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	<ul style="list-style-type: none"> • Table 4 – Bruce Net Fixed Assets • Table 5 – Bruce Costs • Table 6 – Comparison of Bruce Costs • Table 7 – Calculation of Bruce Income Taxes, 2013, 2014, 2015, and 2016 • Table 8 – Calculation of Bruce Income Taxes, 2017, 2018, 2019, 2020, and 2021
H	DEFERRAL AND VARIANCE ACCOUNTS
H1	<p>H1-1-1</p> <ul style="list-style-type: none"> • Table 1 – Deferral and Variance Accounts, Closing Balances, 2014 to 2015 • Table 1a – Deferral and Variance Accounts, Continuity of Account Balances, 2014 to 2015 • Table 2 – Hydroelectric Water Conditions Variance Account, Summary of Account Transactions - 2015 • Table 3 – Ancillary Services Net Revenue Variance Account - Summary of Account Transactions - Projected 2015 • Table 4 – Hydroelectric Incentive Mechanism Variance Account, Summary of Account Transactions – 2015 • Table 5 – Surplus Baseload Generation Variance Account, Summary of Account Transactions – 2015 • Table 6 – Income and Other Taxes Variance Account, Summary of Account Transactions – 2015 • Table 7 – Capacity Refurbishment Variance Account - Hydroelectric, Summary of Account Transactions – 2015 • Table 8 - Pension & OPEB Cash Payment Variance Account and Pension & OPEB Cash vs Accrual Differential Deferral Accounts, Summary of Account Transactions – 2015 • Table 9 – Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, Summary of Account Transactions - 2015 • Table 10 – Nuclear Development Variance Account, Summary of Account Transactions – 2015 • Table 11 – Capacity Refurbishment Variance Account - Nuclear, Summary of Account Transactions – 2015 • Table 11a - Notes to Ex. H1, Tab 1, Sch. 1, Table 11 • Table 12 – Bruce Lease Net Revenues Variance Account, Summary of Account Transactions - 2015 • Table 13 – Nuclear Deferral and Variance Over/Under Recovery Variance Account, Summary of Account Transactions - 2015
	<p>H1-2-1</p> <ul style="list-style-type: none"> • Table 1 – Calculation of Deferral and Variance Account Recovery Payment Riders –Regulated Hydroelectric • Table 2 – Calculation of Deferral and Variance Account Recovery Payment Riders - Nuclear

	H1-3-1 <ul style="list-style-type: none"> No tables
I	DETERMINATION OF PAYMENT AMOUNTS
I1	I1-1-1 <ul style="list-style-type: none"> Table 1 – Summary of Revenue Requirement – Nuclear, 2017 to 2021 Table 2 – Comparison of Revenue Requirement to OEB Approved – Nuclear, 2014 through 2021 Table 3 – Summary of Revenue Deficiency, 2017 to 2021 Table 4 - Determination of 2016 Forecast Return on Equity Table 4a – Notes to Ex. I1, Tab 1, Sch. 1, Table 4
	I1-1-2 <ul style="list-style-type: none"> Table 1 – Annualized Residential Consumer Impact (With Proposed Smoothed Nuclear Rates), EB-2013-0321/EB-2014-0370 to EB 2016-0152 Table 2 - Computation of Percent Change in Payment Amounts (With Proposed Smoothed Nuclear Rates), EB-2013-0321/EB-2014-0370 to EB-2016-0152
	I1-2-1 <ul style="list-style-type: none"> Table 1 – Calculation of 2017-2021 Payment Amounts Table 1a - Notes to Ex I1, Tab 2, Sch. 1, Table 1 Combined Hydroelectric Rate Table 2 - Revised Previously Regulated and Newly Regulated Hydroelectric Payment Amounts Table 2a - Summary of Regulatory Taxable Income for Prescribed Facilities by Segment Revised to Remove the 2015 Nuclear Tax Loss from the Hydroelectric Income Tax Calculation
	I1-3-1 <ul style="list-style-type: none"> Table 1 – Payment Amount and Rider – Nuclear, 2017 to 2021

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ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*;

AND IN THE MATTER OF an Application by Ontario Power Generation Inc. for an order or orders approving payment amounts for prescribed generating facilities commencing January 1, 2017.

APPLICATION

1. The applicant, Ontario Power Generation Inc. (“OPG”) is a corporation, incorporated under the *Ontario Business Corporations Act*, with its head office in the City of Toronto. The principal business of OPG is the generation and sale of electricity in Ontario.
2. In this Application, OPG applies to the Ontario Energy Board (“OEB”) pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* (the “Act”), for an order or orders approving a payment amount for hydroelectric generating facilities (the “regulated hydroelectric facilities”) prescribed under Ontario Regulation 53/05 of the Act, as amended, (“O. Reg. 53/05”) for the period from January 1, 2017 through December 31, 2017 and a payment rider for the regulated hydroelectric facilities for the period from January 1, 2017 through December 31, 2018.
3. Pursuant to section 78.1 of the *Ontario Energy Board Act, 1998*, OPG also seeks an order or orders approving payment amounts for nuclear generating facilities (the “nuclear facilities”) prescribed under O. Reg. 53/05 for the period from January 1, 2017 through December 31, 2021 and a payment rider for the nuclear facilities for the period from January 1, 2017 through December 31, 2018.
4. OPG seeks an order declaring the current payment amounts interim effective January 1, 2017 for the regulated hydroelectric and nuclear facilities, if the order or orders approving

- 1 the payment amounts are not implemented by January 1, 2017 for the regulated
2 hydroelectric and nuclear facilities.
3
- 4 5. For the purposes of section 6 (1) of O. Reg. 53/05, OPG requests that the OEB use the
5 price-cap index methodology proposed in Ex. A1-3-2 for setting payment amounts for the
6 prescribed hydroelectric generating facilities in the period from January 1, 2017 through
7 December 31, 2021.
8
- 9 6. For the purposes of section 6 (1) of O. Reg. 53/05, OPG requests that the OEB use the
10 methodology proposed in Ex. A1-3-2 to approve annual revenue requirements for the
11 nuclear facilities for the period January 1, 2017 to December 31, 2021, and the rate
12 smoothing methodology proposed in Ex. A1-3-3 to approve payment amounts for the
13 nuclear facilities for the period January 1, 2017 to December 31, 2021.
14
- 15 7. OPG seeks approval of the cost of capital presented in Ex. C1-1-1.
16
- 17 8. OPG seeks approval for disposition of the audited balances in all of its deferral and
18 variance accounts as of December 31, 2015, except the Pension & OPEB Cash Versus
19 Accrual Differential Deferral Account. Clearance of that account is subject to the
20 completion of the generic proceeding on pension and OPEB costs (EB-2015-0040).
21
- 22 9. OPG seeks an order continuing established deferral and variance accounts as set out in
23 Ex. H1-1-1.
24
- 25 10. OPG seeks an order establishing certain new deferral and variance accounts presented
26 in Ex. H1-1-1.
27
- 28 11. Pursuant to section 78.1 of the Act, and pursuant to sections 5.5 and 6 (2) of O. Reg.
29 53/05, OPG requests that the OEB approve OPG's nuclear rate smoothing proposal as
30 set out in Ex. A1-3-3, including the establishment of a deferral account and the portion of

1 the OEB-approved nuclear revenue requirement that is to be recorded in that deferral
2 account for January 1, 2017 to December 31, 2021.

3

4 12. OPG seeks approval of a mid-term production review in the first half of 2019 (i.e., prior to
5 July 1, 2019) for:

- 6 • an update of the nuclear production forecast and consequential updates to nuclear
7 fuel costs for the final two-and-a-half years of the five-year application period (July 1,
8 2019 to December 31, 2021); and
- 9 • disposal of applicable audited deferral and variance account balances as well as any
10 remaining unamortized portions of previously approved amounts with recovery period
11 extending beyond December 31, 2018.

12

13 13. To achieve the nuclear revenue requirements and disposition of the nuclear and
14 hydroelectric balances in the deferral and variance accounts, and consistent with the
15 price-cap index methodology for prescribed hydroelectric facilities, OPG is seeking
16 payment amounts and riders as follows:

- 17 • Effective January 1, 2017, \$41.71/MWh for the average hourly net energy production
18 (MWh) from the regulated hydroelectric facilities in any given month (the "hourly
19 volume") for each hour of that month. Where production is over or under the hourly
20 volume, regulated hydroelectric incentive revenue payments will be consistent with
21 the OEB's Payment Amounts Order for EB-2013-0321.

22

- 23 • Approval for recovery of December 31, 2015 audited balances in the regulated
24 hydroelectric deferral and variance accounts, except the Pension & OPEB Cash
25 Versus Accrual Differential Deferral Account, of \$211.3M and a disposition at a rate of
26 \$1.44/MWh for the output from the regulated hydroelectric facilities for the period
27 January 1, 2017 to December 31, 2018.

28

29

- 1 • Approval of the following payment amounts for the nuclear facilities:

Effective Date	Payment Amount
January 1, 2017	\$65.81/MWh
January 1, 2018	\$73.05/MWh
January 1, 2019	\$81.09/MWh
January 1, 2020	\$90.01/MWh
January 1, 2021	\$99.91/MWh

2

- 3 • Approval for recovery of December 31, 2015 audited balances in the nuclear deferral
4 and variance accounts, except the Pension & OPEB Cash Versus Accrual Differential
5 Deferral Account, of \$1,162.4M and a disposition at a rate of \$2.85/MWh for the
6 output from the nuclear facilities for the period January 1, 2017 to December 31,
7 2018.

8

- 9 14. The Application will be supported by written and oral evidence. The written evidence filed
10 by OPG may be supplemented or amended from time to time by OPG prior to the OEB's
11 final decision on the Application.

12

- 13 15. OPG further applies to the OEB pursuant to the provisions of the Act and the OEB Rules
14 of Practice and Procedure for such orders and directions as may be necessary in relation
15 to the Application and the proper conduct of this proceeding.

16

- 17 16. The persons affected by this Application are all electricity consumers in Ontario. It is
18 impractical to set out the names and addresses of the consumers because they are too
19 numerous.

20

- 21 17. OPG requests that copies of all documents filed with the OEB by each party to this
22 Application along with copies of all comments filed with the OEB in accordance with Rule
23 24 of the OEB Rules of Practice and Procedure be served on the applicant and the
24 applicant's counsel as follows:

25

1 (a) The applicant: Barbara Reuber
2 Ontario Power Generation Inc.
3
4 Mailing address: H18 G2
5 700 University Avenue
6 Toronto ON M5G 1X6
7
8 Telephone: 416-592-5419
9
10 Facsimile: 416-592-8519
11
12 Electronic mail: opgregaffairs@opg.com
13
14 (b) The applicant's Counsel: Charles Keizer
15 Torys LLP
16
17 Mailing address: 79 Wellington St. W.
18 PO Box 270
19 Toronto Dominion Centre
20 Toronto ON M5K 1N2
21
22 Telephone: 416-865-0040
23
24 Facsimile: 416-865-7380
25
26 Electronic mail: ckeizer@torys.com
27
28 (c) The applicant's Counsel: Crawford Smith
29 Torys LLP
30
31 Mailing address: 79 Wellington St. W.

1 PO Box 270
2 Toronto Dominion Centre
3 Toronto ON M5K 1N2
4

5 Telephone: 416-865-0040
6

7 Facsimile: 416-865-7380
8

9 Electronic mail: csmith@torys.com
10

11 (d) The applicant's Counsel: Carlton D. Mathias
12 Ontario Power Generation Inc.
13

14 Mailing address: H18 A24
15 700 University Avenue
16 Toronto ON M5G 1X6
17

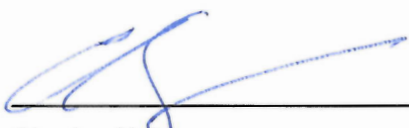
18 Telephone: 416-592-4964
19

20 Facsimile: 416-592-1466
21

22 Electronic mail: carlton.mathias@opg.com
23

24 Dated at Toronto, Ontario, this 27th day of May, 2016.
25

26 Ontario Power Generation Inc.
27

28 
29 _____
30 Charles Keizer
31 Torys LLP

APPROVALS

In this Application, OPG seeks the following specific approvals:

Revenue Requirement

1. The approval of the following revenue requirements for the nuclear facilities, net of the nuclear stretch factor, as set out in Ex. I1-1-1:

Period	Revenue Requirement
January 1, 2017 through December 31, 2017	\$3,189.9M
January 1, 2018 through December 31, 2018	\$3,250.0M
January 1, 2019 through December 31, 2019	\$3,285.0M
January 1, 2020 through December 31, 2020	\$3,774.8M
January 1, 2021 through December 31, 2021	\$3,489.4M

Rate Base

2. The approval of the following rate bases for the nuclear facilities, as summarized in Ex. B1-1-1:

Year	Rate Base
2017	\$4,119.8M
2018	\$4,239.0M
2019	\$4,124.7M
2020	\$8,118.6M
2021	\$8,549.2M

Production Forecasts

3. Approval of the following production forecasts for the nuclear facilities, as presented in Ex. E2-1-1.

Year	Production Forecast (TWh)
2017	38.1
2018	38.5
2019	39.0
2020	37.4
2021	35.4

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Cost of Capital

4. Approval of a deemed capital structure of 51 per cent debt and 49 per cent equity and a combined rate of return on rate base to be determined using data available for the three months prior to the effective date of the payment amounts order, in accordance with the OEB's Cost of Capital Report, and currently forecast at 9.19 per cent for 2017 and adjusted annually using the prevailing rate of return on equity specified by the OEB, as presented in Ex. C1-1-1.

