014	1.02	1.02	1.02

	US
	(USA) Labour Index Growth
2002	1.00
2003	1.03
2004	1.03
2005	1.03
2006	1.03
2007	1.03
2008	1.03
2009	1.03
2010	1.02
2011	1.03
2012	1.02
2013	1.03
2014	1.03

US	US
(USA) GDP-PI Growth	O&M Price Index Growth
1.00	1.00
1.02	1.02
1.03	1.03
1.03	1.03
1.03	1.03
1.03	1.03
1.02	1.03
1.01	1.02
1.01	1.02
1.02	1.02
1.02	1.02
1.02	1.02
1.02	1.02

Note: Indices are for Canada
Source: See StatsCan CANSIM Tables

Share of Labour
Share of Non-labour

Year	(Ontario) Average Weekly Earnings, Industrial	(Ontario) Industrial Labour Index Growth	(Canada) GDP-IPI FDD
2002	710.87	1.00	90.20
2003	728.38	1.02	91.70
2004	748.57	1.03	93.40
2005	775.80	1.04	95.40
2006	788.25	1.02	97.70
2007	818.61	1.04	100.00
2008	837.91	1.02	102.50
2009	848.85	1.01	103.70
2010	881.43	1.04	104.80
2011	893.41	1.01	107.30
2012	906.09	1.01	109.10
2013	920.12	1.02	111.00
2014	938.36	1.02	113.40

63%
37%

	Ontario Industries	Canada GDP-IPI FDI	On+Can O&M	On+Can O&M	On+Can O&M
(Canada) GDP-IPI FDD Growth	**(Ind) Labour Price Index**	**Non-Labour Price Index**	**O&M Price Index Growth**	**O&M Price Index**	**O&M Price Index Growth Rates (%)**
1.00	**1.00**	**1.00**	1.00	**1.00**	
1.02	**1.02**	**1.02**	1.02	**1.02**	2.1%
1.02	**1.05**	**1.04**	1.02	**1.05**	2.4%
1.02	**1.09**	**1.06**	1.03	**1.08**	3.0%
1.02	**1.11**	**1.08**	1.02	**1.10**	1.9%
1.02	**1.15**	**1.11**	1.03	**1.14**	3.2%
1.03	**1.18**	**1.14**	1.02	**1.16**	2.4%
1.01	**1.19**	**1.15**	1.01	**1.18**	1.2%
1.01	**1.24**	**1.16**	1.03	**1.21**	2.8%
1.02	**1.26**	**1.19**	1.02	**1.23**	1.7%
1.02	**1.27**	**1.21**	1.02	**1.25**	1.5%
1.02	**1.29**	**1.23**	1.02	**1.27**	1.6%
1.02	**1.32**	**1.26**	1.02	**1.30**	2.0%
					2.2%

Year	EUCG L shares	O&M price index growth	O&M price index	
2002	0%	1.00	1.00	
2003	0%	1.02	1.02	1.6%
2004	60%	1.02	1.04	2.1%
2005	63%	1.03	1.07	3.0%
2006	61%	1.02	1.09	1.9%
2007	61%	1.03	1.13	3.2%
2008	60%	1.02	1.15	2.4%
2009	62%	1.01	1.17	1.2%
2010	65%	1.03	1.20	2.8%
2011	63%	1.02	1.22	1.7%
2012	65%	1.02	1.24	1.5%
2013	64%	1.02	1.26	1.6%
2014	64%	1.02	1.29	2.0%
				2.1%

Note: Indices are for United States
Source: See US BLS & BEA tables

Share of Labour	63%
Share of Non-labour	37%

Year	(USA) Employment Cost Index, Utilities	(USA) Labour Index Growth	(USA) GDP Price Index	(USA) GDP-PI Growth
2002	91.30	1.00	85.05	1.00
2003	93.78	1.03	86.75	1.02
2004	96.63	1.03	89.13	1.03
2005	99.28	1.03	91.99	1.03
2006	102.35	1.03	94.82	1.03
2007	105.68	1.03	97.34	1.03
2008	109.05	1.03	99.24	1.02
2009	112.13	1.03	100.00	1.01
2010	114.90	1.02	101.21	1.01
2011	118.08	1.03	103.20	1.02
2012	120.98	1.02	105.00	1.02
2013	124.33	1.03	106.59	1.02
2014	127.70	1.03	108.69	1.02

USA Utilities	USA GDP-PI	USA O&M	USA O&M	USA O&M
Labour Price Index	**Non-Labour Price Index**	**O&M Price Index Growth**	**O&M Price Index**	**O&M Price Index Growth Rates (%)**
1.00	**1.00**	1.00	**1.00**	
1.03	**1.02**	1.02	**1.02**	2.4%
1.06	**1.05**	1.03	**1.05**	2.9%
1.09	**1.08**	1.03	**1.09**	2.9%
1.12	**1.11**	1.03	**1.12**	3.0%
1.16	**1.14**	1.03	**1.15**	3.0%
1.19	**1.17**	1.03	**1.18**	2.7%
1.23	**1.18**	1.02	**1.21**	2.0%
1.26	**1.19**	1.02	**1.23**	2.0%
1.29	**1.21**	1.02	**1.26**	2.4%
1.33	**1.23**	1.02	**1.29**	2.2%
1.36	**1.25**	1.02	**1.32**	2.3%
1.40	**1.28**	1.02	**1.35**	2.4%
				2.5%

OPG data only (data from OPG)

	Labour_OM&A share	Capital Share	OM&A Share	Labor OM&A share combine
2002	67%	93%	7%	5%
2003	64%	94%	6%	4%
2004	67%	93%	7%	5%
2005	64%	92%	8%	5%
2006	64%	89%	11%	7%
2007	64%	88%	12%	8%
2008	59%	89%	11%	7%
2009	62%	86%	14%	8%
2010	58%	84%	16%	9%
2011	62%	84%	16%	10%
2012	64%	81%	19%	12%
2013	67%	84%	16%	11%
2014	64%	86%	14%	9%
average 2002-2014	63.5%	88%	12%	8%

EUCG data (industry)

	Labour Share based on Total OM&A (Operations+Maintenance+Environment & Regulatory+Land & Water Rental Fees + Administration)	Labour Share based on OM&A, less Water Rentals/Fees and Indirect Admin	Labour Share based on O&M
2002			
2003			
2004	42%	44%	60%
2005	38%	45%	63%
2006	37%	44%	61%
2007	37%	46%	61%
2008	36%	47%	60%
2009	38%	47%	62%
2010	42%	52%	65%
2011	42%	51%	63%
2012	46%	53%	65%
2013	46%	53%	64%

2014	46%	53%	64%
average 2002-2014	**41%**	**49%**	**63%**

Note: LEI derived the above tables from EUCG data

Other OM&A share combined
2%
2%
2%
3%
4%
4%
5%
5%
7%
6%
7%
5%
5%
4%

StatsCan Tables: http://www5.statcan.gc.ca/cansim/a29?lang=eng&groupid=All&p2=17

See lower for GDP-IPI FDD

Labour Price Indices

Table 281-0027 [4, 14, 15, 16, 18]

Average weekly earnings (SEPH), by type of employee for selected industries classified using the North American Industry Classif
annual (current dollars)
Geography = Ontario
Type of employees = All employees
Overtime = Including overtime
Accessed on January 5, 2016

Industrial aggregate excluding unclassified businesses [11-91N] [5, 6]

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
orig	695.66	710.87	728.38	748.57	775.8	788.25	818.61	837.91	848.85[A]	881.43[A]	893.41[A]	906.09[A]
	695.66	710.87	728.38	748.57	775.8	788.25	818.61	837.91	848.85	881.43	893.41	906.09
		2.16%	2.43%	2.73%	3.57%	1.59%	3.78%	2.33%	1.30%	3.77%	1.35%	1.41%

Utilities [22, 221]

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
orig	1,306.79	1,385.59	1,441.31	1,420.13	1,449.84	1,488.34	1,577.41	1,544.30	1,672.72[A]	1,680.01[A]	1,714.92[A]	1,707.11[A]
	1,306.79	1,385.59	1,441.31	1,420.13	1,449.84	1,488.34	1,577.41	1,544.30	1,672.72	1,680.01	1,714.92	1,707.11
		5.86%	3.94%	-1.48%	2.07%	2.62%	5.81%	-2.12%	7.99%	0.43%	2.06%	-0.46%

NAICS [1	Industri	Utilities [22, 221]
2001	695.66	1306.79
2002	710.87	1385.59
2003	728.38	1441.31
2004	748.57	1420.13
2005	775.80	1449.84
2006	788.25	1488.34
2007	818.61	1577.41
2008	837.91	1544.30
2009	848.85	1672.72
2010	881.43	1680.01
2011	893.41	1714.92
2012	906.09	1707.11
2013	920.12	1758.79

2014	938.36	1915.37

Footnotes:

1 Although the creation of Nunavut officially took place in April 1999, the Survey of employment, payrolls and hours (SEPH) was c
2 Since January 2001, the Survey of employment, payrolls and hours (SEPH) program no longer combines Northw
3 These terminated series are based on the North American Industry Classification System (NAICS) 2002.
4 Data quality indicators are based on the coefficient of variation (CV). Quality indicators indicate the following: A
5 Industrial aggregate covers all industrial sectors except those primarily involved in agriculture, fishing and trap
6 Unclassified businesses (00) are business for which the industrial classification (North American Industry Classi
7 Goods producing industries (11-33N) includes the following sectors: forestry, logging and support (11N), minin
8 Forestry, logging and support (11N) includes the following industries: forestry and logging (113) and support a
9 Non-durable goods (311N) of the manufacturing sector includes the following industries: food manufacturing (3
10 Durable goods (321N) of the manufacturing sector includes the following industries: wood products manufactur
11 Service producing industries (41-91N) includes the following industries: trade (41-45N), transportation and wa
12 Trade (41-45N) industry includes the following sectors: wholesale (41) and retail trade (44-45).
13 Education special (611N) industry includes the following industries: elementary and secondary schools (6111),
14 Source: Labour Statistics Division, Statistics Canada
15 The introduction of administrative data in 2001 and the associated change in methodology resulted in level shi
16 Earnings data are based on gross payroll before source deductions.
17 These terminated series are based on the North American Industry Classification System (NAICS) 2007.
18 Industry estimates in this table are based on the 2012 North American Industry Classification System (NAICS).

Source: Statistics Canada. *Table 281-0027 - Average weekly earnings (SEPH), by type of employee for selected industr*

GDP-IPI FDD

Table 384-0039 [4]

Implicit price indexes, gross domestic product, provincial and territorial

annual (2007=100)

Geography = Canada 1

Index = Implicit price indexes

Estimates = Final domestic demand

Canada

1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
47.7	52.2	55.1	57.4	59.5	61.8	64.3	66.8	69.7	72.4	74.8	76.3
	9.02%	5.41%	4.09%	3.59%	3.79%	3.97%	3.81%	4.25%	3.80%	3.26%	1.99%

Ontario

1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
48.1	52.6	55.8	58.3	60.6	63.2	66.4	69.4	72.7	75.1	77.5	78.4
	8.94%	5.91%	4.38%	3.87%	4.20%	4.94%	4.42%	4.65%	3.25%	3.15%	1.15%

	Canada	***Ontario***
1981	47.70	48.10
1982	52.20	52.60
1983	55.10	55.80
1984	57.40	58.30
1985	59.50	60.60
1986	61.80	63.20
1987	64.30	66.40
1988	66.80	69.40
1989	69.70	72.70
1990	72.40	75.10
1991	74.80	77.50
1992	76.30	78.40
1993	77.70	79.90
1994	79.00	81.00

1995	79.90	81.90
1996	80.80	82.60
1997	82.00	83.90
1998	83.20	85.30
1999	84.40	86.20
2000	86.50	88.20
2001	88.20	90.00
2002	90.20	91.90
2003	91.70	93.40
2004	93.40	95.00
2005	95.40	96.80
2006	97.70	98.30
2007	100.00	100.00
2008	102.50	102.20
2009	103.70	103.30
2010	104.80	104.50
2011	107.30	107.00
2012	109.10	108.70
2013	111.00	110.70
2014	113.40	113.00

ication System (NAICS)

2013	2014	
920.12[A]	938.36[A]	
920.12	938.36	
1.54%	1.96%	1.56%

2013	2014	
1,758.79[A]	1,915.37[A]	
1758.79	1915.37	
2.98%	8.53%	3.28%

Labour Price Indices

Table 281-0028 [3, 12, 13, 14, 15, 16, 17, 18, 19]

Average weekly earnings (SEPH), including overtime, seasonally adjusted, for all emp
monthly (current dollars)
Geography = Ontario
Type of employees = All employees
Overtime = Including overtime
Accessed on April 30, 2014

Industrial aggregate excluding unclassified businesses [11-91N] [4, 5]

	1991	1991	1991	1991	1991	1991	1991	1991
	1	2	3	4	5	6	7	8
orig	560.53(T)	567.77(T)	567.83(T)	570.77(T)	573.76(T)	575.57(T)	576.99(T)	579.08(T)
	560.53	567.77	567.83	570.77	573.76	575.57	576.99	579.08
	560.53	567.77	567.83	570.77	573.76	575.57	576.99	579.08

Utilities [22]

	1991	1991	1991	1991	1991	1991	1991	1991
	1	2	3	4	5	6	7	8
orig	783.05(T)	822.86(T)	864.12(T)	860.22(T)	837.73(T)	842.40(T)	834.83(T)	856.41(T)
	783.05	822.86	864.12	860.22	837.73	842.40	834.83	856.41
	783.05	822.86	864.12	860.22	837.73	842.4	834.83	856.41

NAICS [:	Industri:	Utilities [22]
1991	575.90	854.10
1992	598.57	892.54
1993	612.11	896.30
1994	627.87	921.55
1995	633.98	936.70
1996	649.29	939.75
1997	663.51	987.87
1998	672.53	1033.23

1999	683.48	1050.11
2000	699.93	1067.98

Footnotes:

ɔnly able to begin publishing separate estimate
west Territories and Nunavut. They are

Ⱥ - Excellent (CV from 0% to 4.99%); B
ɔping, private household services, religio
ification System (NAICS) 2012) has yet
ıg, quarrying, and oil and gas extraction
ıctivities to forestry (1153).
311), beverage and tobacco products ma
ring (321), non-metallic mineral product
rehousing (48-49), information and cult

community colleges and CEGEP (6112),

fts for some series. This affects the com

ies classified using the North American I

3 Industrial aggregate covers all industrial sectors except those primaril
4 Le regroupement « ensemble des industries » comprend tous les secte
5 Unclassified businesses (00) are business for which the industrial clas
6 Goods producing industries (11-33N) includes the following sectors: fo
7 Forestry, logging and support (11N) includes the following industries:
8 Non-durable goods (311N) of the manufacturing sector includes the fo
9 Durable goods (321N) of the manufacturing sector includes the follow
10 Service producing industries (41-91N) includes the following industrie
11 Trade (41-45N) industry includes the following sectors: wholesale (41
12 Source: Labour Statistics Division, Statistics Canada
13 Some series exhibit no clear seasonal pattern. In such cases the data
14 The introduction of administrative data in 2001 and the associated cha
15 Estimates for the latest reference month are preliminary.
16 Earnings data are based on gross payroll before source deductions.
17 Average weekly earnings for the industrial aggregate, excluding uncla
18 Industry estimates in this table are based on the 2012 North America
19 Table 281-0028 has been terminated. For more recent estimates, please see tal

Source: Statistics Canada. *Table 281-0028 - Average weekly earnings (SEPH,*

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
77.7	79	79.9	80.8	82	83.2	84.4	86.5	88.2	90.2	91.7	93.4	95.4
1.82%	1.66%	1.13%	1.12%	1.47%	1.45%	1.43%	2.46%	1.95%	2.24%	1.65%	1.84%	2.12%
							1	1.01946	1.04232	1.05951	1.07897	1.10183

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
79.9	81	81.9	82.6	83.9	85.3	86.2	88.2	90	91.9	93.4	95	96.8
1.90%	1.37%	1.10%	0.85%	1.56%	1.65%	1.05%	2.29%	2.02%	2.09%	1.62%	1.70%	1.88%
							1	1.0202	1.04152	1.05838	1.07636	1.09656

ployees, by selected industries classified using the North American Industry Classification System (NAICS), *Terminated*

1991	1991	1991	1991	1992	1992	1992	1992	1992	1992	1992	1992	1992
9	10	11	12	1	2	3	4	5	6	7	8	9
580.44(T)	584.44(T)	585.23(T)	588.43(T)	589.81(T)	590.87(T)	588.05(T)	593.11(T)	598.11(T)	596.75(T)	599.74(T)	603.59(T)	603.43(T)
580.44	584.44	585.23	588.43	589.81	590.87	588.05	593.11	598.11	596.75	599.74	603.59	603.43
580.44	584.44	585.23	588.43	589.81	590.87	588.05	593.11	598.11	596.75	599.74	603.59	603.43

1991	1991	1991	1991	1992	1992	1992	1992	1992	1992	1992	1992	1992
9	10	11	12	1	2	3	4	5	6	7	8	9
856.11(T)	876.23(T)	914.08(T)	901.16(T)	884.58(T)	884.66(T)	887.55(T)	904.94(T)	895.68(T)	880.16(T)	878.41(T)	878.32(T)	905.61(T)
856.11	876.23	914.08	901.16	884.58	884.66	887.55	904.94	895.68	880.16	878.41	878.32	905.61
856.11	876.23	914.08	901.16	884.58	884.66	887.55	904.94	895.68	880.16	878.41	878.32	905.61

y involved in agriculture, fishing and trapping, private household services, religious organisations and the military personnel of the
eurs industriels sauf ceux dont les activités relèvent des secteurs de l'agriculture, de la pêche et du piégeage, des services domesti
sification (North American Industry Classification System (NAICS) 2012) has yet to be determined.
orestry, logging and support (11N), mining, quarrying, and oil and gas extraction (21), utilities (22), construction (23) and manufa
forestry and logging (113) and support activities to forestry (1153).
ollowing industries: food manufacturing (311), beverage and tobacco products manufacturing (312), textiles mills (313), textile pro
ing industries: wood products manufacturing (321), non-metallic mineral products manufacturing (327), primary metal manufactu
s: trade (41-45N), transportation and warehousing (48-49), information and cultural industries (51), finance and insurance (52), r
) and retail trade (44-45).

are not adjusted.
ange in methodology resulted in level shifts for some series. This affects the comparability of pre- and post-2001 estimates.

ssified businesses [11-91N] in Alberta; and service producing industries [41-91N] in Alberta as well as trade [41-45N] in Quebec f
n Industry Classification System (NAICS).
ble 281-0063.

), including overtime, seasonally adjusted, for all employees, by selected industries classified using the North American Industry Cl

2006	2007	2008	2009	2010	2011	2012	2013	2014	
97.7	100	102.5	103.7	104.8	107.3	109.1	111	113.4	
2.38%	2.33%	2.47%	1.16%	1.06%	2.36%	1.66%	1.73%	2.14%	1.97%
1.12808	1.15433	1.18284	1.1966	1.20923	1.23774	1.25833	1.28005	1.30744	

2006	2007	2008	2009	2010	2011	2012	2013	2014	
98.3	100	102.2	103.3	104.5	107	108.7	110.7	113	
1.54%	1.71%	2.18%	1.07%	1.15%	2.36%	1.58%	1.82%	2.06%	1.96%
1.11342	1.13251	1.15716	1.16955	1.18305	1.21102	1.23011	1.25254	1.2783	

1992	1992	1992	1993	1993	1993	1993	1993	1993	1993	1993	1993	1993
10	11	12	1	2	3	4	5	6	7	8	9	10
606.19(T)	606.20(T)	606.98(T)	608.85(T)	608.64(T)	608.37(T)	611.73(T)	610.23(T)	611.22(T)	613.60(T)	612.12(T)	613.91(T)	614.54(T)
606.19	606.20	606.98	608.85	608.64	608.37	611.73	610.23	611.22	613.60	612.12	613.91	614.54
606.19	606.2	606.98	608.85	608.64	608.37	611.73	610.23	611.22	613.6	612.12	613.91	614.54

1992	1992	1992	1993	1993	1993	1993	1993	1993	1993	1993	1993	1993
10	11	12	1	2	3	4	5	6	7	8	9	10
904.58(T)	910.54(T)	895.45(T)	897.15(T)	884.48(T)	884.07(T)	907.93(T)	890.34(T)	895.79(T)	886.23(T)	890.46(T)	906.11(T)	913.13(T)
904.58	910.54	895.45	897.15	884.48	884.07	907.93	890.34	895.79	886.23	890.46	906.11	913.13
904.58	910.54	895.45	897.15	884.48	884.07	907.93	890.34	895.79	886.23	890.46	906.11	913.13

e defence services.
ques aux ménages privés, des organismes religieux et du personnel militaire des services de la défense.

acturing (31-33).

oducts mills (314), clothing manufacturing (315), leather and allied products manufacturing (316), paper manufacturing (322), pri
ring (331), fabricated metal products manufacturing (332), machinery manufacturing (333), computer and electronic products ma
real estate and rental and leasing (53), professional, scientific and technical services (54), management of companies and enterpri

or February 2004, 2008 and 2012 have been corrected.

assification System (NAICS), monthly (current dollars), CANSIM (database). (accessed: 2014-02-26)

1993	1993	1994	1994	1994	1994	1994	1994	1994	1994	1994	1994	1994
11	12	1	2	3	4	5	6	7	8	9	10	11
615.18(T)	616.91(T)	617.54(T)	619.45(T)	624.42(T)	627.55(T)	627.47(T)	629.79(T)	631.65(T)	629.75(T)	631.92(T)	631.04(T)	632.04(T)
615.18	616.91	617.54	619.45	624.42	627.55	627.47	629.79	631.65	629.75	631.92	631.04	632.04
615.18	616.91	617.54	619.45	624.42	627.55	627.47	629.79	631.65	629.75	631.92	631.04	632.04

1993	1993	1994	1994	1994	1994	1994	1994	1994	1994	1994	1994	1994
11	12	1	2	3	4	5	6	7	8	9	10	11
912.85(T)	887.11(T)	915.33(T)	915.32(T)	907.78(T)	924.75(T)	921.67(T)	922.05(T)	919.44(T)	920.64(T)	924.74(T)	932.30(T)	945.21(T)
912.85	887.11	915.33	915.32	907.78	924.75	921.67	922.05	919.44	920.64	924.74	932.30	945.21
912.85	887.11	915.33	915.32	907.78	924.75	921.67	922.05	919.44	920.64	924.74	932.3	945.21

inting and related support activities (323), petroleum and coal products manufacturing (324), chemical manufacturing (325) and p
nufacturing (334), electrical equipment, appliances and components manufacturing (335), transportation equipment manufacturir
ses (55), administrative and support, waste management and remediation services (56), educational services (61), health care an

1994	1995	1995	1995	1995	1995	1995	1995	1995	1995	1995	1995	1995
12	1	2	3	4	5	6	7	8	9	10	11	12
631.85(T)	632.51(T)	631.71(T)	632.52(T)	628.76(T)	627.92(T)	631.46(T)	631.37(T)	636.62(T)	637.87(T)	634.79(T)	636.71(T)	645.52(T)
631.85	632.51	631.71	632.52	628.76	627.92	631.46	631.37	636.62	637.87	634.79	636.71	645.52
631.85	632.51	631.71	632.52	628.76	627.92	631.46	631.37	636.62	637.87	634.79	636.71	645.52

1994	1995	1995	1995	1995	1995	1995	1995	1995	1995	1995	1995	1995
12	1	2	3	4	5	6	7	8	9	10	11	12
909.36(T)	912.21(T)	927.58(T)	927.85(T)	935.23(T)	938.58(T)	942.74(T)	936.41(T)	930.31(T)	940.20(T)	955.56(T)	959.10(T)	934.63(T)
909.36	912.21	927.58	927.85	935.23	938.58	942.74	936.41	930.31	940.20	955.56	959.10	934.63
909.36	912.21	927.58	927.85	935.23	938.58	942.74	936.41	930.31	940.2	955.56	959.1	934.63

lastics and rubber products manufacturing (326).
g (336), furniture and related products manufacturing (337) and miscellaneous manufacturing (339).
d social assistance (62), arts, entertainment and recreation (71), accommodation and food services (72), other services (except p

1996	**1996**	**1996**	**1996**	**1996**	**1996**	**1996**	**1996**	**1996**	**1996**	**1996**	**1996**	**1997**
1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**1**
636.10(T)	638.04(T)	641.65(T)	641.52(T)	647.62(T)	652.29(T)	652.35(T)	653.31(T)	652.52(T)	658.18(T)	658.80(T)	659.12(T)	661.06(T)
636.10	638.04	641.65	641.52	647.62	652.29	652.35	653.31	652.52	658.18	658.80	659.12	661.06
636.1	638.04	641.65	641.52	647.62	652.29	652.35	653.31	652.52	658.18	658.8	659.12	661.06

1996	**1996**	**1996**	**1996**	**1996**	**1996**	**1996**	**1996**	**1996**	**1996**	**1996**	**1996**	**1997**
1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**1**
919.03(T)	927.40(T)	931.97(T)	940.06(T)	931.98(T)	934.57(T)	935.04(T)	935.02(T)	950.50(T)	958.25(T)	970.73(T)	942.46(T)	967.08(T)
919.03	927.40	931.97	940.06	931.98	934.57	935.04	935.02	950.50	958.25	970.73	942.46	967.08
919.03	927.4	931.97	940.06	931.98	934.57	935.04	935.02	950.5	958.25	970.73	942.46	967.08

ublic administration) (81) and public administration (91).

1997	1997	1997	1997	1997	1997	1997	1997	1997	1997	1997	1998	1998
2	3	4	5	6	7	8	9	10	11	12	1	2
662.16(T)	661.00(T)	661.84(T)	669.30(T)	660.14(T)	660.15(T)	660.78(T)	665.70(T)	663.30(T)	669.77(T)	666.89(T)	673.03(T)	675.61(T)
662.16	661.00	661.84	669.30	660.14	660.15	660.78	665.70	663.30	669.77	666.89	673.03	675.61
662.16	661	661.84	669.3	660.14	660.15	660.78	665.7	663.3	669.77	666.89	673.03	675.61

1997	1997	1997	1997	1997	1997	1997	1997	1997	1997	1997	1998	1998
2	3	4	5	6	7	8	9	10	11	12	1	2
969.07(T)	959.15(T)	993.29(T)	999.42(T)	998.34(T)	969.94(T)	974.01(T)	991.88(T)	1,025.73(	1,016.63(	989.92(T)	1,064.65(	1,011.82(
969.07	959.15	993.29	999.42	998.34	969.94	974.01	991.88	1,025.73	1,016.63	989.92	1,064.65	1,011.82
969.07	959.15	993.29	999.42	998.34	969.94	974.01	991.88	1,025.73	1,016.63	989.92	1,064.65	1,011.82

1998	1998	1998	1998	1998	1998	1998	1998	1998	1998	1999	1999	1999
3	4	5	6	7	8	9	10	11	12	1	2	3
672.84(T)	674.36(T)	669.97(T)	670.05(T)	667.01(T)	670.41(T)	670.32(T)	675.97(T)	674.08(T)	676.71(T)	675.36(T)	675.70(T)	677.45(T)
672.84	674.36	669.97	670.05	667.01	670.41	670.32	675.97	674.08	676.71	675.36	675.70	677.45
672.84	674.36	669.97	670.05	667.01	670.41	670.32	675.97	674.08	676.71	675.36	675.7	677.45

1998	1998	1998	1998	1998	1998	1998	1998	1998	1998	1999	1999	1999
3	4	5	6	7	8	9	10	11	12	1	2	3
1,007.16(	1,011.04(	1,013.18(	1,031.88(	1,041.62(	1,039.00(	1,039.92(	1,044.75(	1,044.54(	1,049.20(	1,043.23(	1,039.50(	1,042.05(
1,007.16	1,011.04	1,013.18	1,031.88	1,041.62	1,039.00	1,039.92	1,044.75	1,044.54	1,049.20	1,043.23	1,039.50	1,042.05
1,007.16	1,011.04	1,013.18	1,031.88	1,041.62	1,039.00	1,039.92	1,044.75	1,044.54	1,049.20	1,043.23	1,039.50	1,042.05

1999	1999	1999	1999	1999	1999	1999	1999	1999	2000	2000	2000	2000
4	5	6	7	8	9	10	11	12	1	2	3	4
679.60(T)	684.35(T)	684.20(T)	687.87(T)	686.56(T)	686.46(T)	687.02(T)	686.22(T)	691.02(T)	692.50(T)	694.79(T)	695.61(T)	697.48(T)
679.60	684.35	684.20	687.87	686.56	686.46	687.02	686.22	691.02	692.50	694.79	695.61	697.48
679.6	684.35	684.2	687.87	686.56	686.46	687.02	686.22	691.02	692.5	694.79	695.61	697.48

1999	1999	1999	1999	1999	1999	1999	1999	1999	2000	2000	2000	2000
4	5	6	7	8	9	10	11	12	1	2	3	4
1,062.64(	1,054.36(	1,023.22(	1,049.26(	1,053.32(	1,050.77(	1,057.80(	1,060.68(	1,064.49(	1,064.39(	1,069.17(	1,067.63(	1,065.73(
1,062.64	1,054.36	1,023.22	1,049.26	1,053.32	1,050.77	1,057.80	1,060.68	1,064.49	1,064.39	1,069.17	1,067.63	1,065.73
1,062.64	1,054.36	1,023.22	1,049.26	1,053.32	1,050.77	1,057.80	1,060.68	1,064.49	1,064.39	1,069.17	1,067.63	1,065.73

2000	2000	2000	2000	2000	2000	2000	2000
5	6	7	8	9	10	11	12
698.65(T)	699.54(T)	701.24(T)	703.40(T)	703.73(T)	702.90(T)	704.07(T)	705.23(T)
698.65	699.54	701.24	703.40	703.73	702.90	704.07	705.23
698.65	699.54	701.24	703.4	703.73	702.9	704.07	705.23

2000	2000	2000	2000	2000	2000	2000	2000
5	6	7	8	9	10	11	12
1,064.43(	1,064.89(	1,067.55(	1,067.93(	1,069.10(	1,071.52(	1,070.48(	1,072.96(T)
1,064.43	1,064.89	1,067.55	1,067.93	1,069.10	1,071.52	1,070.48	1,072.96
1,064.43	1,064.89	1,067.55	1,067.93	1,069.10	1,071.52	1,070.48	1,072.96

Employment Cost Index
Original Data Value

Series Id:	CIU2024400000000I
Series Title:	Wages and salaries for Private industry workers in Utilities, Index
Ownership:	Private industry workers
Component:	Wages and salaries
Occupation:	All workers
Industry:	Utilities
Subcategory:	All workers
Area:	United States (National)
Periodicity:	Index number
Years:	2001 to 2015
Source:	http://data.bls.gov/timeseries/CIU2024400000000I

Year	Qtr1	Qtr2	Qtr3	Qtr4	Annual	*Growth*
2001	87.0	88.1	88.3	89.1	**88.1**	
2002	89.8	91.4	91.8	92.2	**91.3**	*3.5%*
2003	93.0	93.6	94.0	94.5	**93.8**	*2.7%*
2004	95.4	96.6	97.1	97.4	**96.6**	*3.0%*
2005	98.4	99.2	99.5	100.0	**99.3**	*2.7%*
2006	100.8	102.1	103.0	103.5	**102.4**	*3.1%*
2007	104.3	105.5	106.1	106.8	**105.7**	*3.2%*
2008	108.0	109.3	109.3	109.6	**109.1**	*3.1%*
2009	111.0	112.0	112.2	113.3	**112.1**	*2.8%*
2010	113.9	114.7	115.4	115.6	**114.9**	*2.4%*
2011	116.9	118.1	118.5	118.8	**118.1**	*2.7%*
2012	119.6	121.3	121.3	121.7	**121.0**	*2.4%*
2013	123.0	124.2	124.9	125.2	**124.3**	*2.7%*
2014	126.6	127.6	128.3	128.3	**127.7**	*2.7%*
2015	129.9	130.8	131.4		**130.7**	
						2.9%

Table 1.1.9. Implicit Price Deflators for Gross Domestic P

[Index numbers, 2009=100]

Bureau of Economic Analysis

Last Revised on: April 30, 2014 - Next Release Date May 29, 2014

accessed on May 22, 2014 source: http://www.bea.gov/iTable/iTable.c

product	
2000	81.89
2001	83.77
2002	85.05
2003	86.75
2004	89.13
2005	91.99
2006	94.82
2007	97.34
2008	99.24
2009	100.00
2010	101.21
2011	103.20
2012	105.00
2013	106.59
2014	108.69

Product

:fm?ReqID=9&step=1#reqid=9&step=3&isuri=1&910=x&911=0&903=13&904=2000&905=2013&906=a

Board Staff Interrogatory #247

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

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 1

OEB staff would like to make an independent calculation of the productivity trend of OPG. A monetary approach would be used to calculate capital cost and the capital quantity index. Please provide the following information *for as many years as the company has data* to calculate productivity trends. It is quite useful to have the required capital cost data for a lengthy sample period even if the O&M expense data aren't available. If there are noteworthy discontinuities in the data, please explain them. Please indicate whether the Company is providing data only for prescribed generating stations or for all generating stations. The latter is satisfactory if it permits a longer sample period:

a) Value of gross additions to hydroelectric plant.

b) Gross value of hydroelectric plant in service and accumulated depreciation on hydroelectric plant.

c) The typical average service life by type of asset used by OPG to determine depreciation rates. These are not required for each year.

d) Total hydroelectric operation, maintenance, and administration (OM&A) expenses by account, itemized by major expenditure category where possible. Please provide any amounts paid for water for power such that it can be removed as it was for the LEI study.

e) Annual depreciation (amortization) charged for hydroelectric plant.

f) The amount of total hydroelectric OM&A related to compensation of company employees. Should this specific dollar figure be confidential or unavailable, please provide a typical percentage of the total (e.g. "about 60%" based on information over 10 years). Does this amount include the cost of pensions and current employee and other post-employment benefits? If so, approximately what percentage of the total is pension and current and post-employment benefits?

g) The weighted average cost of capital, itemized to the extent practicable.

h) The MWh generated by each unit operated by OPG.

i) Nameplate and operational capacity of each hydroelectric generating station operated by OPG.

j) Please identify which units are conventional and which are pumped storage

k) From previous work done for the OEB in the distribution sector, PEG is aware of the Statistical Yearbooks that Ontario Hydro used to produce annually. PEG believes that these documents also contained operational, capacity, production and financial statistics on generation and specifically for Ontario Hydro's electricity generating plants.

   i. Does OPG possess any summary data publications such as the previous Ontario Hydro Statistical Yearbooks, containing data for Ontario Hydro's generation assets, operations and production prior to the reorganization resulting from the *Energy Competition Act* of 1998?
   ii. For which years are these documents available?
   iii. If available, please provide the documents.

l) Please provide any data on the allocation of corporate costs to hydroelectric O&M (e.g., allocation of Total or Admin & General OM&A). Please describe the methodology by which Corporate A&G costs were allocated between regulated hydroelectric. Nuclear, other (including fossil) generation and, for the predecessor Ontario Hydro, transmission and distribution.

Response

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.

Parts a), b) and e)

Chart 1, below, is a continuity schedule for gross property, plant and equipment for OPG's currently regulated hydroelectric assets for the 2002-2015 period.

Chart 1
Continuity of Gross Property, Plant and Equipment - Regulated Hydroelectric ($M)

Line No.	Year	Opening Balance	In-Service Additions	Retirements, Transfers & Adjustments	Closing Balance
		(a)	(b)	(c)	(d)
1	2002	6,917.0	84.4	8.0	7,009.4
2	2003	7,009.4	26.9	21.0	7,057.3
3	2004	7,057.3	109.6	14.4	7,181.3
4	2005	7,181.3	49.7	15.1	7,246.1
5	2006	7,246.1	54.8	(0.8)	7,300.2
6	2007	7,300.2	81.2	(8.8)	7,372.7
7	2008	7,372.7	48.2	(8.8)	7,412.0
9	2009	7,412.0	82.5	(15.0)	7,479.6
9	2010	7,479.6	105.8	(7.5)	7,577.9
10	2011	7,577.9	134.3	(8.2)	7,704.0
11	2012	7,704.0	59.9	(13.7)	7,750.2
12	2013	7,750.2	1,559.1	(9.0)	9,300.3
13	2014	9,300.3	74.3	(85.6)	9,288.9
14	2015	9,288.9	71.2	(6.9)	9,353.2

Note: numbers may not add due to rounding.

Chart 2, below, is a continuity schedule for accumulated depreciation and amortization for OPG's currently regulated hydroelectric assets for the 2002-2015 period.

Chart 2
Continuity of Accumulated Depreciation and Amortization - Regulated Hydroelectric ($M)

Line No.	Year	Opening Balance	Depreciation and Amortization	Retirements, Transfers & Adjustments	Closing Balance
		(a)	(b)	(c)	(d)
1	2002	(305.2)	(107.9)	(2.5)	(415.7)
2	2003	(415.7)	(109.1)	(2.3)	(527.0)
3	2004	(527.0)	(111.6)	0.0	(638.6)
4	2005	(638.6)	(117.6)	(2.9)	(759.0)
5	2006	(759.0)	(112.1)	(1.5)	(872.7)
6	2007	(872.7)	(114.3)	3.3	(983.6)
7	2008	(983.6)	(113.5)	4.4	(1,092.7)
8	2009	(1,092.7)	(114.0)	5.0	(1,201.7)
9	2010	(1,201.7)	(115.3)	3.8	(1,313.2)
10	2011	(1,313.2)	(118.6)	3.2	(1,428.6)
11	2012	(1,428.6)	(121.3)	6.0	(1,544.0)
12	2013	(1,544.0)	(137.1)	4.9	(1,676.3)
13	2014*	(1,676.3)	(138.4)	8.9	(1,805.8)
14	2015	(1,805.8)	(138.2)	3.7	(1,940.4)

*Amount in col. (c) includes an adjustment to reduce the Niagara Tunnel Project in-service amount to the approved value per EB-2013-0321 Payment Amounts Order, App. A, Table 1a, Note 2.

Note: numbers may not add due to rounding.

Part c)

A list of asset classes and associated service lives for the regulated hydroelectric assets can be found at EB-2013-0321 Ex. F5-3-1, Schedule 1A. More detailed descriptions of the asset classes can be found at EB-2013-0321 Ex. L-6.12-1 Staff-157, Attachment 1.

The overall weighted average service for the regulated hydroelectric assets (excluding the Niagara Tunnel Project) is estimated to be between 80-85 years.

Parts d) and l)

Chart 3, below, presents the total operation, maintenance, and administration costs for the hydroelectric facilities by account. Chart 3 also includes Project OM&A Costs (a subset of Maintenance Costs), HTO Central Support Group Costs, and Corporate Allocated Costs (Corporate Support Services, Centrally Held Costs, Asset Service Fees).

Chart 3 reflects changes to OPG's hydroelectric operations over time, including the following:

1. Business reorganizations in 2006 and 2012.
2. The cost and production associated with approximately 30 MW of capacity was removed from the data starting in 2008-2009, when this capacity became contracted. Prior to that time, OPG did not separately track the cost of this generation.
3. The cost and production associated with approximately 485 MW of capacity was removed from the data set starting in 2011, when this capacity became contracted. Prior to that time, OPG did not separately track the cost of this generation.

Neither the costs provided in Chart 3 nor the costs provided to LEI include Gross Revenue Charges and Water Rentals.

Actual corporate costs allocations are available from 2005 onwards. Corporate cost allocations for 2004 were prepared by applying the 2005 allocation methodology to the 2004 data. The 2002-2003 allocations were estimated by extrapolation from the 2004 data.

OPG's corporate cost allocation methodology is described in the following references:

1. EB-2007-0905, Ex. F3-1-1 and Ex. F3-3-1
2. EB-2010-0008, Ex. F3-1-1, Ex. F3-2-1 and Ex. F4-4-1
3. EB-2013-0321, Ex. F3-1-1, Ex. F3-2-1 and Ex. F4-4-1

Chart 3

Hydroelectric Operations, Maintenance, and Administration Costs ($M) [iv]

Years	Operations Cost, $M	Maintenance Cost, $M	Administration Cost, $M	Project OM&A, $M	Total Plant Group Costs, $M	HTO Central Support Group Cost, $M	Corp Allocated Costs, $M	Total Costs, $M
	A	B	C	(i) D	A+B +C	(ii) (v) E	(ii), (iii) F	A+B+C+E+F
2002	13.7	85.9	18.3	24.3	117.9	26.1	56.8	200.9
2003	14.8	96.7	19.2	30.1	130.7	19.1	58.1	207.8
2004	15.4	96.3	20.5	26.1	132.2	11.2	59.7	203.1
2005	15.4	106.0	21.0	30.1	142.4	15.8	65.4	223.6
2006	16.9	115.1	24.6	34.3	156.6	20.1	84.9	261.6
2007	17.5	123.2	24.3	33.4	165.0	19.8	94.7	279.4
2008	18.1	142.6	25.1	41.6	185.7	22.3	96.3	304.3
2009	20.4	133.9	30.8	33.5	185.1	28.5	85.2	298.8
2010	17.8	142.5	24.4	45.1	184.7	23.1	90.6	298.4
2011	17.6	129.0	28.0	28.4	174.6	24.4	93.5	292.5
2012	17.4	135.9	24.9	34.1	178.1	16.5	110.1	304.8
2013	19.2	138.7	24.7	34.6	182.6	17.2	111.1	310.9
2014	21.0	145.2	21.8	37.7	188.0	20.7	126.0	334.7
2015	21.2	161.7	27.3	52.3	210.2	32.2	140.0	382.4

Notes:
(i) Project OM&A is provided for information only. It is a subset of Maintenance Costs (Column B).
(ii) Classification between Operations, Maintenance, and Administration is not available for HTO Central Support Group and Corporate Allocated Costs.
(iii) Corporate Allocated Costs includes Corporate Support Services, Centrally Held Costs, and Asset Service Fees. IESO non-energy charges are excluded.
(iv) Includes data for currently regulated stations, as well as certain other stations for periods prior to becoming contracted or divested by OPG.
First Nations provision funding amounts are excluded from Plant Group OM&A costs.

Numbers may not add due to rounding.

Part f)

Approximately 60% of regulated hydroelectric OM&A ("Total Costs" shown in Chart 3) is related to the compensation of company employees. This includes the current service cost of pensions and other post employment benefits, and current employee benefits. Approximately 23% of the compensation costs (or 14% of the total OM&A costs) is associated with these benefits. In addition, total costs include the regulated hydroelectric portion of non-current service components of pension and OPEB costs held centrally.

Part g)

Chart 4, below, provides the itemized weighted average cost of capital as approved by the OEB.

Chart 4
Weighted Average Cost of Capital, based on OEB Approved Values

Line No.		2008	2009	2010	2011	2012	2013	2014	2015
1	Debt Ratio (%)[1]	53%	53%	N/A	53%	53%	N/A	55%	55%
2	Debt Cost ($M)[1]	5.76%	5.89%	N/A	5.44%	5.50%	N/A	4.81%	4.85%
3	Equity Ratio (%)[1]	47%	47%	N/A	47%	47%	N/A	45%	45%
4	ROE (%)[1]	8.65%	8.65%	N/A	9.43%	9.55%	N/A	9.36%	9.30%
5	Tax Rate (%)[2]	31.50%	31.00%	N/A	26.50%	25.00%	N/A	25.00%	25.00%
6	**WACC**	**8.99%**	**9.01%**	**N/A**	**8.91%**	**8.90%**	**N/A**	**8.26%**	**8.25%**

Notes
1 2008-2009 from EB-2007-0905 Payment Amount Order Appendix A, Tables 4b, 5b respectively
2011-2012 from EB-2010-0008 Payment Amount Order Appendix A, Tables 4b, 5b respectively
2014-2015 from EB-2013-0321 Payment Amount Order Appendix A, Tables 5b, 6b respectively
2 2008-2009 from EB-2007-0905 Ex. F3-2-1 Table 7, line 32
2011-2012 from EB-2010-0008 Payment Amount Order Appendix A, Tables 6, 7 respectively
2014-2015 from EB-2013-0321 Payment Amount Order Appendix A, Tables 7, 8 respectively

Part h)

Chart 5, below, presents total generation in MWh, including electricity generated in segmented mode of operations. Chart 5 presents the total generation data in MWh, with and without Pump Generating Station (PGS) operation. Generation including PGS is lower due to the reduction in net production that results from the energy costs of pumped storage generation.

OPG does not have consistent generation data for at the unit level, as the energy meters for many stations are installed at station level or IESO/Hydro One Injection points.

Chart 5
Total Hydroelectric Generation (TWh)

Years	Generation	Generation with PGS
2002	33.9	33.8
2003	33.1	33.0
2004	35.3	35.2
2005	33.4	33.2
2006	34.2	34.0
2007	32.9	32.7
2008	37.4	37.3
2009	36.3	36.2
2010	30.5	30.4
2011	31.3	31.2
2012	29.5	29.4
2013	31.4	31.3
2014	31.5	31.4
2015	30.3	30.2

Part i)

The individual units in many stations have undergone several upgrades since the original in-service dates. As a result, the nameplate capacity does not accurately reflect the capacity of the facilities. OPG defines operational capacity as the Maximum Continuous Rating (MCR) in MW for each operating hydroelectric unit, as registered with the IESO.

The current MCR information for OPG's regulated hydroelectric facilities is provided in Ex. A1-4-2, p. 2, Chart 1. The MCR in MW for all hydroelectric stations operated by OPG from 2002 to 2015 is provided in Chart 6, below. Chart 6 is net of any divested, decommissioned or contracted stations from the date of divesture, decommissioning or contract execution.

Chart 6
Maximum Continuous Rating -
Hydroelectric Facilities (MW)

Years	Generation Capacity / MCR
2002	6899
2003	6926
2004	6958
2005	6924
2006	6971
2007	6971
2008	6999
2009	6905
2010	6906
2011	6422
2012	6422
2013	6433
2014	6433
2015	6428

Part j)

OPG only operates one pump generating station, which is listed at Ex. A1-4-2, p. 2, Chart 1: Sir Adam Beck PGS under Niagara Operations. All other regulated hydroelectric generating stations are conventional hydroelectric generating stations.

Part k)

The requested materials all date prior to 2002. For the reasons stated on page 2 of this response, OPG declines to provide these materials.

Board Staff Interrogatory #248

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

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 2

The Navigant Study filed was finalized on August 17, 2015 and contains 2013 data. This study was not updated for the filing of OPG's application on May 27, 2016.

a) Please explain why the study was not updated subsequent to the August 17, 2015 study. Would the 2014 data have been available later in 2015 or by early 2016 to provide more current data?
b) Please provide OPG's views as to why this benchmarking study based on 2013 data should be considered reasonable and representative of OPG's performance on the prescribed hydroelectric generating assets for the prospective five-year term of 2017 to 2021 inclusive.

Response

a) As discussed in Ex. L-11.1-1 Staff-230 part a), OPG's hydroelectric benchmarking results have been stable over time, which is consistent with a mature industry such as hydroelectric generation. As a result, OPG did not conduct a study based on a single year of more current information (2014 vs. 2013). OPG confirms that 2014 data would have been available later in 2015 or by early 2016.

b) As noted in part a) and in Ex. L-11.1-1 Staff-230, part b) i), the stability of OPG's hydroelectric benchmarking results over time suggests that 2013 data is representative of the performance of OPG's prescribed hydroelectric generating assets for the 2017 to 2021 period.

Board Staff Interrogatory #249

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

Interrogatory

Reference:
Ref: Exh A1-3-2-Attachment 2

Footnote 1 on page 3 states that the Navigant benchmarking is with respect to one year performance, for 2013: "Quartiles are determined by comparing OPG's 2013 performance to the peer group values in each functional area."

In general, hydroelectric generation facilities are long-lived assets. They are also costly to build or replace, but once in service, can often have relatively long periods between major capital investments.

a) Since the benchmarking only looks at one year's worth of performance data for OPG and the comparator group, how reliable are the results provided on pages 12-21 as representative of where OPG ranks against similar utilities on a long-run basis?

b) The Navigant results typically interpret "lowest cost" as being first quartile, while highest cost as being in the fourth quartile. Is this actually a valid way of interpreting the results in all of the dimensions, particularly with respect to capital investments?
   i. Is having lower investment (i.e. being in the first quartile) actually indicative of "superior" performance? For example, could sustained under-investment be indicative of "harvesting" of assets, which will lead to significant investment cost at some point in the future to refurbish or replace the asset?
   ii. Please provide Navigant's views on whether, since only one year's worth of data is examined for all firms in the peer group, the stage in the life cycle of assets could influence which quartile is shown in? For example, with respect to lower capital investments, could the results be materially influenced by one firm having completed a major investment a few years prior, thus obviating the need for major investments for a period of time, relative to most other firms?

Response

a) The results are very reliable. The peer groups (i.e. segments) and metrics used for comparison are based on a statistical analysis which makes the data within each segment most comparable and clustered around the median value. Each segment has several dozen data points which is well above the minimum needed for a statistically significant comparison. In addition, the same tasks are generally performed each year (except for the Investment function) which makes a single year of data a good indication of normal operations, particularly after normalizing costs by the primary cost driver for each function (e.g. MWh).

b)

i) For the investment function, it is not necessarily desirable to be in the first quartile. Sustained under-investment (i.e., 1st quartile in Investment expenditures) may be indicative of "harvesting" of assets. Sustained over-investment (i.e., 4th quartile) may be inefficient or wasteful. Costs in the 2nd or 3rd quartile are in a safer, middle ground, although a company's specific circumstances may justify spending that results in any of the quartiles.

ii) Based on a statistical analysis, only the investment function is significantly affected by the age of the asset, which is the reason that investment segments are defined by the average age of the station group. The effect of major investments that are made in any particular year is minimized due to the reporting of investment costs on a five-year annual average basis. Also, the median value for a segment will not be significantly affected if a plant in the comparator group has an unusually high investment.

Board Staff Interrogatory #250

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

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 2

Footnote 4 on page 3 of the Navigant study states that dollars shown on pages 3, 13-20 are in $USD, while all other pages are expressed in $CDN.

Please provide the exchange rate or Purchase Power Parity (PPP) conversion factor used to convert $CDN to $USD in this study.

Response

The PPP conversion factor of 0.8011 USD/CAD was used for this study.

Board Staff Interrogatory #251

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

Interrogatory

Reference:
Ref: Exh A1-3-2 Attachment 2

Regarding pages 4 and 5, OPG is ranked in the worst quartile with respect to Public Affairs & Regulatory (PA&R) costs. Footnote 1 on page 5 states:

> The largest components of OPG's regulated Hydroelectric PA&R are the Gross Revenue Charge In lieu of Property Tax ($204M) and the Gross Revenue Charge for water rental fees ($121M). Neither of these charges are controllable by OPG and both are prescribed by regulation.

Is it possible to break out OPG's PA&R costs to isolate these "non-controllable" costs, and to do similar break outs for other firms in the comparator group, so that some form of "apples-to-apples" comparison of such costs could be made? If an analysis is possible, why was it not done? If it is not possible, please explain the reasons for this.

Response

Navigant considers the following three PA&R categories to be non-controllable:

- FERC and regulatory fees
- Taxes
- Water usage fees

An "apples-to-apples" comparison of OPG's 2014 controllable and non-controllable PA&R costs to the median and quartiles of the comparator group is shown in Chart 1:

Chart 1

(Thousands of USD/MW)	Total PA&R	Controllable PA&R	Uncontrollable PA&R
Weighted Average OPG Regulated Hydro	40	0.3	39.7
Quartile Thresholds			
Minimum	0	0	0
1st Quartile	3	0.0	0.0
Median	14	0.5	0.0
3rd Quartile	27	2.0	1.6
Peer Group Maximum	153	148	129
Peer Group Average	20	9	11

Please note that these figures are in 2013$ using a Purchasing Power Parity conversion rate of 0.8011 USD/CAD for the OPG station groups. The first column of Chart 1 is the same as shown on p. 19 in Ex. A1-3-2, Attachment 2.

This analysis was not done previously because, except for $1M ($326M from Ex. A1-3-2, Attachment 2, p. 5 less $325M, which is the sum of the two dollar amounts shown in footnote 1 on p. 6), all of OPG's PA&R cost is non-controllable.

Board Staff Interrogatory #252

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

Interrogatory

Reference:
Ref: Exh A1-3-2-Attachment 2

Regarding page 18 on PA&R costs, the study indicates that the range of costs within the total group is from $0(000/MW) to $153(000/MW), with costs expressed in $USD.

a) Please provide a detailed description of what constitutes PA&R costs for:
   i. OPG; and
   ii. Other hydroelectric generating utilities in the comparator group.

b) Please explain why there appears to be such a wide cost range per MW. What characteristics of the operating environments, jurisdictions that they operate in, or age, technology or water source are the major reasons impacting on the variation in these costs?

Response

a) Public Affairs and Regulatory ("PA&R") costs include all activities associated with managing regulatory, environmental, and community issues as well as those activities that are required to maintain the franchise to use the water. The activities that constitute PA&R costs are:
   - Operation and maintenance of visitor centers, parks and recreational facilities
   - Fish and wildlife operations
   - Fish and wildlife studies
   - Relicensing
   - Real estate management, including leases and other community relations (for PA&R assets)
   - Environmental compliance
   - FERC and regulatory fees
   - Taxes
   - Water usage fees
   - Other PA&R

In 2013, OPG had PA&R costs in the following activities:
- Operation and maintenance of visitor centers, parks and recreational facilities

- Fish and wildlife operations
- Fish and wildlife studies
- FERC and regulatory fees
- Taxes
- Water usage fees
- Other PA&R

b) PA&R costs that are incurred by each station group are largely driven by the requirements of the jurisdictions in which they operate, their ownership structure, and the impact that the hydro operations have on the environment. For example, station groups that are owned by the U.S. government are generally not subject to taxes or FERC/regulatory fees. In contrast, water usage fees are usually the largest category for Canadian station groups. Visitor centers and parks are generally associated with large reservoirs. Fish and wildlife issues are a function of the number and type of endangered or threatened species that are affected by dams and other hydro operations.

CME Interrogatory #2

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

Interrogatory

Reference:
Ref: Exhibit A1, Tab 3, Schedule 1, page 5 of 12

OPG proposes a comprehensive IR framework for the company's hydroelectric assets based on a price cap index that is "closely modelled" on the 4th Generation Incentive Rate-setting Method ("4GIRM") in the Renewed Regulatory Framework for Electricity Distributors ("RRFE"). CME would like to better understand all of the differences between OPG's proposed IR framework and the existing 4GIRM. Please identify all elements of the comprehensive IR framework proposed by OPG that are different from the 4GIRM with an explanation as to why OPG has elected to propose different framework elements.

Response

Chart 1 of Ex. A1-3-2 details OPG's proposal against the 4GIRM ratemaking elements. The rationale for any modifications from 4GIRM is provided on page 8, lines 10-25.

CME Interrogatory #4

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

Issue Number: 11.3
Issue: Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?

Interrogatory

Reference:
Ref: Exhibit A1, Tab 3, Schedule 2, page 4 of 54

OPG states that following consultation with stakeholders, it made a number of changes to the planned application. CME wishes to better understand the drivers for the changes, as well as to better understand whether any of the changes were the result of input received from stakeholders at the information sessions. In this regard, please provide the following information :

(a) For each of the six (6) changes set out at Exhibit A1, Tab 3, Schedule 2, pages 4 to 5 of 54, please provide a detailed explanation as to why the changes were made;

(b) For each of those six (6) changes, please confirm whether the proposed changes were as a result of information or feedback received by stakeholders at the information sessions. If they were, please provide a detailed explanation of the stakeholder feedback which resulted in the changes; and

(c) Please provide all internal memoranda, PowerPoints, emails or other written documents relating to the six (6) changes to the planned application which were presented either to senior management, or by senior management to OPG's Board of Directors.

Response

a) and b)

OPG values feedback from the OEB Staff and other participants during the stakeholder consultation process. OPG expanded its stakeholder consultation in support of this application relative to past applications. For further context, OPG refers to the Stakeholder Consultation

Notes that were posted publicly on OPG's website following the stakeholder consultations, available at: http://www.opg.com/about/regulatory-affairs/stakeholder-information/Pages/payment-amounts.aspx.

Following the consultations, OPG continued to make changes to its developing application. This is part of the normal course of preparing an application; an application will evolve as facts are determined and assumptions are challenged. The application that was ultimately filed reflects OPG's position in this application, supported by the filed evidence.

For the reasons discussed in part c), the information requested in parts a) and b) is not relevant to the determination of the issues before the OEB in this proceeding. However, for context, below OPG has provided a summary of the feedback that OPG received from stakeholders on the changes identified at Ex. A1-3-2, pages 4 and 5.

Change 1: Eliminating the proposal to establish hydro base rates using a 2017 forecast test year cost of service review.

Summary: The February 8, 2015 Stakeholder Consultation Session Notes reflect OPG's response to the question: "Why is OPG rebasing?" on page 9. As noted, OPG was advised that rebasing in 2017 after setting cost of service based rates on a forward test period basis for 2014 and 2015 is not consistent with the RRFE, and not consistent with the EB-2012-0340 *Report of the Board* on incentive rate-making for OPG. Please also refer to Ex. L-11.1-13 PWU-18, part g).

Change 2: Eliminating the proposed symmetrical earnings sharing mechanism (ESM) for nuclear and hydroelectric businesses.

Summary: As noted at the January 22, 2015 *Initial Hydroelectric Incentive Regulation Plan Proposal*, at page 3; the February 18, 2015 *Initial Hydroelectric Incentive Regulation Plan Proposal (Update)* at page 3; the January 22, 2015 *Initial Nuclear Multi-Year Cost-of-Service Regulation Plan Proposal* at page 3; and the *Initial Nuclear Multi-Year Cost-of-Service Regulation Plan Proposal (Update)* at page 3, OPG proposed a symmetric ESM of actual return after tax with a +/- 100 basis point (hydroelectric) or +/- 200 basis point (nuclear) dead band.

Stakeholders expressed concern with a symmetrical ESM (Stakeholder Information Session Notes, January 22, 2015 at page 7). The February 18, 2015 Stakeholder Consultation Session Notes at page 6 provide OPG's rationale and research relating to ESMs and the proposal for a symmetric earnings sharing. Stakeholder questions and comments on the ESM are provided on page 6 and 7.

Change 3: Eliminating the planned cost of Capital Variance Account proposed to record differences in hydro return on equity during the IR term.

Summary: OPG introduced the account in its February 8, 2016 presentation *Regulatory Methodology – Hydroelectric* at page 5. As noted at page 9 of the February 8, 2016 Stakeholder Consultation Session notes, a stakeholder asked, **"**Can you clarify the I-factor calculation, as there appears to be some aspect of cost of capital incorporated?" Following the February 8, 2016 presentation, OEB Staff provided OPG with a reference to the OEB's findings in the EB-2006-0088 *Report of the Board on 2nd Generation IRM*, in which the OEB addresses the issue of changes in return on equity and debt during an IRM term at pages 29 and 30.

Change 4: Modifying the hydroelectric x-factor, increasing the annual productivity adjustment from -1% (as indentified by the independent Total Factor Productivity study) to 0%, based on OEB policy in the electric distribution sector.

Summary: OPG proposed to apply the result of the TFP study as reflected in its January 22, 2015 *Initial Hydroelectric Incentive Regulation Plan Proposal*, at page 4 and its February 18, 2015 *Initial Hydroelectric Incentive Regulation Plan Proposal (Update)* at page 4.

Page 11 of the February 8, 2016 Stakeholder Consultation Session Notes include the following question: "In the Board's study on distribution, the productivity factor was negative, but it was reflected at 0. What is the rationale behind OPG's proposal to maintain a negative value?" OPG revised its proposal as discussed in L-11.1-13 PWU-18, part b) and c).

Change 5: Expanding the application of the nuclear stretch factor applied to include corporate support costs.

Summary: Page 6 of the February 8, 2016 *Regulatory Methodology - Nuclear* presentation states that OPG's stretch factor was proposed to be applied only to nuclear base OM&A costs as they are considered more amenable to productivity gains.

Page 10 of the February 8, 2016 Stakeholder Consultation session Notes include the question: "Why is the stretch factor not applied to the nuclear allocated common costs?" OPG responded by explaining that its nuclear incentive rate-setting proposal targeted the bucket of nuclear costs that are most susceptible to productivity enhancements. OPG also stated that it would consider this suggested change.

Change 6: Expanding the proposed performance reporting metrics to include all of the key hydroelectric performance areas filed in OPG's prior payment amounts application (EB-2013-0321, Ex F1-1-1, Appendix B) and all measures used in annual nuclear benchmarking.

Summary: The February 18, 2015 *Initial OPG Performance Reporting-Service Quality Metrics Proposal* presentation outlined the three metrics OPG proposed to report. Pages 9 and 10 of the February 18, 2015 Stakeholder Consultation Session Notes indicate a number of areas where stakeholders believed additional information was warranted, including information on the Darlington Refurbishment Project, economic efficiency and financial performance.

c) OPG declines to provide the requested documents on the basis of relevance and litigation privilege. The same type of material was requested in EB-2010-0008. The OEB Panel in that proceeding decided that the requested material was not relevant, stating:

> The Board has decided not to order production of the materials sought in the CME and CCC motions. In the Board's view, these materials are not relevant to the determination of the issues before the Board in this proceeding. The Board will make its decision on the application and supporting materials filed by the applicant and the evidence of intervenors, all of which is subject to cross-examination.
>
> This evidence goes to the financial and operational impacts of the application and of the alternatives which have been considered.
>
> The material which has been sought through the motions includes the communication between OPG's management and its board of directors, seeking approval to file the application, delegated authority to deal with the proceeding, and the analysis of "likely prospects for success." This material does not form part of the application and does not enhance nor detract from the merits of the application. The evidence is that no changes to the business plans and budgets which underpin the application were sought or made as a result of the board of directors' meeting. These plans and budgets have been filed.
>
> Intervenors can explore, through the witness, whether alternatives to the application should have been considered, and the impacts of OPG's choices. None of this relies on what management presented to the board of directors.
>
> Having found that the materials are not relevant and need not be produced, the question of privilege will not be addressed.
>
> That concludes the Board's decision, and subject to any questions, we can continue with the cross-examination. EB-2010-0008, Tr. Vol. 1, pages 113-114.

CME Interrogatory #6

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

Interrogatory

Reference:
Ref: Exhibit A1, Tab 3, Schedule 2, pages 22 and 23 of 54

OPG has set the proposed hydroelectric stretch factor based on the company's performance on Partial Function Cost. While the Partial Function Cost is effectively at the median for the hydroelectric generation industry, the Total Function Cost is not. In this regard, the median for Total Function Cost is 318 while OPG's regulated hydroelectric Total Function Cost is 527. Please explain why OPG did not propose a hydroelectric stretch factor based on the company's performance on the Total Function Cost rather than the Partial Function Cost.

Furthermore, had OPG set the proposed hydroelectric stretch factor based on the company's performance on Total Function Cost instead of Partial Function Cost, what would the resulting stretch factor have been?

Response

Please see Ex. L-11.1-1 Staff 229 part a.

OPG's Total Function Cost of $527M is above that median range, but below the third quartile reference cost of $625M, indicating a stretch factor of 0.45.

CCC Interrogatory #42

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

Interrogatory

Reference:
Reference: Ex. A1/T3/S2/p. 4

Would OPG accept some form of an earnings sharing mechanism (ESM) as part of its hydroelectric rate plan in order to share earnings above the allowed return with its customers? If not, why not? If so, what form of an ESM would be acceptable to OPG?

Response

Please see L-1.2-5 CCC-6.