Payment Amounts

5. Effective January 1, 2017, \$41.71/MWh for the average hourly net energy production (MWh) from the regulated hydroelectric facilities in any given month (the "hourly volume") for each hour of that month. Where production is over or under the hourly volume, regulated hydroelectric incentive revenue payments will be consistent with the OEB's Payment Amounts Order in EB-2013-0321. The calculation of the payment amount for the regulated hydroelectric facilities is set out in Ex. I1-2-1.
6. Approval of the rate-setting formula and related elements for setting payment amounts for the prescribed hydroelectric generating facilities in the period from January 1, 2017 through December 31, 2021, as proposed in Ex. A1-3-2.
7. Approval of the following payment amounts for the nuclear facilities:

Effective Date	Payment Amount
January 1, 2017	\$65.81/MWh
January 1, 2018	\$73.05/MWh
January 1, 2019	\$81.09/MWh
January 1, 2020	\$90.01/MWh
January 1, 2021	\$99.91/MWh

1
2 **Rate Smoothing and Mid-term Production Review**

3
4 8. Approval of the nuclear rate smoothing proposal as set out in Ex. A1-3-3, including
5 the establishment of a rate smoothing deferral account and the portion of the
6 approved nuclear revenue requirement that is to be recorded in that deferral account.
7 Specifically, OPG proposes that annual nuclear base payment amounts reflect a
8 constant 11 per cent per year rate increase during the 2017 to 2021 test period
9 resulting in a deferred revenue requirement of \$683M, \$440M, \$121M, \$413M,
10 \$(46)M in 2017, 2018, 2019, 2020 and 2021, respectively.

11
12 9. Approval of a mid-term production review in the first half of 2019 (i.e., prior to July 1,
13 2019) for:
14 i. an update of the nuclear production forecast and consequential updates to
15 nuclear fuel costs for the final two-and-a-half years of the five-year
16 application period (July 1, 2019 to December 31, 2021); and
17 ii. disposal of applicable audited deferral and variance account balances as
18 well as any remaining unamortized portions of previously approved
19 amounts with recovery period extending beyond December 31, 2018.

20
21 **Deferral and Variance Accounts**

22
23 10. Approval for recovery of the audited December 31, 2015 balances of the deferral and
24 variance accounts identified in Exhibit H.

25

1 11. Approval to continue existing deferral and variance accounts, including interest, as
2 proposed in Ex. H1-1-1.

3
4 12. Approval of a hydroelectric payment rider to recover the approved balances of the
5 hydroelectric deferral and variance accounts (except the Pension & OPEB Cash
6 Versus Accrual Differential Deferral Account) at a rate of \$1.44/MWh applied to the
7 output from the hydroelectric facilities, beginning January 1, 2017 and terminating
8 December 31, 2018.

9
10 13. Approval of a nuclear payment rider to recover the approved balances of the nuclear
11 deferral and variance accounts (except the Pension & OPEB Cash Versus Accrual
12 Differential Deferral Account) at a rate of \$2.85/MWh applied to the output from the
13 nuclear facilities, beginning January 1, 2017 and terminating December 31, 2018.

14
15 14. Approval to establish the following deferral and variance accounts as described in Ex.
16 H1-1-1:

- 17 i. Darlington Refurbishment Rate Smoothing Deferral Account;
- 18 ii. Mid-term Nuclear Production Variance Account;
- 19 iii. Nuclear ROE Variance Account; and
- 20 iv. Hydroelectric Capital Structure Variance Account.

21
22 **Project Approvals**

23
24 15. OPG seeks the following approvals for the Darlington Refurbishment Program:

- 25 i. In-service additions to rate base of: (i) \$350.4M in the 2016 Bridge Year;
26 and (ii) for the test period, \$374.4M in 2017, \$8.9M in 2018, \$4,809.2M in
27 2020, and \$0.4M in 2021 on a forecast basis. These amounts reflect the
28 addition to rate base of \$4,800.2M related to Unit 2 in-service addition in
29 2020 and 2021, as well as \$743.1M related to Unit Refurbishment Early
30 In-Service Projects, Safety Improvement Opportunities, and Facilities &
31 Infrastructure Projects. If actual additions to rate base are different from

1 forecast amounts, the cost impact of the difference will be recorded in the
2 Capacity Refurbishment Variance Account (“CRVA”) and any amounts
3 greater than the forecast amounts added to rate base will be subject to a
4 prudence review in a future proceeding; and
5 ii. OM&A expenditures of \$41.5M in 2017, \$13.8M in 2018, \$3.5M in 2019,
6 \$48.4M in 2020, and \$19.7M in 2021 (Ex. F2-7-1).

7
8

9 **Interim Payment Amounts**

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11
12
13

16. An order from the OEB declaring OPG’s current payment amounts for regulated hydroelectric and nuclear facilities interim as of January 1, 2017, if the order or orders approving the payment amounts are not implemented by January 1, 2017.

SUMMARY OF APPLICATION

OVERVIEW AND CONTEXT

Ontario Power Generation Inc. (“OPG”) produces about half of the electricity Ontarians use every day, and it is committed to doing so safely, reliably, and using technologies that are environmentally sustainable. In 2014, OPG ceased burning coal for electricity production, delivering North America’s single largest action to combat climate change.

At the same time, OPG remains the low cost generator in Ontario. OPG controls costs and continuously improves performance through a number of processes, including top-down target setting for key resource envelopes such as OM&A and Capital. OPG continues to look for ways to improve its performance and the value it delivers to electricity customers; finding efficiencies is an ongoing goal for OPG.

OPG is committed to safety in all aspects of its operations. In 2015, the Canadian Electricity Association awarded OPG the *President’s Silver Award for Safety Excellence*. OPG is proud of achieving top quartile performance in the company-wide All Injury Rate and Accident Severity Rate. Given the inherent hazards of nuclear and hydroelectric generation, OPG will continue working to reduce and eliminate risks to public and employee safety.

In the period covered by this application, 2017 to 2021, OPG will undertake several major initiatives aimed at ensuring that it can continue to deliver safe, reliable, sustainable electricity. In 2016, OPG began the execution phase of the \$12.8 billion refurbishment of the Darlington Nuclear Generating Station (“Darlington”). Through this massive endeavour, OPG will renew a workhorse of Ontario’s electricity grid. Darlington provides approximately 20 per cent of Ontario’s electricity needs. The Darlington Refurbishment Program (“DRP”) will also contribute to the province’s economy. According to the *Conference Board of Canada*, the construction phase alone is expected to generate \$14.9 billion in economic benefits to Ontario. At its peak, refurbishment will create 11,700 jobs per year, with an average of 8,800 annually between 2014 and 2023. It is also expected to increase household revenues in Ontario by \$8.5 billion.

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At the same time, OPG plans to invest in the Pickering Nuclear Generating Station (“Pickering”). Extending operations at Pickering until 2024 will provide necessary generating capacity while the units at Darlington are being refurbished and as the first units of the Bruce Nuclear Generating Station are being refurbished by Bruce Power. Together, these projects will allow OPG to continue producing virtually emission-free electricity for future generations.

ABOUT THIS APPLICATION

This application reflects a number of significant changes in the rate-setting framework for OPG’s regulated hydroelectric and nuclear assets.

Focus on Benchmarking

Both the hydroelectric and nuclear incentive rate-setting (“IR”) frameworks are directly tied to OPG’s benchmarking performance. OPG conducts extensive benchmarking of the company’s performance. This application includes benchmarking reports on both the hydroelectric and nuclear generation businesses, as well as separate benchmarking studies on OPG’s nuclear staffing, corporate support costs, and total compensation.

Hydroelectric Incentive Rate-setting

For the company’s regulated hydroelectric facilities, this application marks OPG’s transition to a comprehensive IR framework. For all five years covered by this application, the company’s hydroelectric payments will be determined mechanistically by a price-cap index (including a stretch factor) that parallels the OEB rate-setting method for electricity distributors. By the time of OPG’s expected rebasing in 2022, the company’s hydroelectric payments will have been decoupled from its costs for six years.

Nuclear Incentive Rate-setting

For the nuclear facilities, OPG has developed a custom incentive rate-setting (“Custom IR”) framework that includes a five-year forecast of nuclear revenue requirement adjusted by a stretch factor. The application includes five annual nuclear payment amounts, covering the period from January 1, 2017 through December 31, 2021. The requested nuclear payment

1 amounts are based on a rate-smoothing proposal that limits the annual increase in nuclear
2 payment amounts to 11 per cent during the period.

3
4 In addition to the performance improvements built into OPG's business plan, OPG is
5 proposing a partial nuclear stretch factor, applied to aspects of the company's operating
6 costs that will be largely independent of the DRP and Pickering extended operations. The
7 stretch factor was derived based on total generation cost benchmarking performance.

8 9 **Corporate Overview**

10 The basis for the application can be found in O. Reg. 53/05 and section 78.1 of the *Ontario*
11 *Energy Board Act, 1998* (the "Act").

12
13 OPG's prescribed generating facilities consist of both hydroelectric generating stations and
14 nuclear generating stations, all of which participate in the IESO - administered electricity
15 market in accordance with the Ontario Market Rules. The regulated facilities, which are the
16 subject of this Application, consist of two nuclear generating stations with a total capacity of
17 6,606 MW and 54 hydroelectric generating stations (the "regulated hydroelectric facilities")
18 with a total capacity of 6,425 MW for a combined regulated generating capacity of 13,031
19 MW.

20
21 The budgeting and business planning process that underlies this application is described in
22 Ex. A2-2-1 (Corporate) and in Ex. F2-1-1 (Nuclear).

23 24 25 **PRIORITY ISSUES**

26 In its Decision and Order in EB-2010-0008, the OEB encouraged the participating parties to
27 focus their attention in future applications on the highest priority issues. Accordingly, OPG
28 has crafted its application in such a way as to highlight what it considers to be the highest
29 priority issues. A description of these issues is set out below for reference.

30
31

1 **Darlington Refurbishment Program**

2 This application includes detailed evidence on the DRP. Darlington Refurbishment Program
3 outages will commence when the first unit comes out of service for refurbishment, scheduled
4 for October 2016, and conclude when the fourth unit returns to service in February 2026.

5
6 The DRP is a multi-year, multi-phase mega-project that will enable the Darlington to continue
7 safe and reliable operation until approximately 2055. It involves the replacement of life-
8 limiting critical components, the completion of upgrades to meet applicable regulatory
9 requirements, and the rehabilitation of components at Darlington's four units. As
10 demonstrated by the pre-filed evidence in this application, OPG has successfully performed
11 the detailed planning work and put in place the resources and organizational structure
12 necessary to ensure successful execution of Unit 2 refurbishment, and the DRP in its
13 entirety, on time and on budget.

14
15 The comprehensive planning undertaken by OPG and its contractors during the Definition
16 Phase, including the completion of the full scale reactor mock-up, tooling development and
17 testing, as well as the Unit 2 engineering design modification packages, has enabled the
18 development of a detailed four-unit budget and schedule, known as the Release Quality
19 Estimate. OPG has a high level of confidence in the Release Quality Estimate, which
20 establishes a Program-level baseline against which the success of the DRP will be measured
21 and an envelope within which the budget for Unit 2 and the rest of the units will be managed.
22 OPG also has in place the resources, organization and processes to ensure successful
23 Program execution, including various functional support groups that perform critical
24 oversight, coordination and integration roles in relation to the contractors for the major work
25 bundles and ongoing station operations.

26
27 As part of the work completed during the Definition Phase, all major contracts required to
28 execute the scope of the DRP have been awarded. Given the magnitude, scale and
29 complexity of the DRP, OPG has adopted a "multi-prime contractor" model, where each of
30 the prime contractors is responsible for completing the work under its particular contract. As
31 the owner, OPG is able to exercise control of the entire Program (largely through the support

1 of the functional groups as noted above), and to achieve a reasonable balance between risk
2 transfer to contractors and the costs of contractor services by strategically allocating risks to
3 those best able to manage those risks. For each of the major work bundles, a contracting
4 strategy reflects the suitable sourcing approach, contract structure, and pricing mechanism
5 (including the appropriate incentives to drive effective execution) for that specific work
6 bundle.