CCC Interrogatory #43

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

Interrogatory

Reference:
Reference: Ex. A1/T3/S2/p. 4

Please explain why a productivity factor of 0 is appropriate for OPG. Please recast the revenue requirement for each of the test years assuming a stretch factor of .6%.

Response

The rationale for proposing a 0% productivity factor is provided in response to Ex. L-11.1-13 PWU-18.

As this question references the hydroelectric facilities rate-setting proposal, OPG responds in relation to the hydroelectric stretch factor. The stretch factor for hydroelectric operations is used in the calculation of the annual escalation of payment amounts, not revenue requirement. Therefore OPG has provided the forecast revenue under an increased stretch factor.

The illustrative revenues in the application are based on a 1.5% annual price escalation based on a 0.3% stretch factor. Using a 0.6% stretch factor, the annual escalation is 1.2%. The illustrative revenues at a 1.2% annual increase are provided in below:

Hydroelectric Rate using a 0.6% Stretch Factor

	2017	2018	2019	2020	2021
Hydroelectric IRM Rate ($/MWh)	$41.58	$42.08	$42.59	$43.10	$43.62
Forecast Hydroelectric Production (TWh)	30.2	30.2	30.2	30.2	30.2
Hydroelectric Revenue ($M)	$1,257	$1,272	$1,287	$1,303	$1,318

CCC Interrogatory #44

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

Interrogatory

Reference:
Reference: Ex. A1/T3/S2/Attachment 1

London Economics International LLC (LEI) undertook a study for OPG regard Total Factor Productivity:

a. Was the LEI study subject to an RFP process? In not, why not? If so, please provide the RFP and the Terms of Reference for the work; and

b. What is the total cost of the study and how are those costs recovered?

Response

a) LEI was selected to provide through an RFP process to provide advice and assistance on potential incentive regulation mechanisms which may be suitable for setting payment amounts for OPG's regulated facilities. The LEI study prepared to assist OPG in considering incentive regulation mechanisms pursuant to that RFP.

The specifications of the RFP, which include the background, scope of work and schedule for the requested work, is attached as Attachment 1.

b) The combined cost of the 2002-2012 TFP study and the updated study including 2013 and 2014 data was approximately $0.3M. The forecast costs of work to provide advice and assistance on incentive regulation are included in the forecast Regulatory Affairs budget reflected in the EB-2013-0321 payment amounts. The requirement to perform a TFP study was known and included as part of forecast costs for LEI's work.

POTENTIAL TO USE INCENTIVE REGULATION METHODS TO SET THE PAYMENT AMOUNTS FOR OPG'S PRESCRIBED FACILITIES

SPECIFICATIONS

1. INTRODUCTION

OPG wishes to engage a consultant to provide advice and assistance on potential incentive regulation mechanisms which may be suitable for setting payment amounts for OPG's prescribed facilities.

2. BACKGROUND

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG's focus is on the efficient production and sale of electricity from its generating assets, while operating in a safe, open and environmentally responsible manner. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the "Province").

As at March 31, 2011, OPG's electricity generating portfolio had an in-service capacity of more than 19,000 megawatts ("MW"). OPG's electricity generating portfolio consists of three nuclear generating stations, five thermal generating stations, 65 hydroelectric generating stations, of which four are being redeveloped, and two wind power turbines. In addition, OPG and TransCanada Energy Ltd. co-own the Portlands Energy Centre gas-fired combined cycle generating station. OPG, ATCO Power Canada Ltd., and ATCO Resources Ltd. co-own the Brighton Beach gas-fired combined cycle generating station. OPG also owns two other nuclear generating stations, which are leased on a long-term basis to Bruce Power L.P. ("Bruce Power").

Under the *Ontario Energy Board Act*, some of OPG's facilities (collectively the "Prescribed Facilities") are subject to rate regulation by the Ontario Energy Board ("OEB"). These are the Sir Adam Beck 1, Sir Adam Beck 2 and Sir Adam Beck Pump Generating Station, DeCew Falls 1 and DeCew Falls 2, and R.H. Saunders hydroelectric facilities, and Pickering A, Pickering B and Darlington nuclear facilities.

Section 78.1(1) of the Ontario Energy Board Act establishes the OEB's authority to set payment amounts for the prescribed hydroelectric and nuclear generation facilities of OPG. Ontario Regulation 53/05, *Payments Under Section 78.1 of the Act*, provides that the OEB may establish the form, methodology, assumptions and calculations used in making an order that sets the payment amounts.

In 2006, the OEB issued a report (EB-2006-0064) entitled, *A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc*. The report indicated that payment amounts would be set by cost of service regulation and that an incentive regulation formula would be implemented when the Board was satisfied that the base payment amounts would provide a robust starting point for that formula.

The OEB issued its EB-2010-0008 Decision with Reasons on March 10, 2011 setting payment amounts for prescribed facilities for 2011 and 2012. The OEB concluded that incentive regulation beginning in 2015 should be considered, and that it will commence work in 2011 to lay out the scope of the required IRM and productivity studies to be filed by OPG. This review may include options and preferences on the general type(s) of incentive regulation mechanisms which may be suitable for setting payment amounts for OPG's regulated facilities. The OEB stated that this preliminary process will allow for input from OPG and all other interested stakeholders and that the outcome of this review is expected to be available no later than the first quarter of 2012.

3. SCOPE OF WORK AND SCHEDULE

OPG wishes to retain a consultant to provide advice and assistance on potential incentive regulation mechanisms which may be suitable for setting payment amounts for OPG's regulated facilities.

The assignment is to identify, review and provide an analysis of potential methods of setting payment amounts including cost of service, incentive regulation, and other methods.

The assignment may include participation in a regulatory proceeding and/or a consultation process as an expert witness; the work may include giving presentations, the preparation of evidence, responding to interrogatories, participating in technical conferences or other public meetings, oral testimony, and assistance with argument.

The work is expected to commence in August, 2011 and continue until the conclusion of the regulatory proceeding dealing with alternative methods of setting payment amounts, expected to be in 2013 or 2014.

CCC Interrogatory #45

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

Interrogatory

Reference:
Reference: Ex. A/T3/S2/Attachment 2

Navigant Consulting Inc. (Navigant) provided a benchmarking study:

a. Was the Navigant study subject to an RFP process? If not, why not? If so please provide the RFP and the Terms of Reference for the work; and

b. What was the total cost of the study and how are those costs recovered?

Response

a) Yes. Please see attachment 1.

b) The total cost of the study was $46,335. The amounts for studies conducted to support regulatory activities are included in OPG's Regulatory Affairs budget forecast as approved by the OEB.

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SCOPE OF WORK **(SOW)**

Vendor Name:		**Reference:**	Secondary Bid process as per RFP BG2012-005 RAD Consulting Services Program
Issue Date:	January 20, 2015	**Required/Start Date:**	February 05, 2015
[1] **Response Due Date:**	February 02, 2015	**Complete Date:**	April 30, 2015
SOW #	2015-DB-002	**Category/ Subcategory:**	Cat 3 - Technical Studies

Request Pricing Type:
T&M ☐ Fixed ☐ Combination ☒

Requester:	David Barr

Requirements
See attached document "Benchmarking OPG Hydroelectric Business Costs"

Criteria

Technical Criteria			
Item	Description	Weighting	Score[2]
1	Experience benchmarking generation utilities (20%) and experience in business process design and performance monitoring for large generating utilities (20%).	35%	
2	Qualifications of experts engaged in the assignment (15%) and quality of workplan (10%) .	25%	
3	Familiarity with hydroelectric generation business in North America (5%) and an understanding Ontario's electricity market, OPG operations and regulatory proceedings (5%).	10%	
4	Benchmarking database access and/or plan to source data	10%	

[1] Responses must be received by 3pm EST via email to OPG Supply Chain
[2] Scores are given from 1-10, 10 being highest

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	required for benchmarking.		
	Sub-Total		
Pricing Criteria			
Item	Description	Weighting	Score
1	Cost	20%	
	Total	100%	

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Vendor Submission Information

Proposed Resource (T&M[3])						
Item	Name	Role	Title	Available Date	Cost	[4]Duration Hrs/Days
1					$	
2					$	
3					$	
4					$	
5					$	
6					$	

Proposed Resource (Fixed[5])[6]						
Item	Name	Role	Title	Available Date	Cost	Duration Hrs/Days
1					$	
2					$	
3					$	
4					$	
5					$	
6					$	
				Fixed Total	$	

Additional Information

[3] If quoting T&M cost, fill in all the information in this table. The hourly rates should be the same as per the executed Contract Standard for these services.
[4] Indicate if Hours = h or Days = d (e.g. 300 Hours – 300h, 10 Days = 10d
[5] If quoting Fixed cost, fill in all the information in this table
[6] If quoting Combination, fill in all the information in this table for the Fixed cost. For the hourly rates, fill in the T&M table where rates must be the same or lower than the rates in the executed Contract Standard for these services.

Scope of Work

Benchmarking Analysis of OPG's Hydroelectric Business Costs

Objective:

To perform an independent benchmarking analysis of OPG's hydroelectric business. This study is in response to the Ontario Energy Board's direction to OPG in its EB-2013-0321 Decision.

Requirements:

Requirement 1: Benchmarking Analysis Report

The successful proponent must compile relevant information on OPG's hydroelectric business operations and costs and prepare a report that compares OPG's performance with relevant industry peers ("Benchmarking Analysis").

At a minimum, the Benchmarking Analysis will involve the following activities:

a) Select the appropriate peer group(s) against which OPG's hydroelectric performance should be benchmarked. As part of this activity, OPG expects the consultant to establish appropriate selection criteria for inclusion in the peer group(s).

b) Select the type of hydroelectric operations and costs to be benchmarked. If there are hydroelectric operations or costs unique to OPG that cannot be included in the Benchmarking Analysis, the reasons for their exclusion must be documented.

c) Select appropriate financial and non-financial benchmark metrics to assess OPG's performance relative to industry performance.

d) Carry out the analysis using data not older than 2013.

e) Present the results of the analysis in a manner that facilitates transparent and meaningful comparison to top performing companies within the appropriate peer group(s).

f) Recommend improvement areas for OPG. These recommendations should consider industry best practices as well as the reasonableness and cost-effectiveness of addressing any identified gaps.

g) Prepare a final report that includes description of the methodology, results of the analysis and recommendations for priority improvement areas.

January 19, 2015

Initial draft of the Benchmarking Analysis should be submitted to OPG by April 15, 2015 for OPG's review. Final Benchmarking Analysis to be delivered by April 30, 2015.

Subject to non-disclosure agreements, OPG can provide the successful candidate with access to various sources of benchmarking data.

Requirement 1 will be completed on a fixed price basis.

Requirement 2: Potential to Support Evidence in OPG's Next Payment Amounts Application(s)

The successful proponent must be prepared to participate in OPG's next hydroelectric and nuclear payment amounts applications including, but not limited to, the following activities: preparing evidence, responding to interrogatories, providing oral testimony, responding to undertakings and supporting the preparation of argument.

Requirement 2 will be carried out on a time and materials basis.

All activities will be performed on an as required basis at OPG's request. For each work package, OPG will provide the consultant with specific instructions and the consultant will then provide OPG with a forecast level of effort to complete the work at agreed upon hourly rates. OPG will then approve the consultant's forecast in advance of the work being undertaken.

OPG expects to file its next payments amounts application with the OEB in Q2-Q3 of 2015.

Background:

In OPG's most recent payment amounts proceeding (EB-2013-0321), OPG presented results of its hydroelectric benchmarking initiatives used to assess station performance and to identify best practices across three metrics: reliability, costs and safety performance. See Exhibit F-1-1-1 for additional details.

In the EB-2013-0321 Decision (pp. 17-18), the OEB directed OPG to undertake a fully independent benchmarking study of its hydroelectric operations as soon as possible.

Request for Quote:

For each requirement identified above, indicate who will be providing the work for that task and their billing rate. Indicate any non-labour costs separately, highlighting the purpose of these expenses.

January 19, 2015

CCC Interrogatory #46

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

Interrogatory

Reference:
Reference: Ex. A1/T3/S2/p. 22

It is OPG's position that, consistent with the 4GIRM Report it would be able to request Incremental Capital Module (ICM) or Advanced Capital Module (ACM) for qualifying hydroelectric capital projects. Does OPG expect that it will be filing for an ICM or ACM during the test period? If so, what are the estimated amounts in each year of the rate plan? Under what circumstances would it apply for an ACM or ICM?

Response

Please refer to Ex. L-11.1 Staff-228.

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

CCC Interrogatory #47

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

Interrogatory

Reference:
Reference: Ex. A1/T3/S2/p. 22

OPG is proposing that the OEB's policy on unforeseen events would apply during the term of this application (Z-factor) and that the materiality threshold of $10 million would be applied. How was the $10 million derived? Does this represent a cost amount or a revenue requirement amount?

Response

OPG derived the $10M materiality threshold for the Z-factor included as part of its Hydroelectric IRM proposal based on the materiality threshold of $10M that OPG has applied in prior regulatory proceedings to determine whether to update evidence.

The threshold is based on the principle that materiality should be relative to one or more key financial aspects of a company (e.g., rate base, revenue requirement, income). As electricity generation is a capital-intensive business, OPG derived the $10M threshold from the application of a formula to the company's rate base. Specifically, the $10M threshold reflects approximately 0.25% of hydroelectric rate base in existence when the materiality threshold was selected, as illustrated in the following table using the annual rate base amounts approved by the OEB in OPG's initial rate proceeding.

Average Annual Hydroelectric Rate Base ($M)	Materiality Threshold %	Materiality Threshold ($M)
$3,875.1*	0.25%	$9.7

*(EB-2007-0905, Payment Amounts Order, Appendix A, Table 1)

OPG is aware that the OEB also uses a similar formulaic approach to determine materiality for electricity distributors. In the OEB's *Filing Requirements for Electricity Distribution Rate Applications* (July 16, 2015), page 13, the OEB calculates materiality as 0.5% of service revenue requirement.

For context, OPG has calculated the Hydroelectric materiality threshold using a formula that blends the rate base and revenue requirement approaches and incorporates the most recently approved Hydroelectric rate base and revenue requirement figures. As shown in the table below, using this blended approach the result would be a materiality threshold of $12.7M.

	Note	Formula Value ($M)	Materiality Threshold %	Materiality Threshold ($M)
Revenue Requirement	1	$1,325.6	0.50%	$6.6M
Rate Base	2	$7,507.6	0.25%	$18.8
Average Threshold Value				$12.7

Note 1: EB-2013-0321 Payment Amounts Order, Appendix A, Tables 1 and 2, line 24, column (i) annualized, applying the same 0.5% value used to determine materiality for electricity distributors based on their revenue requirements.
Note 2: EB-2013-0321 Payment Amounts Order, Appendix A, Tables 1 and 2, line 4, column (i) annualized.

Based on the context provided above, OPG believes that $10M remains a reasonable threshold for determining materiality.

EP Interrogatory #29

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

Interrogatory

Reference:
Application Ex A1-Tab 3-Sch 2

The Application states at p.5 that following public consultations, OPG modified "the hydroelectric x-factor, increasing the annual productivity adjustment from -1% (as identified by the independent Total Factor Productivity study) to 0% reflecting OEB policy in the electric distribution sector". At p.9, the Application states that the Board had declined to accept a negative productivity factor in the context of electricity distribution. At p.11, the Application states "in deference to Board policy, OPG has increased the proposed productivity factor to zero."

In its Report of the Board in EB-2010-0379 issued as corrected on December 4, 2013, the Board determined "that the appropriate value for the productivity factor (Industry TFP) for Price Cap IR is zero". The Board concluded that zero was a reasonable balance between the measured negative productivity growth over the last ten years and a value that is reasonable to project into the future as an on-going industry benchmark which all distributors should be expected to achieve. (Report of the Board at p.18)

1. Since the Report of the Board in EB-2010-0379 was released in December 2013, what discussion(s) or development(s) at the public consultations referred to above led OPG to modify its proposed hydroelectric x-factor from -1% to 0%?

2. In OPG's view, are the industry conditions in distribution and in hydroelectric generation so similar that a value that is reasonable to project into the future for distributors ought to be applied to OPG's hydroelectric generation business?

3. If the answer to the above question is yes, please identify those conditions that are so similar as to suggest the adoption of the same productivity growth rate in both.

4. If the answer to question 2 above is no, what value would be reasonable in OPG's view to project into the future for as an on-going benchmark which all hydroelectric generators should be expected to achieve?

Response

1. The February 8, 2016 stakeholder session notes are publicly available at:

   http://www.opg.com/about/regulatory-affairs/stakeholder-information/Documents/Payment_Amounts/20160208_Stakeholder_Info_Session_Notes.pdf.

   A summary of the discussion on the TFP study and productivity factor during the February 8 stakeholder session is reflected under the following headings:

   > Page 10: Is it reasonable to propose that the TFP growth potential will decline by 1% for the next five years?
   >
   > Page 11: In the Board's study on distribution, the productivity factor was negative, but it was reflected at 0. What is the rationale behind OPG's proposal to maintain a negative value?

   As discussed in Ex. L11.1-13 PWU-18, the OEB has stated that a negative productivity factor is "counter to facilitating a culture of continuous improvement." In deference to the OEB's policy statement, OPG amended its proposal to reflect a productivity factor of 0%.

2. & 3. OPG lacks the expertise to comment on the conditions in distribution business and therefore cannot comment on their similarity to the industry conditions facing electricity generation. It would seem peculiar to conduct an industry specific TFP study, and then assess whether past productivity would continue based on conditions facing a different industry.

4. As noted in the stakeholder session on February 8, 2016 (Page 10), based on the results of the LEI TFP Study, it is reasonable to project a negative 1 percent productivity factor going forward as hydroelectric generation is a mature industry with little prospect of notable technological improvements. OPG notes that the initial TFP study based on information to 2012 was updated to reflect 2013 and 2014 data (i.e., future years at the time of the initial study). As discussed in Ex A1-3-2 p.18-19, the negative 1 percent productivity factor remained stable when the additional two years of data were added, indicating a consistently negative level of productivity. LEI explained why negative productivity for the industry can be expected, and indicates that this trend should continue going forward at Ex. L-11.1-15 SEC-100.

EP Interrogatory #30

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

Interrogatory

Reference:
Application Ex A1-Tab 3-Sch 2 and Attachment 1

"Empirical Analysis of Total Factor Productivity Trends in the North American Hydroelectric Generation Industry, prepared for OPG Inc. by London Economics International LLC, December 19, 2014

"Total Factor Productivity Study for OPG's Regulated Hydroelectric Business", Presentation by London Economics International LLC, prepared for stakeholder consultations, December 17, 2014 ("LEI Presentation")

Attachment 1 is the report dated February 19, 2016 that London Economics International LLC prepared for OPG (the "Update Report"); it updates the LEI report to OPG on total factor productivity dated December 19, 2014 (the "Initial Report").

At p.48 of its Update Report, LEI estimates that the industry TFP growth over the period 2002-2014 is "in the range of -1% per annum". LEI further states that "negative TFP results can be expected for a TFP study on a mature hydroelectric industry".

The LEI Presentation states (at slide 13):

>Negative TFP trend should be "expected" for a mature hydroelectric business because of the fixed production capability, fixed capital stock and rising costs of maintenance through the life cycle of a hydroelectric resource

1. Output levels should be *on average* stable over time (given generator design)
2. Capital inputs are constant (once a hydroelectric plant is put into service
3. OM&A would likely be increasing over time in order to maintain the assets' operational capability

Citing notes from the stakeholder consultation, the Application elaborates as follows:

> LEI explained that a negative productivity factor for the hydroelectric generation industry is expected, given it is an industry with substantial fixed productive capability, fixed capital stock, and increasing operating and maintenance costs that would naturally lead to negative productivity growth. (Ex A1-Tab 3-Sch 2 at p.19)

1. In OPG's view, is it realistic to consider OPG's hydroelectric production capability and capital stock as fixed or substantially fixed? Please take in consideration such developments as the Niagara Tunnel Project.

2. Does OPG contend that LEI's reported negative productivity growth rate is the result of OPG's inability to recover its "rising costs of maintenance" in rates, with the result that it been unable to generate sufficient profits to reinvest into plant and equipment while maintaining adequate dividends to its shareholder? Stated differently, does OPG attribute LEI's negative productivity growth rate to inadequacies in the cost-of-service regulatory regime?

3. For how long, according to LEI, has (i) the North American hydroelectric generation industry and (ii) OPG's hydroelectric business been "mature"? Were one or both of them mature in the years before the study period used in the LEI study?

4. If either of both of the industry and OPG's hydroelectric business have been mature for a period significantly longer that its study period, would LEI expect to see negative productivity growth throughout that period for the industry or OPG?

5. If the answer to question 4 above is no, please explain what other factors may have caused LEI's total productivity growth factor to be negative for the period of LEI's study but not prior to that period.

6. Did LEI review any of the various studies published by the independent statistical agency Statistics Canada on long-term multifactor productivity growth trends in Canada at the aggregate or industry level?

Response

The following response was provided by LEI, except for parts 1 and 2, which were prepared by OPG.

1. Yes, in OPG's view it is reasonable to consider the company's hydroelectric production capability and capital stock to be substantially fixed.

   The reference relates to the hydroelectric generation industry generally, not OPG specifically. The sample selection included firms to have multiple plants and a medium sized (defined by LEI as 500MW – 1,000 MW) or large sized (greater than 1,000MW), generation fleet of an age similar to OPG. In this context, the development of an incremental new plant by one or more firms in the peer group should not have a significant impact on the results of the TFP study. OPG agrees with the statements for the industry referenced in the question that output is stable on average over time and capital inputs (costs) are minimal once a plant is put into service. Capital inputs (costs) typically increase 30 to 50 years after a station goes into service to replace equipment at the end of their service lives. Given the number of OPG's plants and their capacity (54

OPG plants and 6,433 MW, as of the 2014 data reflected in the LEI Report), projects intended to increase capacity and OPG's capital stock should not change significantly over time; therefore it would reasonable to conclude that they are substantially fixed.

2. The contention advanced in this question is based on an incorrect understanding of LEI's study. The -1.01% TFP index growth identified by the study is the result of the productivity trend for the North American hydroelectric generation industry, not only OPG. While OPG's productivity contributes to the result of the study, it is only one among sixteen firms studied, each of which is subject to its own rate-setting regime. The TFP study considers rising costs of maintenance as an input cost in assessing productivity, regardless of whether such costs are recovered in rates or not.

3. The specific years that define a period of maturity for the North American hydroelectric generation industry and OPG's hydroelectric business is somewhat subjective. However, LEI considers that both OPG and the industry were mature during the study timeframe (2002-2014) and for some years prior to the study period. This consideration was one of the reasons that LEI considered the average age of hydroelectric generation when selecting peers. While there may be some developers building new hydroelectric power plants in North America, the majority of installed capacity in the industry is relatively old. As stated in LEI's response to L-11.1-1 Staff-233, for a number of the peers, a substantial portion of their assets were constructed in the 1950s and 1960s. Notwithstanding, LEI did not eliminate any potential peers solely because of the age of their hydroelectric assets.

4. LEI did not look into productivity trends for any period dating back before 2002-2014. LEI believes the selected study period captures the productivity trends of a mature industry trends. As described in L-11.1-15 SEC-100, 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.

5. See response to part 4.

6. LEI did not review the published studies from Statistics Canada in the context of this project. LEI is not aware of any multifactor productivity indices published by Statistics Canada that would be relevant to productivity growth trend for the hydroelectric generation industry. Statistics Canada provides generic multifactor productivity trends for the electric power generation, transmission and distribution industry, of which hydroelectric generation is only a small part.

EP Interrogatory #31

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

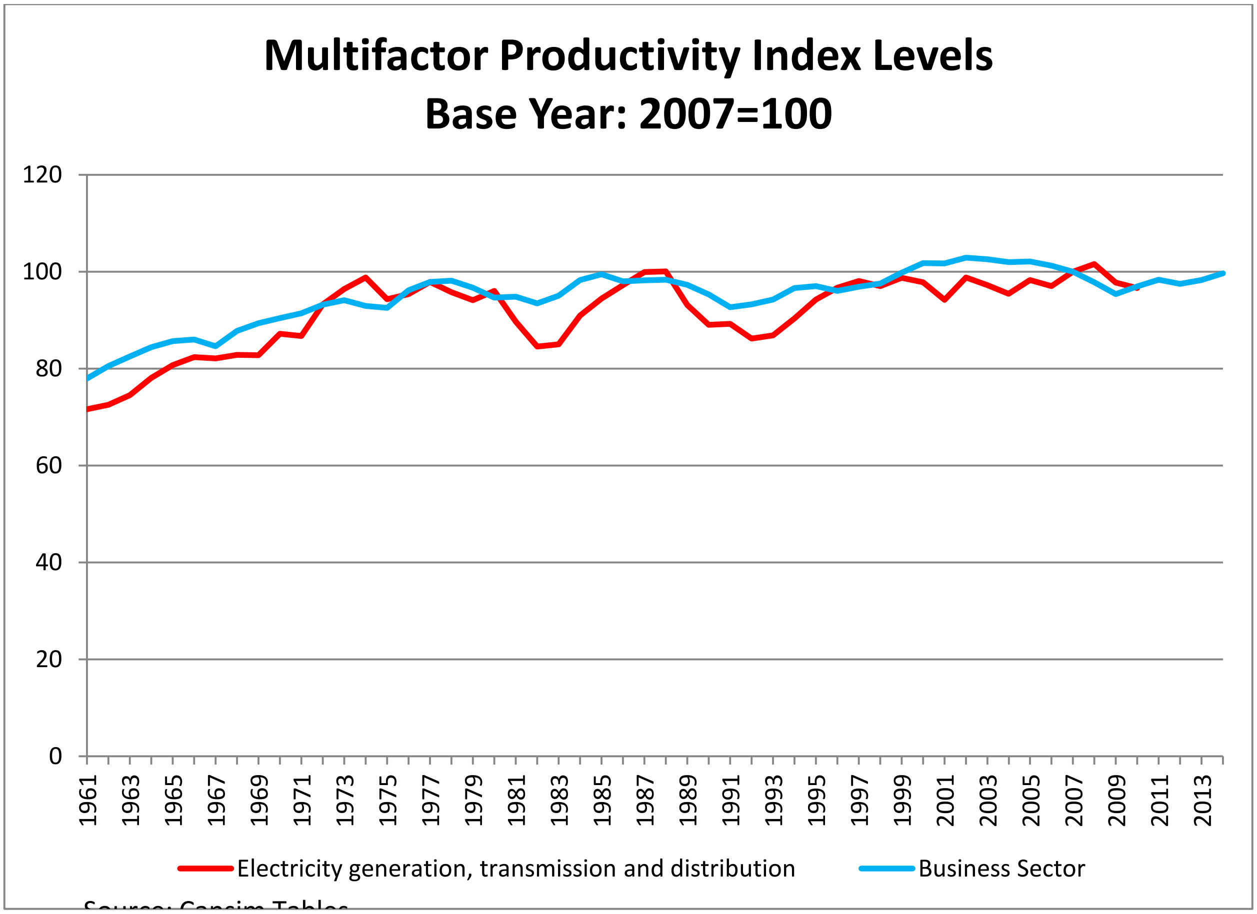
Interrogatory

Reference:
Application Ex A1-Tab 3-Sch 2 and Attachment 1

CANSIM Table 383-0021: Multifactor productivity…in the Canadian business sector

CANSIM Table 383-0032: Multifactor productivity…in Electric power generation, transmission and distribution

Statistics Canada maintains and updates the Canadian Productivity Accounts, and has multi-factor and other productivity data for years going back to 1961. Data in CANSIM Table 383-0021 indicate that levels of multi-factor productivity in the Canadian business sector fell in eight of the eleven years 2000-2010 inclusive. In the industry category "Electric power generation, transmission and distribution", data in CANSIM Table 383-0032 productivity levels fell in seven of those years. The following chart is based on the CANSIM tables referenced above.



The LEI Updated Report used a study period of 2002-2014. According to Figure 27 of the Updated Report, total-factor productivity growth was negative in five of those years.

The CANSIM data tend to support LEI's conclusion of declining productivity growth in the study period used in its Updated Report. In the overlapping eight years, the CANSIM series has 5 negative growth years and the mean annual growth rate is -0.25%; the Updated Report (Figure 27) has 3 negative growth years and the mean annual growth rate is -0.54%.

In the Report of the Board in EB-2010-0379, the Board refers to the "long-run productivity of the sector" (at p.15).

1. Please confirm that the study period used in the Updated Report was selected, in part, because LEI could not obtain comparable data for earlier years.

2. Does OPG regard LEI's study period as providing evidence on the "long-term productivity growth rate" to which the Board has referred?

3. Do the charted CANSIM data suggest that the long-term productivity growth rate for hydroelectric generation would be more accurately measured by examining a much longer time period if the relevant data were available?

4. Do the charted CANSIM data tend to support the conclusion that the long-term productivity growth rate for hydroelectric generation would be negative or zero if the relevant data were available?

5. Might the fact that levels of multi-factor productivity in the Canadian business sector fell in eight of the years 2000-2010 plausibly suggest that the negative growth rate for hydro reported by LEI had much more to do with factors and events external to OPG rather than those factors suggested by LEI?

6. Please confirm that for the 49 years from 1961-2010 inclusive, the mean productivity growth rate for the industry category "Electric power generation, transmission and distribution" was 0.668% per year with a standard deviation of 3.347%. Energy Probe will provide the charted data from CANSIM Table 383-0032 on annual productivity levels.

Response

The following response was provided by LEI, except for part 2, which was prepared by OPG.

1. Yes, while FERC Form 1 data is available going back to 1994, data for non-FERC jurisdictional entities, such as Seattle City & Light and Southeastern Power Administration, is not readily available going back for earlier years.

2. Yes, OPG believes that LEI's study and the period on which it was based provide evidence on the long-term productivity growth rate of the North American hydroelectric generation industry.

   In the context of studying the productivity of the electricity distribution industry, Pacific Economics Group observed dramatic changes in TFP results when 2012 data was added to their 2002 to 2011 data set.[1] PEG identified three unusual and one-time events that appeared to create the largest impact, and updated the analysis to exclude those events. In contrast, when two additional years of data were included in LEI's TFP study, the negative 1 percent TFP values did not change (Ex. A1-3-2, p. 16). The consistency of the TFP result supports the conclusion that the study period provides evidence of a long-term trend.

3. No. The CANSIM data from Table 383-0032 is for the broad electric utility industry and therefore includes productivity trends associated with other electric utility operations,

[1] Report of the Board: *Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, EB-2010-0379, Issued on November 21, 2013 and as corrected on December 4, 2013, p. 15.

such as transmission and distribution, as well as non-hydroelectric generation. As such this data is not specific to hydroelectric generation. It is worth noting that this data series has been terminated by Statistics Canada and no data is available subsequent to 2010.

4. Without analyzing the CANSIM data further, it is difficult to draw concrete conclusions with respect to correlation. That said, the data on multifactor productivity trends in the two data series are showing a negative growth trend as implied in the question over the 2002-2010 period. Indeed, the CANSIM data shows a negative average MFP trend even if we go back to the late 1990s.

5. LEI has not investigated the CANSIM data and drivers of the productivity trends presented in the data series that have been highlighted in this question. On the other hand, LEI has specifically calculated a total factor productivity growth trend for the hydroelectric generation industry using actual operating data from North American peers of OPG and OPG, itself. It is clear in LEI's Report that the negative TFP trend estimated for the hydroelectric industry is wholly based on drivers specific to inputs and outputs for the industry and not external factors as presupposed in the question

6. LEI confirms that taking the average of year over year productivity growth rates for the 1961-2010 period results in 0.668% with a standard deviation of 3.347%. As noted in Ex. L-11.1-6 EP-30, the data cited in this question is for the electric power generation, transmission and distribution industry, of which hydroelectric generation is only a small part.

LPMA Interrogatory #8

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

Interrogatory

Reference:
Ref: Exhibit A1, Tab 3, Schedule 2, page 14

OPG's proposed annual adjustment mechanism uses generation industry weighting for the inflation factor rather than company specific weighting. It is stated that this is consistent with the OEB determination of using a weighting of distribution industry sub-indices. Are there any other reasons that OPG determined that the industry weighting was more appropriate than the company specific weighting?

Response

In addition to consistency with the OEB's practice in the context of the electric distribution sector, the use of an industry weighting is a better proxy for the input price pressures that firms in the aggregate would face in a competitive market environment, which is what the IRM scheme is intending to simulate. When OPG discussed this issue with LEI in the course of developing the proposed inflation factor, LEI supported the use of industry weights, because they would ensure consistency with the theoretical underpinnings of IRM (e.g., mimic the competitive market) and avoid a self-referential inflation factor. In summary, an inflation factor, based on the industry weights, would reflect the overall input price pressures that would exist in the generation sector and appropriately compensate OPG for those generic inflationary trends.

In addition, OPG notes that the OPG-specific weighting (92% for non-labour) is not materially different from the generation industry weighting (88%). Using OPG-specific weighting would result in the same inflation factor of 1.8%.

LPMA Interrogatory #9

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

Interrogatory

Reference:
Ref: Exhibit A1, Tab 3, Schedule 2, page 22

a) Please provide an example of the materiality threshold calculation that would be required for an ICM application for inclusion as a 2020 rate rider.

b) In particular, please identify what figures would be used for each of the variables in the materiality threshold formula as set out in the *Report of the OEB: New Policy Options for the Funding of Capital Investments: Supplemental Report* (EB-2014-0219), issued January 24, 2016. For example, would the rate base, depreciation and growth factors be specific to the regulated hydroelectric assets or would they include the nuclear side of the business as well?

c) Does OPG accept the means test as set out in the *Report of the Board: New Policy Options for the Funding of Capital Investments* (EB-2014-0219), issued September 18, 2014? If no, please explain why not. If yes, please explain why OPG believes that the 300 basis point figure is appropriate for OPG.

d) Would the means test be based on the regulated hydroelectric earnings only or would it be based on the entire company, including the nuclear assets?

Response

a) and b)

An example of the materiality threshold calculation for an ICM application for a 2020 rate rider identifying the figures and their sources is provided below, consistent with the referenced Report of the Board.

An ICM is specific to a 4GIRM indexed price cap, which is the ratemaking approach OPG has proposed for hydroelectric operations to set payment amounts for 2017 to 2021. As such, all values in the example are specific to hydroelectric operations.

Hydroelectric ICM Threshold Calculation

Line No.		2020
		(a)
	Hydroelectric ICM Calculation:	
	Rate Base ($M)[1]	7507.7
	Depreciation Expense Included in Rate Base ($M)[2]	143.2
	Distribution Revenue Change from Load Growth (%)[3]	0.00%
	Price Cap Index (%)[4]	1.50%
	Threshold (%)	188.6%
	Eligibility Threshold ($M)	270.14

Notes:

1 Average of 2014 & 2015 Hydroelectric Rate Base, EB-2013-0321 Payment Amount Order, Appendix A, Tables 1 and 2, line 4.

2 Average of 2014 & 2015 Hydroelectric Depreciation Expense, EB-2013-0321 Payment Amount Order, Appendix A, Tables 1 and 2, line 17

3 Not applicable to electric generators

4 Exhibit I1-2-1 Table 1, line 6

c) Yes, OPG accepts the means test as set out in the referenced Report of the Board. OPG has accepted the requirements of the 4GIRM approach to rate setting provided in the RRFE with modification only as required to address differences in the electricity distribution and generation businesses and to facilitate OPG's initial transition to 4GIRM.

d) OPG believes that a means test should be based on the entirety of the company’s regulated earnings.

OPG understands that, under OEB policy, the purpose of a means test is to assess whether a regulated company should be able to fund necessary incremental capital work out of existing cash flow during the IR Term without seeking additional revenue from ratepayers. In the September 18, 2014 Report of the Board, the OEB says the following:

“While a means test that doesn’t allow incremental funding if a distributor is earning more than its Board-approved ROE may be a barrier to a distributor seeking efficiency improvements during the IR term, a threshold of 300 basis points retains some flexibility for distributors to maximize their earnings while also recognizing that funding in advance of the next rebasing is likely not required from a cash flow perspective. Distributors will have the option of explaining any overearnings."[1]

This policy allows distributors to retain earnings below the level that would trigger an off-ramp, but requires them to either fund incremental capital out of any additional earnings (i.e., earnings beyond the 300 BPS threshold), or provide an explanation for the over-earnings.

OPG operates as a single company, with a single cost of capital that covers both the hydroelectric and nuclear generating facilities. OPG believes that the ICM/ACM means test should be consistent with that structure and with the off-ramp proposal in this application, which is based on a combined ROE. A means test based only on hydroelectric earnings would not accurately reflect OPG's cash flow and its ability to fund necessary capital work during the IR term.

[1] *Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, EB-2014-0219, p. 16.

LPMA Interrogatory #10

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

Interrogatory

Reference:
Ref: Exhibit A1, Tab 3, Schedule 2, page 22

a) Please provide some examples of unforeseen events that OPG believes would qualify as a Z-factor.

b) Would a change in income tax rates, capital cost allowance rates or tax credits be an unforeseen event that would qualify as a Z-factor? Please explain fully.

Response

a) OPG's proposal is to apply the OEB's policy on unforeseen events as noted in the above reference. While it is impossible to exhaustively identify what unforeseen events may arise, changes in operations in response to security or environmental requirements are examples of events that may result in a Z-factor application.

b) In EB-2007-0905, the OEB directed OPG to establish an Income and Other Taxes Variance Account, which OPG proposes to continue in this application (see Ex. H1-1-1, pp. 11-12). To the extent a material change occurred in income tax rates, capital cost allowance rates or tax credits that is not captured in the Income and Other Taxes Variance Account, OPG would consider the costs associated with that change in the context of the OEB's policy discussed in part a).

PWU Interrogatory #18

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

Interrogatory

Reference:
Ref: Exhibit A1-3-2, Pages 18 & 19

> LEI calculated TFP results using two methods: average index growth, and a trend regression approach. The results of the Initial TFP Study and the Updated TFP Study are summarized in Chart 5.
>
> **Chart 5 – Summary of Hydroelectric TFP Results**
>
> | Approach | 2002-2012 Information | 2013-2014 Update |
> |---|---|---|
> | Average Index | (1.02) | (1.01) |
> | Trend Regression Index | (1.00) | (1.19) |
>
> …LEI explained that a negative productivity factor for the hydroelectric generation industry is expected, given it is an industry with substantially fixed productive capability, fixed capital stock, and increasing operating and maintenance costs that would naturally lead to negative productivity growth.
>
> The results of the TFP studies notwithstanding, OPG has elected to increase the productivity factor from negative 1% to zero. OPG believes this approach is consistent with OEB policy. In the electricity distribution context, the OEB has elected not to set rates based on negative productivity growth in the electricity distribution context. In its report on the distribution productivity factor under the RRFE, the OEB stated that it "does not believe it appropriate for a rate setting regime to project and entrench declining productivity expectations into the future." The OEB determined that the productivity factor value would be zero, despite the negative result of the industry TFP study.
>
> While OPG believes that the -1% TFP factor resulting from both the Initial TFP Study and the Updated TFP Study is accurate, it understands the OEB's policy position and proposes a zero 18 productivity factor in this application.

a) Does OPG agree with LEI's explanation of the reasons or factors that lead to negative productivity growth and why negative productivity growth should be expected for hydroelectric generation?

b) Does OPG agree with the Board's reasons why the Board has elected not to set rates based on negative productivity growth in the electricity distribution context?

c) Does OPG think or believe that the Board's position on negative productivity growth in the electricity distribution context is equally relevant and applicable to hydroelectric generation?

d) If OPG believes, as indicated above, that the -1% TFP factor resulting from both the Initial TFP Study and the Updated TFP Study is accurate, why is OPG proposing a zero % TFP just because it would be consistent with the Board's position in the context of electricity distribution?

e) Please confirm that by proposing a zero % TFP and not the -1% TFP, and given that OPG is proposing a 0.3 Stretch factor, OPG is essentially proposing a 1.3% Stretch factor?

f) Please provide a chart comparing rates and payment amounts under a zero % and -1% TFP assumptions for each of the 5 years covered by the application.

g) Please confirm if the reason why OPG chose to not rebase hydroelectric payment amounts and instead file an IR mechanism is because it was so directed by the Board?

Response

a) Yes.

b) The reasons cited for the OEB's treatment of negative productivity factors is outlined in the November 21, 2013 Report of the Board, in which it determined the rate-setting parameters for electricity distributors under the RRFE. The main policy statement from the OEB is on page 17:

> "… the Board does not believe it appropriate for a rate setting regime to project and entrench declining productivity expectations into the future. The productivity component of the X-factor is intended to be an external benchmark which all distributors are expected to achieve. Setting a productivity benchmark for the industry that would not encourage distributors to achieve and share productivity gains is inconsistent with the Board's policy direction – doing so would be counter to facilitating a culture of continuous improvement."[1]

OPG accepts the OEB's determination on this matter.

c) OPG understands from the quote in part (b) of this response that the OEB's decision on this point is a matter of policy, and that it is not based on actual growth trends in the

[1] EB-2010-0379, Report of the Board, Issued on November 21, 2013 and as corrected on December 4, 2013, p. 17.

relevant sector. OPG understands that the OEB's policy statement in the Report referenced above would apply to OPG as well as distributors.

d) OPG believes that the results of its TFP study are reflective of the hydroelectric business and therefore relevant to the determination of an appropriate X-factor. As noted in Ex. A1-3-2, page 19, lines 21-24, the effect of accepting a zero productivity factor is to create an additional 1% stretch factor on the company's Hydroelectric business. 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. However, it has accepted the OEB's direction on incentive rate-setting.

e) As per (d) above, OPG believes that negating the negative TFP result is effectively a commensurate increase to the stretch factor.

f) OPG assumes that the reference to rates in the resulting annual price cap change used to determine the payment amounts. The illustrative payment amounts at a 1.5% price cap index (Ex. I1-2-1 Table 1, line 6) reflect a 0% TFP for each of the five years covered by this application as determined in Ex. I1-2-1 Table 1, line 8. As the TFP is subtracted in determining the price cap, subtracting a negative 1% TFP increases the price cap to 2.5%. Illustrative payment amounts at a negative 1% TFP and a comparison to the proposed amounts are provided in the table below:

Payment Amounts ($/MWh)

Payment Amounts	2017	2018	2019	2020	2021
1.5% price cap (using 0% TFP)	41.71	42.33	42.97	43.61	44.27
2.5% price cap (using 0% TFP)	42.12	43.17	44.25	45.36	46.49
Increase in payment amounts	0.41	0.84	1.28	1.75	2.22

g) As outlined in section 1 of Ex. A1-3-2, in its letter dated February 17, 2015, on Incentive Rate-setting for Ontario Power Generation's Prescribed Generation Assets, the OEB outlined its expectation that OPG's next payment amount application would implement an IR framework for its Hydroelectric assets consistent with the RRFE.

PWU Interrogatory #19

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

Interrogatory

Reference:
Ref: Exhibit A1-3-2, Attachment 2, Pages 4 & 5

	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

Legend
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.

a) The Charts on pages 4 and 5 show that OPG hydro`s cost performance based on Partial Function is in the second quartile whereas based on Total Function OPG is in the third quartile. However, Note 3 on page 4 states that "OPG's Total Function Costs are bottom quartile on average primarily due to high PA&R Costs (Gross Revenue Charges)". Please clarify the discrepancy.

Response

a) Note 3 should read "…OPG's Total Function Costs are **third** [emphasis added] quartile on average primarily due to high PA&R Costs (Gross Revenue Charges).

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

SEC Interrogatory #96

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

Interrogatory

Reference:

The attached spreadsheet sets out a simple calculation of the expected increases in costs from a capital-intensive business like hydroelectric power generation. It shows $1 million of 50 year assets going into service in year one, with annual costs for cost of capital (debt, equity and taxes) of 8% and depreciation of 2%. OM&A is 15% of total annual costs (excluding gross revenue charge), and there are annual capital additions to replenish the original asset equal to depreciation plus the cumulative impact of inflation.

With respect to the cost drivers affecting a capital-intensive business like hydroelectric power generation:

a. Please confirm that this pattern is an accurate, if simplified, description of the cost drivers on such a business over time. If it is not, please explain the primary ways in which it is incorrect.

b. Please confirm that if both operating and capital costs increase at the rate of inflation every year, with zero productivity, the overall revenue requirement for the business will increase at an average of slightly more than 40% of inflation. Please confirm that this effect will decline (i.e. annual costs will get closer to inflation) as inflation- driven operating costs become a higher percentage of annual costs relative to capital, and will increase (i.e. annual costs will increase at a lower percentage of inflation) as those operating costs become a lower of percentage of annual costs relative to capital. Please confirm that annual costs can only be equal to or greater than inflation if:

   i. Operating costs are 100% of annual costs, or

   ii. Operating costs or capital costs rise significantly faster than inflation

c. Please explain the primary factors causing the costs of the OPG to follow a pattern of increases that are not comparable to the standard cost drivers for capital intensive businesses.

Response

Questions a) and c)

OPG cannot confirm whether the spreadsheet attached to this question accurately reflects the cost drivers of a hypothetical hydroelectric power generator or other sufficiently similar capital-intensive business. OPG is concerned that the broad assumptions made by SEC cannot accurately reflect the cost drivers for a business with the scale and complexity of a province-wide hydroelectric generator like OPG.

OPG has the following specific comments on the assumptions employed in the spreadsheet:

1) **Depreciation**: For capital investment with a defined 50 year life, 2 percent depreciation may be reasonable. In the case of OPG, this value would be lower, closer to 1%.
2) **Cost of Capital and Income Taxes**: If the hypothetical company is based in Ontario, an 8 percent pretax cost of capital is low over the long term. A higher risk hypothetical company would have a higher pre-tax cost of capital.
3) **OM&A excluding Fuel/Gross Revenue Charges**: OPG has no basis to assess the percentage of OM&A costs for a hypothetical utility. OPG's OM&A costs less GRC were approximately 35% of revenue requirement based on the EB-2013-0321 Payment Amount order, which is the base rate proposed for incentive regulation in this application.
4) **Annual Capital Additions**: OPG has no basis to assess whether capital additions at depreciation plus inflation will in fact replenish the asset. For OPG, capital additions are primarily directed at the non-civil structures.

The OEB has regulated capital intensive industries for decades, including both gas and electricity distribution. The OEB has applied several generations of incentive regulation using an index-based incentive regulation methodology to establish rates for these utilities. Hydroelectric generation is similarly capital intensive. There is no fundamental difference in applying a price cap to set rates for hydroelectric generation and natural gas or electricity regulation: all have significant historic investment in property, plant and equipment that is depreciated over its expected useful life, all earn a cost of capital using an industry wide ROE with relative risk reflected in approved common equity ratios, all invest in capital to maintain assets and expand operations, all pay income and property taxes (or taxes in lieu) in Ontario and all incur some level of OM&A costs. The degree of capital intensity among capital intensive industries may be different, but that would not change the fundamental similarities in the underlying costs, nor should it change the regulatory methodology used to establish rates. Given the similarities in the cost structure, and the OEB’s long history of applying index-based approaches to establish rates for natural gas and electric distributors, a hypothetical example to illustrate the impacts of index based price cap regulation appears unnecessary.

Question b)

Assuming that capital investment increases by inflation, under cost of service regulation the incremental depreciation and cost of capital on that investment reflected in the revenue requirement will increase by only a portion of the increase in capital investment. As a result, OPG confirms that under cost of service regulation:

1) Assuming that capital and operating costs increase by inflation, a cost of service-based revenue requirement will increase by less than inflation (however, OPG cannot confirm the 40% amount given its comments on the assumptions above);
2) Revenue requirement will increase at a rate closer to inflation as inflation-driven operating costs become a higher percentage of annual costs relative to capital, and vice-versa; and
3) Annual costs (i.e. revenue requirement) can only be equal to or greater than inflation if operating costs are 100% of annual costs, or operating costs or capital costs rise significantly faster than inflation.

OPG further notes that the generic confirmations above would apply to all utilities regulated under cost of service regulation.

SEC Interrogatory #97

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

Interrogatory

Reference:

Please provide a table showing, for each of the hydroelectric generating stations currently included in the prescribed facilities:

a) The name and capacity of the facility.

b) The original capital cost of the facility.

c) The first year in-service.

d) The original capital cost and capacity of any capacity additions to the facility (but not including any capital additions that did not add to capacity), and the date of the capacity addition.

e) Any adjustments to net book value of the facility prior to 2016.

f) The current net book value of the facility, net of all capital additions (not just those that add capacity) and all depreciation and other adjustments.

Response

For the reasons described in Ex. L-11.1-1 Staff-247, OPG has provided historical data from 2002 onward. Because no facilities were built subsequent to 2002, OPG is not providing any data in response to part b). In addition, original capital costs would not be helpful, since OPG's hydroelectric assets were revalued in 1999 upon their acquisition by OPG from Ontario Hydro. Finally, OPG notes that it does not have a complete set of Ontario Hydro's original capital cost data for all prescribed hydroelectric generating stations, some of which are more than 100 years old.

a), c), d), and f) Please see Attachment 1, Table 1.

b) Please refer to the preamble to this response.

e) Please see Ex. L-11.1-1 Staff-247, parts a) b) and c).

Attachment 1
Table 1
Plant Name, Capacity, In-Service Dates, Capacity Additions and Costs and Current Net Book Value

Plant Group	Generating Station	Number of In-Service Units	Net In-Service Capacity (MW)	Original Unit In-Service Dates	Capacity or Energy Additions, year	Capacity or Energy Addition: Capacity Addition (MW)	Energy Addition (GWh)	Capital Expenditure, $M	Total OM&A Costs, $M	Net Book Value, Dec 31, 2015, $M
Niagara Operations	Sir Adam Beck I	8	436	1922 – 1930	2009	10.8	11.3	5.4		1,176.1
					2010	10.8	10.0	3.4		
					2013	9.0	8.0	1.7		
	Sir Adam Beck II	16	1,499	1954 – 1958	2002	24.2	52.9	5.3		2,125.5
					2003	24.2	40.6	5.4		
					2004	12.1	17.9	4.0	0.8	
					2005	12.1	17.9	1.0	0.3	
	Sir Adam Beck PGS	6	174	1957 – 1958						121.6
	Niagara Tunnel Project				2013	0.0	1500	1464.2	4.6	Included in SAB I and SAB II
	DeCew Falls I	4	23	1898						29.4
	DeCew Falls II	2	144	1948						168.4
Eastern Operations	R.H. Saunders	16	1,045	1958 – 1959	2002	9.7	5.7	1.5		1,211.9
	Arnprior	2	82	1976-1977						45.0
	Barrett Chute	4	176	1942-1968						77.3
	Calabogie	2	5	1917						7.4
	Mountain Chute	2	170	1967						95.5
	Stewartville	5	182	1948-1969						75.2
	Chats Falls (OPG owns 4 of 8 units)	4	96	1931-1932	2003	0.0	4.7	2.7		91.1
					2004	0.0	5.2	0.7	0.6	
					2005	0.0	4.0	0.7	0.7	
					2006	0.0	4.0	0.7	0.5	
					2007	1.0	2.4	0.8	0.7	
					2010	0.0	2.0	1.2	0.8	
	Chenaux	8	144	1950-1951						137.0
	Des Joachims	8	429	1950-1951	2007	0.0	11.6	4.7	1.4	446.8
					2008	0.0	9.8	2.5	1.8	
					2009	0.0	8.9	2.7	2.2	
					2011	0.0	5.7	2.7	1.7	
					2012	0.0	1.7	3.2	1.9	
					2013	0.0	1.0	2.5	2.9	
					2014	0.0	0.5	2.0	2.2	
	Otto Holden	8	243	1952-1953						231.0
Central Operations	Auburn	3	2	1911-1912						0.6
	Big Chute	1	10	1909-1919 (rebuilt 1993)						6.1
	Big Eddy	2	8	1941						4.0
	Bingham Chute	2	1	1923-1924						0.7
	Coniston	3	4	1905-1915						1.8
	Crystal Falls	4	8	1921						6.9
	Elliot Chute	1	2	1929						1.7
	Eugenia Falls	3	6	1915-1920						2.8
	Frankford	4	3	1913						5.2
	Hagues Reach	3	4	1925						1.3
	Hanna Chute	1	1	1926						2.7
	High Falls	3	3	1920						1.6
	Lakefield	1	2	1928						0.7
	McVittie	2	3	1912	2009	0.7	3.1	3.4	1.0	5.6
	Merrickville	2	2	1915-1919						0.5
	Meyersberg	3	5	1924						3.5
	Nipissing	2	0	1909						0.3
	Ragged Rapids	2	8	1938	2009	0.2	1.1	0.3	1.9	10.9
					2014	0.2	1.1			
	Ranney Falls	3	10	1922-1926	2006	0.8	4.0	2.4	0.4	7.7
					2007	0.8	4.0			
	Seymour	5	6	1909						3.1
	Sidney	4	4	1911						4.1
	Sills Island	2	2	1900						0.7
	South Falls	3	5	1916-1925						14.3
	Stinson	2	5	1925						1.0
	Trethewey Falls	1	2	1929						2.3
Northeast Operations	Abitibi Canyon	5	349	1933-1959	2006	20.0	15.4	5.9	7.1	244.0
					2007	10.0	3.9	1.6	2.0	
	Otter Rapids	4	182	1961-1963						124.2
	Lower Notch	2	274	1971						129.4
	Matabitchuan	4	10	1910						25.1
	Indian Chute	2	3	1923-1924						8.4
Northwest Operations	Aguasabon	2	47	1948						39.9
	Alexander	5	69	1930-1958	2010	1.2	5.6			68.4
	Cameron Falls	7	92	1920-1958	2003	1.4	4.8	1.1		78.9
					2009	2.0	4.9	1.5	0.4	
					2010	1.8	4.2			
	Caribou Falls	3	91	1958	2006	4.1	14.8	0.5	1.3	85.2
	Kakabeka Falls	4	25	1906-1914						22.9
	Manitou Falls	5	73	1956-1958						51.7
	Pine Portage	4	145	1950-1954	2013	2.0	14.4	4.1	3.8	121.4
					2014	2.0	7.6			
	Silver Falls	1	48	1959						39.3
	Whitedog Falls	3	68	1958						68.4

SEC Interrogatory #98

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

Interrogatory

Reference:

Please confirm that Hydro Quebec's cost to generate each kWh of electricity from hydroelectric sources has declined relative to inflation, and declined in absolute terms, for the last ten years. Please explain in detail the differences between the current and expected cost drivers for Hydro Quebec and OPG that justify annual inflationary increases for OPG, while such increases do not appear to be required for Hydro Quebec. The cost per kWh for Hydro Quebec in 2015-2016 is 2.08 cents, according to their most recent Cue Card financial results report. Please provide the comparably calculated cost per kwh. for the OPG, and explain the material factors making the OPG's cost for the same period higher than the Hydro Quebec cost.

Response

The question requests information that OPG does not possess and inter-jurisdictional analysis that OPG is not equipped to conduct. OPG is not aware of the amount or drivers of Hydro Quebec's costs, and is therefore unable to provide the requested detailed explanation of the differing cost drivers faced by the two companies. OPG is unfamiliar with how Hydro Quebec calculates the price per kWh referenced, and is unable to provide the comparison requested.

As directed by the Board in EB-2013-0321, OPG completed a fully independent benchmarking study of its Hydroelectric operations in support of its IRM proposal submitted with this application.

SEC Interrogatory #99

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

Interrogatory

Reference:
[A1/3/2/ Attach 1, p.38]

Please explain what steps were taken to verify that the data available for Canadian peers, even if not sufficiently granular to use in the study, was comparable to similar data available for the US peer group used, i.e. to demonstrate that the US peers are a reasonable proxy for the Canadian peer group. What were the results of that verification process? Please provide copies of all analyses that show that the US peers are comparable to the Canadian peers, and thus an appropriate proxy group.

Response

The following response was provided by LEI.

The peer group on the study consists of 16 firms, OPG and 15 US firms (13 investor-owned and 2 federal and municipal operators). Note that other than OPG, no other Canadian company had the necessary data to be included in the TFP study.[1]

As far as comparability between US and Canadian utilities, there is a wealth of precedent for combining such firms into one industry. OPG recognizes US hydroelectric generation companies as peers. For example, OPG is a member of the EUCG's Hydroelectric Productivity Committee.[2] This Committee maintains a database of both US and Canadian hydroelectric operators (including OPG), which allows for "comparative analysis".[3] Note, LEI had analysed the EUCG dataset for the purposes of the TFP study, but unfortunately the data did not span the 13 years needed and some companies were not consistently represented over the historical timeframe (see footnote 32 in LEI's report).

In addition to the overall compatibility of data, LEI also took particular care in selecting similar peers based on similarity of operating drivers, such as size of fleet and age of assets, as discussed in Section 5.1. As well, LEI undertook data consistency checks between OPG data and FERC Form 1 data (please refer to on pages 32-33 and Figure 20). Also please see the response to Ex. L-11.1-1 Staff-243 b).

[1] Please see Section 5.2.4 in LEI's report for discussion on efforts undertaken to obtain Canadian data.
[2] EUCG. Hydroelectric Productivity Committee. <https://www.eucg.org/committees/hydro.cfm>
[3] Ibid.

SEC Interrogatory #100

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

Interrogatory

Reference:
[A1/3/2, p.19 and Attach. 1, p.48]

Please provide a detailed calculation, or equivalent narrative explanation, showing the basis for LEI's assertion that mature hydroelectric facilities should show negative productivity.

Response

The following response was provided by LEI.

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

SEC Interrogatory #101

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

Interrogatory

Reference:
[A1/3/2, Attach. 1, p.42]

Please explain why the output measures were not adjusted for hydrology to remove volatility. Please advise to what extent costs for a hydroelectric facility are independent of annual variations in hydrology.

Response

The following response was provided by LEI.

LEI did not adjust the annual generation data for hydrology for a number of reasons, some related to practical considerations and others related to conceptual factors. First, hydrology adjusted data was not readily available from peers other than OPG. Hydrology-adjusted or weather-normalized generation data are typically not published. In addition, the form of TFP methodology (an Index-based approach) does not lend itself to consideration for such factors to "control" for deviations in hydroelectric output. For example, in an econometric analysis, it is far easier to introduce explanatory weather variables, such as precipitation or snowmelt statistics. Finally, and most importantly, LEI accounted for the variability in hydroelectric output from year-to-year by using many years of data that are on average consistent with long run mean/median water conditions (please see page 18 of the LEI Report).

Regarding the second part of the question, 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). This lack of relationship over time between costs and hydroelectric output does not invalidate the use of annual electric generation as the proper measurement of output in the TFP study.

SEC Interrogatory #102

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

Interrogatory

Reference:

Please provide a table showing the impact of timing differences on the tax consequences of the Niagara Tunnel for all years of its planned life. Please break out the CCA and depreciation amounts for each year, the annual and cumulative difference in UCC and net book value, and the annual and cumulative reduction in PILs arising out of the differences.

Response

OPG declines to provide the requested information on the basis of relevance. This interrogatory seeks information related to the hydroelectric revenue requirement. The OEB determined that this type of information was outside the scope of the hearing and therefore the request is not relevant to deciding any issue on the approved Issues List in this application. (Decision on Issues List, September 23, 2016, page 13). Moreover this interrogatory seeks information that goes decades beyond the IR period.

SEC Interrogatory #103

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

Interrogatory

Reference:

Please confirm that, assuming constant production, the gross revenue charge increases by the same percentage as the payments amounts for hydroelectric generation. Please confirm that, under the proposal from the OPG, the gross revenue charge would increase annually by the inflation factor, less the stretch factor.

Response

OPG's understanding is that IRM decouples costs and revenues; therefore revenues and costs do not escalate at the same rate. OPG's proposal is specific to revenue escalation, as contemplated by the 4GIRM price-cap index method in the RRFE. OPG has not proposed that the GRC increase by the inflation factor.

Board Staff Interrogatory #253

Issue Number: 11.2
Issue: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?

Interrogatory

Reference:
Ref: Exh A1-3-2 page 16

OPG proposes that the current hydroelectric payment amounts as approved in EB-2013-0321 be used as the "going in" rates for the 2017-2021 period, adjusted to correct for the one-time allocation of nuclear tax losses to the hydroelectric business in the prior application. The current payment amounts reflect the OEB's findings in EB-2013-0321 to only allow OPG to recover its cash requirements for pensions and other post-employment benefits.

Are there one-time OM&A costs that were factored into the approved 2014-2015 hydroelectric payments amounts? Please identify all of these and the approved costs. Please explain why OPG has not adjusted the "going-in" hydroelectric payments for these other "one-time" costs.

Response

There were no material one-time OM&A costs included in the forecast used to establish the EB-2013-0321 approved hydroelectric payment amounts.

The allocation of nuclear tax losses to the hydroelectric business in EB-2013-0321 is not a selective treatment for a single, specific one-time cost. As explained in Ex. A1-3-2, pp. 15-16, the nuclear tax losses were applied to reduce OPG's approved hydroelectric payment amounts in order to "provide customers the benefit of the nuclear tax loss sooner than would be the case if they were carried forward within the nuclear business unit". The nuclear tax loss had nothing to do with hydroelectric operations or OM&A costs; it was simply applied to reduce the hydroelectric payment amount and, by so doing, lowered the combined hydroelectric and nuclear payment amount used to calculate the rate increase and customer bill impacts in EB-2013-0321. The application of nuclear tax losses to hydroelectric operations was accepted as part of the Rate Order process in that proceeding.[1]

OPG did not consider an adjustment to remove any one-time hydroelectric OM&A costs from base rates or to add any forecast one-time OM&A costs to determination of base rates, and believes that doing so would have been inconsistent with 4GIRM rate-setting under the

[1] EB-2013-0321, OPG Response to Intervenor Comments on the Draft Payment Amounts Order, December 12, 2014, page 4.

RRFE. To the extent that OPG's costs differ from its payment amounts during the IR term, OPG understands that such decoupling is an expected element of price-cap index-based rate-setting.

Board Staff Interrogatory #254

Issue Number: 11.2
Issue: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?

Interrogatory

Reference:
Ref: Exh A1-3-2 page 16

The current hydroelectric payment amounts as approved in EB-2013-0321 are used as the "going in" rates for the 2017-2021 period, adjusted to correct for the one-time allocation of nuclear tax losses to the hydroelectric business in the prior application. Please identify the approximate impact on base payment amounts if OPG had filed a rebasing application for the regulated hydroelectric facilities for 2017.

Response

OPG declines to provide the requested information as it is not relevant to an issue in this proceeding. Specifically, the impact of a hypothetical 2017 rebasing application on base hydroelectric payment amounts is not relevant to whether the adjustments made to OPG's approved hydroelectric payment amounts are appropriate under the incentive regulation mechanism proposed in this application.

For the Draft Issues List, OEB Staff proposed that Issue 11.2 be:

> *Are OPG's hydroelectric payment amounts arising from EB-2013-0321, as adjusted, appropriate as base rates for applying the hydroelectric incentive regulation mechanism over the 2017-2021 period?*

The OEB ultimately rejected this issue, accepting OPG's submission that the proposed issue "could open the question of rebasing hydroelectric payment amounts and a re-evaluation of the costs underpinning the hydroelectric payment amounts approved in EB-2013-0321."[1]

As approved, Issue 11.2 is limited to the adjustments that OPG has proposed to the approved hydroelectric payment amounts. While the question in this interrogatory may have been appropriate in the issue originally proposed in the Draft Issues List, it is not relevant to final Issue 11.2. If allowed, the request could open the same question of rebasing hydroelectric payment amounts that the OEB rejected in the Issues List Decision.

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[1] Decision on Issues List, September 23, 2016, page 13 [Issues List Decision].

CCC Interrogatory #48

Issue Number: 11.2
Issue: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?