7
8 Recognizing that the DRP is a mega-project comprising hundreds of individual projects, OPG
9 has also conducted a thorough evaluation of risks to determine the appropriate level of
10 contingency at the Program and project levels, and established processes and tools to
11 proactively manage and monitor risks on an ongoing basis. The DRP will be executed in a
12 dynamic environment and many issues and events can be expected to arise during the
13 project's execution that will require adjustments to individual elements of cost and schedule.
14 The effective management of risks together with the detailed planning provides OPG with a
15 high degree of confidence in its ability to execute within the budget and schedule established
16 for the DRP.

17 18 **Transition to Incentive Rate-setting**

19 This application is a transition from OPG's past cost of service applications to IR for OPG's
20 hydroelectric and nuclear generating facilities. Consistent with OEB guidance, OPG has
21 proposed different forms of IR for the two technologies, reflecting the work planned for each
22 line of the business.

23
24 OPG proposes a comprehensive IR framework for the company's hydroelectric assets,
25 based on a price-cap index that is closely modelled on the Fourth Generation Incentive Rate-
26 setting Method ("4GIRM") in the *Renewed Regulatory Framework for Electricity Distributors*
27 (the "RRFE").

28
29 The decision not to rebase the hydroelectric payment amounts has allowed OPG to simplify
30 the hydroelectric evidence, relative to a cost of service application. Since no OPG-specific IR
31 filing guidelines exist, and since the proposed hydroelectric IR mechanism is closely modeled

1 on 4GIRM, OPG has used the OEB's filing requirements for electricity distributors' IR
2 applications (the "IR Filing Requirements")¹ to determine what evidence is required to
3 support the requested hydroelectric payment amounts. Attachment 1 to this schedule is a
4 table of concordance with the IR Filing Requirements, identifying where each requirement
5 can be found within the application. A copy of the final Revenue Requirement Work Form
6 filed in OPG's most recent payment amounts application (EB-2013-0321) is filed as
7 Attachment 2 to this schedule.

8
9 To maintain consistency and to facilitate comparison with prior applications, OPG has
10 maintained the same evidentiary structure as prior payment amounts applications. For
11 example, OPG has previously filed hydroelectric and nuclear capital project evidence as
12 Exhibits D1 and D2, respectively. Rather than renumbering the nuclear capital project
13 evidence in this application, OPG has filed a blank Exhibit D1 and maintained nuclear capital
14 evidence as Exhibit D2.

15
16 In this application, OPG initiates its transition from cost of service to a Custom IR
17 methodology for its nuclear facilities. OPG's nuclear IR proposal includes the use of
18 benchmarking to support its forecasts, commitment to efficiency improvement initiatives as
19 part of the company's business plan, and an annual stretch-factor based reduction to certain
20 nuclear and corporate OM&A costs to provide an incentive for continuous improvement. The
21 proposed stretch factor was derived based on annual nuclear total cost benchmarking. OPG
22 proposes to apply the stretch factor to approximately \$1.7 billion, or approximately 75% of
23 OPG's total nuclear OM&A in each year of the application. The stretch factor is cumulative,
24 producing an increasing annual stretch reduction throughout the term of the application.

25
26 OPG's nuclear Custom IR proposal is consistent with the OEB's guidance on incentive rate-
27 setting at OPG in EB-2012-0340. In the Board Report from that proceeding, the OEB stated
28 that "the large capital expenditures and reduced production associated with the DRP and the
29 Pickering closure do not favour the implementation of a 'pure IR regime' (i.e., one based on

¹ *Filing Requirements for Electricity Distribution Rate Applications – 2015 Edition for 2016 Rate Applications – Chapter 3: Incentive Rate-Setting Applications*, July 16, 2015.

1 total factor productivity (“TFP”) with input cost indices, Z-factors, and off-ramps) in the
2 immediate future.”² Given the cost and scale of the DRP and the planned extension of the life
3 of Pickering, OPG would not be able to execute the planned nuclear work under a pure IR
4 framework (like the one proposed for the hydroelectric facilities).

6 **Pickering Extended Operations**

7 OPG plans to extend the operations of Pickering until 2024.³ This extension will benefit
8 Ontario’s electricity system by mitigating capacity uncertainties during the refurbishment of
9 the Darlington and Bruce Nuclear Generating Stations. It will also benefit Ontario’s electricity
10 customers by moderating the upward pressure on rates that would otherwise occur during
11 the height of the Darlington refurbishment. The estimated cost of the incremental work
12 required to safely extend the operations of the Pickering facility is \$307M over the 2016-2020
13 period. The IESO has conducted an independent analysis for the Ministry of Energy that
14 calculates the Ontario Electricity System benefits of Pickering Extended Operations at
15 between \$300M and \$500M. Details on the extended operation of Pickering are provided in
16 Ex. F2-2-3.

18 **Rate Smoothing and Mid-term Production Review**

19 OPG proposes that nuclear payment amounts increase at 11 per cent per year during the
20 term of the application. OPG based the rate smoothing proposal on O. Reg. 53/03, which
21 was recently amended with several new requirements related to OPG’s nuclear payment
22 amounts during and following the DRP. An 11% annual increase achieves the objective
23 established in O. Reg. 53/05 of “making more stable the year-over-year changes in the
24 payment amount” while balancing other considerations including the overall customer bill
25 impacts resulting from the total deferred revenue requirement and associated carrying costs,
26 minimizing the transition when rate smoothing ends, and maintaining OPG’s financial
27 viability.

² EB-2012-0340, *Report of the Board: Incentive Rate-making for Ontario Power Generation’s Prescribed Generation Assets*, p. 8.

³ All six units at the Pickering facility will continue operating until 2022, at which point two units will be shut down. The facility was previously scheduled to end commercial operations in 2020.

1 Under O. Reg. 53/05, the OEB is required approve a separate nuclear revenue requirement
2 for each year of the application period. The regulation also requires that the OEB determine
3 a specific amount of revenue requirement to defer each year, with a view to making more
4 stable the year-over-year changes in the nuclear payment amount. The regulation requires
5 that the OEB make both of these determinations on a five year basis. OPG has proposed
6 specific annual revenue requirement deferral amounts that result in a consistent payment
7 amount increase in each year of the period.

8
9 Given the long term of this application and the uncertainty associated with nuclear production
10 during the term of the application, OPG believes that it will be necessary to review and update
11 the company's nuclear production forecast (and consequential fuel costs) at the mid-point of
12 the five-year period covered by this application. A number of factors have the potential to
13 materially increase or decrease nuclear production during the application period. The
14 proposed mid-term production review would allow the OEB to review OPG's production
15 forecast for the latter half of the term and record the impact on revenue requirement in a
16 variance account. OPG also proposes to clear audited December 31, 2018 balances in
17 deferral and variance accounts in conjunction with the mid-term production review.

18
19 Details regarding OPG's rate smoothing and mid-term review proposals are provided in Ex.
20 A1-3-3.

21 22 **Deferral and Variance Accounts**

23 OPG proposes to clear the audited, year-end 2015 balances for all of its deferral and
24 variance accounts except the Pension & OPEB Cash Versus Accrual Differential Deferral
25 account through payment riders for the period January 1, 2017 to December 31, 2018.
26 Details regarding proposed account clearance and riders are presented in Ex. H1-2-1.

27
28 OPG is proposing to continue all of its existing deferral and variance accounts and is
29 proposing three new deferral and variance accounts which facilitate the regulatory rate-
30 making methodology changes in this application, details of which are provided in Ex. H1-1-1:

- 31 i. Darlington Refurbishment Rate Smoothing Deferral Account,

- 1 ii. Mid-term Nuclear Production Variance Account,
- 2 iii. Nuclear ROE Variance Account, and
- 3 iv. Hydroelectric Capital Structure Variance Account.

4

5 **Approach to Pension and OPEB Amounts**

6 The OEB's EB-2013-0321 Decision on the cost recovery approach for pensions and OPEB
7 provided that rates would be established to provide OPG with sufficient revenue to fund its
8 cash needs until a comprehensive review of pension and OPEB costs is undertaken through
9 a generic proceeding and that, in the absence of OEB policy, the OEB will not allow the
10 collection of funds from ratepayers in 2014 and 2015, of an amount higher than OPG's cash
11 needs. The EB-2013-0321 Decision provided that, until OEB policy is established, the OEB
12 would approve a new deferral account (i.e., the Pension & OPEB Cash Versus Accrual
13 Differential Deferral Account noted above).

14

15 OPG's evidence reflects the continuation of the approach taken in the OEB's EB-2013-0321
16 Decision given that the generic proceeding is ongoing. While OPG continues to believe that
17 accrual accounting is the appropriate basis for recovery of these costs, the company
18 recognizes that the issue is subject to a generic proceeding and, based on the stakeholder
19 feedback, has modified its approach for this application.

20

21 **PROPOSED PAYMENT AMOUNTS AND RIDERS**

22 OPG is requesting that the OEB establish a payment amount of \$41.71 per MWh for the
23 regulated hydroelectric generation facilities effective January 1, 2017.

24

25 For the nuclear generation facilities, OPG is requesting that the OEB establish smoothed
26 payment amounts of:

- 27 1. \$65.81/MWh effective January 1, 2017;
- 28 2. \$73.05/MWh effective January 1, 2018;
- 29 3. \$81.09/MWh effective January 1, 2019;
- 30 4. \$90.01/MWh effective January 1, 2020; and
- 31 5. \$99.91/MWh effective January 1, 2021.

1

2 In addition, OPG is requesting payment riders for the regulated hydroelectric and nuclear
3 production to amortize the audited balances of the deferral and variance accounts as of
4 December 31, 2015 (excluding the Pension & OPEB Cash Versus Accrual Differential
5 Deferral Account). The proposed riders are \$1.44/MWh for hydroelectric payment amounts
6 and \$2.85/MWh for nuclear payment amounts, as calculated in Ex. H1-2-1.

7

8 As described in Ex. I1-1-2, the forecast combined impacts of the proposed smoothed
9 payment amounts and payment riders on the monthly bill of a typical residential customer bill
10 are:

- 11 i. A decrease of \$1.29 in 2017,
- 12 ii. An increase of \$1.73 in 2018,
- 13 iii. An increase of \$1.07 in 2019,
- 14 iv. An increase of \$1.86 in 2020, and
- 15 v. An increase of \$1.89 in 2021.⁴

16

17 **Rate Base and Cost of Capital**

18 The nuclear rate base will increase significantly during the 2017 to 2021 period as the first
19 stage of the DRP is completed. The actual nuclear rate base was \$3,655.2M at the end of
20 2015. It is forecast to increase to \$4,119.8M in 2017, due to 2016-2017 in-service additions.
21 The nuclear rate base is forecast to be stable in 2018 and 2019, increasing to \$8,118.6M in
22 2020, as Darlington Unit 2 returns to service in 2020, and increasing to \$8,549.2M in 2021.

23

24 Further discussion of nuclear rate base, including variance explanations, can be found in
25 Exhibit B.

26

27 Additional details on in-service additions for the nuclear facilities and corporate capital
28 projects impacting rate base are provided in Exhibits D2 and D3, respectively. Additional
29 detail on depreciation and amortization expense is provided in Ex. F4-1-1.

⁴ As payment riders have only been proposed for 2017 and 2018, no amounts for clearance of deferral and variance accounts is included in forecast bill impacts for 2019-2021. Bill impacts will also vary with changes in the hydroelectric I-factor sub-indices during the test period.

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OPG has calculated its requested return on equity using the formula approved in the OEB's Cost of Capital Report in EB-2009-0084, applied to the regulated rate base using a capital structure of 49 per cent common equity, 51 per cent debt. This proposed capital structure reflects the material increases in OPG's business and financial risks since the prior payment amounts application (EB-2013-0321), including the greater proportion of nuclear assets within the company's rate base, as well as the significant risks associated with the DRP and extension of operations at Pickering. OPG's proposed capital structure is supported by a study prepared by Concentric Energy Advisors, which is filed at Ex. C1-1-1, Attachment 1.

Revenue Requirement

OPG's nuclear revenue requirement, net of the proposed stretch factor is \$3,189.9M for 2017, \$3,250.0M for 2018, \$3,285.0M for 2019, \$3,774.8M for 2020, and \$3,489.4M for 2021, excluding amortization of any deferral and variance accounts. The derivation of nuclear revenue requirement is set out in Ex. I1-1-1 Table 1.