Interrogatory

Reference:
Reference: Ex. A1/T3/S2/p. 15

OPG is proposing that the Company's current hydroelectric payment amounts as approved in EB-2013-0321 be used as the "going in" rates for the 2017-2021 period, adjusted to correct for the one-time allocation of nuclear tax losses to the hydroelectric business in the prior application. Please provide evidence that the payment amounts approved in EB-2013-0321 represent an appropriate base for setting rates for the test period. Is the tax loss the only one-time, non-recurring item included in the approved revenue requirement? Were there other items that OPG considered making adjustments for? If so, please explain why those adjustments were not made.

Response

Please refer to Ex. L-11.2-1 Staff-253 and Ex. L-11.2-1 Staff-254.

IESO Interrogatory #1

Issue Number: 11.2
Issue: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?

Interrogatory

Reference:

Ancillary Services

Preamble:
Ancillary services means services necessary to maintain the reliability of the IESO- controlled grid, and include regulation and operating reserve. Regulation means the service required to control power system frequency and maintain the balance between load and generation; operating reserve ("OR") means generation capacity or load reduction capacity which can be called upon on short notice by the IESO to replace scheduled energy supply which is unavailable as a result of an unexpected outage or to augment scheduled energy as a result of unexpected demand or other contingencies.

OPG has historically been a significant provider of OR and regulation in Ontario. The IESO indicated in its latest 18 Month Outlook (issued September 22, 2016 at http://www.ieso.ca/Documents/marketReports/18MonthOutlook_2016sep.pdf) that there is an increased need for regulation service to help manage the variations in generation and demand under a continuously evolving generation mix and demand patterns. There has also been a significant decrease in OR offered by hydroelectric resources, as noted by the Market Surveillance Panel in its May 2016 report (page 75 Section 3.2.3 (http://www.ontarioenergyboard.ca/oeb/Industry/About%20the%20OEB/Electricity%20Market%20Surveillance/Market%20Surveillance%20Panel%20Reports)

a) Please explain the reasons for OPG's declining production for each of OR and regulation.

b) Please explain if both the amount of regulation and OR expected to be offered into the market and revenues from regulation and OR are forecast to decline and by how much.

c) The current OEB-approved payment amounts structure for ancillary services appears to not provide any incentive for OPG to offer more of these services in the future, either from its current operating capabilities or from new investments for that purpose. How could the OEB-approved payment amounts incentive structure be changed in order to result in OPG offering more regulation and OR into the market?

Response

OPG declines to provide the requested information on the basis of relevance. This interrogatory seeks information on OPG Hydroelectric Other Revenues that is not relevant to deciding any issue on the approved Issues List in this application. The IESO's attempt to add an issue addressing the subject matter of this question was withdrawn, and in any event, consideration of this matter would be inconsistent with OPG's IRM application as the OEB staff has noted in the quote from the OEB's Issues List Decision presented below:

> The IESO indicated an interest in examining OPG's operations for the purposes of earning other revenue. The IESO proposed an issue related to the design of payment amounts issue in OPG's draft issues list: *Are OPG's payment amounts appropriately designed to incent OPG to operate its regulated generation facilities to earn Other Revenues so as to fairly benefit both OPG and ratepayers?* OEB staff replied that the IESO's proposal is not required as it relates to a hydroelectric payment amount application under cost of service or Custom IR, while the current application is IRM. OPG's reply also noted that incentives for ancillary services affect OPG as well as other market participants. OPG submitted that this matter is not appropriate for an OPG payment amounts proceeding. In correspondence filed on September 12, 2016, the IESO informed the OEB that, after discussions with OPG, the IESO and OPG have committed to working together outside the formal regulatory process to address the IESO's concerns. Accordingly, the OEB will not add the issue originally proposed by the IESO. (Decision on Issues List, September 23, 2016, p. 13)

IESO Interrogatory #2

Issue Number: 11.2
Issue: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?

Interrogatory

SMO

Preamble:
Segregated Mode of Operation ("SMO") is when an Ontario generator is physically disconnected from the IESO-controlled grid and then directly connected via a radial interconnection transmission line to the neighbouring control area.

The IESO is looking to better understand how OPG operates its regulated facilities for the purpose of earning Other Revenues. In particular, the IESO is interested in understanding the allocation of costs and calculation of net revenues from SMO as well as whether payments received from Quebec for the energy delivered during SMO (including inadvertent energy payment streams) contribute to OPG's "Other Revenues".

Please explain which energy delivery and inadvertent energy payment streams contribute to OPG's "Other Revenues".

Response

Please see OPG's response in Ex. L-11.2-9 IESO-1.

IESO Interrogatory #3

Issue Number: 11.2
Issue: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?

Interrogatory

SMO

Preamble:
Segregated Mode of Operation ("SMO") is when an Ontario generator is physically disconnected from the IESO-controlled grid and then directly connected via a radial interconnection transmission line to the neighbouring control area.

The IESO is looking to better understand how OPG operates its regulated facilities for the purpose of earning Other Revenues. In particular, the IESO is interested in understanding the allocation of costs and calculation of net revenues from SMO as well as whether payments received from Quebec for the energy delivered during SMO (including inadvertent energy payment streams) contribute to OPG's "Other Revenues".

Are revenues received from Quebec when OPG is operating in SMO included in "Other Revenues"?

Response

Please see OPG's response in L-11.2-9 IESO-1.

IESO Interrogatory #4

Issue Number: 11.2
Issue: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?

Interrogatory

SMO

Preamble:
Segregated Mode of Operation ("SMO") is when an Ontario generator is physically disconnected from the IESO-controlled grid and then directly connected via a radial interconnection transmission line to the neighbouring control area.

The IESO is looking to better understand how OPG operates its regulated facilities for the purpose of earning Other Revenues. In particular, the IESO is interested in understanding the allocation of costs and calculation of net revenues from SMO as well as whether payments received from Quebec for the energy delivered during SMO (including inadvertent energy payment streams) contribute to OPG's "Other Revenues".

Does the "Production Forecast" in OPG's application include production from SMO? Is "inadvertent" energy included in the production forecast as SMO production? If not how is it reported? Is it subject to revenue sharing?

Response

Please see OPG's response in L-11.2-9 IESO-1.

IESO Interrogatory #5

Issue Number: 11.2
Issue: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?

Interrogatory

SMO

Preamble:
Segregated Mode of Operation ("SMO") is when an Ontario generator is physically disconnected from the IESO-controlled grid and then directly connected via a radial interconnection transmission line to the neighbouring control area.

The IESO is looking to better understand how OPG operates its regulated facilities for the purpose of earning Other Revenues. In particular, the IESO is interested in understanding the allocation of costs and calculation of net revenues from SMO as well as whether payments received from Quebec for the energy delivered during SMO (including inadvertent energy payment streams) contribute to OPG's "Other Revenues".

Please explain how differences in actual "Other Revenues" from forecast are treated / accounted for?

Response

Please see OPG's response in L-11.2-9 IESO-1.

IESO Interrogatory #6

Issue Number: 11.2
Issue: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?

Interrogatory

Capacity Exports

Ref: Exhibit H1, Tab 1, Schedule 1, Page 9

Preamble:
An IESO Stakeholder Engagement is currently addressing the export of Ontario generation capacity to other jurisdictions.

Does OPG anticipate that over the term of its IRM it may receive "Other Revenues" from sources in addition to those addressed in its current "Other Revenues" forecast, e.g., capacity exports? If yes, how does OPG intend to account for these potential additional revenues pending its next payment amounts application?

Response

Please see OPG's response in L-11.2-9 IESO-1.

IESO Interrogatory #7

Issue Number: 11.2
Issue: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?

Interrogatory

Cost Allocation

Preamble:
OPG allocates specific costs that are incurred at Corporate or Plant Group levels to the generation facilities that operate within each of the various Plant Groups. The manner of the allocation of these costs can either be determined as a direct allocation or by an allocated portion based on an operating parameter.

Will the previously approved cost allocation methodology continue under an IRM structure? If yes, could OPG explain that methodology (for example, providing a breakdown by category or function of the various Corporate, Support Services, Plant Group or other Resource Service costs that are currently allocated to the various Plant Groups and the generation assets; the parameters that are utilized to allocate each of the specific costs that are allocated to the generation facilities; how it allocates costs across its facilities, specifically regulated generation facilities vs. non regulated generation facilities; and the allocation methodology used by each of the different Plant Groups to allocate its Corporate and Plant Group Level costs to each of the assets contained in each of the Plant Group)?

Response

Please see OPG's response in L-11.2-9 IESO-1.

IESO Interrogatory #8

Issue Number: 11.2
Issue: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?

Interrogatory

Cost Allocation

Preamble:
OPG allocates specific costs that are incurred at Corporate or Plant Group levels to the generation facilities that operate within each of the various Plant Groups. The manner of the allocation of these costs can either be determined as a direct allocation or by an allocated portion based on an operating parameter.

Are the parameters for the allocation methodologies used by each of the Plant Groups completed the same (e.g., number of generating units, amount of production, capacity of the generation facility, etc.) or are some allocated using a specific parameter (e.g., number of generating units) and others are allocated through the use of another parameter (e.g., amount of production)?

Response

Please see OPG's response in L-11.2-9 IESO-1.

IESO Interrogatory #9

Issue Number: 11.2
Issue: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?

Interrogatory

Cost Allocation

Preamble:
OPG allocates specific costs that are incurred at Corporate or Plant Group levels to the generation facilities that operate within each of the various Plant Groups. The manner of the allocation of these costs can either be determined as a direct allocation or by an allocated portion based on an operating parameter.

If the allocation methodologies for allocating costs to the generation facilities is not completed using the same parameters, how does OPG ensure costs are allocated consistently to the various generation facilities?

Response

Please see OPG's response in L-11.2-9 IESO-1.

VECC Interrogatory #45

Issue Number: 11.2
Issue: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?

Interrogatory

Reference:
Reference: A1/T3/S2/Attachment 1 TFP Study pg.16

a) Dr. Denis Lawrence is acknowledged in this report but not noted as an author. Please describe the role of Dr. Lawrence in this study.

b) Please provide the TFP studies that were reviewed by the authors as part of this engagement.

Response

The following response was provided by LEI.

a) Dr. Denis Lawrence acted as a senior advisor to the LEI team. He reviewed the quantitative results of the TFP study. Dr. Lawrence is a leading advisor in the regulation, benchmarking and performance measurement of infrastructure enterprises. Furthermore, Dr. Lawrence has served in this senior advisory role on other projects with LEI.

b) As discussed on page 16 of LEI's report, LEI reviewed eighteen TFP studies on electricity generation companies and distribution utilities in preparation of its TFP study for OPG's hydroelectric operations. Please find below the list of publicly available TFP studies:

Abbott, Malcolm. *The productivity and efficiency of the Australian electricity supply industry*. Auckland, New Zealand: Energy Economics, 2005.
http://raceadmv3.nuca.ie.ufrj.br/buscarace/Docs/mabbott1.pdf

Arocena, Pablo. Price, Catherine Waddams. *Generating efficiency: economic and environmental regulation of public and private electricity generators in Spain*. Navarra, Spain: International Journal of Industrial Organization, 1999.
http://curis.ku.dk/ws/files/23184214/1999-09.pdf

Behera, S. K. Farooquie, J. A. Dash, A. P. *Productivity change of coal-fired thermal power plants in India: a Malmquist index approach*. India: IMA Journal of Management Mathematics, 2011. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=2537053

Economic Insights Pty Ltd. *The Total Factor Productivity Performance of Victoria's Gas Distribution Industry*. March 26, 2012. http://www.economicinsights.com.au/reports/Economic_Insights_Victorian_GDB_TFP_Report_26Mar2012.pdf

Diewert, W. Erwin. Nakamura, Alice O. *Benchmarking and the measurement of best practice efficiency: an electricity generation Application*. Canadian Economics Association, 1997. http://econ.sites.olt.ubc.ca/files/2013/06/pdf_paper_erwin-diewert-benchmarking-measurement1.pdf

Chien, Chen-Fu. Chen, Wen-Chih. Lo, Feng-Yu. Lin, Yi-Chiech. *A Case Study to Evaluate the Productivity Changes of the Thermal Power Plants of the Taiwan Power Compan*y. IEEE Transactions on Energy Conversion, 2007. https://ir.nctu.edu.tw/bitstream/11536/10392/1/000249039200016.pdf

Heshmati, Almas. Kumbhakar, Subal C. Sun, Kai. *Estimation of Productivity in Korean Electric Power Plants: A Semiparametric Smooth Coefficient Model*. Germany: Institute for the Study of Labor, 2013. http://repec.iza.org/dp7277.pdf

Hosseini, Mirza Hassan. Hasanpour, Javad. *Evaluating the efficiency changes of the Thermal Power Plants in Iran and Examining its Relation with Reform using DEA Model & Malmquist Index*. Iran: University of Payame Noor, 2011. http://www.ipedr.com/vol12/50-C123.pdf

Jaraitė, Jūratė. Di Maria, Corrado. *Efficiency, productivity and environmental policy: A case study of power generation in the EU*. Energy Economics, 2010. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=1718358

Kumar Jha, Deependra. Yorino, Naoto. Zoka, Yoshifumi. *Benchmarking Results of Electricity Generating Plants in Nepal Using Modified DEA Models*. Japan, 2007. http://www.neajc.org/seminar_papers/Jha_Dipendra.pdf

Makholm, Jeff D. *Total Factor Productivity and Performance-Based Ratemaking for Electricity and Gas Distribution*. Alberta: NERA Economic Consulting, 2011. http://www.nera.com/content/dam/nera/publications/archive2/PUB_TFP_Makholm_Ros.pdf

Shiu, Alice. Lam, Pun-Lee. *Total Factor Productivity Growth in China's Power Generation*. Hong Kong: Hong Kong Polytechnic University, 1999. https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0ahUKEwiL4aPwi9vPAhVEbD4KHV9_Df4QFggjMAA&url=http%3A%2F%2Fwww.ibrarian.net%2Fnavon%2Fpaper%2FTOTAL_FACTOR_PRODUCTIVITY_GROWTH_IN_CHINA_S_POWER.pdf%3Fpaperid%3D227140&usg=AFQjCNGKztZnP6eTmVmcxwi0xPTA2mVZDA&sig2=kz1dpZ7Ht-CeQlvJWQXnvQ

The remaining studies, not publicly available, are listed below:

Fong, See Kok. Mustapha, Nik Hashim. Sin, Kee Diang. *Efficiency Change in Malaysian Electricity Generation Industry*. Malaysia, 2005.

Rungsuriyawiboon, Supawat. Coelli, Tim. *Regulatory Reform and Economic Performance in US Electricity Generation*. Queensland, Australia: Centre for Efficiency and Productivity Analysis, 2004.

Zeitsch, John, Lawrence, Denis. *Decomposing Economic Inefficiency in Base-Load Power Plants*. Australia: The Journal of Productivity Analysis, 1996. Available for purchase here: http://link.springer.com/article/10.1007/BF00162047

Nelson, Randy A. Wohar, Mark E. *Regulation, Scale Economies, and Productivity In Steam-Electric Generation*. Osaka University, Institute of Social and Economic Research, 1983. Available for purchase here: http://www.jstor.org/stable/2526115?seq=1#page_scan_tab_contents

Gollop, Frank M. Roberts, Mark J. *Environmental Regulations and Productivity Growth: The Case of Fossil-fueled Electric Power Generation*. Chicago: Journal of Political Economy, 1983. Available for purchase here: https://www.jstor.org/stable/1831072?seq=1#page_scan_tab_contents

Daly, Michael J. *Productivity, Scale Economies, and Technical Change in Ontario Hydro*. Ottawa: Economic Council of Canada, 1986.

VECC Interrogatory #46

Issue Number: 11.2
Issue: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?

Interrogatory

Reference:
Reference: A1/T3/S2/Attachment 1 TFP Study pg.19

The authors of the TFP Study state that they believe "*variability in annual hydrology should not be an obstacle to this TFP study*." Please explain what study was made of hydrology issues, including prolonged drought in the U.S. southwest that allowed the authors to come to this conclusion.

a) Specifically, did the authors use water flow variation of OPG to show the historical norm. Did the authors complete a similar analysis on each of the peer group participants? If yes, please provide this analysis.

b) Please explain why water rental rates were removed from the TFP study.

Response

The following response was provided by LEI.

a) After LEI collected data for all peers to conduct the TFP study, LEI also investigated whether each peer had anomalies in their generation trends over the study timeframe (2002-2014). Generation data was compiled from FF1, EIA-923 form, and annual reports. For example, one peer was excluded from the final study due to an abnormal hydrology cycle – WAPA (please refer to page 37 on the report).

LEI also utilized the trend regression method of calculating TFP growth rate, in order to compensate for any possible volatility in the first and last year of the study period hydrology, which further supports the statement that the question is quoting from LEI's Report. As noted in Section 6.2.2 of the LEI Report, the results from the trend regression were similar to those of the average growth method.

LEI examined the 20 year water flow statistics (monthly Cubic Meters per second) for OPG as presented in figure 8 of page 19 of the LEI Report. For the other peers, we examined the average generation (monthly MWh) over a similar (20 year) timeframe, as hydrology was not available.

b) As discussed in footnote 74 on page 58, water rental rates are essentially a pass through and not a true cost for production of hydroelectricity, similar to a tax. This applies to OPG as well as U.S. peers.

VECC Interrogatory #47

Issue Number: 11.2
Issue: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?

Interrogatory

Reference:
Reference: A1/T3/S2/Attachment 1 TFP Study pgs.27-

a) The authors choose a period of 2002-2014 for the study. Was a sensitivity analysis done of the time period? If yes what were the results?

b) Given the difficulty of obtaining a full year's revenue data for OPG for 2002 why was 2003 not considered a better starting point? What difference would starting the study at 2003 have made to the results?

c) Why was Purchasing Power Parity used to adjust for currency difference rather than exchange rates? Was an analysis of the trend completed using exchange rates? If yes please provide those results.

d) Please provide the annual difference as between to daily average annual exchange rate and the PPP.

Response

The following response was provided by LEI.

a) LEI originally conducted a TFP study for the 2002-2012 period. That report was issued for stakeholder review on December 19, 2014. Subsequently, LEI updated the study with additional years of data (2002-2014), which resulted in the current report dated February 19, 2016, which was then filed as Attachment 1 to Ex. A1-3-2.

In the process of evaluating the data, LEI also performed sensitivity analysis to assess the average TFP growth rate for shorter timeframes within the 2002-2014 period. Please refer to figure 27 on the LEI report for the annual TFP index growth rates using the average growth method. A summary of the industry average TFP growth rates for varying periods is summarized in the table below:

10-year timeframe (2005–2014)	-1.83%
11 year timeframe (2004-2014)	-1.49%
12 year timeframe (2003-2014)	-1.75%
13 year timeframe (2002-2014)	-1.01%

b) LEI preferred to use as many years of data as possible. Use of 2002 financial data was deemed robust for purposes of calculating a TFP trend for the industry, inclusive of OPG, as described on page 27 of the LEI Report.

Notwithstanding the above, if LEI started with 2003, the results for the average TFP growth rate would not change materially. Under the average growth method, and as described above in answer to part a), the TFP growth for the industry would be -1.75%. If we use the trend regression method for the 2003-2014 data, the TFP growth rate would be -1.39%.

c) Purchasing Power Parity (PPP) is defined by the OECD, as the "rates of currency conversion that equalise the purchasing power of different currencies by eliminating the differences in price levels between countries".[1] In LEI's study, the 2014 OECD PPP for GDP, at a rate of 1.23 was used to convert any implicit quantities to a common currency so that that U.S. and Canadian peers could be compared on an equal basis. PPP was chosen over exchange rates as it better reflects underlying fundamentals (excluding the effect of speculation, for example) and is a less volatile measurement and therefore more appropriate for a long term productivity study. This is discussed in footnote 64 on page 39 of LEI's Report. Performing an analysis with exchange rates rather than PPP was not done at the time we completed our TFP study, however, sensitivity analysis around the PPP value used did not change results (also discussed on page 39 of the LEI Report).

d) LEI did not have exchange rates on file, as discussed in answer to part c) above, because LEI did not use exchange rates in this TFP Study. That notwithstanding, LEI collated, for the purpose of this response, historical average US-Canadian exchange rates from 2001-2014 (Bloomberg), as shown in the following chart:

[1] Source: https://stats.oecd.org/glossary/detail.asp?ID=2205

	PPP (OECD)	Δ	USD/CAD (Bloomberg)	Δ
2001	1.22		1.55	
2002	1.23	1%	1.57	1%
2003	1.23	0%	1.40	-11%
2004	1.23	0%	1.30	-7%
2005	1.21	-2%	1.21	-7%
2006	1.21	0%	1.13	-6%
2007	1.21	0%	1.07	-5%
2008	1.23	2%	1.07	-1%
2009	1.20	-2%	1.14	7%
2010	1.22	2%	1.03	-10%
2011	1.24	2%	0.99	-4%
2012	1.24	0%	1.00	1%
2013	1.22	-2%	1.03	3%
2014	1.23	1%	1.10	7%
2015	1.25	2%	1.28	16%
Average annual Δ		0%		-1%

VECC Interrogatory #48

Issue Number: 11.2
Issue: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?

Interrogatory

Reference:
Reference: A1/T3/S2/Attachment 1 TFP Study pg.38

a) Please explain specifically what data is unavailable from Hydro Quebec, Newfoundland & Labrador Hydro and Manitoba Hydro that precluded their inclusion in this study.

b) Please explain what businesses other than hydro- electric production was included in the available data of these utilities that precluded their inclusion in the TFP study.

Response

The following response was provided by LEI.

a) As noted in Section 5.2.4 of the LEI Report, while most operational data was collected, hydroelectric specific O&M data was lacking from all Canadian peers which prevented their inclusion in an industry TFP study. Furthermore, complete series of annual hydroelectric generation revenues was missing for certain Canadian peers.

b) For the excluded Canadian peers, O&M data was either not available (as was the case with Nalcor Energy) or was combined with other generation type O&M (for example, thermal and or nuclear were included for Manitoba Hydro, BC Hydro, Hydro Quebec and New Brunswick Power) which precluded these peers from being included in the study. As stated in Section 5.2.4, LEI reached out to Canadian peers directly in attempt to isolate the appropriate hydro specific O&M costs, but was unable to obtain the information.

AMPCO Interrogatory #156

Issue Number: 11.3
Issue: Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?

Interrogatory

Reference:
Ref: A1-3-2 Page 33 Chart 10

a) Please recast Table 10 based on a production-weighted average stretch factor that sets the Darlington Stretch factor at 0.15%.

Response

a) The stretch factor calculation in Ex. A1-3-2, p. 32, Chart 9 is reproduced below with Darlington at 0% (as proposed by OPG) and Darlington at 0.15% (as requested).

Input	Value (Proposed)	Value (Per Question)
OEB-approved 2015 Darlington production (TWh)	25.0	25.0
OEB-approved 2015 Pickering production (TWh)	21.6	21.6
Darlington stretch factor	0.0%*	0.15%**
Pickering stretch factor (based on benchmark performance)	0.6%	0.6%
Production-weighted average stretch factor	0.3%***	0.3%****

*Value proposed is based on benchmark performance.
**Value per questions is based on the AMPCO request.
***0.28%, rounded to nearest 4GIRM stretch factor value
****0.36%, rounded to nearest 4GIRM stretch factor value

As illustrated above, the resulting production-weighted average stretch factor rounds to 0.3% regardless of whether a 0% or a 0.15% stretch factor is used for Darlington. Since the information in Table 10 would be unchanged, there is no need to recast it.

CME Interrogatory #3

Issue Number: 11.3
Issue: Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?

Interrogatory

Reference:
Ref: Exhibit A1, Tab 3, Schedule 1, page 6 of 12

OPG proposes to apply the stretch factor to approximately $1.7 billion, or approximately 75% of OPG's total nuclear OM&A in each year of the application. Please explain why the stretch factor is being applied to only 75% of OPG's total nuclear OM&A, and not to 100% of OPG's total nuclear OM&A in each year of the application

Response

OPG's Nuclear stretch factor proposal and the rationale that supports it are detailed in section 3.2 of Ex. A1-3-2, pages 28 to 33.

CME Interrogatory #7

Issue Number: 11.3
Issue: Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?

Interrogatory

Reference:
Ref: Exhibit A1, Tab 3, Schedule 2, page 24 of 54

OPG states that it has developed a Custom IR framework that is based on the principles set out in the RRFE, the OEB's prior guidance on incentive ratemaking, and on stakeholder feedback. Please provide a list of the "OEB's prior guidance on incentive ratemaking" that has been relied upon by OPG in developing its proposed Custom IR framework.

In this regard, OPG states that the nuclear Custom IR framework has been informed by various sources including the OEB's 2012/2013 consultation on incentive rate-making at OPG, and also "prior OEB decisions". Please provide a list of the "prior OEB decisions" that OPG has relied upon, and any other OEB information generically included in the phrase "OEB's prior guidance on incentive ratemaking".

Response

The sources that informed OPG's proposed Custom IR framework are listed on lines 16-24 of page 24 of Ex. A1-3-2. Further, the sources relied upon to address RRFE policy objectives are detailed in chart 8 of Ex. A1-3-2.

OPG's methodology for setting payment amounts has been discussed extensively since OPG was first regulated by the OEB. A summary of its methodology evolution is outlined in section 10.1 of the OEB's Decision with Reasons of EB-2013-0321. Most recently, OPG relied upon the OEB letter of February 17, 2015 regarding Incentive Rate-setting for Ontario Power Generation's Prescribed Generation Assets.

CME Interrogatory #8

Issue Number: 11.3
Issue: Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?

Interrogatory

Reference:
Ref: Exhibit A1, Tab 3, Schedule 2, page 28 of 54

OPG proposes to apply benchmark-based stretch factor to revenue requirement attributable only to the company's nuclear Base OM&A and allocated corporate support services OM&A. Please explain why the proposed stretch factor applies only to these two (2) elements of OPG's OM&A and not all of OPG's OM&A.

Response

Please see Ex. L-11.3-3 CME-3.

CME Interrogatory #9

Issue Number: 11.3
Issue: Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?

Interrogatory

Reference:
Ref: Exhibit A1, Tab 3, Schedule 2, page 33 of 54, Chart 10 — Stretch Reduction Amounts

Chart 10 – Stretch Reduction Amounts shows the product of applying the 0.3% stretch factor to Base OM&A and allocated Corporate Support OM&A. Please re-create Chart 10 as follows:

(a) Replace the stretch factor of 0.3% with a stretch factor of 0.6%; and

(b) Please apply a stretch factor of 0.3% and 0.6% to OPG's total OM&A instead of just the Base and Corporate Support OM&A.

Response

a) The revised chart requested is presented below:

Stretch Reduction Amounts using a Stretch Factor of 0.6%

($M)	2018	2019	2020	2021
Base & Corporate Support OM&A	1,663.2	1,691.1	1,709.7	1,730.4
Stretch Factor	0.6%	0.6%	0.6%	0.6%
Annual Stretch Reduction to Nuclear Revenue Requirement	10.0	20.1	30.4	40.8
Base & Corporate Support OM&A Used to Determine Payment Amounts	1,653.2	1,671.0	1,679.3	1,689.6

b) The revised charts requested are presented below:

Stretch Reduction Applied to Total Nuclear OM&A using a Stretch Factor of 0.3%

($M)	2018	2019	2020	2021
Total OM&A	2,327.1	2,347.9	2,368.0	2,248.7
Stretch Factor	0.3%	0.3%	0.3%	0.3%
Annual Stretch Reduction to Nuclear Revenue Requirement	**7.0**	**14.0**	**21.1**	**27.9**
Total OM&A Used to Determine Payment Amounts	**2,320.1**	**2,333.9**	**2,346.8**	**2,220.8**

Stretch Reduction Applied to Total Nuclear OM&A using a Stretch Factor of 0.6%

($M)	2018	2019	2020	2021
Total OM&A	2,327.1	2,347.9	2,368.0	2,248.7
Stretch Factor	0.6%	0.6%	0.6%	0.6%
Annual Stretch Reduction to Nuclear Revenue Requirement	**14.0**	**28.1**	**42.3**	**55.8**
Total OM&A Used to Determine Payment Amounts	**2,313.2**	**2,319.8**	**2,325.7**	**2,193.0**

CME Interrogatory #10

Issue Number: 11.3
Issue: Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?

Interrogatory

Reference:
Ref: Exhibit A1, Tab 3, Schedule 2, page 33 of 54

OPG states that it is not proposing a nuclear industry productivity factor because the nature and scale of capital work planned for the IR period would make past productivity trends an unreasonable indicator of predicted productivity for OPG during the IR period. In order for CME to better understand OPG's anticipated productivity during the IR term, please provide the following information:

(a) Does OPG believe that it will achieve any productivity gains during the IR period? If yes, please set out the anticipated productivity gains. If no, please explain why OPG believes that it will not achieve any productivity for the period 2018 to 2021;

(b) If OPG believes that it will not achieve any productivity gains during the proposed IR term, does OPG agree that this is a reason not to adopt incentive regulation concurrent with the capital work planned for the IR period? Specifically, does OPG believe that this is a reason to consider continuing with cost of service ratemaking instead of incentive regulation? If not, please explain;

(c) Is OPG aware of the Board approving an incentive regulation mechanism for any regulated utility in Ontario that does not include a productivity factor? If yes, please identify the utility and the Board's corresponding decision; and

(d) Is OPG aware of any regulator in North America approving an incentive regulation mechanism which does not include a productivity factor? If yes, please identify the utility and the regulator, as well as the decision reference.

Response

a) Yes. OPG expects that the company will continue to improve performance and efficiency throughout the term of this application. The business plan on which the application is based includes a series of major nuclear performance initiatives, as identified in Ex. A1-3-2, p. 37 and described in more detail in the Nuclear Business Planning and Benchmarking evidence at Ex. F2-1-1. To the extent that

OPG is unable to achieve the targeted benefits from these initiatives, the company's costs and forecast production are at risk.

The initiatives have varied and, in some cases, overlapping effects on OPG's performance. As a result, OPG cannot quantify specific OM&A savings attributable to individual initiatives. However, as noted in Ex. L-6.2-20 VECC-25 part (b), OPG's 100% variable rate design creates a natural incentive to meet and exceed the performance targets in the company's business plan.

b) Not applicable, per response to part (a).

c) The OEB has not always required that incentive rate-setting frameworks include a productivity factor. In the case of electric distributors, the OEB has historically applied a productivity factor based on some form of industry productivity analysis, which does not exist for the nuclear generation sector. In the OEB's regulation of natural gas distributors, productivity expectations and utility-specific stretch factor considerations were combined to inform rate paths[1] or to form a single adjustment to the I-factor in a variant of the index based IRM.[2]

d) As London Economics International LLC (LEI) is an expert in incentive regulation, OPG asked LEI to respond to this question. LEI provided the following response:

Incentive Regulation Mechanism (IRM) is an umbrella term that encompasses a variety of regulatory approaches that aim to provide incentives for utilities to lower rates and costs or improve non-price performance. IRM is an alternative to traditional cost of service (COS) approach that can motivate larger efficiency improvements among utilities leading to lower rates for customers in the long run. It is best conceptualized as a continuum, ranging from "soft" to "hard" mechanisms, rather than a single type of regulatory regime.

For example, jurisdictions which implement a rate freeze or earnings sharing mechanisms (ESM) can be considered to be under an IRM regime. The rate freeze approach includes minor modifications to the traditional COS rate-setting, however, the company retains efficiency gains until the next regulatory review.

[1] EB-2012-0459, Decision with Reasons, July 14, 2014: Enbridge's Custom Incentive Regulation rate setting framework is based on a 5-year forecast of capital and operating costs inclusive of productivity savings, for the period 2014-2018.
[2] EB-2007-0606: Settlement Agreement, January 3, 2008, Section 3: "the X factor (inclusive of any stretch factor) that will be used in Union's price cap index is fixed at 1.82% for the IR term"; EB-2007-0615, Decision, February 11, 2008: Enbridge settled for an inflation coefficient "P" in formula of 0.60, 0.55, 0.55, 0.50 and 0.45 for 2008 to 2012; EB-2013-0202, Settlement Agreement, July 31, 2013, Section 3: "Union will commit to pursuing productivity of 60% of GDP IPPI-FDD, inclusive of a stretch factor".

Depending on the implementation (the period over which rates are frozen, for example), the rate freeze approach can also be seen as a "hard" mechanism, comparable to a price cap. Similarly, the ESM approach allows the utility to retain a portion of the efficiency gains, with the remainder being shared among its customers. A productivity factor might not be necessary under these regulatory regimes. Below are a few examples of utilities under rate freeze and ESM in North America.

- Rate Freeze:
  - Gulf Power (Florida): Rate freeze expires on 7/1/2017. The company obtained approval for a base rate increase in 2015 and cannot request an increase to be effective prior to 7/1/15 unless return on equity falls below 9.25%. (Docket 150112)
  - Duke Energy Florida (Florida): Rate freeze expires on 1/1/19. The company was required to freeze base rates through 2018 – as per 10/17/13 rate case settlement. (Docket 130249)
  - Florida Power & Light (Florida): Rate freeze expires on 1/1/17. The company obtained approval for a base rate increase on 1/1/13, which requires a rate case moratorium through Dec. 2016, except for increases in 2013, 2014, and 2016 to address three generating plant modernization projects. (Docket 120244)

- Earnings Sharing Mechanism:
  - NYSEG: revenue requirements based on 10% allowed ROE applied to an equity ratio of 48%. Earnings above the allowed return are shared. The ESM is subject to specified downward adjustments if NYSEG fails to meet certain reliability and customer service measures. (Financial Statements 2015 and 2014, NYSEG Rate Plans, page 15)
  - Yankee Gas Services Company (subsidiary of Eversource): ESM 50:50 in any earnings exceeding a 9.5% ROE in a twelve month period commencing with the period from April 1, 2015 through March 31, 2016. (Financial Statements 2015 and 2014, 2015 Regulatory Development, page 9)

LEI is not aware of any nuclear generators under an IRM scheme similar to the OEB's framework (i.e. an I-X formulaic approach).

LPMA Interrogatory #11

Issue Number: 11.3
Issue: Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?

Interrogatory

Reference:
Ref: Exhibit A1, Tab 3, Schedule 2, page 34

a) Please explain why the revenue requirement impact of the variance between the forecast ROE approved for 2018 to 2021 in this application and the actual ROE that the OEB will specify annually for 2018 to 2021 would be recorded in the proposed Nuclear ROE Variance Account rather than be reflected in rates for each of 2018 to 2021, at the same time as OPG files for the updated inflation factor for the regulated hydroelectric assets.

b) Would the amount included in the Nuclear ROE Variance Account be based only on the difference in the ROE percentage?

c) Would the amount included in the Nuclear ROE Variance Account be based on the forecasted and approved nuclear rate base or would actual nuclear rate base be used? Please explain fully.

Response

a) See L-03.2-1 Staff-023 part d).

b) As discussed in Ex. H1-1-1, Section 6.3, OPG is proposing to record the annual nuclear revenue requirement impact of the difference between the OEB's annually updated prescribed ROE and the annual ROE incorporated into the 2018 to 2021 annual revenue requirements approved by the OEB.

c) As discussed in Ex. H1-1-1, Section 6.3, OPG is proposing to multiply the difference in ROE in each of 2018 to 2021 by the forecast nuclear rate base financed by capital structure for each year in 2018 to 2021 that is approved by the OEB in this Application.

VECC Interrogatory #49

Issue Number: 11.3
Issue: Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?

Interrogatory

Reference:
Reference: A1/T3/S2/pg.30-31

a) For the 25% of costs which OPG will not apply the stretch factor please identify all the individual area (e.g. emergency preparedness) and the total annual test year costs in those areas.

b) For each area please give the portion of costs that are compensation and benefit related.

c) OPG notes that these are areas in which it will not, or cannot compromise its commitments. However, it does not explain why it is not possible to execute its responsibilities in these areas in a more efficient manner. For each of the areas identified please explain the reason no efficiencies can be found while still carrying out the prescribed duties.

Response

a) A summary of nuclear operating cost information is provided in Ex. F2-1-1 Table 1. Of the costs identified in Table 1, the stretch factor applies to Nuclear Base OM&A and Corporate Support OM&A. The major operational components of the remaining Nuclear OM&A are Project OM&A (detailed provided in Ex. F2-3-1) and Outage OM&A (detailed provided in Ex. F2-4-1). The costs in these areas are not budgeted on the basis of individual areas (like emergency preparedness). Project OM&A is comprised of "temporary, unique endeavour[s] undertaken outside the routine base activities of the normal work program" (Ex. F2-3-1, p. 1, lines 23-24). Outage OM&A costs are tied to specific outages, and "vary year over year depending on the number and scope of outages and therefore cannot be trended over time" (Ex. F2-4-1, p. 1, lines 7-8).

   The other material components of Nuclear OM&A to which the stretch factor does not apply are:
   - Darlington Refurbishment OM&A (details provided in Ex. F2-7-1)
   - Centrally Held and Other Costs (detailed provided in Ex. F4-4-1)
   - Asset Service Fees (detailed provided in Ex. F3-2-1)

b) Please see Chart 1 below.

Chart 1: Labour Component of Costs Excluded from Nuclear Stretch Factor ($M)

Cost Component	2018	2019	2020	2021	Reference
Outage OM&A					
Labour	124.3	121.4	88.6	50.6	
Total Outage	393.8	415.3	394.4	308.5	F2-4-1 Table 2
Labour % of Total	32%	29%	22%	16%	
Project OM&A					
Labour	26.7	26.5	25.4	20.7	
Total Projects	109.1	100.1	100.2	86.8	F2-3-1 Table 1
Labour % of Total	24%	26%	25%	24%	

There are no material labour costs associated with Darlington Refurbishment OM&A, and Asset Service Fees. The centrally-held compensation-related costs primarily consist of centrally-held pension and OPEB accrual costs (Ex. F4-4-1 Table 3, line 1), performance incentives (Ex. F4-4-1 table 3 line 5) and a negative adjustment that converts pension and OPEB costs from an accrual to a cash basis (Ex. F4-4-1 table 3, line 2). On a net basis, these amounts result in annual reductions in costs of approximately -$48.3M in 2018, -$34.2M in 2019, -$38.2M in 2020, and -$26.3M in 2021.

c) The question appears to misinterpret the referenced evidence. At the reference, OPG states that Base OM&A (which is already subject to the proposed stretch factor) "includes several critical, regulated functions including safety, emergency preparedness, inspections, operations and maintenance" that OPG will not compromise, despite the fact that the associated costs <u>are subject to the stretch factor</u>. The necessary effect of consistent spending in these areas is to put additional pressure on OPG to find efficiencies in other nuclear costs.

Board Staff Interrogatory #255

Issue Number: 11.4
Issue: Does the Custom IR application adequately include expectations for productivity and efficiency gains relative to benchmarks and establish an appropriately structured incentive-based rate framework?

Interrogatory

Reference:
Ref: Exh A1-3-2 pages 35-36
Ref: Exh F4-3-1 page 6

OPG notes that operational effectiveness is one of the four outcomes that the OEB seeks to promote through the RRFE, specifically continuous improvement in productivity and cost performance. OPG lists the ways that the nuclear business achieves these outcomes in Exh A1-3-2.

a) OPG states that there are “staffing and compensation strategies designed to ensure key resources are available when needed, to minimize risk, and to ensure safe and efficient operations.”
    i. Have these staffing and compensation strategies been revised recently? If yes, please explain the changes.
    ii. Please explain the effectiveness of the staffing and compensation strategies given the higher than expected number of retirements in the nuclear business in 2015, of which “over two thirds of the 2015 retirements were in the critical operations, maintenance and technical roles and will need to be replaced.”

b) OPG states that the “performance-based planning process allows OPG to track the company’s results against targets, and to set appropriate targets for each successive year, creating a cycle of continuous performance and cost efficiency improvement.” Please provide examples of the cycle of continuous performance and cost efficiency improvement.

Response

a) Please find OPG’s responses to parts (i) and (ii) below.

    i. Yes, OPG revised its staffing and compensation strategies in 2015 and 2016.

    For staffing, OPG has launched a simplified hiring process for internal and external staffing, re-organized and augmented the recruitment team, and added additional vendor partners to support the needs of the business. The process is now managed end-to-end by OPG's resourcing team.

For compensation, as described in Ex. F4-3-1, pp. 12 and 21, OPG re-instated its annual base pay increase program for management staff below the Vice President level as part of its pay for performance program and implemented new salary ranges that were aligned with OPG's target market positioning. OPG also aligned pension reforms with those recently negotiated for represented staff (i.e. Rule of 90 implementation for existing employees takes effect in 2025 when the PWU and Society changes are made). OPG will continue to monitor its compensation relative to external labour markets to ensure its compensation is competitive, affordable and aligned with OPG's business strategy and the environment in which it operates.

ii. The number of retirements OPG has experienced is largely a function of the demographic profile of its employee population. The strategies referred to above are not expected to reduce the number of retirements overall. Instead, they seek to ensure we are able to attract, develop and retain the leadership talent required to deliver power to the province of Ontario in a manner that is aligned with both Shareholder and stakeholder expectations.

OPG's new staffing model referred to above in (i) has allowed OPG to hire more than three times the total number of staff compared to previous years and is now well positioned to meet staffing needs for 2017 and beyond.

It is expected that the changes made to OPG's compensation program will take 1-3 years to materially impact the risk.

b) Examples of the cycle of continuous performance and cost efficiency improvement are reflected in the prior gap closure initiatives described at Ex. F2-1-1, Attachment 4.

Board Staff Interrogatory #256

Issue Number: 11.4
Issue: Does the Custom IR application adequately include expectations for productivity and efficiency gains relative to benchmarks and establish an appropriately structured incentive-based rate framework?

Interrogatory

Reference:
Ref: Exh A1-3-2 page 28 to 33
Ref: Exh A2-2-1 Attachment 1 page 3
Ref: Exh F2-1-1 Attachment 1 page 89

OPG's nuclear Custom IR framework is based on five individual nuclear revenue requirements, but includes incremental year over year reductions based on a proposed 0.3% stretch factor. OPG's derivation of the stretch factor is based on production weighting top quartile performance by Darlington (0% stretch) and fourth quartile performance by Pickering (0.6% stretch).

The OPG 2016-2018 Business Plan states that "Starting in 2016, OPG is adopting Total Generating Cost (TGC) per MWh as an enterprise-wide measure of operational cost effectiveness."

The EUCG indicator results summary of value for money performance is provided at page 89 of Attachment 1 of Exh F2-1-1. OPG's average nuclear TGC is $50.61/MWh, while the median is $42.53/MWh and the best quartile is $37.12/MWh.

Please explain why a 0.3% stretch factor is appropriate.

Response

Consistent with the 2016-2018 Business Plan, the Nuclear stretch factor was determined by the respective Total Generating Cost (TGC) of the Darlington and Pickering stations. As described in section 3.2.1 of Ex. A1-3-2, OPG calculated individual stretch factors for each station based on their TGC performance. The proposed 0.3% stretch factor was calculated by production-weighting the individual stations' stretch factors for as detailed in Chart 9 of Ex. A1-3-2.

The Darlington and Pickering stations are different from each other in significant ways. The stations have different designs, are at different states of their life cycles, and, as a result, have different improvement opportunities available. A stretch factor that uses OPG's average TGC blends the two stations' results and does not appropriately represent the opportunities for efficiency gains at the two facilities. Darlington has historically achieved high levels of efficiency and identifying further improvement beyond the requirements in the business plan would be very challenging. While Pickering's historic benchmarking performance may seem to suggest there are opportunities for efficiency improvements, the evidence is that opportunities are limited due to the size of units, its first generation CANDU technology design, and the reduction in capability factor during the outages required to enable extended operations (Ex. F2-1-1 pp. 5 and 9).

OPG has also benchmarked Darlington and Pickering TGC on a per unit basis, which shows both stations in the top quartile (Ex. F2-1-1 p. 5 and Chart 3). This benchmarking eliminates generation impacts at Pickering due to unit size, design and the extensive outage program. It recognizes that each nuclear unit has costs driven by the equipment in the unit, safety procedures, etc., that exist irrespective of the generation output of the unit. It shows that Pickering has been effective at driving down the costs of operating each unit, largely through staff reduction.

OPG therefore believes that a stretch factor determined at the plant level and then combined by production-weighting the values is the most appropriate approach. Further, as the Darlington and Pickering stations are significantly different from each other and are operated independently, the stretch factor assigned to each station should reflect the performance of that station, and the basis of peer comparison should similarly be assessed against a sample of individual plants rather than the sample noted in the question (i.e. operators with two or more plants).

Notwithstanding the above position, if the stretch factor were calculated based on a combined average TGC value the result would still be 0.3%. The 0.3% stretch factor is the middle stretch factor value, which would apply to a range of total generation cost values above and below the median value. If the lower bound of the median range is half way between the median value ($44.61/MWh) and the top quartile ($38.71/MWh), and the upper bound is half way between the median and third quartile value ($57.02/MWh), the median range is $41.66/MWh to $50.82/MWh. OPG's production weighted TGC amount referenced in the question is $50.61/MWh, which is in the median range.

OPG's approach is appropriate because it creates the right incentives for both station groups. An effective stretch factor is one that motivates each facility to continuously improve its performance.

PWU Interrogatory #20

Issue Number: 11.4
Issue: Does the Custom IR application adequately include expectations for productivity and efficiency gains relative to benchmarks and establish an appropriately structured incentive-based rate framework?

Interrogatory

Reference:
Ref (a): Exhibit A1-3-2, Page 29 of 54:

The proposed stretch reduction targets elements of the company's nuclear costs that constitute a significant amount of OPG's nuclear revenue requirement during this application. The stretch factor applies to an average of $1.7 billion or approximately 75% of OPG's total nuclear OM&A in each year of the application.

Ref (b): Exhibit A1-3-2, Page 32 of 54, Chart 9:

Chart 9 – Derivation of Nuclear Stretch Factor

Input	Value
OEB-approved 2015 Darlington production (TWh)	25.0
OEB-approved 2015 Pickering production (TWh)	21.6
Darlington stretch factor (based on benchmark performance)	0.0%
Pickering stretch factor (based on benchmark performance)	0.6%
Production-weighted average stretch factor	0.3%

a) What is OPG's view on the appropriateness of a custom IR application for its nuclear business?

b) The Pickering stretch factor is 0.6%. Does OPG consider applying the 0.6% stretch factor to Pickering appropriate as poor benchmark performance may reflect that it is an ageing nuclear asset?

c) Does the stretch factor apply to OM&A costs that are related to safety measures?

Response

a) As outlined in section 3.1 of Ex. A1-3-2, OPG's proposed Custom IR framework was informed by various sources.

A Price Cap Index IR mechanism, similar to the model proposed to set hydroelectric payment amounts, is not appropriate to set payment amounts for OPG's nuclear facilities. However, OPG understand that the OEB expects the company's nuclear payment amounts to be set under a Custom IR framework based on the principles of the RRFE. Custom IR methods can take various forms, and OPG believes that this specific form of Custom IR proposed for the nuclear facilities is appropriate for the company's nuclear business. The proposed Custom IR framework will create meaningful incentives to deliver value to customers by maintaining and improving performance over the 2017-2021 period, while still allowing OPG to execute the significant work planned for the next five years.

b) As discussed in section 2 of Ex. F2-1-1, there are a number of factors that contribute to Pickering's benchmark performance, including small unit size, first generation CANDU technology, and low capability factor due to extensive planned outage programs tied to extending the life of the station. When normalizing for unit size and comparing Pickering's performance a per unit basis, the station benchmarks in the top quartile (charts 2 and 3 of Ex. F2-1-1). Pickering's performance has improved, most notably in Forced Loss Rate (FLR), achieving its best ever rate in 2015.

At the same time, OPG is a strong proponent of continuous improvement and accepts that the stretch factor should be determined by its performance on a benchmark metric that matters to customers: the cost of the energy. This is why OPG has proposed a nuclear stretch factor based on Total Generating Cost performance, despite the issues outlined in the preceding paragraph. For further discussion of the proposed stretch factor, please see Ex. L-11.4-1 Staff-256.

c) OPG has proposed that the Nuclear stretch factor apply to Nuclear Base OM&A and allocated Corporate Support costs, reflecting approximately 75% of its total nuclear OM&A. As described in section 3.2 of Ex. A1-3-2, OPG views this proportion of OM&A as a proxy for the overall level of OPG's nuclear expenditures where it is reasonable to drive efficiencies. As specifically outlined on page 30, OPG will not compromise functions that are mandated by the CNSC or where cuts could otherwise increase safety or environmental risks, regardless of whether those functions are subject to the stretch factor.

Board Staff Interrogatory #257

Issue Number: 11.5
Issue: Is OPG's proposed mid-term review appropriate?

Interrogatory

Reference:
Ref: Exh A1-3-3, page 12
The evidence states that, "Subject to the OEB concluding that rates are no longer just and reasonable pursuant to Section 78.1 of the Act, the regulation does not entitle the OEB to revisit those approved revenue requirement amounts during the five years. However, while the revenue requirement must be determined on a five-year basis, no such limitation exists for the determination of production."

Please explain on what basis the OEB would determine that "rates are no longer just and reasonable."

Response

Under Section 78.1 of the Act, it is within the OEB's determination to fix just and reasonable rates either on an application for a payment amounts order or at any other time if the OEB is not satisfied that the prevailing payment amount is just and reasonable.

Board Staff Interrogatory #258

Issue Number: 11.5
Issue: Is OPG's proposed mid-term review appropriate?

Interrogatory

Reference:
Ref: Exh A1-3-3
OPG states that the scope of its mid-term review would be limited to the nuclear production forecast from July 1, 2019 through December 31, 2021, revisions to forecast fuel costs, and disposition of audited balances in deferral and variance accounts.

Does OPG propose to file for a mid-term review if the difference between the production forecast approved in the EB-2016-0152 proceeding is insignificantly different from the future OPG approved business plan? If not, what materiality test does OPG propose to use to determine whether or not the difference in the production forecast is significant enough to warrant a mid-term review?

Response

OPG proposes to file a mid-term review regardless of the predicted production forecast variance at that time. The OEB could then determine the nature of the proceeding warranted in the circumstances.

Board Staff Interrogatory #259

Issue Number: 11.5
Issue: Is OPG's proposed mid-term review appropriate?

Interrogatory

Reference:
Ref: Exh H1-1-1, page 30, Exh A1-3-3, page 12

In its evidence, OPG describes the entries to be included in the Mid-term Nuclear Production Variance Account, as follows:

> To determine entries into the account, the monthly production variance will be multiplied by the approved smoothed nuclear payment amount. The resulting amount would then be reduced by an amount determined as a monthly production variance multiplied by the average fuel cost in the approved revenue requirement for the applicable year.

a) Please provide a sample calculation that would show the practical application of methodology outlined in Exh H1-1-1.

b) In Exh A, it's stated that "the regulation does not entitle the OEB to revisit those approved revenue requirement amounts during the five years". How is OPG's proposed adjustment to fuel cost in the Mid-term Nuclear Production Variance Account consistent with the preceding statement?

Response

a) A sample calculation for the year 2020 is provided in Chart 1 below, based on the following assumptions:

   1) The OEB approves a production forecast for July 1, 2019 to July 2021 that is 1 TWh less (the "Mid-term Production") for 2020 than OPG approved in the current application; and

   2) The OEB approves OPG's proposal in the current application, in particular:
      a. that nuclear payment amounts increase at a constant rate of 11% per year in the IR Term, and
      b. the Nuclear production forecast and fuel cost for all years in the IR Term.

The relevant values for 2020 are reflected in Chart 1:

Chart 1 – Sample Calculation

Line	Description	Amount	Evidence Reference
1	Smoothed Rate ($/MWh)	90.01	Ex. A1-3-3, p. 10, Chart 4, line 3
2	Fuel Cost ($M)	223.6	Ex. F2-5-1 Table 1 (line7 – line 6)
3	Production (TWh)	37.36	Ex. A1-3-3, p. 10, Chart 4, line 2
4	Average Fuel Cost ($/MWh)	5.985	Chart (line 2 / line 3)

The approach is described in Ex. A1-3-3, p. 14, lines 6-12. The annual production variance (i.e., 1TWh) will be multiplied by the net of the approved smoothed nuclear payment amount (i.e., $90.01/MWh) and the average fuel cost in the approved revenue requirement ($5.985/MWh) for the applicable year. The amounts determined above (i.e., 1TWh x ($90.01/MWh - $5.985/MWh) = $84.025M) will be recorded in the proposed Mid-Term Nuclear Production Variance Account described in Ex. H1-1-1. The related accounting entries would be:

Mid-Term Nuclear Production Variance Account	$84.0325M	(Debit)
Fuel Expense	$5.985M	(Debit)
Revenues	$90.01M	(Credit)

b) Unlike other costs, Nuclear fuel is a direct marginal cost associated with production. OPG believes it is appropriate that fuel cost be revised to correspond with any update to the Nuclear production forecast as part of the mid-term review. Any approved changes in nuclear fuel cost would be recorded in the Mid-term Nuclear Production Variance Account and would not involve re-opening the approved nuclear revenue requirement.

Board Staff Interrogatory #260

Issue Number: 11.5
Issue: Is OPG's proposed mid-term review appropriate?

Interrogatory

Reference:
Ref: Exh E2-1-1, Tables 1 and 2, Exh I1-3-1, Table 1

OPG has provided the monthly production forecast in Table 2 of Exhibit E2-1-1 with two significant digits of numerical precision. The annual production forecast in Table 1 of Exhibit E2-1-1 has been provided to three significant digits of numerical precision. When performing calculations in this application, such as the derivation of the nuclear payment amounts in Exhibit I1-3-1, OPG has mostly used data that is at least 3 significant digits of numerical precision.

a) Please provide an updated version of Table 2 showing the monthly production forecast to three decimal places.

b) Does OPG have any objection to the use of the monthly production forecasts to three decimal places as the basis for the determination of balances in the mid-term nuclear production variance account?

Response

a) OPG has provided Ex. E2-1-1 Table 2 to five decimal places in an excel file as part of the prefiled evidence.

b) OPG does not have any objection to the use of the monthly production forecast to three decimal places as the basis for the determination of balances in the mid-term nuclear production variance account.

Board Staff Interrogatory #261

Issue Number: 11.5
Issue: Is OPG's proposed mid-term review appropriate?

Interrogatory

Reference:
Ref: Exh A1-3-3 pages 10-14

OPG is proposing a mid-term nuclear production review to address the inherent uncertainty of out-year production forecasts in a five-year forecast cycle. OPG proposes a Mid-term Nuclear Production Variance Account to accumulate revenue deviations that may result from an updated production forecast. OPG states that "….a completely variable rate provides a strong financial incentive to OPG to achieve or surpass the OEB approved production forecast…."

a) OPG lists five risks that may make a mid-term production review attractive. Three of these five risks are inherent, generic risks to any production forecast (public policy changes, regulatory requirements and approvals, aging facilities), one is specific to this application (DRP and post-DRP loss rates), and one is a sub-issue to regulatory requirements specific to this application (CNSC approval to extend Pickering operations). Does OPG consider the proposed review a "one-time" only occurrence or a recurring event that could be included in future applications?

b) Has OPG prepared any analysis or accessed any research that assesses the impact of a mid-term production review on incentives? Does OPG have any examples from other jurisdictions where updating production forecasts has increased productivity or efficiency?

Response

a) OPG has not determined whether a mechanism to address production risk (which may or may not be in the same form as the mid-term review) will be necessary in the company's future payment amounts applications.

   OPG expects that its nuclear business will continue to undergo a significant transition over the next decade, as DRP continues to be executed and commercial operations end at Pickering. OPG expects that achieving the company's forecast nuclear production will continue to be challenging. As a result, OPG expects that the company and customers will continue to face significant risks related to nuclear production.

b) OPG has not prepared any such analysis or conducted any such research.

However, OPG observes that the company's nuclear rate design creates a strong production incentive, regardless of the approved forecast. Since OPG's payments are 100% variable, OPG will continue to have a strong incentive to produce, irrespective of the approved production forecast and any changes to that forecast that result from the mid-term production review.

Board Staff Interrogatory #270

Issue Number: 11.5
Issue: Is OPG's proposed mid-term review appropriate?

Interrogatory

Reference:
Ref: Exh A1-3-3 pages 11-12

OPG states it is extremely difficult to accurately forecast OPG's annual nuclear production over a five-year period and has also stated that it has never met its own two-year forecast (as approved by the OEB in prior years). OPG profiles five uncertainties that may have an impact on production (and implicitly associated costs):

1. Public policy changes
2. Pickering extended operations
3. Execution of Darlington refurbishment program
4. Regulatory requirements and approvals
5. Aging facilities

OPG does not quantify these uncertainties. Please provide "high and low" forecasts for production and associated cost impacts for each of these uncertainties. Please use the attached spreadsheet.

Response

The mid-term review is necessary specifically because OPG cannot quantify the effects of these uncertainties on the company's production forecast. Depending on the specific circumstances, each uncertainty could have a wide range of effects on OPG's production and fuel costs, and on its capital and operating budgets.

The range of potential permutations and combinations within and between the uncertainties prohibits OPG from producing individual forecasts that would be representative of each. This unpredictability is the basis of OPG's decision to include the mid-term Nuclear production review in this application.

As described in Ex. E2-1-1, OPG has a rigorous production forecast that accounts for uncertainties to the extent possible. For example, OPG has established a detailed high confidence schedule for the Darlington Refurbishment Program which is reflected in the production forecast.

OEB ATTACHMENT 1

i. Public Policy Changes - LTEP (how change in refurbishment schedule could alter productior

	Production Forecast (TWh)	Anticipated Cost Impact: Investment ($M CAPEX)	Anticipated Cost Impact: Maintenance Costs ($M OPEX)
Low forecast			
Baseline forecast	37.67	$ 1,282.40	$ 394.50
High forecast			

ii. Pickering Extended Operations (how Pickering units could alter production)

	Production Forecast (TWh)	Anticipated Cost Impact: Investment ($M CAPEX)	Anticipated Cost Impact: Maintenance Costs ($M OPEX)
Low forecast			
Baseline forecast	37.67	$ 1,282.40	$ 394.50
High forecast			

iii. Execution of Darlington Refurbishment (how refurbishment could alter production)

	Production Forecast (TWh)	Anticipated Cost Impact: Investment ($M CAPEX)	Anticipated Cost Impact: Maintenance Costs ($M OPEX)
Low forecast			
Baseline forecast	37.67	$ 1,282.40	$ 394.50
High forecast			

iv. Regulatory Requirements and Approvals (how changing requirements could alter product

	Production Forecast (TWh)	Anticipated Cost Impact: Investment ($M CAPEX)	Anticipated Cost Impact: Maintenance Costs ($M OPEX)
Low forecast			
Baseline forecast	37.67	$ 1,282.40	$ 394.50
High forecast			

v. Aging Facilities (how risk of unplanned outages could alter production)

	Production Forecast (TWh)	Anticipated Cost Impact: Investment ($M CAPEX)	Anticipated Cost Impact: Maintenance Costs ($M OPEX)
Low forecast			
Baseline forecast	37.67	$ 1,282.40	$ 394.50
High forecast			

* Production, Mainenance and Fuel Cost averages forecasted from Rev
Workform (Filed May 27 2016). Investment average forecasted Total N
2016-0152, Exhibit A2-2-1, Attachment 1, Page 30 of 37 (Filed: 2016-05

n)

ts

	Fuel ($M)
$	15.50 *

ts

	Fuel ($M)
$	15.50 *

ts

	Fuel ($M)
$	15.50 *

tion)

ts

	Fuel ($M)
$	15.50 *

ts

	Fuel ($M)
$	15.50 *

enue Requirement
uclear Capital from EB-
5-27)

			Average Annual Forecast
TWh	*		37.67
Investment ($M CAPEX)	**	$	1,282.40
Maintenenance Costs ($M OPEX)	*	$	394.50
Fuel ($M)	*	$	15.50

* Average forecasted from Revenue Requirement Workform (File

**Average forecasted Total Nuclear Capital from EB-2016-0152,

ed May 27 2016)
Exhibit A2-2-1, Attachment 1, Page 30 of 37 (Filed: 2016-05-27)

			Public Policy Changes - LTEP		Pickering Extendd Operations		Execution of Darlington Refurbishment Program
						Difference from Basel	
TWh	Low	-	37.67	-	37.67	-	37.67
	Baseline		-		-		-
	High	-	37.67	-	37.67	-	37.67
Investment ($M CAPEX)	Low	-$	1,282.40	-$	1,282.40	-$	1,282.40
	Baseline	$	-	$	-	$	-
	High	-$	1,282.40	-$	1,282.40	-$	1,282.40
Maintenenance Costs ($M OPEX)	Low	-$	394.50	-$	394.50	-$	394.50
	Baseline	$	-	$	-	$	-
	High	-$	394.50	-$	394.50	-$	394.50
Fuel ($M)	Low	-$	15.50	-$	15.50	-$	15.50
	Baseline	$	-	$	-	$	-
	High	-$	15.50	-$	15.50	-$	15.50

Regulatory Requirements and Approvals	Aging Facilities
line	
- 37.67	- 37.67
-	-
- 37.67	- 37.67
-$ 1,282.40	-$ 1,282.40
$ -	$ -
-$ 1,282.40	-$ 1,282.40
-$ 394.50	-$ 394.50
$ -	$ -
-$ 394.50	-$ 394.50
-$ 15.50	-$ 15.50
$ -	$ -
-$ 15.50	-$ 15.50

AMPCO Interrogatory #157

Issue Number: 11.5
Issue: Is OPG's proposed mid-term review appropriate?

Interrogatory

Reference:
Ref: A1-3-1 Page 8

Preamble: OPG indicates that given the long term of this application and the uncertainty associated with nuclear production, OPG believes that it will be necessary to review OPG's production forecast and consequential fuel costs at the mid-point of the five-year period covered by this application. OPG also proposes to clear December 31, 2018 balances in deferral and variances accounts in conjunction with the mid-term production review.

a) Please identify other costs in the application that have a significant risk of deviations from forecast increasing in the second half of the application.

Response

OPG has not identified any specific costs that have significantly higher risks of deviating from forecast in the second half of the term. The accuracy of all forecast costs is inherently lower the further into the future they are made. However, OPG accepts the principles of the RRFE and incentive rate-setting terms of five years. Further, O. Reg. 53/05 (s. 6(2)(12)(ii)) requires Nuclear revenue requirements to be set on a five-year basis (please also see Ex. L-11.5-5 CCC-50).

CCC Interrogatory #49

Issue Number: 11.5
Issue: Is OPG's proposed mid-term review appropriate?

Interrogatory

Reference:
Reference: Ex. A1/T3/S3/p. 10

OPG is seeking a mid-term review to update the nuclear production forecast and updates to nuclear fuel costs. In addition, the mid-term review will dispose of audited deferral and variance account balances. Please provide a complete list of the deferral and variance accounts that will be cleared at that time. Does OPG have projections of the likely balances in those accounts? If not, why not? Has OPG considered what the range of those amounts might be and the potential size of the rate riders for recovery of those amounts?

Response

Attachment 1 provides a list of the deferral and variance accounts OPG expects to present for clearance on the basis of December 31, 2018 audited balances in conjunction with the proposed mid-term nuclear production review. This list reflects all currently approved accounts (other than those previously ordered by the OEB to be terminated as of December 31, 2016) and OPG-proposed new accounts excluding the Nuclear Rate Smoothing Deferral Account and the Mid-Term Nuclear Production Variance Account.

OPG does not have projections of likely balances in the deferral and variance accounts as of December 31, 2018 and is unable to assess a potential range of such amounts at this time. Specifically, the December 31, 2018 account balances will include amounts accumulated over the 36-month period between January 1, 2016 and December 31, 2018. While OPG has a projection of the 2016 additions to the accounts as outlined in Ex. L-03.1-20 VECC-6, Attachment 2, for most accounts, OPG currently has no basis to project amounts that likely would be recorded in 2017 and 2018. Given the nature of the accounts, projections of future variances would depend on a host of variables that are outside of OPG's control and are very difficult to predict. The potential size of rate riders would depend not only on the balances in the accounts but also on the recovery/refund periods approved.