CONCLUSION

OPG has prepared an application that will enable it to proceed with a challenging mandate. During the term of this application, OPG will begin executing the largest single project ever presented to the OEB, renewing a critical station that supplies approximately 20 per cent of Ontario's electricity. At the same time, OPG has proposed benchmark-based IR frameworks for both hydroelectric and nuclear generation, driving the company to improve its performance and to continue delivering value for customers' money.

Through the work proposed in this application, OPG will continue to serve Ontario's electricity customers as their low-cost generator of virtually emission-free electricity.

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ATTACHMENTS

- Attachment 1: Incentive Rate-setting Filing Requirements Comparison
- Attachment 2: Final OPG Revenue Requirement Work Form filed in EB-2013-0321

Hydroelectric Rate-setting IR Framework – Comparison with LDC IR Filing Requirements

LDC Filing Requirements (s. 3.1.3)	OPG Equivalent	Location in Evidence
A manager's summary thoroughly documenting and explaining all rate adjustments applied for	Same	A1-3-1: Summary of Application A1-3-2: Rate-Setting Framework
The contact information for the application	Same	A1-2-1: Application
A completed rate generator and supplementary work forms as applicable	Hydroelectric facilities rate setting proposal	A1-3-2: Rate-Setting Framework
	Continuity Schedule for Deferral and Variance Accounts	H1-2-1: Table 1
	Calculation of 2017-2021 Payment Amounts including the proposed regulated hydroelectric payment rider	I1-2-1: Table 1 H1-2-1: Table 1
	Shared Tax Savings	Not Applicable
	Bill Impact	I1-1-2: Table 1
A PDF copy of the current tariff sheet	Calculation of a single 2014-2015 production-weighted average payment amount for OPG's prescribed hydroelectric facilities	I1-1-2: Table 2a
Supporting documentation cited within the application (including RRWF filed with last payment amount rate order)	Hydroelectric TFP Study	A1-3-4: Hydroelectric TFP Study
	Hydroelectric Benchmarking Study	A1-3-5: Hydroelectric Benchmarking Study
	Revenue Requirement Work Form from last payment amount rate order	A1-3-1: Attachment 2
A statement as to who would be affected by the application	Same	A1-2-1: Application
A statement confirming the accuracy of the billing determinants for pre-populated models	Not Applicable	Not Applicable
A text searchable Adobe PDF format of all documents	Same	All

Updated for OEB Decision of November 20, 2014

EB-2013-0321
Revenue Requirement Work Form

Ontario Power Generation

Ontario Power Generation

EB-2013-0321 Revenue Requirement Work Form

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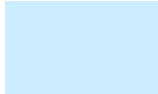

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9	Requested Payment Amounts
10	Recovery of Deferral and Variance Accounts and Riders
11	Test Period Consumer Impact

Ontario Power Generation

EB-2013-0321 Revenue Requirement Work Form

Legend / Colour Scheme

-  OPG Proposed Amounts
-  Adjustment Input Cells For OEB Use
-  Automatically Generated Calculations

OEB Adjustment Input Sheet

Line No.	Description	Total Generating Facilities									
		2014					2015				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)		
Capital Structure											
1	Common Equity	47.0%	47.0%	47.0%	-2.0%	45.0%	47.0%	47.0%	47.0%	-2.0%	45.0%
2	Debt	53.0%	53.0%	53.0%	2.0%	55.0%	53.0%	53.0%	53.0%	2.0%	55.0%
Cost of Capital											
3	Short-Term Debt Facility Cost (\$M)	3.8	3.8	3.8	-	3.8	3.8	3.8	-	3.8	
4	Short-Term Debt Interest Cost (\$M)	4.0	4.0	4.0	-	4.0	6.2	6.2	-	6.2	
5	Short-Term Debt Cost (\$M)	7.0	7.0	7.0	-	7.0	9.0	9.0	-	9.0	
6	Regulated Portion of Short-Term Debt Cost Rate	89.41%	89.41%	89.41%	0.00%	89.41%	89.41%	89.41%	0.00%	89.41%	
7	Existing and Planned Long-Term Debt Cost Rate	4.85%	4.85%	4.85%	0.00%	4.85%	4.86%	4.86%	0.00%	4.86%	
8	Other Long-Term Debt Provision Cost Rate	4.85%	4.85%	4.85%	0.00%	4.85%	4.86%	4.86%	0.00%	4.86%	
9	Common Equity Cost Rate ROE	8.98%	8.98%	9.36%	0.00%	9.36%	8.98%	8.98%	9.53%	-0.23%	9.30%
10	Adjustment for Lesser of UNL/ARC Cost Rate	5.37%	5.37%	5.37%	0.00%	5.37%	5.37%	5.37%	0.00%	5.37%	
Capitalization (\$M)											
11	Short-Term Debt Principal	192.2	192.2	192.2	-	192.2	192.2	192.2	-	192.2	
12	Existing and Planned Long-Term Debt Principal	3,372.7	3,372.7	3,372.7	-	3,372.7	3,481.6	3,481.6	-	3,481.6	
13	Adjustment for Lesser of UNL/ARC	1,389.5	1,389.5	1,389.5	-	1,389.5	1,308.8	1,308.8	-	1,308.8	

Line No.	Description	Previously Regulated Hydroelectric Facilities														
		2014					2015					Total				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)		
Rate Base (\$M)																
14	Gross Plant at Cost	6,079.9	6,079.9	6,079.9	(112.4)	5,967.4	6,118.4	6,118.4	6,118.4	(116.0)	6,002.4	12,198.3	12,198.3	12,198.3	(228.4)	11,969.9
15	Accumulated Depreciation/Amortization	974.3	974.3	974.3	(1.2)	973.1	1,056.2	1,056.2	1,056.2	(2.4)	1,053.8	2,030.5	2,030.5	2,030.5	(3.6)	2,026.9
16	Cash Working Capital	21.7	21.7	21.7	-	21.7	21.7	21.7	21.7	-	21.7	43.4	43.4	43.4	-	43.4
17	Materials and Supplies	0.7	0.7	0.7	-	0.7	0.7	0.7	0.7	-	0.7	1.4	1.4	1.4	-	1.4
18	Nuclear Fuel Inventory	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
19	Total	5,128.0	5,128.0	5,128.0	(111.3)	5,016.7	5,084.6	5,084.6	5,084.6	(113.6)	4,971.0	10,212.6	10,212.6	10,212.6	(224.8)	9,987.7
Expenses (\$M)																
20	OM&A	145.5	149.2	145.1	(17.0)	128.2	141.1	144.2	140.0	(14.0)	126.0	286.5	293.5	285.2	(31.0)	254.1
21	GRC	253.3	267.2	267.2	-	267.2	269.5	280.8	280.8	-	280.8	522.8	548.0	548.0	-	548.0
22	Depreciation/Amortization	82.1	82.1	82.1	(1.2)	80.8	81.9	81.9	81.9	(1.3)	80.6	164.0	164.0	164.0	(2.5)	161.5
23	Property Taxes	0.3	0.3	0.3	-	0.3	0.3	0.3	0.3	-	0.3	0.6	0.6	0.6	-	0.6
24	Total	481.1	498.8	494.7	(18.2)	476.5	492.9	507.2	503.0	(15.3)	487.7	973.9	1,006.1	997.8	(33.5)	964.2
Other Revenues (\$M)																
25	Bruce Lease Revenues Net of Direct Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26	Ancillary and Other Revenue	19.9	34.0	34.0	7.3	41.3	20.2	34.6	34.6	7.8	42.4	40.1	68.6	68.6	15.1	83.7
27	Total	19.9	34.0	34.0	7.3	41.3	20.2	34.6	34.6	7.8	42.4	40.1	68.6	68.6	15.1	83.7
28	Forecast Production (TWh)	19.1	20.1	20.1	-	20.1	20.2	21.0	21.0	-	21.0	39.3	41.1	41.1	-	41.1

Line No.	Description	Newly Regulated Hydroelectric Facilities														
		2014					2015					Total				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)		
Rate Base (\$M)																
29	Gross Plant at Cost	3,275.1	3,275.1	3,275.1	(2.5)	3,272.7	3,347.7	3,347.7	3,347.7	(9.7)	3,338.0	6,622.9	6,622.9	6,622.9	(12.2)	6,610.6
30	Accumulated Depreciation/Amortization	772.6	772.6	772.6	(0.0)	772.6	828.5	828.5	828.5	(0.2)	828.4	1,601.2	1,601.2	1,601.2	(0.2)	1,601.0
31	Cash Working Capital	8.3	8.3	8.3	-	8.3	8.3	8.3	8.3	-	8.3	16.5	16.5	16.5	-	16.5
32	Materials and Supplies	0.7	0.7	0.7	-	0.7	0.7	0.7	0.7	-	0.7	1.4	1.4	1.4	-	1.4
33	Nuclear Fuel Inventory	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
34	Total	2,511.5	2,511.5	2,511.5	(2.4)	2,509.0	2,528.2	2,528.2	2,528.2	(9.6)	2,518.6	5,039.7	5,039.7	5,039.7	(12.0)	5,027.6
Expenses (\$M)																
35	OM&A	232.5	239.3	234.9	(31.4)	203.6	237.2	242.6	237.3	(25.1)	212.2	469.7	482.0	472.3	(56.5)	415.8
36	GRC	75.6	75.6	75.6	-	75.6	77.5	77.5	77.5	-	77.5	153.1	153.1	153.1	-	153.1
37	Depreciation/Amortization	62.2	62.2	62.2	(0.1)	62.2	63.1	63.1	63.1	(0.2)	62.9	125.3	125.3	125.3	(0.3)	125.1
38	Property Taxes	0.1	0.1	0.1	-	0.1	0.1	0.1	0.1	-	0.1	0.2	0.2	0.2	-	0.2
39	Total	370.4	377.3	372.9	(31.4)	341.4	377.9	383.3	378.0	(25.3)	352.7	748.3	760.6	750.9	(56.8)	694.1
Other Revenues (\$M)																
40	Bruce Lease Revenues Net of Direct Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
41	Ancillary and Other Revenue	22.7	22.7	22.7	19.5	42.2	23.1	23.1	23.1	22.5	45.6	45.8	45.8	45.8	42.0	87.8
42	Total	22.7	22.7	22.7	19.5	42.2	23.1	23.1	23.1	22.5	45.6	45.8	45.8	45.8	42.0	87.8
43	Forecast Production¹ (TWh)	5.5	5.5	5.5	-	5.5	12.5	12.5	12.5	-	12.5	17.9	17.9	17.9	-	17.9

Line No. Description		Nuclear Facilities										Total				
		2014					2015					Total				
		OPG Proposed	OPG Proposed	OPG Proposed	OEB	OEB	OPG Proposed	OPG Proposed	OPG Proposed	OEB	OEB	OPG Proposed	OPG Proposed	OPG Proposed	OEB	OEB
		27/9/13	6/12/13	16/5/2014	Adjustment	Approved	27/9/13	6/12/13	16/5/2014	Adjustment	Approved	27/9/13	6/12/13	16/5/2014	Adjustment	Approved
		(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)
Rate Base (\$M)																
44	Gross Plant at Cost	6,262.8	6,262.8	6,262.8	-	6,262.8	6,510.7	6,510.7	6,510.7	-	6,510.7	12,773.5	12,773.5	12,773.5	-	12,773.5
45	Accumulated Depreciation/Amortization	3,299.0	3,299.0	3,299.0	-	3,299.0	3,580.1	3,580.1	3,580.1	-	3,580.1	6,879.1	6,879.1	6,879.1	-	6,879.1
46	Cash Working Capital	32.0	32.0	32.0	-	32.0	32.0	32.0	32.0	-	32.0	64.0	64.0	64.0	-	64.0
47	Materials and Supplies	427.2	427.2	427.2	-	427.2	422.0	422.0	422.0	-	422.0	849.2	849.2	849.2	-	849.2
48	Nuclear Fuel Inventory	283.6	283.6	283.6	-	283.6	274.4	274.4	274.4	-	274.4	558.0	558.0	558.0	-	558.0
49	Total	3,706.7	3,706.7	3,706.7	-	3,706.7	3,659.0	3,659.0	3,659.0	-	3,659.0	7,365.7	7,365.7	7,365.7	-	7,365.7
Expenses (\$M)																
50	OM&A	2,422.7	2,491.8	2,401.4	(316.0)	2,085.4	2,473.3	2,531.3	2,419.8	(253.5)	2,166.3	4,896.0	5,023.0	4,821.1	(569.4)	4,251.7
51	Fuel	280.5	268.6	266.5	2.1	268.6	267.9	260.5	260.5	2.2	262.6	548.4	529.0	526.9	4.3	531.2
52	Depreciation/Amortization	273.7	273.7	273.7	-	273.7	288.5	288.5	288.5	-	288.5	562.3	562.3	562.3	-	562.3
53	Property Taxes	15.9	15.9	15.9	-	15.9	16.4	16.4	16.4	-	16.4	32.4	32.4	32.4	-	32.4
54	Total	2,992.8	3,050.0	2,957.5	(313.8)	2,643.6	3,046.3	3,096.7	2,985.2	(251.3)	2,733.9	6,039.1	6,146.7	5,942.7	(565.1)	5,377.5
Other Revenues (\$M)																
55	Bruce Lease Revenues Net of Direct Costs	39.7	39.7	39.7	-	39.7	40.6	40.6	40.6	-	40.6	80.3	80.3	80.3	-	80.3
56	Ancillary and Other Revenue	33.2	33.2	33.2	4.4	37.6	30.5	30.5	30.5	7.1	37.6	63.7	63.7	63.7	11.5	75.2
57	Total	72.9	72.9	72.9	4.4	77.3	71.1	71.1	71.1	7.1	78.2	144.0	144.0	144.0	11.5	155.5
58	Forecast Production (TWh)	49.7	49.0	48.5	0.5	49.0	48.0	46.1	46.1	0.5	46.60	97.7	95.1	94.6	1.0	95.6