Attachment 1
List of Deferral and Variance Accounts Expected to Be Presented for Clearance in Conjunction with Mid-Term Nuclear Production Review

Existing Accounts

- Hydroelectric Water Conditions Variance Account
- Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub-Accounts
- Hydroelectric Incentive Mechanism Variance Account
- Hydroelectric Surplus Baseload Generation Variance Account
- Income and Other Taxes Variance Account
- Capacity Refurbishment Variance Account
- Pension and OPEB Cost Variance Account
- Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
- Gross Revenue Charge Variance Account
- Pension & OPEB Cash Payment Variance Account
- Pension & OPEB Cash Versus Accrual Differential Deferral Account[*]
- Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account
- Nuclear Liability Deferral Account
- Nuclear Development Variance Account
- Bruce Lease Net Revenues Variance Account – Derivative and Non-Derivative Sub-Accounts
- Nuclear Deferral and Variance Over/Under Recovery Variance Account
- Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account

Proposed New Accounts

- Hydroelectric Capital Structure Variance Account
- Nuclear ROE Variance Account

[*] Clearance of the account is subject to the outcome of the EB-2015-0040 generic proceeding on the regulatory treatment of pension and OPEB costs.

CCC Interrogatory #50

Issue Number: 11.5
Issue: Is OPG's proposed mid-term review appropriate?

Interrogatory

Reference:
Reference: Ex. A1/T3/S3/p. 10

Why is OPG limiting the mid-term review to an update of the production forecast and nuclear fuel costs? From OPG's perspective does the regulation preclude a consideration of other issues by the OEB through this mid-term review?

Response

Under O. Reg. 53/05, s. 6(2)(12)(ii), the OEB is required to determine nuclear revenue requirements on a five-year basis in this application. This requirement precludes re-examination of nuclear revenue requirement at the mid-term review. No such restriction exists for production forecasts, which are not part of revenue requirement. OPG has included Nuclear fuel costs in the mid-term review for the reasons outlined in Ex. L-11.5-20 VECC-50, part c).

EP Interrogatory #28

Issue Number: 11.5
Issue: Is OPG's proposed mid-term review appropriate?

Interrogatory

Reference:
Reference: Exhibit A1, Tab 3, Schedule 3

Will the mid-term production review also include a review of the costs and schedule of the Unit 2 refurbishment? If not, how will the Board or ratepayers in general know if the project will be completed on time and on schedule?

Response

No, the mid-term production review does not include a review of the costs and schedule of the Unit 2 refurbishment.

OPG has proposed a range of reporting measures on the Darlington refurbishment project, as identified in Ex. D2-2-9, pages 9 and 10, Section 7.0. The proposed public reporting on the DRP consists of twelve metrics across five key program categories. In OPG's view, these reporting measures will provide the OEB and customers with sufficient information to understand the progress and scheduling of the DRP, as well as key information on the safety, quality and cost of the program. Additional reporting is discussed in Ex. L-10.4-1 Staff-223.

VECC Interrogatory #50

Issue Number: 11.5
Issue: Is OPG's proposed mid-term review appropriate?

Interrogatory

Reference:
Reference: A1/T3/S3/pg.12-

a) Is the sole purpose of the mid-term review to adjust for changes in the nuclear power production and fuel cost?

b) In OPG's view at what point might an adjustment to the production forecast call into question the reasonableness of the approved revenue requirement?

c) Why are fuel costs being included in the mid-term review? What is the materiality of potential change in fuel costs?

Response

a) Yes.

b) OPG does not believe that it is not possible to define, in the abstract, the point at which changes to the production forecast could call the reasonableness of the revenue requirement into question.

c) Please refer to Ex. L-11.5-1 Staff-259. As detailed in Chart 1 of F2-1-1, OPG's fuel cost per MWh is $5.74 and $5.13 for Pickering and Darlington respectively. The fuel cost associated with a one TWh production variance is therefore between $5.13M and $5.74M.

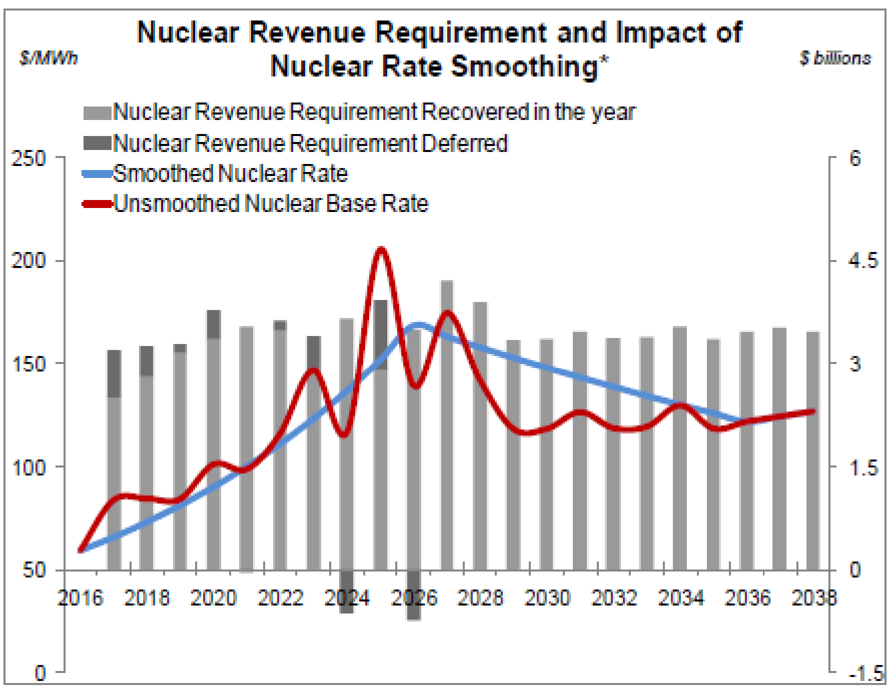
Board Staff Interrogatory #262

Issue Number: 11.6
Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:
Ref: Exh A2-2-1 page 5
Ref: Exh A1-3-3, page 6
Ref: Exh A1-3-3 Chart 1

The 2016-2018 business plan states that nuclear rate smoothing will moderate price spikes during DRP and eventual Pickering closure period, and the following graph is provided in the business plan.



* Information beyond 2021 is included for illustrative purposes

a) Please explain the DRP and Pickering events that contribute to each swing in the unsmoothed rate in the period 2016 to 2038.

b) OPG states at page 6 of Exh A1-3-3 that O. Reg. 53/05 “requires the OEB to set smoothed annual payment amounts.” Please provide the specific regulation reference requiring “the OEB to set smoothed annual payment amounts.”

c) OPG has proposed a smoothed rate to reflect a constant 11% per year base payment amount increase during 2017 to 2021. Section 6(2)12(i) of O.Reg. 53/05 states that the OEB “shall determine the portion of the Board-approved revenue requirement for the nuclear facilities for each year that is to be recorded in the deferral account established under subsection 5.5 (1), with a view to making more stable the year-over-year changes in the payment amount that is used in the determination of the undeferred payments”. In OPG’s view, is the requirement of the regulation met if the swings in the unsmoothed rate are dampened, but not at a constant percent increase on base payment amounts?

d) Please explain the “Total” column in Chart 1 on page 6.

Response

a) There are six distinct or noticeable “spikes” or “dips” in the unsmoothed nuclear rate curve as reproduced above. The main causes for each are:

The 2023 spike is due to a decrease in nuclear production from 2022, as two of the six operating Pickering units are planned to cease operations at the end of 2022. As well, three Darlington units are scheduled to be under refurbishment for a portion of the year compared to two units during all of 2022, which results in a further year-over-year decrease in nuclear generation.

The 2024 dip relative to 2023 reflects a year-over-year increase in nuclear production as only one unit is scheduled to be under refurbishment by the end of 2024 and as Pickering production is expected to benefit from a lower number of planned outage days in its last year of operation.

The 2025 spike is driven by both a reduction in nuclear production due to the planned closure of the remaining four Pickering units at the end of 2024 and staff downsizing costs associated with the Pickering closure.

The 2026 dip relative to 2025 reflects the higher staff downsizing costs incurred in 2025 and an increase in nuclear production as the final Darlington unit is scheduled to return to service in early 2026.

The 2027 spike relative to 2026 reflects a year-over-year increase in downsizing costs associated with staff engaged in defueling and dewatering of the Pickering units in preparation for the safe store period, and a year-over-year decrease in nuclear production and increase in OM&A expenses as a result of a four-unit Vacuum Building Outage (VBO) at Darlington. Following the VBO and with the completion of staff downsizing programs, both nuclear costs and generation levels are assumed to be relatively stable during the later years depicted in the graph.

b) There is no specific regulation reference to the words "requires the OEB to set smoothed annual payment amounts". The effect of Section 6(2)12(i) discussed in part c) is that the OEB will establish smoothed payment amounts.

c) Yes. The regulation requires the OEB to defer amounts of OPG's nuclear revenue requirement "with a view to making more stable the year-over-year changes in the payment amount." Dampening the swings in the unsmoothed payment amounts is directionally consistent with the regulation as it results in more stable payment amounts than otherwise would be the case for unsmoothed payment amounts. O. Reg 53/05 specifically uses the word stable. Stable is synonymous with unvarying and unwavering, both of which imply a constant rate. A constant rate of change best achieves rate stability and, while dampening the swings in the unsmoothed payment amounts would not optimally satisfy the legislative requirement, OPG expects that dampening swings in unsmoothed payment amounts would be sufficient to satisfy O. Reg. 53/05.

d) There was an error in the 'Total' column as originally filed. The following chart provides the correct totals:

	2017	2018	2019	2020	2021	Total
Proposed Revenue Requirement* ($M)	$3,190	$3,250	$3,285	$3,775	$3,489	$16,989
Forecast Production (TWh)	38.10	38.47	39.03	37.36	35.38	188.33

** reflects the revenue requirement net of the 0.3% stretch factor*

Board Staff Interrogatory #263

Issue Number: 11.6
Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:
Ref: Exh A1-3-3, page 1

The evidence at page 1 states, "The rate impact and volatility in the test period are driven by reduced production as Darlington units are taken out of service to be refurbished, partially offset by production at the Pickering generating station in 2021 due to the plan to extend operations, and costs associated with the Darlington Refurbishment Program ("DRP")."

Please provide the analysis that summarizes the rate impact and smoothing requirement of the scenario in which Pickering operations are not extended beyond 2020.

Response:

OPG cannot provide a detailed analysis of a scenario in which a decision had been made not to extend Pickering's operations because any such analysis would require OPG to make assumptions about the factors that precluded the extension of Pickering operations and the timing of the decision not to proceed. Without knowing the specifics of these matters, any attempt to forecast payment amounts, revenue requirement or rate smoothing impacts would be highly speculative.

For illustrative purposes, OPG is able to estimate the directional impacts of Pickering ending operations in 2020, had that decision been made in 2016.

Chart 1 below shows the anticipated nuclear revenue requirement, nuclear production and average unsmoothed rate over the deferral and recovery period, had it been decided not to extend Pickering operations beyond 2020. Chart 1 is provided in the same form as Ex. A1-3-3 Chart 2.

Chart 1

	2017-2021	2022-2026	2027-2031	2032-2036
Anticipated Revenue Requirement ($BN)	$ 16.0	$ 15.1	$ 17.4	$ 17.1
Anticipated Production (TWh)	176	79	136	141
Average Rate ($/MWh)	$ 91	$ 190	$ 128	$ 121

The rate impact in the 2017 to 2021 application period, absent smoothing, would be negligible, as closure-related costs and reduced production offset any reduction in operating expenses. The average rate in this period would be approximately $91/MWh, compared to $90/MWh based on the pre-filed evidence.

Without extended operations at Pickering, the average unsmoothed rate would be significantly higher during the 2022-2026 period, as the impact of the lower revenue requirement is more than offset by the impact of the lower production from the earlier Pickering closure. The average unsmoothed rate in the 2027 to 2031 period would be modestly lower absent the Pickering extension, as the assumed closure costs would be reflected in prior periods, and production would be the same in both scenarios because in both scenarios the plant is closed. In the 2032 to 2036 period, the anticipated revenue requirement, production and average rate would be the same under both scenarios.

The smoothing requirement impacts of the hypothetical scenario of a 2016 decision not to extend Pickering operations are summarized in Chart 2 under OPG's 11% per year proposal.

Chart 2

2017 - 2021 Rate Increase	11% No Extension	11% As Filed	Variance (a)-(b)
	(a)	(b)	(c)
2022- 2026 Rate Increase	11.0%	11.0%	0.0%
2027 - 2035 Rate Increase	(0.9)%	(3.4)%	2.5%
Peak Account Balance ($B)	$7.7	$3.5	$4.2
2017 - 2036 Total Interest ($B)	$3.8	$1.6	$2.3
Interest Cost / Deferred Revenues Ratio	0.6	0.5	0.1
Transition Impact: 2037 Rate Change ($/MWh / %)	$(33)/MWh / (21%)	$2/MWh / 2%	$35/MWh / 23%
Average Bill Impact: 2017-2036 (%)	0.3%	0.3%	0.0%
Average Bill Impact: 2017-2036 ($ / month)	$0.46	$0.42	$0.04

OPG has used the smoothing criteria provided in Ex. A1-3-3 to compare the impact of OPG's proposed 11% smoothing option if the decision had been made not to extend operations at Pickering (No Extension) to OPG's proposal based on extended operations (As Filed).

At the proposed 11% smoothing rate, the Rate Smoothing Deferral Account (RSDA) peak balance is the main difference between the two scenarios. Under the No Extension scenario, the RSDA balance more than doubles. The result of the No Extension scenario is higher interest costs and a higher annual rate (lower rate of annual decreases) during the recovery period, and a significant rate reduction of 21% on transition to the post recovery period. As this illustrative analysis demonstrates, customers benefit from extended Pickering operations because the higher nuclear production during the 2021-2024 periods provides substantial "natural smoothing" to the nuclear payment amounts. This mitigates the need for either a higher rate smoothing trajectory during the deferral period or higher recoveries during the recovery period.

Board Staff Interrogatory #264

Issue Number: 11.6
Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:
Ref: Exh A1-3-3, page 2
Ref: Exh A1-3-3 Chart 1

The evidence states, "The regulation requires that, for each year of the deferral period, the OEB must approve a nuclear revenue requirement and must also determine a portion of that approved revenue requirement to defer. The OEB is required to make this decision with the aim of stabilizing year-over-year changes in payment amounts."

a) A new ONFA reference plan is expected in 2017. Does OPG agree that significant riders are possible when the nuclear liability account is disposed? Can the ratepayer expect smoothing or stability under circumstances such as these?

b) OPG's proposal results in a drop in payment amounts (including riders) in 2017 vs 2016. Does OPG consider this impact to be consistent with smoothing or stability?

c) In OPG's view, does the regulation prohibit the OEB from considering deferral and variance account recovery in the making of smoothed or stabilized payment amounts?

Response

a) Further to Ex. L-8.2-1 Staff-208, the new ONFA reference plan could result in an increase or a decrease to revenue requirements. Should the 2017-2021 ONFA Reference Plan be approved by the Province in the course of the proceeding, and result in material changes, OPG would follow the OEB's Rules of Practice and Procedure and bring the matter forward as part of this proceeding, including the impact on revenue requirement. If the new ONFA reference plan is not approved until after the hearing, OPG would record the differences in the Nuclear Liability Deferral Account and the Bruce Lease Net Revenue Variance Account, as appropriate, to be addressed when OPG next seeks to clear deferral and variance (D&V) accounts (refer to Ex. C2-1-1 section 6). In the latter scenario, as discussed in parts b) and c), OPG's view is that the clearance of deferral and variance account balances would not be a proper consideration when fixing smoothed payment amounts, under O. Reg. 53/05.

b) and c)

In OPG's view, the regulation precludes the OEB from considering D&V account balance recovery in fixing the smoothed payment amounts.

The regulation requires that, for each year of the deferral period, the OEB must approve a Nuclear revenue requirement and must also determine a portion of that approved revenue requirement to defer. The OEB is required to make this decision with the aim of stabilizing year-over-year changes in the payment amounts for the Nuclear facilities. The regulation confirms that rate smoothing applies when determining the amount of revenue requirement to defer and that the OEB's approval of OPG's Nuclear revenue requirement is not restricted by rate smoothing.

Mechanically, pursuant to the regulation, OPG is required to establish a rate smoothing deferral account to record the difference between: (A) the total OEB-approved revenue requirement for the Nuclear facilities for each year in the deferral period, and (B) the portion of the revenue requirement in (A) that is used in connection with setting payment amounts for the Nuclear facilities for that year.

The regulation also states that the OEB must approve both the annual Nuclear revenue requirements and the amount of the approved revenue requirement to be deferred on a five year basis for the first ten years of the deferral period, and then periodically as determined by the OEB. The OEB must also ensure that OPG recovers the balance recorded in the deferral account on a straight line basis over a period not to exceed ten years, beginning at the end of the deferral period.

Overall, the thrust of the regulation is to focus the OEB's analysis on two issues: the revenue requirements associated with the nuclear facilities and the amount of those revenue requirements to defer having regard to Nuclear facilities payment amount stability. Nowhere does the regulation refer to the impact of other factors not included in the Nuclear facilities payment amounts (whether recorded in a deferral or variance accounts or otherwise). A rider arising from a D&V account relates to a deferral or variance from a prior period(s) and not the period for which the payment amounts are being determined.

The nature of D&V accounts also militates against consideration of D&V account balance recovery in smoothing payment amounts. By their nature, future D&V account balances are inherently uncertain. It would be impossible for the OEB to have regard to an uncertain D&V amount when determining how much of the Nuclear facilities revenue requirements to defer.

Finally, the typical recovery period for deferral and variance accounts is inconsistent with the period for setting smooth payment amounts under the regulation. O. Reg. 53/05 specifies that payment amount smoothing must be determined on a five year basis. However, recovery of D&V balances typically, and by OEB order, occurs over a shorter time period.

OPG believes that its rate smoothing proposal is consistent with O. Reg 53/05.

Board Staff Interrogatory #265

Issue Number: 11.6
Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:
Ref: Exh A1-3-3, page 7
Chart 2 summarizes the unsmoothed revenue requirement, production and average payment amount for the period 2017-2036.

a) What pension accounting assumptions underpin the analysis?

b) Please prepare a similar chart for the smoothed scenario, assuming 11% increases in payment amounts in 2017-2021 and 2022-2026 (as per Chart 3), and recovery of the rate smoothing deferral account at the completion of DRP on a straight line basis over 10 years. Please show the recovery of the rate smoothing deferral account on a separate line. Please list assumptions.

Response

a) OPG used the funding contribution (cash) basis of cost recovery of pension costs for the 2017-2021 IR term covered by this application. OPG has used the accrual basis of cost recovery for years subsequent to 2021.

b) The following chart represents the values of the five year smoothed revenue requirements, production and smoothed average rates assuming an 11% annual increase in payment amounts in 2017-2021 and 2022-2026. Recovery of the rate smoothing deferral account at completion of the DRP is on a straight line basis over 10 years, assuming constant annual payment amounts during the recovery period.

	2017-2021	2022-2026	2027-2031	2032-2036
Anticipated Revenue Requirement ($BN)	15.4	18.0	20.6	18.0
Anticipated Production (TWh)	188	130	136	141
Average Rate ($/MWh)	82	138	152	128

The following chart provides detail on the recovery of the deferred amounts and the interest collected on outstanding balances:

	2017-2021	2022-2026	2027-2031	2032-2036
Net Amount Deferred and (Recovered) [including interest Recovery]($M)	1,610	121	(2,364)	(913)
Total Interest Added to the Balance ($M)	267	799	424	56
Account Balance at End of Period ($M)	1,876	2,797	856	0

Board Staff Interrogatory #266

Issue Number: 11.6

Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:

Ref: Exh A1-3-3 page 4 and Chart 3

Chart 3 summarizes the smoothing alternatives OPG considered, and compares projected outcomes on the basis of several financial and bill impact criteria and transition to the post-smoothing period. Please confirm that the financial criteria refer to OPG and not the nuclear business.

Response

Confirmed. The financial metrics are determined for OPG as a whole as this is the basis that credit rating agencies assess OPG's creditworthiness. However, the difference in the financial metric values for the rate smoothing options considered is driven entirely by changes in the nuclear payment amount as all other factors have been held constant.

Board Staff Interrogatory #267

Issue Number: 11.6
Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:
Ref: Exh A1-3-3 page 4 and Chart 3

OPG used two financial metrics to gauge the potential impact of rate smoothing. One of the metrics was Debt to EBITDA ratio. OPG's preferred threshold for Debt to EBITDA ratio is equal to or less than 5.5.

a) Please provide the Debt to EBITDA ratio for the 2012 to 2015 period for OPG.

b) All alternatives in Chart 3 appear to have ratios greater than 5.5 in the 2017-2021 period. Considering that uncertainty of outcomes increases over time, shouldn't the near term ratios have greater weight in choosing options?

Response

a) OPG's debt to EBITDA ratio has improved steadily from 2012 to 2015 as reflected in the following table:

Ratio	2012	2013	2014	2015
Debt to EBITDA	6.5	5.8	5.0	4.4

b) No. While OPG accepts that uncertainty of outcomes increases over time, it does not agree that this fact should decrease the weighting of the longer term metrics. Just because a longer term metric has more potential variability doesn't mean that it is less important. OPG has indicated that intergenerational equity is an important consideration when selecting the appropriate rate smoothing approach. Longer term metrics provide the best indication of the impact of near term decisions on future customers. OPG is concerned that decreased emphasis on longer-term metrics would diminish the importance of intergenerational equity considerations.

Board Staff Interrogatory #268

Issue Number: 11.6
Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:
Ref: Exh A1-3-3 pages 4 and 9 and Chart 3

OPG refers to a ratio of Funds from Operations (FFO) Adjusted Interest Coverage ratio as a key financial indicator.

a) OPG states that higher values for the interest coverage ratio are preferred with a minimum target of three. Please provide the FFO Adjusted Interest Coverage ratio for the 2012 to 2015 period for OPG.

b) In Chart 3 there is a line labeled "Interest Cost/Deferred Revenues Ratio". Is this a mis-labelling or is the reported ratio equivalent to an FFO Adjusted Interest Coverage ratio? If not, please provide the FFO Adjusted Interest Coverage ratio for all the alternatives set out in Chart 3.

c) On page 9 OPG states that the Interest Cost/Deferred Revenues is ratio is an indicator of intergenerational equity. What is the target for the Interest Cost/Deferred Revenues ratio?

Response

a) OPG's FFO Adjusted Interest Coverage ratios were 2.3 times for 2012, 2.8 times for both 2013 and 2014, and 5.0 times for 2015.

b) The "Interest Cost/Deferred Revenues Ratio" line in Chart 3 is not mislabelled. The interest cost (numerator in above ratio) is the total interest paid over the deferral and recovery period associated for various smoothing alternatives. The deferred revenues are the total amounts deferred for recovery in a subsequent period associated with various smoothing scenarios.

   The FFO Adjusted Interest Coverage ratio results associated with various smoothing scenarios for the 2017 to 2021 and 2022 to 2026 periods are provided in Chart 3 immediately following the Interest Cost/Deferred Revenues Ratio. Due to an administrative error, the description appears blank in the first column of Chart 3. OPG will correct Chart 3 when it updates its evidence. For clarity, the FFO Adjusted Interest coverage ratio for the rate smoothing scenarios presented in Chart 3 is provided in the table below:

2017-2021 Rate increase	12%	11%	10%	9%	8%
Interest Cost / Deferred Revenues Ratio	0.2	0.5	0.8	0.9	0.9
FFO Adjusted Interest Coverage >=3.0* (2017-2021) / (2022-2026)	3.7/6.3	3.6/5.3	3.5/4.5	3.5/3.9	3.4/3.3

*Weakest ratio

c) There is no target ratio for the Interest Costs/Deferred Revenue Ratio. As stated in Ex A1-3-3, Page 9, lines 15 to 18), "Intergenerational equity involves striking a balance between the benefits of deferring revenue and the costs of the deferral; therefore OPG's assessment place value on a ratio that best reflects this balance (i.e., neither the highest nor the lowest ratio)." Lower year-over-year payment amount increases result in larger deferred revenue requirement recovery; which in turn increases the interest costs in the Rate Smoothing Deferral Account. The ratio effectively provides the cost of a dollar of deferral over the deferral period. As seen in the chart above, the cost of deferring revenue increases from $0.20 per dollar when the payment amounts grow by 12% per year, to $0.90 per dollar at an 8% annual payment amount increase.

Smoothing necessarily involves some level of intergenerational inequity. Future customers will be required to pay for the deferred revenue requirement. They will also be required to pay the interest costs associated with deferred recovery of revenue requirement. The ratio therefore reflects the impact on future customers of different levels of revenue requirement deferral.

Board Staff Interrogatory #269

Issue Number: 11.6
Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:
Ref: Exh A1-3-3 page 8-9

OPG has five criteria for choosing a smoothing option. Did OPG have a weighting system for the criteria or were all criteria given equal weight in the choice of options?

Response

OPG used six criteria to assess smoothing options:

1. Financial Viability,
2. Rate Stability,
3. Long-term Perspective,
4. Post-recovery Transition,
5. Intergenerational Equity, and
6. Customer Bill Impact.

OPG did not use a weighting system to assess the smoothing options. Weighting the considerations would necessarily require OPG to compare the relative importance of one consideration over another. Since all of the criteria are important, it would be subjective to assign them a relative weighting.

The considerations are not mutually exclusive. Evaluating the rate smoothing options requires assessing the impacts of each option on each of the considerations, across the full deferral and recovery period.

AMPCO Interrogatory #158

Issue Number: 11.6
Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:
Ref: A1-3-3 Page 8 Chart 3
Ref: Nuclear Rate Smoothing Presentation September 23, 2016, Slides 5 and 9
Ref: A1-3-3 Page 10 Chart 4

Preamble: OPG proposes that annual nuclear base payment amounts reflect a constant 11 per cent per year increase during the 2017 to 2021 test period resulting in deferred revenue requirement.

At Reference 1, OPG provides a summary of outcomes related to smoothing alternatives.

At Reference 2, Slide 9 of the presentation shows a Nuclear Payment Amount Rate Smoothing at 11% compared to a Customer Rate Impact Smoothing of 0.7% bill impact.

a) Please confirm the smoothing alternatives at Reference 1 reflect five nuclear payment amount rate smoothing proposals based on a range of 8%-12% annual increases and a customer bill impact smoothing proposal is not included.

b) Please reproduce slide 5 of the presentation to include the customer impact smoothed rate line for an annual increase of 0.7%.

c) Please reproduce slide 6 of the presentation to reflect the mechanics of a rate smoothing proposal based on the customer impact smoothed rate of 0.7% annually.

d) Please reproduce Chart 4 at A1-3-3 Page 10 to show the deferred revenue requirement under the customer impact smoothing at 0.7% and 1.5% annually.

e) Please confirm the customer smoothing proposal does not increase the risk of a credit rating downgrade.

Response

a) Confirmed.

b) and c)

Slide 5 and 6 revised to show the customer impact smoothed rate line for an annual increase of 0.7% is provided in Attachment 1.

d) Attachment 2 provides the requested analyses, showing the deferred revenue requirement under the customer impact smoothing at 1.5% and 0.7% annually. Since Chart 4 was based on a constant annual payment amount increase of 11% (which does not apply to the requested customer impact smoothing scenario), OPG has added a row (row 4 in both Table 1 [1.5% analysis] and Table 2 [0.7% analysis] in Attachment 2) for both the customer impact smoothing analyses to show the annual change in payment amounts. The unsmoothed payment amounts are shown in Row 1 of both Tables 1 and 2 in Attachment 2 to provide context for the annual deferral amount calculation.

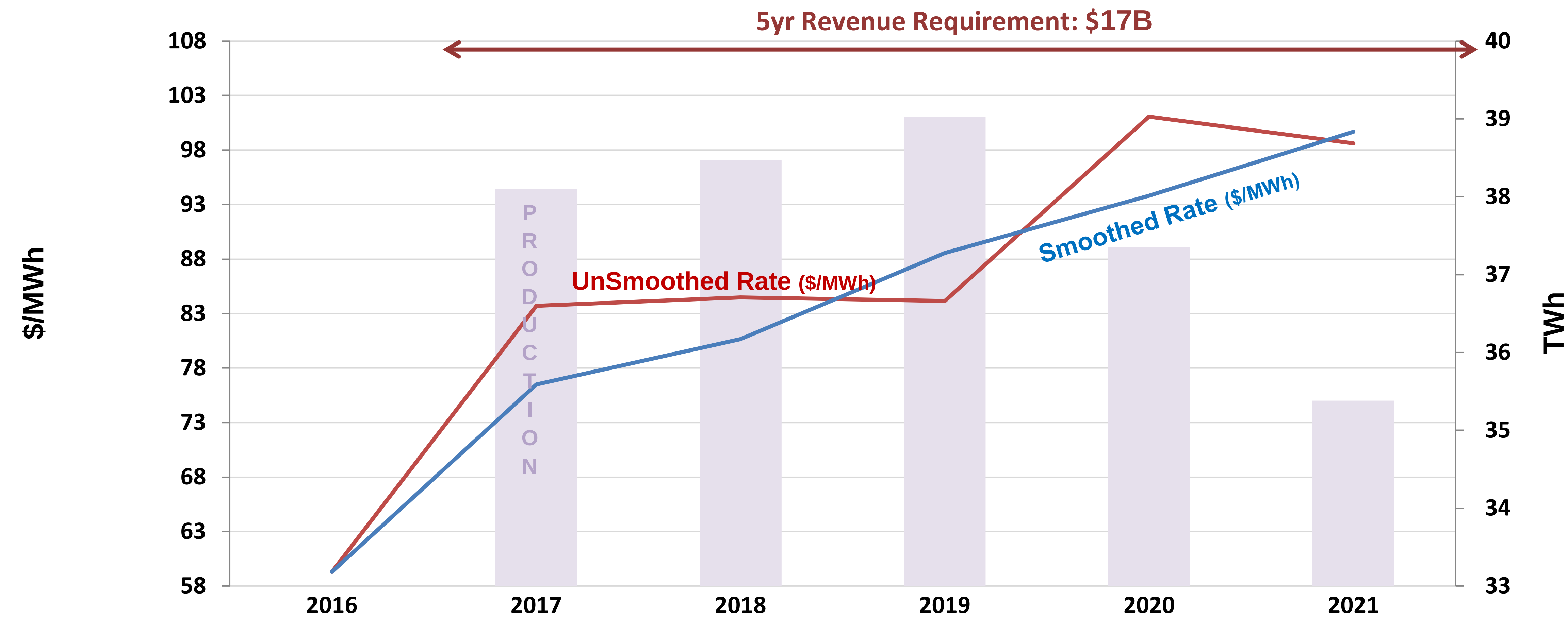
e) The following table shows the total amount of deferred revenue requirement associated with OPG's proposal and comparative customer impact results.

Constant Payment Amount changes @11% Annually	$1,610M
Constant Annual Residential Customer Bill Impact of 0.7%	$483
Constant Annual Residential Customer Bill Impact of 1.5%	($2,633M)

Customer impact smoothing results in payment amount increases in 2017 that are much higher than OPG's rate smoothing proposal, and generally higher payment amounts throughout the 2017 to 2021 term. Higher payment amounts result in less deferred revenue requirement and higher cash flows. As a result, customer impact smoothing does not increase the risk of a credit rating downgrade.