Line No. Description		Total Generating Facilities										Total				
		2014					2015					Total				
		OPG Proposed	OPG Proposed	OPG Proposed	OEB	OEB	OPG Proposed	OPG Proposed	OPG Proposed	OEB	OEB	OPG Proposed	OPG Proposed	OPG Proposed	OEB	OEB
		27/9/13	6/12/13	16/5/2014	Adjustment	Approved	27/9/13	6/12/13	16/5/2014	Adjustment	Approved	27/9/13	6/12/13	16/5/2014	Adjustment	Approved
		(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)
Rate Base (\$M)																
59	Gross Plant at Cost	15,617.8	15,617.8	15,617.8	(114.9)	15,502.9	15,976.9	15,976.9	15,976.9	(125.7)	15,851.1	31,594.7	31,594.7	31,594.7	(240.7)	31,354.0
60	Accumulated Depreciation/Amortization	5,045.9	5,045.9	5,045.9	(1.2)	5,044.7	5,464.8	5,464.8	5,464.8	(2.6)	5,462.3	10,510.7	10,510.7	10,510.7	(3.8)	10,506.9
61	Cash Working Capital	62.0	62.0	62.0	-	62.0	62.0	62.0	62.0	-	62.0	123.9	123.9	123.9	-	123.9
62	Materials and Supplies	428.6	428.6	428.6	-	428.6	423.4	423.4	423.4	-	423.4	852.0	852.0	852.0	-	852.0
63	Nuclear Fuel Inventory	283.6	283.6	283.6	-	283.6	274.4	274.4	274.4	-	274.4	558.0	558.0	558.0	-	558.0
64	Total	11,346.1	11,346.1	11,346.1	(113.7)	11,232.4	11,271.8	11,271.8	11,271.8	(123.2)	11,148.6	22,617.9	22,617.9	22,617.9	(236.9)	22,381.0
Expenses (\$M)																
65	OM&A	2,800.6	2,880.3	2,781.4	(364.3)	2,417.1	2,851.6	2,918.1	2,797.1	(292.6)	2,504.5	5,652.2	5,798.4	5,578.5	(657.0)	4,921.6
66	Fuel and GRC	609.3	611.4	609.3	2.1	611.4	615.0	618.8	618.8	2.2	621.0	1,224.3	1,230.2	1,228.1	4.3	1,232.4
67	Depreciation/Amortization	418.0	418.0	418.0	(1.3)	416.7	433.6	433.6	433.6	(1.5)	432.1	851.6	851.6	851.6	(2.8)	848.8
68	Property Taxes	16.3	16.3	16.3	-	16.3	16.8	16.8	16.8	-	16.8	33.2	33.2	33.2	-	33.2
69	Total	3,844.3	3,926.1	3,825.1	(363.5)	3,461.6	3,917.0	3,987.3	3,866.3	(292.0)	3,574.3	7,761.3	7,913.4	7,691.3	(655.4)	7,035.9
Other Revenues (\$M)																
70	Bruce Lease Revenues Net of Direct Costs	39.7	39.7	39.7	-	39.7	40.6	40.6	40.6	-	40.6	80.3	80.3	80.3	-	80.3
71	Ancillary and Other Revenue	75.7	89.8	89.8	31.2	121.0	73.8	88.2	88.2	37.4	125.6	149.5	178.0	178.0	68.7	246.7
72	Total	115.4	129.5	129.5	31.2	160.7	114.4	128.8	128.8	37.4	166.3	229.8	258.3	258.3	68.7	327.0
73	Forecast Production (TWh)	74.2	74.6	74.1	0.5	74.6	80.7	79.6	79.6	0.5	80.1	154.9	154.2	153.7	1.0	154.6

Line No. Description		2014					2015				
		OPG Proposed	OPG Proposed	OPG Proposed	OEB	OEB	OPG Proposed	OPG Proposed	OPG Proposed	OEB	OEB
		27/9/13	6/12/13	16/5/2014	Adjustment	Approved	27/9/13	6/12/13	16/5/2014	Adjustment	Approved
		(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)
Applicable Tax Rates											
74	Federal Rate	15.00%	15.00%	15.00%	0.00%	15.00%	15.00%	15.00%	15.00%	0.00%	15.00%
75	Provincial Rate	11.00%	11.00%	11.00%	0.00%	11.00%	11.00%	11.00%	11.00%	0.00%	11.00%
76	Provincial Manufacturing & Processing Profits Deduction	-1.00%	-1.00%	-1.00%	0.00%	-1.00%	-1.00%	-1.00%	-1.00%	0.00%	-1.00%
77	Total Tax Rate	25.00%	25.00%	25.00%	0.00%	25.00%	25.00%	25.00%	25.00%	0.00%	25.00%
Tax Credits and Payment Adjustments (\$M)											
78	SR&ED Investment	(10.4)	(10.4)	(10.4)	-	(10.4)	(10.4)	(10.4)	(10.4)	-	(10.4)
79	Single Payments Amount Adjustment	12.3	12.3	12.3	129.1	141.4	(12.3)	(12.3)	(12.3)	(129.1)	(141.4)
Table Income Adjustments (\$M)											
Additions											
80	Depreciation and Amortization	418.0	418.0	418.0	(1.3)	416.7	433.6	433.6	433.6	(1.5)	432.1
81	Nuclear Waste Management Expenses	59.3	59.3	59.3	-	59.3	62.2	62.2	62.2	-	62.2
82	Receipts from Nuclear Segregated Funds	62.6	62.6	62.6	-	62.6	116.5	116.5	116.5	-	116.5
83	Pension and OPEB/SPP Accrual	682.0	761.7	675.8	(675.8)	-	672.7	739.1	618.1	(618.1)	-
84	Regulatory Asset Amortization - Bruce Lease Net Revenues Variance	41.9	41.9	41.9	-	41.9	-	-	-	-	-
85	Regulatory Liability Amortization - Income and Other Taxes Variance	(12.4)	(12.4)	(12.4)	-	(12.4)	-	-	-	-	-
86	Adjustment Related to Financing Cost for Nuclear Liabilities	74.6	74.6	74.6	-	74.6	70.3	70.3	70.3	-	70.3
87	Table SR&ED Investment Tax Credits of Prior Periods	14.8	14.8	14.8	-	14.8	10.4	10.4	10.4	-	10.4
88	Other	45.9	45.9	45.9	-	45.9	49.7	49.7	49.7	-	49.7
89	Total Additions	1,386.7	1,466.4	1,380.5	(677.1)	703.4	1,415.4	1,481.8	1,360.8	(619.6)	741.2
Deductions											
90	CCA	419.0	419.0	419.0	(22.4)	396.6	467.0	467.0	467.0	(5.7)	461.3
91	Cash Expenditures for Nuclear Waste & Decommissioning	148.8	148.8	148.8	-	148.8	197.6	197.6	197.6	-	197.6
92	Contributions to Nuclear Segregated Funds	170.1	170.1	170.1	-	170.1	172.8	172.8	172.8	-	172.8
93	Pension Plan Contributions	238.0	355.3	357.6	(357.6)	-	340.2	401.8	407.6	(407.6)	-
94	OPEB/SPP Payments	99.7	89.3	89.6	(89.6)	-	106.5	95.8	95.8	(95.8)	-
95	Other	0.5	0.5	0.5	-	0.5	0.5	0.5	0.5	-	0.5
96	Total Deductions	1,076.1	1,183.0	1,185.6	(469.6)	716.0	1,284.6	1,335.4	1,341.2	(509.1)	832.2

Deferral and Variance Account Recovery 2015											
Line No.	Description	Projected Balance at December 31, 2013					Recovery Period (Months)				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
		(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)
Previously Regulated Hydroelectric Facilities (\$M)											
97	Capacity Refurbishment Variance	114.4	114.4	112.7	-	112.7	24	24	24	(12)	12
98	Hydroelectric Incentive Mechanism Variance	(2.4)	(2.4)	(5.0)	-	(5.0)	12	12	12	-	12
99	Surplus Baseload Generation Variance	8.1	8.1	19.2	-	19.2	12	12	12	-	12
100	Total	120.1	120.1	127.0	-	127.0	n/a	n/a	n/a	n/a	n/a
Nuclear Facilities (\$M)											
101	Capacity Refurbishment Variance - Capital Portion	3.7	3.7	5.7	-	5.7	12	12	12	-	12
102	Nuclear Development Variance	69.4	69.4	56.5	-	56.5	12	12	12	-	12
103	Total	73.1	73.1	62.2	-	62.2	n/a	n/a	n/a	n/a	n/a

1 Newly Regulated Hydroelectric Facilities 18 month (July 2014 - December 2015) test period forecast production

OPG Rate Base and Cost of Capital

OPG Rate Base and Cost of Capital

		Total Generating Facilities									
Line No.	Description	2014					2015				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
		(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)
1	Previously Regulated Hydroelectric Rate Base (\$M)	5,128.0	5,128.0	5,128.0	(111.3)	5,016.7	5,084.6	5,084.6	5,084.6	(113.6)	4,971.0
2	Newly Regulated Hydroelectric Rate Base (\$M)	2,511.5	2,511.5	2,511.5	(2.4)	2,509.0	2,528.2	2,528.2	2,528.2	(9.6)	2,518.6
3	Nuclear Rate Base Financed by Capital Structure (\$M)	2,317.2	2,317.2	2,317.2	-	2,317.2	2,350.2	2,350.2	2,350.2	-	2,350.2
4	Previously Regulated Hydroelectric Allocation factor	51.50%	51.50%	51.50%	-0.54%	50.97%	51.03%	51.03%	51.03%	-0.52%	50.52%
5	Newly Regulated Hydroelectric Allocation Factor	25.22%	25.22%	25.22%	0.27%	25.49%	25.38%	25.38%	25.38%	0.22%	25.60%
6	Nuclear Allocation Factor	23.27%	23.27%	23.27%	0.27%	23.54%	23.59%	23.59%	23.59%	0.30%	23.88%

		Previously Regulated Hydroelectric Facilities														
Line No.	Description	2014					2015					Total				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
		(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)
Capitalization (\$M)																
7	Total Rate Base	5,128.0	5,128.0	5,128.0	(111.3)	5,016.7	5,084.6	5,084.6	5,084.6	(113.6)	4,971.0	10,212.6	10,212.6	10,212.6	(224.8)	9,987.7
8	Adjustment for Lesser of UNL/ARC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
9	Rate Base Financed by Capital Structure	5,128.0	5,128.0	5,128.0	(111.3)	5,016.7	5,084.6	5,084.6	5,084.6	(113.6)	4,971.0	10,212.6	10,212.6	10,212.6	(224.8)	9,987.7
10	Common Equity	2,410.1	2,410.1	2,410.1	(152.6)	2,257.5	2,389.8	2,389.8	2,389.8	(152.8)	2,237.0	4,799.9	4,799.9	4,799.9	(305.4)	4,494.5
11	Total Debt	2,717.8	2,717.8	2,717.8	41.4	2,759.2	2,694.8	2,694.8	2,694.8	39.2	2,734.1	5,412.7	5,412.7	5,412.7	80.6	5,493.3
12	Short-Term Debt	99.0	99.0	99.0	(1.0)	98.0	98.1	98.1	98.1	(1.0)	97.1	197.1	197.1	197.1	(2.0)	195.1
13	Existing and Planned Long-Term Debt	1,737.0	1,737.0	1,737.0	(18.1)	1,719.0	1,776.8	1,776.8	1,776.8	(17.9)	1,758.9	3,513.8	3,513.8	3,513.8	(36.0)	3,477.8
14	Other Long-Term Debt Provision	881.8	881.8	881.8	60.5	942.3	819.9	819.9	819.9	58.2	878.1	1,701.7	1,701.7	1,701.7	118.6	1,820.3
Cost of Capital (\$M)																
15	Adjustment for Lesser of UNL/ARC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
16	Common Equity	216.4	216.4	225.6	(14.3)	211.3	214.6	214.6	227.7	(19.7)	208.0	431.0	431.0	453.3	(34.0)	419.3
17	Existing and Planned Long-Term Debt	84.2	84.2	84.2	(0.9)	83.4	86.4	86.4	86.4	(0.9)	85.5	170.6	170.6	170.6	(1.7)	168.9
18	Other Long-Term Debt Provision	42.8	42.8	42.8	2.9	45.7	39.8	39.8	39.8	2.8	42.7	82.6	82.6	82.6	5.8	88.4

		Newly Regulated Hydroelectric Facilities														
Line No.	Description	2014					2015					Total				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
		(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)
Capitalization (\$M)																
19	Total Rate Base	2,511.5	2,511.5	2,511.5	(2.4)	2,509.0	2,528.2	2,528.2	2,528.2	(9.6)	2,518.6	5,039.7	5,039.7	5,039.7	(12.0)	5,027.6
20	Adjustment for Lesser of UNL/ARC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21	Rate Base Financed by Capital Structure	2,511.5	2,511.5	2,511.5	(2.4)	2,509.0	2,528.2	2,528.2	2,528.2	(9.6)	2,518.6	5,039.7	5,039.7	5,039.7	(12.0)	5,027.6
22	Common Equity	1,180.4	1,180.4	1,180.4	(51.3)	1,129.1	1,188.2	1,188.2	1,188.2	(54.9)	1,133.4	2,368.6	2,368.6	2,368.6	(106.2)	2,262.4
23	Total Debt	1,331.1	1,331.1	1,331.1	48.9	1,380.0	1,339.9	1,339.9	1,339.9	45.3	1,385.2	2,671.0	2,671.0	2,671.0	94.2	2,765.2
24	Short-Term Debt	48.5	48.5	48.5	0.5	49.0	48.8	48.8	48.8	0.4	49.2	97.3	97.3	97.3	0.9	98.2
25	Existing and Planned Long-Term Debt	850.7	850.7	850.7	9.0	859.7	883.5	883.5	883.5	7.7	891.1	1,734.2	1,734.2	1,734.2	16.7	1,750.8
26	Other Long-Term Debt Provision	431.9	431.9	431.9	39.4	471.3	407.7	407.7	407.7	37.2	444.9	839.6	839.6	839.6	76.6	916.1
Cost of Capital (\$M)																
27	Adjustment for Lesser of UNL/ARC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
28	Common Equity	106.0	106.0	110.5	(4.8)	105.7	106.7	106.7	113.2	(7.8)	105.4	212.7	212.7	223.7	(12.6)	211.1
29	Existing and Planned Long-Term Debt	41.3	41.3	41.3	0.4	41.7	42.9	42.9	42.9	0.4	43.3	84.2	84.2	84.2	0.8	85.0
30	Other Long-Term Debt Provision	20.9	20.9	20.9	1.9	22.9	19.8	19.8	19.8	1.8	21.6	40.8	40.8	40.8	3.7	44.5

Line No.	Description	Nuclear Facilities														
		2014					2015					Total				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)		
Capitalization (\$M)																
31	Total Rate Base	3,706.7	3,706.7	3,706.7	-	3,706.7	3,659.0	3,659.0	3,659.0	-	3,659.0	7,365.7	7,365.7	7,365.7	-	7,365.7
32	Adjustment for Lesser of UNL/ARC	1,389.5	1,389.5	1,389.5	-	1,389.5	1,308.8	1,308.8	1,308.8	-	1,308.8	2,698.2	2,698.2	2,698.2	-	2,698.2
33	Rate Base Financed by Capital Structure	2,317.2	2,317.2	2,317.2	-	2,317.2	2,350.2	2,350.2	2,350.2	-	2,350.2	4,667.4	4,667.4	4,667.4	-	4,667.4
34	Common Equity	1,089.1	1,089.1	1,089.1	(46.3)	1,042.7	1,104.6	1,104.6	1,104.6	(47.0)	1,057.6	2,193.7	2,193.7	2,193.7	(93.3)	2,100.3
35	Total Debt	1,228.1	1,228.1	1,228.1	46.3	1,274.5	1,245.6	1,245.6	1,245.6	47.0	1,292.6	2,473.7	2,473.7	2,473.7	93.3	2,567.1
36	Short-Term Debt	44.7	44.7	44.7	0.5	45.3	45.3	45.3	45.3	0.6	45.9	90.1	90.1	90.1	1.1	91.2
37	Existing and Planned Long-Term Debt	784.9	784.9	784.9	9.1	794.0	821.3	821.3	821.3	10.3	831.6	1,606.2	1,606.2	1,606.2	19.3	1,625.5
38	Other Long-Term Debt Provision	398.5	398.5	398.5	36.8	435.2	379.0	379.0	379.0	36.2	415.1	777.5	777.5	777.5	72.9	850.4
Cost of Capital (\$M)																
39	Adjustment for Lesser of UNL/ARC	74.6	74.6	74.6	-	74.6	70.3	70.3	70.3	-	70.3	144.9	144.9	144.9	-	144.9
40	Common Equity	97.8	97.8	101.9	(4.3)	97.6	99.2	99.2	105.3	(6.9)	98.4	197.0	197.0	207.2	(11.2)	196.0
41	Existing and Planned Long-Term Debt	38.1	38.1	38.1	0.4	38.5	39.9	39.9	39.9	0.5	40.4	78.0	78.0	78.0	0.9	78.9
42	Other Long-Term Debt Provision	19.3	19.3	19.3	1.8	21.1	18.4	18.4	18.4	1.8	20.2	37.7	37.7	37.7	3.5	41.3

Line No.	Description	Total Generating Facilities														
		2014					2015					Total				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)		
Capitalization (\$M)																
43	Total Rate Base	11,346.1	11,346.1	11,346.1	(113.7)	11,232.4	11,271.8	11,271.8	11,271.8	(123.2)	11,148.6	22,617.9	22,617.9	22,617.9	(236.9)	22,381.0
44	Adjustment for Lesser of UNL/ARC	1,389.5	1,389.5	1,389.5	-	1,389.5	1,308.8	1,308.8	1,308.8	-	1,308.8	2,698.2	2,698.2	2,698.2	-	2,698.2
45	Rate Base Financed by Capital Structure	9,956.7	9,956.7	9,956.7	(113.7)	9,843.0	9,963.0	9,963.0	9,963.0	(123.2)	9,839.8	19,919.7	19,919.7	19,919.7	(236.9)	19,682.8
46	Common Equity	4,679.6	4,679.6	4,679.6	(250.3)	4,429.3	4,682.6	4,682.6	4,682.6	(254.7)	4,427.9	9,362.2	9,362.2	9,362.2	(505.0)	8,857.3
47	Total Debt	5,277.0	5,277.0	5,277.0	136.6	5,413.6	5,280.4	5,280.4	5,280.4	131.5	5,411.9	10,557.4	10,557.4	10,557.4	268.1	10,825.5
48	Short-Term Debt	192.2	192.2	192.2	(0.0)	192.2	192.2	192.2	192.2	0.0	192.2	384.4	384.4	384.4	-	384.4
49	Existing and Planned Long-Term Debt	3,372.7	3,372.7	3,372.7	(0.0)	3,372.7	3,481.6	3,481.6	3,481.6	0.0	3,481.6	6,854.2	6,854.2	6,854.2	-	6,854.2
50	Other Long-Term Debt Provision	1,712.1	1,712.1	1,712.1	136.6	1,848.7	1,606.6	1,606.6	1,606.6	131.5	1,738.1	3,318.8	3,318.8	3,318.8	268.1	3,586.9
Cost of Capital (\$M)																
51	Adjustment for Lesser of UNL/ARC	74.6	74.6	74.6	-	74.6	70.3	70.3	70.3	-	70.3	144.9	144.9	144.9	-	144.9
52	Common Equity	420.2	420.2	438.0	(23.4)	414.6	420.5	420.5	446.3	(34.5)	411.8	840.7	840.7	884.3	(57.9)	826.4
53	Existing and Planned Long-Term Debt	163.6	163.6	163.6	(0.0)	163.6	169.2	169.2	169.2	0.0	169.2	332.8	332.8	332.8	-	332.8
54	Other Long-Term Debt Provision	83.0	83.0	83.0	6.6	89.7	78.1	78.1	78.1	6.4	84.5	161.1	161.1	161.1	13.0	174.1

OPG Regulatory Income Taxes

Line No.	Description	Total Generating Facilities									
		2014					2015				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)		
Applicable Tax Rates											
1	Federal Rate	15.00%	15.00%	15.00%	0.00%	15.00%	15.00%	15.00%	15.00%	0.00%	15.00%
2	Provincial Rate	11.00%	11.00%	11.00%	0.00%	11.00%	11.00%	11.00%	11.00%	0.00%	11.00%
3	Provincial Manufacturing & Processing Profits Deduction	-1.00%	-1.00%	-1.00%	0.00%	-1.00%	-1.00%	-1.00%	-1.00%	0.00%	-1.00%
4	Total Tax Rate	25.00%	25.00%	25.00%	0.00%	25.00%	25.00%	25.00%	25.00%	0.00%	25.00%
Taxable Income (\$M)											
5	Earnings Before Tax	637.2	604.4	598.6	(22.9)	575.7	519.8	525.0	517.1	(230.8)	286.3
6	Adjustments: Additions	1,386.7	1,466.4	1,380.5	(677.1)	703.4	1,415.4	1,481.8	1,360.8	(619.6)	741.2
7	Adjustments: Deductions	1,076.1	1,183.0	1,185.6	(469.6)	716.0	1,284.6	1,335.4	1,341.2	(509.1)	832.2
8	Total Taxable Income (with Carryover)	947.8	887.8	793.5	(514.4)	279.1	650.6	671.4	536.6	(268.9)	267.7
Income Taxes (\$M)											
9	Federal Income Taxes	142.2	133.2	119.0	(77.2)	41.9	97.6	100.7	80.5	(40.3)	40.2
10	Provincial Income Taxes	94.8	88.8	79.3	(51.4)	27.9	65.1	67.1	53.7	(26.9)	26.8
11	Tax Credits (SR&ED Investment)	(10.4)	(10.4)	(10.4)	-	(10.4)	(10.4)	(10.4)	(10.4)	-	(10.4)
12	Total Income Taxes	226.5	211.5	188.0	(128.6)	59.4	152.3	157.5	123.8	(67.2)	56.5
Earnings Before Tax (\$M)											
13	Requested After Tax ROE	438.0	420.2	438.0	(23.4)	414.6	420.5	420.5	446.3	(34.5)	411.8
14	Bruce Lease Net Revenues	39.7	39.7	39.7	-	39.7	40.6	40.6	40.6	-	40.6
15	Income Taxes	226.5	211.5	188.0	(128.6)	59.4	152.3	157.5	123.8	(67.2)	56.5
16	Single Payments Amount Adjustment	12.3	12.3	12.3	129.1	141.4	(12.3)	(12.3)	(12.3)	(129.1)	(141.4)
17	Total Earnings Before Tax	637.2	604.4	598.6	(22.9)	575.7	519.8	525.0	517.1	(230.8)	286.3
Adjustments (\$M)											
Additions											
18	Depreciation and Amortization	418.0	418.0	418.0	(1.3)	416.7	433.6	433.6	433.6	(1.5)	432.1
19	Nuclear Waste Management Expenses	59.3	59.3	59.3	-	59.3	62.2	62.2	62.2	-	62.2
20	Receipts from Nuclear Segregated Funds	62.6	62.6	62.6	-	62.6	116.5	116.5	116.5	-	116.5
21	Pension and OPEB/SPP Accrual	682.0	761.7	675.8	(675.8)	-	672.7	739.1	618.1	(618.1)	-
22	Regulatory Asset Amortization - Bruce Lease Net Revenues Variance	41.9	41.9	41.9	-	41.9	-	-	-	-	-
23	Regulatory Liability Amortization - Income and Other Taxes Variance	(12.4)	(12.4)	(12.4)	-	(12.4)	-	-	-	-	-
24	Adjustment Related to Financing Cost for Nuclear Liabilities	74.6	74.6	74.6	-	74.6	70.3	70.3	70.3	-	70.3
25	Taxable SR&ED Investment Tax Credits of Prior Periods	14.8	14.8	14.8	-	14.8	10.4	10.4	10.4	-	10.4
26	Other	45.9	45.9	45.9	-	45.9	49.7	49.7	49.7	-	49.7
27	Total Additions	1,386.7	1,466.4	1,380.5	(677.1)	703.4	1,415.4	1,481.8	1,360.8	(619.6)	741.2
Deductions											
28	CCA	419.0	419.0	419.0	(22.4)	396.6	467.0	467.0	467.0	(5.7)	461.3
29	Cash Expenditures for Nuclear Waste & Decommissioning	148.8	148.8	148.8	-	148.8	197.6	197.6	197.6	-	197.6
30	Contributions to Nuclear Segregated Funds	170.1	170.1	170.1	-	170.1	172.8	172.8	172.8	-	172.8
31	Pension Plan Contributions	238.0	355.3	357.6	(357.6)	-	340.2	401.8	407.6	(407.6)	-
32	OPEB/SPP Payments	99.7	89.3	89.6	(89.6)	-	106.5	95.8	95.8	(95.8)	-
33	Other	0.5	0.5	0.5	-	0.5	0.5	0.5	0.5	-	0.5
34	Total Deductions	1,076.1	1,183.0	1,185.6	(469.6)	716.0	1,284.6	1,335.4	1,341.2	(509.1)	832.2