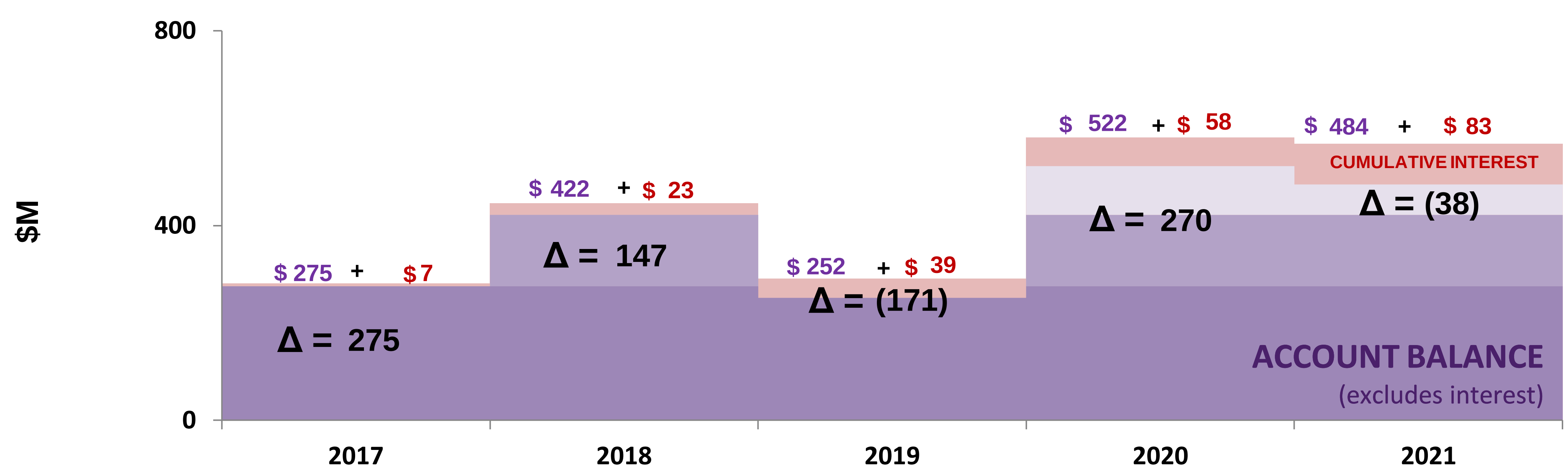
Numbers may not add due to rounding.

Customer Impact Smoothing Analysis 2017-2021



		2016	2017	2018	2019	2020	2021
1) Proposed Production	(TWh)		38.1	38.5	39.0	37.4	35.4
2) Unsmoothed Rates	($/MWh)	59.29	83.73	84.48	84.17	101.05	98.62
3) Smoothed Rate	($/MWh)	59.29	76.51	80.65	88.55	93.82	99.68

Customer Impact Smoothing Analysis 2017-2021 Account



		2017	2018	2019	2020	2021
1) Proposed Production	(TWh)	38.1	38.5	39.0	37.4	35.4
2) Unsmoothed Rates	($/MWh)	83.73	84.48	84.17	101.05	98.62
3) Smoothed Rate	($/MWh)	76.51	80.65	88.55	93.82	99.68
4) Deferred Amount	($M)	275	147	(171)	270	(38)
5) Est. Interest Expense	($M)	7	16	16	19	25
6) Accumulated Interest	($M)	7	23	39	58	83

Numbers may not add due to rounding.

Table 1: AMPCO #158d
Interrogatory Proposed Deferred Nuclear Revenue Requirement
1.5% Smoothing of Customer Impact

	2016	2017	2018	2019	2020	2021
Unsmoothed Rate ($/MWh)		$ 83.73	$ 84.48	$ 84.17	$ 101.05	$ 98.62
Unsmoothed Revenue Requirement ($M)		$ 3,190	$ 3,250	$ 3,285	$ 3,775	$ 3,490
Forecast Production (TWh)		38.10	38.47	39.03	37.36	35.38
Smoothed Customer Impact Rate ($/MWh)	$ 59.29	$ 82.04	$ 91.60	$ 104.85	$ 116.07	$ 128.45
Rate of Change		38.36%	11.66%	14.46%	10.71%	10.66%
Smoothed Customer Impact Revenue ($M)		$ 3,125	$ 3,524	$ 4,092	$ 4,336	$ 4,545
Deferred Revenue Requirement ($M)		$ 65	$ (274)	$ (807)	$ (561)	$ (1,055)

Table 2: AMPCO #158d
Interrogatory Proposed Deferred Nuclear Revenue Requirement
0.7% Smoothing of Customer Impact

	2016	2017	2018	2019	2020	2021
Unsmoothed Rate ($/MWh)		$ 83.73	$ 84.48	$ 84.17	$ 101.05	$ 98.62
Unsmoothed Revenue Requirement ($M)		$ 3,190	$ 3,250	$ 3,285	$ 3,775	$ 3,490
Forecast Production (TWh)		38.10	38.47	39.03	37.36	35.38
Smoothed Customer Impact Rate ($/MWh)	$ 59.29	$ 76.51	$ 80.65	$ 88.55	$ 93.82	$ 99.68
Rate of Change		29.05%	5.40%	9.80%	5.95%	6.25%
Smoothed Customer Impact Revenue ($M)		$ 2,915	$ 3,102	$ 3,456	$ 3,505	$ 3,527
Deferred Revenue Requirement ($M)		$ 275	$ 148	$ (171)	$ 270	$ (38)

CME Interrogatory #11

Issue Number: 11.6
Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:
Ref: Exhibit A1, Tab 3, Schedule 3, pages 7 and 8 of 14

At Chart 3, entitled "Smoothing Alternatives – Outcomes", OPG provides a summary of the outcomes from a range of rate Smoothing Alternatives. For each alternative, OPG has provided the approximate peak RSDA account balance, an estimate of the total interest accumulated in the RSDA to the end of the recovery period, projected credit metrics during the deferral period, the rate change both in $/MWh and percentage terms on transition to the steady state rate following the recovery period (i.e. approximately $120/MWh), and an estimated average monthly customer bill impact over the full deferral and recovery periods. CME wishes to better understand the proposed Smoothing Alternatives:

(a) For the Smoothing Alternatives, incorporating 12%, 11% and 10% rate increases between 2017 to 2026, results in rate decreases for the 2027 to 2015 rate period. Does this mean that for these 3 scenarios, OPG will be over-recovering during the period 2017 to 2026? If so, please explain why OPG would implement a smoothing mechanism that over-recovers, rather than no longer implementing a smoothing mechanism once full recovery has been achieved;

(b) OPG has used $120/MWh as the steady state rate following the recovery period. Please explain how OPG has determined that the steady state rate should be $120/MWh .

Response

(a) OPG has interpreted this question to be in reference the 2027 to 2035 period rather than the 2027 to 2015 period as stated. On that basis, the decline in rates during the recovery period does not mean that OPG has over-recovered during the 2017-2026 period. The peak account balance provided in Ex. A1-3-3, page 8, Chart 3, line 4 indicates the maximum amount of revenue requirement to be deferred for future recovery including interest. The deferred revenue requirement will be recovered during the recovery period when the smoothed rate is greater than the unsmoothed rate. This difference provides for the recovery of the deferred revenue requirement.

(b) The steady state rate following the recovery period reflects OPG's view on longer-term revenue requirement and production forecasts. As stated at Ex. A1-3-3, page 7, "OPG believes that the average forecast 2032 to 2036 rate is a reasonable proxy for the rate that will prevail after the cost deferral and recovery cycle." The forecast production and revenue requirement in that period is presented in Ex. A1-3-3, Chart 2. Since the production and revenue requirement reflected in the 2032 to 2036 period is more than five years after Darlington refurbishment and Pickering closure, OPG expects that costs and production will be relatively stable during that period.

CCC Interrogatory #51

Issue Number: 11.6

Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:

Reference: Ex. A1/T3/S3/p. 2

Ontario Regulation 53/05 sets out certain processes and parameters that OPG and the OEB must follow regarding the smoothing of OPG's nuclear payment amounts. OPG also states that although the regulation establishes these processes and parameters the OEB is required to apply its judgment in order to set a smoothed rate that is just and reasonable. Is it OPG's position that the OEB is limited to smoothing the payment amounts that OPG receives rather than considering an approach that takes into account smoothing customer bill impacts?

Response

Ontario Regulation 53/05 s. 6(2)(12)(i) requires that the OEB determine the portion of the total nuclear facilities revenue requirement to defer each year "with a view to making more stable the year-over-year changes in the payment amount that is used in the determination of the undeferred payments made… with respect to the nuclear facilities" [emphasis added].

OPG understands this sub-paragraph of the regulation to require that the OEB determine the amount of nuclear revenue requirement to defer with the objective of stabilizing annual changes in the nuclear payment amount, not customer bills.

Please also refer to Ex. L-11.6-1 Staff-264.

CCC Interrogatory #52

Issue Number: 11.6

Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:

Reference: Ex. A1/T3/S3/pp. 4-8

What were all of the rate smoothing proposals available to OPG having regard to Ontario Regulation 53/05? How did OPG weigh the set of considerations set out in the evidence? Did OPG consider the other factors that contribute to electricity bills when assessing the alternatives – the cost of other supply sources, distribution costs, CDM costs?

Response

After taking into consideration the criteria outlined in section 2.3 of Ex. A1-3-3, OPG established alternatives as detailed in section 2.4 of Ex. A1-3-3. The range of scenarios that OPG assessed is summarized in Chart 3. With regard to weighting the criteria, please refer to L-11.6-1 Staff-269. When determining the customer bill impact, OPG's approach was consistent with how OPG has computed the average residential customer bill in prior proceedings (please refer to slides 14-15 of OPG's September 23, 2016, untranscribed technical conference presentation on Nuclear Rate Smoothing and L-1.3-5 CCC-9).

CCC Interrogatory #53

Issue Number: 11.6

Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:

Reference: Ex. A1/T3/S3

Has the 11% rate increase for the period 2017-2021 been explicitly approved by the Ministry of Energy? If so, please provide any documentation setting out this approval.

Response

No. As established under section 78.1 of the Act and O. Reg. 53/05, OPG's payment amounts are determined by the OEB, not the Ministry of Energy.

CCC Interrogatory #54

Issue Number: 11.6
Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:
Reference: Ex. A1/T3/S3/pp. 6-7

The evidence states: "Since rates set for the 2017 to 2021 period will necessarily have implications for the rates set later in the deferral and recovery periods, an understanding of forecast nuclear costs and production for the entire deferral and recovery period is necessary for the rate smoothing proposal." What relief is OPG asking for from the OEB, if any, with respect to rates beyond 2021?

Response

OPG is not seeking any relief for rates beyond 2021. The quoted evidence is highlighting the fact that, when assessing rate smoothing scenarios in the context of O. Reg. 53/05 requirements, it must be done by considering the implications through the full deferral and recovery period.

EP Interrogatory #32

Issue Number: 11.6
Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:
Exhibit A1, Tab 3, Schedule 3, page 5

OPG states that its proposal for a constant 11% annual increases for the nuclear revenue requirement are based on interpreting provincial legislation as "stability implies a constant rate change each year…"

a) Can OPG explain why it's taken such a narrow view of the legislation? Would it be opposed to, for example, a steady increase annually (11% in year one, 12% in year 2 and so on), which would limit that amount of money that would have to be deferred?

b) Can OPG calculate the amount of money that would be deferred if it increased its nuclear revenue requirement by 11% in year one, 12% in year two, 13% in year 3, 14% in year 4 and 15% in year 5?

Response

a) OPG has articulated the six criteria that it considered in the assessment of various rate smoothing scenarios in section 2.3 of Ex. A1-3-3. OPG believes that predictability is an important consideration and that stability implies that the rate treatment for 2022-2026 be the same as it is for 2017-2021. From a statutory interpretation perspective the reference to "stable" means constancy of rates whereas the proposal reflects an escalating trend.

   OPG believes that there are significant drawbacks to the escalating approach proposed in this question, when assessed across the full deferral and recovery period. Extrapolating this proposed rate increase trend through the remaining forecasted deferral period of 2022-2026 (i.e., 16% increase in 2022, 17% in 2023, etc.), OPG believes that it would not meet the objective of a number of the smoothing criteria:

   - **Stability and Long-term Perspective**: The proposed approach would result in a "steep up and a steep down" set of rates, getting up to $250/MWh in 2026, and then dropping down to $50MWh in 2036 (due to over collection of deferred revenues). The rate decrease in the recovery period would be (15%) per year.
   - **Post-recovery Transition**: Under the proposed approach, the step-change after 2036 would be significant – rates would increase from the $50/MWh smoothed rate up to $121/MWh (a 146% increase).

- **Customer Bill Impact**: During the 2017-2021 term, the proposed approach would be result in an average customer bill impact of $1.44/month, per year.

b) The amount of revenue requirement deferred through 2017-2021 under this scenario would total $985M, compared to $1.6B under OPG's proposal. The annual breakdown of deferred revenue requirement is provided below (refer to chart 4 of A1-3-3 for a comparison to OPG's proposed annual deferral amounts).

2017: $683M
2018: $414M
2019: $34M
2020: $228M
2021: ($374M)

EP Interrogatory #33

Issue Number: 11.6
Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:
Exhibit I1, Tab 1, Schedule 2, table 1

Would a decline in provincial demand over the time period of the rate application have a material impact on the bill changes as they are currently presented?

Response

OPG does not believe that a decline in provincial demand over the time period of this rate application will have a material impact on the bill changes as presented in Ex, I1-1-2 Table 1.

EP Interrogatory #34

Issue Number: 11.6
Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:
Exhibit I1, Tab 1, Schedule 2, table 1

Can you calculate that table, but use the unsmoothed nuclear revenue requirement.

Response

See L-01.3-1 Staff 5 for the unsmoothed customer bill impact analysis.

ED Interrogatory #24

Issue Number: 11.6
Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:
Reference: Chris Fralick & Randy Pugh, "Nuclear Rate Smoothing" (September 23, 2016)

Please state OPG's proposed smoothed nuclear rate ($ per MWh) for each year from 2016 to 2036 inclusive.

Response

OPG's rate smoothing proposal results in Nuclear rates increasing at 11% per year through the deferral period and then decreasing at 3.4% per year through the ten year recovery period. The resulting nuclear base rates are outlined in Chart 1 below. The rates for the period beyond the term of this application, 2022-2036, are illustrative only, and subject to change in subsequent rates proceedings.

Chart 1 Smoothed Nuclear Base Rates 2016 - 2036

Year	**Nuclear Base Rates ($/MWh)**
2016	59.29
2017	65.81
2018	73.05
2019	81.09
2020	90.01
2021	99.91
2022	110.90
2023	123.10
2024	136.64
2025	151.67
2026	168.35
2027	162.63
2028	157.10
2029	151.76
2030	146.61
2031	141.62
2032	136.81
2033	132.16
2034	127.67
2035	123.33
2036	119.14

GEC Interrogatory #60

Issue Number: 11.6
Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:

If not already done, please provide a copy of the September 23rd slides so they will appear in the record.

Response

These materials were filed with the OEB on September 23, 2016 and are available on the OEB's Advanced Regulatory Document Search website.

GEC Interrogatory #61

Issue Number: 11.6
Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:

Please provide 20 year versions (covering the full deferral and recovery period) of slides 5, 6 and 9 of the rate smoothing presentation made on September 23rd. Please add a row with OPG's projected revenue requirement in each year.

Response

See response to Ex. L-9.7-15 SEC-93.

GEC Interrogatory #62

Issue Number: 11.6
Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:

For the 20 year deferral and recovery period, please add lines to each of the two approaches illustrated on Slide 9 of the September 23rd rate smoothing presentation showing the absolute and percentage difference in average monthly customer bills between current bills and projected smoothed and unsmoothed bills in each year (as opposed to the year over year impact).

Response

In Attachment, 1 OPG has added lines 3 and 4 for the Nuclear Payment Amount Rate Smoothing (as filed) approach (i.e., unsmoothed bills referred to in the question) and lines 11 and 12 for the Customer Impact Smoothing (i.e., smoothed bills referred to in the question) assessment, as illustrated on Slide 9 of the September 23 rate smoothing presentation. These lines show the absolute and percentage difference in average customer bills between current bills and projected smoothed payment amounts. The information is presented for the 2017 to 2021 period consistent with information provided on Slide 9 referenced in the presentation. OPG has not provided annual information post-2021, as discussed in Ex. L-9.7-15 SEC-093.

Numbers may not add due to rounding.

Table 1: GEC #062
Ammended Comparison of Smoothing Proposals

Line No.	Description	2017 Amount	2018 Amount	2019 Amount	2020 Amount	2021 Amount	5 Year Average
		(a)	(b)	(c)	(d)	(e)	(e)
	RATE SMOOTHING PROPOSED BY OPG						
1	**Typical Bill Impact ($/Month)**	**(1.29)**	**1.73**	**1.07**	**1.86**	**1.89**	**1.05**
2	**Typical Bill Impact (%)**	-0.9%	1.1%	0.7%	1.2%	1.3%	0.7%
3	**Typical Bill Impact ($/Month), Relative to 2016**	**(1.29)**	**0.44**	**1.51**	**3.37**	**5.26**	
4	**Typical Bill Impact (%), Relative to 2016**	-0.9%	0.3%	1.0%	2.2%	3.5%	
5	**Prior Year weighted average rate with proposed payment amounts and riders** ($/MWh)	60.66	57.37	61.76	64.45	69.26	
6	**Current Year weighted average rate with proposed payment amounts and riders** ($/MWh)	57.37	61.76	64.45	69.26	74.27	
7	**Change in OPG weighted average rate ($/MWh)**	(3.29)	4.39	2.69	4.81	5.02	
8	**Resulting percent change in nuclear rates, year over year (%)**	11%	11%	11%	11%	11%	
	CUSTOMER IMPACT SMOOTHING ASSESSMENT						
9	**Typical Bill Impact ($/Month)**	**1.05**	**1.05**	**1.05**	**1.05**	**1.05**	**1.05**
10	**Typical Bill Impact (%)**	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%
11	**Typical Bill Impact ($/Month), Relative to 2016**	**1.05**	**2.10**	**3.15**	**4.20**	**5.25**	
12	**Typical Bill Impact (%), Relative to 2016**	0.7%	1.4%	2.1%	2.8%	3.5%	
13	**Prior Year weighted average rate with proposed payment amounts and riders ($/MWh)**	60.66	63.34	66.01	68.65	71.36	
14	**Current Year weighted average rate with proposed payment amounts and riders ($/MWh)**	63.34	66.01	68.65	71.36	74.14	
15	**Change in OPG weighted average rate ($/MWh)**	2.68	2.67	2.63	2.71	2.79	
16	**Resulting percent change in nuclear rates, year over year (%)**	29.1%	5.4%	9.8%	6.0%	6.3%	

PWU Interrogatory #21

Issue Number: 11.6
Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:
Ref: Exhibit A1-3-3, Page 6 (Chart 1 - Nuclear Revenue Requirement and production)

a) Please explain what the numbers under the column 'Total' ($3,617M of proposed revenue requirement and 26.01 TWh production forecast) represent and how they are arrived at?

Response

a) The column is reported in error. A revised chart is provided in Ex. L-11.6-1 Staff-262 Part d).

VECC Interrogatory #51

Issue Number: 11.6
Issue: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

Interrogatory

Reference:
Reference: A1/T3/S3

a) Please amend Chart 4 to include the unsmoothed rate.

b) Please set out the relevant parts of O. Reg. 53/05 that address the issue of production forecast risk?

c) O.Reg. 53/05 s. 5.5 addresses the issue of Darlington refurbishment. Does the proposed revenue requirement shown at chart 1 (A1/T3/S3/pg.6) show the revenue requirement of all nuclear (Darlington and Pickering) or just the Darlington refurbishment? If the former please explain how this is contemplated under O. Reg. 53/05.

Response

a)

Chart 4
OPG Proposed Deferred Nuclear Revenue Requirement

	2017	2018	2019	2020	2021
Proposed Revenue Requirement ($M)	$ 3,190	$ 3,250	$ 3,285	$ 3,775	$ 3,489
Forecast Production (TWh)	38.10	38.47	39.03	37.36	35.38
Unsmoothed Rate ($/MWh)	$ 83.73	$ 84.48	$ 84.17	$ 101.05	$ 98.62
Smoothed Rate ($/MWh)	$ 65.81	$ 73.05	$ 81.09	$ 90.01	$ 99.91
Smoothed Revenue ($M)	$ 2,507	$ 2,810	$ 3,165	$ 3,362	$ 3,535
Deferred Revenue Requirement ($M)	$ 683	$ 440	$ 121	$ 413	$ (46)

b) There are no specific provisions in O. Reg. 53/05 that address production forecast risk.

c) Section 5.5 of O. Reg. 53/05 is not limited to Darlington refurbishment. It establishes a deferral account that records the difference between the total approved nuclear revenue requirement and the deferred amounts. OPG's nuclear revenue requirement necessarily includes all costs associated with the operation of both the Darlington and Pickering facilities. The regulation does not limit the amounts recorded to this account to the Darlington Refurbishment Program.

Board Staff Interrogatory #271

Issue Number: 11.7
Issue: Is OPG's proposed off-ramp appropriate?

Interrogatory

Reference:
Ref: Exh A1-3-2 page 23

In section 2.7, OPG has proposed an off-ramp mechanism pertaining to a situation whereby OPG's regulated ROE is outside of a deadband of +/- 300 basis points from its allowed ROE. In this case, a regulatory review could be initiated.

The proposal is that the regulated ROE would be determined on the basis of all rate regulated generation assets (i.e., both hydroelectric and nuclear).

a) In this application, the payment setting plans for nuclear and regulated hydroelectric generating assets will be different in terms of the economic and cost-recovery basis. Further, cost recovery for the nuclear generating assets is complicated by the proposed rate smoothing mechanism. How will the actual regulated return on equity for regulated generation assets be calculated over the 2017-2021 term plan?

b) Since the regulated return is based on both nuclear and regulated hydroelectric generation assets, would the regulatory review be on both the nuclear and hydroelectric plans?

c) While OPG labels this an "off-ramp", it indicates that the +/- 300 basis point deviation would be used to determine "whether a regulatory review may be initiated." [Emphasis added] This implies less than certainty that the off-ramp occurs.

   i. Under what conditions, beyond the 300 basis point deviation between achieved and approved returns, does OPG consider that a review and/or off-ramp would be required?

   ii. Under what conditions does OPG consider that a review and/or off-ramp would not be required even when the deviation between actual and approved regulated returns exceeds 300 basis points?

Response

a) The current methodologies used in determining return on equity (ROE) for the nuclear and regulated hydroelectric generating assets were established by the OEB in EB-2010-0008 and were subsequently applied in EB-2013-0321. OPG does not contemplate any changes to the calculation and/or annual reporting of its ROE for regulated generating assets during the IR Term.

The rate smoothing mechanism will not affect the calculation of OPG's regulated ROE during the IR Term. The OEB-approved ROE is reflected in the unsmoothed revenue requirement. The OEB will determine the amount of deferred revenue requirement to be recorded in the Rate Smoothing Deferral Account (RSDA) each year. The amount recorded in the RSDA will be recorded in income in the year it is recorded in the RSDA.

The following example provides a comparison of how OPG would calculate regulated ROE under smoothed and unsmoothed rates, assuming actual production and costs are incurred as approved:

Assumptions:
1) Unsmoothed Revenue Requirement = $100M
2) Approved Rate Base = $200M
3) Approved Common Equity Ratio = 50%
4) Approved Return on Equity @ 10% = $10M
5) Approved costs = Revenue Requirement less ROE = ($100M - $10M) = $90M
6) Deferred Revenue Requirement (RSDA Entry) = $2M
7) Approved Production = 10 TWhs
8) Unsmoothed Rate = $100M 10TWhs = $10.00 / MWh
9) Smoothed Rate = ($100M - $2M) / 10 TWhs = $9.80/MWh

ROE Calculation - Unsmoothed Rates:
$10/MWh * 10TWhs - $90M costs = $10M

ROE Calculation - Smoothed Rates:
$9.80/MWh * 10TWhs + $2M RSDA Entry - $90M costs = $10M

b) OPG's regulated ROE is calculated on a combined basis, including both regulated hydroelectric and nuclear generation lines of business. As described in Ex. A1-3-2, page 23, a regulatory review may be initiated if the achieved ROE for the regulated business (i.e. both hydroelectric and nuclear combined) varies from the ROE included in the payment amounts by more than 300 basis points.

The RRFE defines off-ramps as follows: "Each rate-setting method will include a trigger mechanism with an annual ROE dead band of ±300 basis points. When a distributor performs outside of this earnings dead band, a regulatory review may be initiated.......This approach will, in turn, allow the Board to take corrective action if required".[1]

[1] *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, page 11.

In order to determine whether corrective action is required, the OEB will need information on the specific circumstances of the ROE variance. As part of its reporting, OPG intends to assess the drivers of the ROE variance, and submit the assessment to the OEB with a proposal on what corrective action is required (if any). OPG's proposal would address whether an application for new rates is warranted, and, if so, whether such an application should apply to one or both technologies.

c)

i) The only proposed off-ramp is the ±300 basis points variance identified in section 2.7 of Ex. A1-3-2.

ii) OPG cannot identify all situations in which the ±300 basis points ROE threshold would be triggered, but where an off-ramp would not be required. As a hypothetical example, if OPG were to experience a substantial but short-term variance in ROE, OPG might propose that the OEB maintain the approved rate-setting methodology for the remainder of the IR term. Any proposal would depend on the specific circumstances underlying the ROE variance.

CCC Interrogatory #55

Issue Number: 11.7
Issue: Is OPG's proposed off-ramp appropriate?

Interrogatory

Reference:
Reference: Ex. A1/T3/S2/p. 23

OPG has proposed an off-ramp whereby a regulatory review will be triggered if the actual regulated ROE is outside of a dead band of +/- 300 basis points relative to the allowed ROE. Please set out in detail how OPG intends to calculate its actual ROE given the payment amounts are determined through the smoothing mechanism. What would be the dollar value of 300 basis points for each year of the rate term?

Response

For details on how OPG intends to calculate its ROE during the IR term, please see Ex. L-11.7-1 Staff-271 part a).

The dollar values of the threshold for each year of the rate term are provided in the table below:

Threshold Associated with a 300-Basis Point Off-Ramp

Line No.		2017	2018	2019	2020	2021
1	Return on Common Equity[1] ($M)	487.3	495.1	491.9	679.0	704.4
2	Return on Common Equity[1] (%)	9.19%	9.19%	9.19%	9.19%	9.19%
3	Threshold (%)	3.00%	3.00%	3.00%	3.00%	3.00%
4	Threshold ($M) (line 1 / line 2 x line 3)	159.1	161.6	160.6	221.7	229.9

1 Ex. C1-1-1 Tables 1-5, line 5, columns (c) and (d)

EP Interrogatory #35

Issue Number: 11.7
Issue: Is OPG's proposed off-ramp appropriate?

Interrogatory

Reference:

Has OPG prepared any plan for off-ramping the DRP? At what cost or delay in refurbishing Unit 2 would the company considering scrapping the refurbishment of later units?

If the company has any documents related to this question, please provide them.

Response

OPG has not prepared any plan for off-ramping the Darlington Refurbishment Program nor has OPG established a cost threshold or schedule delay where the company would consider cancelling the refurbishment of later units (please see L-04.3-1 Staff 44). Consistent with the principles in the 2013 LTEP, OPG has built appropriate clauses into its contracts that would allow OPG to exercise an off-ramp (please see L-04.3-8 GEC-8).

LPMA Interrogatory #12

Issue Number: 11.7
Issue: Is OPG's proposed off-ramp appropriate?

Interrogatory

Reference:
Ref: Exhibit A1, Tab 3, Schedule 2, page 23

With respect to the off-ramp, would the calculation be based on the calculation of the ROE for OPG in total or only on the ROE for the regulated hydroelectric portion of OPG? If the former, please confirm that the ROE for the regulated hydroelectric portion of OPG could exceed 300 basis points above the approved ROE while that for the entire company could be under the 300 basis points trigger.

Response

OPG's regulated ROE is calculated on a combined basis, including both regulated hydroelectric and nuclear generation lines of business. As described in Ex. A1-3-2, page 23, a regulatory review may be initiated if the achieved ROE for the regulated business (i.e. both hydroelectric and nuclear combined) varies from the ROE underpinning the payment amounts by more than 300 basis points.

OPG operates as a single company, with a single management structure and a single cost of capital that covers both the hydroelectric and nuclear generating facilities. On that basis, OPB believes that its financial performance should be assessed on a total company basis.

Under OPG's proposal, it is possible that the ROE for one or both lines of business could fall above or below the approved OEB-approved ROE by greater than 300 basis points without triggering the threshold for a regulatory review, as long as the combined ROE was within 300 basis points of the OEB-approved ROE.

OPG notes that it has never exceeded its OEB-approved ROE. Please see Ex. L-3.1-20 VECC-6.

PWU Interrogatory #22

Issue Number: 11.7
Issue: Is OPG's proposed off-ramp appropriate?

Interrogatory

Reference:
Ref: Exhibit A1-3-3, Pages 10-14

OPG seeks approval of a mid-term production review in the first half of 2019 (i.e., prior to 9 July 1, 2019). The application will present the impact of the production variance from July 1, 2019 to December 2021. The production variance will be the difference between:
(i) the nuclear production forecast approved in this Application and, (ii) the nuclear production forecast proposed by OPG in the mid-term review application.

OPG is also proposing a Mid-Term Nuclear Production Variance Account to record revenue variance arising from an updated production forecast.

OPG states that since the inception of regulation by the OEB, there have been a number of variances between OEB approved and actual production. It has proven difficult to forecast nuclear production in the past where OPG's Pickering and Darlington facilities were operating in a comparatively steady state compared to the operating circumstances that will be facing these facilities during the application period.

Ref: Exhibit E2-1-1, Page 2

The OEB approved nuclear production for the period 2008 to 2015 was greater than actual production. As shown on Chart 2 below, the average annual production shortfall for this period was 3.2 TWh. This resulted in an average negative revenue impact of $154.0M borne each year by OPG's shareholder.

Chart 2

OPG Nuclear Production Variance and Revenue Impact

Line No.		2008	2009	2010	2011	2012	2013	2014	2015	Average	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	OPG Application - TWh	51.4	49.9	-	48.9	50.0	-	48.5	46.1		
2	OEB Approved - TWh+	51.4	49.9	50.7	50.4	51.5	51.0	49.0	46.6		
3	Actual -TWh	48.2	46.8	45.8	48.6	49.0	44.7	48.1	44.5		
4	Variance (TWh) (line 3 - line 2)	-3.2	-3.1	-4.9	-1.8	-2.5	-6.3	-0.9	-2.1	-3.2	-24.7
5	Revenue Impact - $M#	-159.9	-154.9	-242.4	-87.3	-121.3	-305.7	-45.9	-114.3	-154.0	-1231.8

\+ 2010 is the average of 2008 and 2009 Board Approved; 2013 is average of 2011 and 2012 Board Approved.
\# At OEB-approved rates of $52.98/MWh for 2008-2010 less fuel cost, and $51.52/MWh for 2011-2013 less fuel cost.
For 2014, 10 months at OEB–approved rate of $51.52/MWh and 2 months at OEB approved rate of $59.29/MWh, less fuel cost (average $52.82/MWh).
For 2015, at OEB approved rate of $59.29/MWh less fuel cost

Given OPG's experience that even for applications involving shorter test periods (2-3 years) there have been production forecast variances, let alone a 5 year forecast:

a) Why is OPG proposing a nuclear production variance account only for the 2nd part of the application (i.e., only for difference between the nuclear production forecast approved in this Application and, (ii) the nuclear production forecast proposed by OPG in the mid-term review application) and not for the first half of the application?

b) Given that both the nuclear production forecast approved in this Application and the nuclear production forecast that will be proposed by OPG in the mid-term review application are forecasts, why is OPG not proposing a production forecast variance account covering the entire test period?

c) Please clarify if OPG's proposal for mid-term production forecast review is conditional on the materiality of the variance between current production forecast and production forecast that OPG will present at the mid-term review application or whether OPG will apply for review anyway.

Response

a) & b) The variance account is intended to reflect the difference between the production forecast approved in the current application for 2017 to 2021, and an updated production forecast for the second half of that period (July 1, 2019 to December 31, 2021).

Until that subsequent production forecast is reviewed and approved by the OEB, there is by definition no variance to record. Since there will be no variance for the first half of the application term (January 1, 2017 to June 30, 2019), the account can only cover the period after the effective date of the updated production forecast (proposed to be July 1, 2019).

c) Please see Ex. L-11.5-1 Staff-258.