OPG Revenue Requirement

OPG Revenue Requirement

		Previously Regulated Hydroelectric Facilities														
Line No.	Description	2014					2015					Total				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)
Cost of Capital (\$M)																
1	Short-term Debt	3.6	3.6	3.6	(0.0)	3.6	4.6	4.6	4.6	(0.0)	4.5	8.2	8.2	8.2	(0.1)	8.1
2	Long-Term Debt	127.0	127.0	127.0	2.1	129.1	126.2	126.2	126.2	2.0	128.2	253.2	253.2	253.2	4.0	257.2
3	ROE	216.4	216.4	225.6	(14.3)	211.3	214.6	214.6	227.7	(19.7)	208.0	431.0	431.0	453.3	(34.0)	419.3
4	Adjustment for Lesser of UNL/ARC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
5	Total	347.1	347.1	356.2	(12.3)	343.9	345.4	345.4	358.5	(17.8)	340.7	692.4	692.4	714.7	(30.1)	684.7
Expenses (\$M)																
6	OM&A	145.5	149.2	145.1	(17.0)	128.2	141.1	144.2	140.0	(14.0)	126.0	286.5	293.5	285.2	(31.0)	254.1
7	GRC	253.3	267.2	267.2	0.0	267.2	269.5	280.8	280.8	0.0	280.8	522.8	548.0	548.0	0.0	548.0
8	Depreciation/Amortization	82.1	82.1	82.1	(1.2)	80.8	81.9	81.9	81.9	(1.3)	80.6	164.0	164.0	164.0	(2.5)	161.5
9	Property Taxes	0.3	0.3	0.3	0.0	0.3	0.3	0.3	0.3	0.0	0.3	0.6	0.6	0.6	0.0	0.6
10	Total	481.1	498.8	494.7	(18.2)	476.5	492.9	507.2	503.0	(15.3)	487.7	973.9	1,006.1	997.8	(33.5)	964.2
Other Revenues (\$M)																
11	Bruce Lease Net Revenues	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
12	Ancillary and Other Revenue	19.9	34.0	34.0	7.3	41.3	20.2	34.6	34.6	7.8	42.4	40.1	68.6	68.6	15.1	83.7
13	Total	19.9	34.0	34.0	7.3	41.3	20.2	34.6	34.6	7.8	42.4	40.1	68.6	68.6	15.1	83.7
14	Regulatory Income Tax (\$M)	49.7	48.0	49.7	(2.3)	47.4	61.5	61.8	64.2	(24.1)	40.1	111.2	109.8	113.9	(26.4)	87.5
15	Revenue Requirement (\$M)	858.0	860.0	866.6	(40.1)	826.6	879.5	879.8	891.2	(65.0)	826.1	1,737.5	1,739.7	1,757.8	(105.1)	1,652.7

		Newly Regulated Hydroelectric Facilities														
Line No.	Description	2014					2015					Total				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)
Cost of Capital (\$M)																
16	Short-term Debt	1.8	1.8	1.8	0.0	1.8	2.3	2.3	2.3	0.0	2.3	4.0	4.0	4.0	0.0	4.1
17	Long-Term Debt	62.2	62.2	62.2	2.3	64.6	62.7	62.7	62.7	2.2	64.9	125.0	125.0	125.0	4.5	129.5
18	ROE	106.0	106.0	110.5	(4.8)	105.7	106.7	106.7	113.2	(7.8)	105.4	212.7	212.7	223.7	(12.6)	211.1
19	Adjustment for Lesser of UNL/ARC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20	Total	170.0	170.0	174.5	(2.4)	172.0	171.7	171.7	178.3	(5.6)	172.6	341.7	341.7	352.7	(8.1)	344.6
Expenses (\$M)																
21	OM&A	232.5	239.3	234.9	(31.4)	203.6	237.2	242.6	237.3	(25.1)	212.2	469.7	482.0	472.3	(56.5)	415.8
22	GRC	75.6	75.6	75.6	0.0	75.6	77.5	77.5	77.5	0.0	77.5	153.1	153.1	153.1	0.0	153.1
23	Depreciation/Amortization	62.2	62.2	62.2	(0.1)	62.2	63.1	63.1	63.1	(0.2)	62.9	125.3	125.3	125.3	(0.3)	125.1
24	Property Taxes	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.0	0.1	0.2	0.2	0.2	0.0	0.2
25	Total	370.4	377.3	372.9	(31.4)	341.4	377.9	383.3	378.0	(25.3)	352.7	748.3	760.6	750.9	(56.8)	694.1
Other Revenues (\$M)																
26	Bruce Lease Net Revenues	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	Ancillary and Other Revenue	22.7	22.7	22.7	19.5	42.2	23.1	23.1	23.1	22.5	45.6	45.8	45.8	45.8	42.0	87.8
28	Total	22.7	22.7	22.7	19.5	42.2	23.1	23.1	23.1	22.5	45.6	45.8	45.8	45.8	42.0	87.8
29	Regulatory Income Tax (\$M)	32.2	30.6	29.9	(8.5)	21.4	43.2	43.8	42.7	(16.9)	25.8	75.4	74.5	72.6	(25.4)	47.2
30	Revenue Requirement (\$M)	549.9	555.2	554.6	(61.9)	492.7	569.7	575.8	575.9	(70.3)	505.5	1,119.7	1,131.0	1,130.5	(132.2)	998.3

OPG Revenue Requirement

		Nuclear Facilities														
Line No.	Description	2014					2015					Total				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)
Cost of Capital (\$M)																
31	Short-term Debt	1.6	1.6	1.6	0.0	1.6	2.1	2.1	2.1	0.0	2.1	3.7	3.7	3.7	0.0	3.8
32	Long-Term Debt	57.4	57.4	57.4	2.2	59.6	58.3	58.3	58.3	2.3	60.6	115.7	115.7	115.7	4.5	120.2
33	ROE	97.8	97.8	101.9	(4.3)	97.6	99.2	99.2	105.3	(6.9)	98.4	197.0	197.0	207.2	(11.2)	196.0
34	Adjustment for Lesser of UNL/ARC	74.6	74.6	74.6	0.0	74.6	70.3	70.3	70.3	0.0	70.3	144.9	144.9	144.9	0.0	144.9
35	Total	231.4	231.4	235.6	(2.1)	233.5	229.9	229.9	236.0	(4.6)	231.4	461.4	461.4	471.6	(6.7)	464.8
Expenses (\$M)																
36	OM&A	2,422.7	2,491.8	2,401.4	(316.0)	2,085.4	2,473.3	2,531.3	2,419.8	(253.5)	2,166.3	4,896.0	5,023.0	4,821.1	(569.4)	4,251.7
37	Fuel	280.5	268.6	266.5	2.1	268.6	267.9	260.5	260.5	2.2	262.6	548.4	529.0	526.9	4.3	531.2
38	Depreciation/Amortization	273.7	273.7	273.7	0.0	273.7	288.5	288.5	288.5	0.0	288.5	562.3	562.3	562.3	0.0	562.3
39	Property Taxes	15.9	15.9	15.9	0.0	15.9	16.4	16.4	16.4	0.0	16.4	32.4	32.4	32.4	0.0	32.4
40	Total	2,992.8	3,050.0	2,957.5	(313.8)	2,643.6	3,046.3	3,096.7	2,985.2	(251.3)	2,733.9	6,039.1	6,146.7	5,942.7	(565.1)	5,377.5
Other Revenues (\$M)																
41	Bruce Lease Net Revenues	39.7	39.7	39.7	0.0	39.7	40.6	40.6	40.6	0.0	40.6	80.3	80.3	80.3	0.0	80.3
42	Ancillary and Other Revenue	33.2	33.2	33.2	4.4	37.6	30.5	30.5	30.5	7.1	37.6	63.7	63.7	63.7	11.5	75.2
43	Total	72.9	72.9	72.9	4.4	77.3	71.1	71.1	71.1	7.1	78.2	144.0	144.0	144.0	11.5	155.5
44	Regulatory Income Tax (\$M)	144.6	132.8	108.3	(117.7)	(9.4)	47.5	51.9	16.8	(26.3)	(9.4)	192.1	184.7	125.2	(144.0)	(18.8)
45	Revenue Requirement (\$M)	3,296.0	3,341.4	3,228.5	(438.1)	2,790.4	3,252.6	3,307.4	3,166.9	(289.3)	2,877.6	6,548.6	6,648.8	6,395.4	(727.4)	5,668.1

		Total Generating Facilities														
Line No.	Description	2014					2015					Total				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)
Cost of Capital (\$M)																
46	Short-term Debt	7.0	7.0	7.0	0.0	7.0	9.0	9.0	9.0	0.0	9.0	16.0	16.0	16.0	0.0	16.0
47	Long-Term Debt	246.6	246.6	246.6	6.6	253.2	247.3	247.3	247.3	6.4	253.7	493.9	493.9	493.9	13.0	506.9
48	ROE	420.2	420.2	438.0	(23.4)	414.6	420.5	420.5	446.3	(34.5)	411.8	840.7	840.7	884.3	(57.9)	826.4
49	Adjustment for Lesser of UNL/ARC	74.6	74.6	74.6	0.0	74.6	70.3	70.3	70.3	0.0	70.3	144.9	144.9	144.9	0.0	144.9
50	Total	748.5	748.5	766.2	(16.8)	749.4	747.0	747.0	772.8	(28.1)	744.7	1,495.5	1,495.5	1,539.0	(44.9)	1,494.1
Expenses (\$M)																
51	OM&A	2,800.6	2,880.3	2,781.4	(364.3)	2,417.1	2,851.6	2,918.1	2,797.1	(292.6)	2,504.5	5,652.2	5,798.4	5,578.5	(657.0)	4,921.6
52	Fuel and GRC	609.3	611.4	609.3	2.1	611.4	615.0	618.8	618.8	2.2	621.0	1,224.3	1,230.2	1,228.1	4.3	1,232.4
53	Depreciation/Amortization	418.0	418.0	418.0	(1.3)	416.7	433.6	433.6	433.6	(1.5)	432.1	851.6	851.6	851.6	(2.8)	848.8
54	Property Taxes	16.3	16.3	16.3	0.0	16.3	16.8	16.8	16.8	0.0	16.8	33.2	33.2	33.2	0.0	33.2
55	Total	3,844.3	3,926.1	3,825.1	(363.5)	3,461.6	3,917.0	3,987.3	3,866.3	(292.0)	3,574.3	7,761.3	7,913.4	7,691.3	(655.4)	7,035.9
Other Revenues (\$M)																
56	Bruce Lease Net Revenues	39.7	39.7	39.7	0.0	39.7	40.6	40.6	40.6	0.0	40.6	80.3	80.3	80.3	0.0	80.3
57	Ancillary and Other Revenue	75.7	89.8	89.8	31.2	121.0	73.8	88.2	88.2	37.4	125.6	149.5	178.0	178.0	68.7	246.7
58	Total	115.4	129.5	129.5	31.2	160.7	114.4	128.8	128.8	37.4	166.3	229.8	258.3	258.3	68.7	327.0
59	Regulatory Income Tax (\$M)	226.5	211.4	187.9	(128.6)	59.4	152.3	157.5	123.7	(67.2)	56.5	378.8	368.9	311.7	(195.8)	115.9
60	Revenue Requirement (\$M)	4,703.9	4,756.5	4,649.8	(540.1)	4,109.7	4,701.8	4,763.0	4,633.9	(424.6)	4,209.3	9,405.8	9,519.5	9,283.7	(964.7)	8,319.0

OPG Revenue Requirement Deficiency / (Sufficiency)

Line No.	Description	Previously Regulated Hydroelectric Facilities														
		2014					2015					Total				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
	(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)	
Production & Revenue																
1	Forecast Production (TWh)	19.1	20.1	20.1	0.0	20.1	20.2	21.0	21.0	0.0	21.0	39.3	41.1	41.1	0.0	41.1
2	Current Payment Rate (\$/MWh)	35.78	35.78	35.78	n/a	35.78	35.78	35.78	35.78	n/a	35.78	n/a	n/a	n/a	n/a	n/a
3	Revenue From Current Payment Rate (\$M)	681.9	718.6	718.6	0.0	718.6	723.6	752.4	752.4	0.0	752.4	1,405.5	1,471.1	1,471.1	0.0	1,471.1
Revenue Requirement																
4	Revenue Requirement (\$M)	858.0	860.0	866.6	(40.1)	826.6	879.5	879.8	891.2	(65.0)	826.1	1,737.5	1,739.7	1,757.8	(105.1)	1,652.7
5	Revenue Requirement Deficiency (Sufficiency) (\$M)	176.1	141.3	148.0	(40.1)	107.9	155.9	127.3	138.7	(65.0)	73.7	332.0	268.6	286.7	(105.1)	181.6

Line No.	Description	Nuclear Facilities														
		2014					2015					Total				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
	(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)	
Production & Revenue																
6	Forecast Production (TWh)	49.7	49.0	48.5	0.5	49.0	48.0	46.1	46.1	0.5	46.6	97.7	95.1	94.6	1.0	95.6
7	Current Payment Rate (\$/MWh)	51.52	51.52	51.52	n/a	51.52	51.52	51.52	51.52	n/a	51.52	n/a	n/a	n/a	n/a	n/a
8	Revenue From Current Payment Rate (\$M)	2,560.5	2,526.8	2,501.0	23.4	2,524.5	2,473.0	2,373.4	2,373.4	27.5	2,400.8	5,033.5	4,900.2	4,874.4	50.9	4,925.3
Revenue Requirement																
9	Revenue Requirement (\$M)	3,296.0	3,341.4	3,228.5	(438.1)	2,790.4	3,252.6	3,307.4	3,166.9	(289.3)	2,877.6	6,548.6	6,648.8	6,395.4	(727.4)	5,668.1
10	Revenue Requirement Deficiency (Sufficiency) (\$M)	735.5	814.6	727.5	(461.5)	265.9	779.6	934.0	793.5	(316.7)	476.8	1,515.1	1,748.6	1,521.0	(778.3)	742.7

Line No.	Description	Total Previously Regulated Hydroelectric and Nuclear Generating Facilities														
		2014					2015					Total				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
	(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)	
Production & Revenue																
12	Forecast Production (TWh)	68.8	69.1	68.6	0.5	69.1	68.2	67.1	67.1	0.5	67.6	137.0	136.2	135.7	1.0	136.7
12	Current Payment Rate (\$/MWh)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
13	Revenue From Current Payment Rate (\$M)	3,242.4	3,245.4	3,219.7	23.4	3,243.1	3,196.6	3,125.8	3,125.8	27.5	3,153.2	6,439.0	6,371.2	6,345.5	50.9	6,396.4
Revenue Requirement																
14	Revenue Requirement (\$M)	4,154.0	4,201.3	4,095.2	(478.2)	3,617.0	4,132.1	4,187.2	4,058.1	(354.3)	3,703.8	8,286.1	8,388.5	8,153.2	(832.5)	7,320.7
15	Revenue Requirement Deficiency (Sufficiency) (\$M)	911.6	955.9	875.5	(501.6)	373.9	935.5	1,061.4	932.3	(381.8)	550.5	1,847.1	2,017.2	1,807.8	(883.4)	924.4

OPG Requested Payment Amounts

		Previously Regulated Hydroelectric Facilities														
Line No.	Description	2014					2015					2014-2015 Test Period				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
		(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)
1	Revenue Requirement (\$M)	858.0	860.0	866.6	(40.1)	826.6	879.5	879.8	891.2	(65.0)	826.1	1,737.5	1,739.7	1,757.8	(105.1)	1,652.7
2	Forecast Production (TWh)	19.1	20.1	20.1	0.0	20.1	20.2	21.0	21.0	0.0	21.0	39.3	41.1	41.1	0.0	41.1
3	Requested Payment Amount (\$/MWh) (line 1 / line 2)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	44.23	42.31	42.75	(2.56)	40.20

		Newly Regulated Hydroelectric Facilities														
Line No.	Description	July 1, 2014 - December 31, 2014					2015					July 1, 2014 - 2015 Test Period				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
		(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)
4	Revenue Requirement ¹ (\$M)	275.0	277.6	277.3	(30.9)	246.4	569.7	575.8	575.9	(70.3)	505.5	844.7	853.4	853.2	(101.3)	751.9
5	Forecast Production ² (TWh)	5.5	5.5	5.5	0.0	5.5	12.5	12.5	12.5	0.0	12.5	17.9	17.9	17.9	0.0	17.9
6	Requested Payment Amount (\$/MWh) (line 4 / line 5)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	47.10	47.59	47.57	(5.65)	41.93

		Nuclear Facilities														
Line No.	Description	2014					2015					2014-2015 Test Period				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
		(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)
7	Revenue Requirement (\$M)	3,296.0	3,341.4	3,228.5	(438.1)	2,790.4	3,252.6	3,307.4	3,166.9	(289.3)	2,877.6	6,548.6	6,648.8	6,395.4	(727.4)	5,668.1
8	Forecast Production (TWh)	49.7	49.0	48.5	0.5	49.0	48.0	46.1	46.1	0.5	46.6	97.7	95.1	94.6	1.0	95.6
9	Requested Payment Amount (\$/MWh) (line 7 / line 8)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	67.03	69.91	67.60	(8.31)	59.29

		Total Generating Facilities														
Line No.	Description	2014					2015					2014-2015 Test Period				
		OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
		(a)	(aa)	(b)	(c)	(d)	(e)	(ee)	(f)	(g)	(h)	(i)	(ii)	(j)	(k)	(l)
10	Revenue Requirement (\$M)	4,429.0	4,478.9	4,372.5	(509.1)	3,863.3	4,701.8	4,763.0	4,633.9	(424.6)	4,209.3	9,130.8	9,130.8	9,006.4	(933.8)	8,072.6
11	Forecast Production (TWh)	74.2	74.6	74.1	0.5	74.6	80.7	79.6	79.6	0.5	80.1	154.9	154.9	153.7	1.0	154.6
12	Requested Payment Amount (\$/MWh)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

1 Amount represents 50% of 2014 revenue requirement
 2 Newly Regulated Hydroelectric Facilities 18 month (July 2014 - December 2015) test period forecast production

OPG Recovery of Deferral and Variance Accounts and Riders

		Previously Regulated Hydroelectric Facilities				
		Amortization 2015				
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
		(a)	(aa)	(b)	(c)	(d)
Variance Accounts (\$M)						
1	Capacity Refurbishment Variance	57.2	57.2	56.4	56.4	112.7
2	Hydroelectric Incentive Mechanism Variance	(2.4)	(2.4)	(5.0)	0.0	(5.0)
3	Surplus Baseload Generation Variance	8.1	8.1	19.2	0.0	19.2
4	Total	62.9	62.9	70.6	56.4	127.0
5	Forecast Production (TWh)	20.2	21.0	21.0	0.0	21.0
6	Rider (\$/MWh) (line 4 / line 5)	3.11	2.99	3.36	2.68	6.04

		Nuclear Facilities				
		Amortization 2015				
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
		(a)		(b)	(c)	(d)
Variance Accounts (\$M)						
7	Capacity Refurbishment Variance	3.7	3.7	5.7	0.0	5.7
8	Nuclear Development Variance	69.4	69.4	56.5	0.0	56.5
9	Total	73.1	73.1	62.2	0.0	62.2
10	Forecast Production (TWh)	48.0	46.1	46.1	0.5	46.6
11	Rider (\$/MWh) (line 9 / line 10)	1.52	1.59	1.35	(0.02)	1.33

OPG 2014-2015 Test Period Consumer Impact

		Residential Consumers				
		EB-2010-0008 / EB-2012-0002 >> EB-2013-0321				
		Previously Regulated Hydroelectric & Nuclear Facilities				
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	
Production and Demand						
1	Typical Usage, including Line Losses ¹ (kWh/Month)	842.3	842.3	842.3	n/a	842.3
2	Forecast Production (TWh)	137.0	136.2	135.7	1.0	136.7
3	IESO Forecast Provincial Demand ² (TWh)	282.4	282.4	282.4	n/a	282.4
4	OPG Proportion of Consumer Usage (line 2 / line 3)	48.51%	48.24%	48.06%	0.35%	48.41%
5	Typical Usage of OPG Generation (kWh/Month) (line 1 x line 4)	408.6	406.3	404.8	2.9	407.8
6	Typical Bill¹ (\$/Month)	118.69	118.69	118.69	n/a	118.69
Production-Weighted Average Rates						
7	EB-2010-0008 / EB-2012-0002 Production-Weighted Average Rate (\$/MWh) (line 23)	52.35	52.06	52.04	0.04	52.09
8	EB-2013-0321 Production-Weighted Average Rate (\$/MWh) (line 41)	63.28	64.38	62.84	(6.12)	56.73
Impact						
9	Typical Bill Impact³ (\$/Month)	4.47	5.00	4.37	(2.48)	1.89
10	Percentage Change of Typical Bill (line 9 / line 6)	3.8%	4.2%	3.7%	-2.1%	1.6%

		EB-2010-0008 / EB-2012-0002				
		Current Rates				
		Previously Regulated Hydroelectric & Nuclear Facilities				
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OPG Proposed 16/5/2014	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	
Payment Amounts (\$MWh)						
11	Previously Regulated Hydroelectric	35.78	35.78	35.78	n/a	35.78
12	Nuclear	51.52	51.52	51.52	n/a	51.52
Riders (\$MWh)						
13	Previously Regulated Hydroelectric	3.04	3.04	3.04	n/a	3.04
14	Nuclear	6.27	6.27	6.27	n/a	6.27
Total Annual Rates (\$MWh)						
15	Previously Regulated Hydroelectric	38.82	38.82	38.82	n/a	38.82
16	Nuclear	57.79	57.79	57.79	n/a	57.79
Forecast Production EB-2013-0321 (TWh)						
17	Previously Regulated Hydroelectric	39.3	41.1	41.1	-	41.1
18	Nuclear	97.7	95.1	94.6	1.0	95.6
19	Total	137.0	136.2	135.7	1.0	136.7
Production-Weighted Average Rates (\$MWh)						
20	Previously Regulated Hydroelectric	11.13	11.72	11.76	(0.08)	11.67
21	Nuclear	41.22	40.35	40.28	0.13	40.41
22	Total (line 20 + line 21)	52.35	52.06	52.04	0.04	52.09
23	Total Production-Weighted Average Rate (\$MWh)	52.35	52.06	52.04	0.04	52.09

		EB-2013-0321			
		Test Period Revenue			
		Previously Regulated Hydroelectric & Nuclear Facilities			
Line No.	Description	OPG Proposed 27/9/13	OPG Proposed 6/12/13	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)
EB-2012-0002 2014 Approved Riders and Forecasted Revenue (\$M)					
24	Previously Regulated Hydroelectric Rider	2.02	2.02	2.02	n/a
25	Previously Regulated Hydroelectric Rider Revenue	38.50	40.57	40.57	-
26	Nuclear Rider	4.18	4.18	4.18	n/a
27	Nuclear Rider Revenue	207.75	205.01	202.92	1.90
28	Total Revenue	246.24	245.58	243.49	1.90
EB-2013-0321 2015 Proposed Riders and Forecasted Revenue (\$M)					
29	Previously Regulated Hydroelectric Rider	3.11	2.99	3.36	2.68
30	Previously Regulated Hydroelectric Rider Revenue	62.88	62.88	70.63	56.37
31	Nuclear Rider	1.52	1.59	1.35	(0.02)
32	Nuclear Rider Revenue	73.07	73.07	62.16	-
33	Total Revenue	135.95	135.95	132.79	56.37
EB-2013-0321 2014-2015 Test Period Revenue Requirement (\$M)					
34	Previously Regulated Hydroelectric Revenue	1,737.5	1,739.7	1,757.8	(105.1)
35	Nuclear Revenue	6,548.6	6,648.8	6,395.4	(727.4)
36	Total Revenue	8,286.1	8,388.5	8,153.2	(832.5)
37	Total Test Period Revenue (\$M) (line 28 + line 33 + line 36)	8,668.3	8,770.0	8,529.5	(774.2)
Forecast Production EB-2013-0321 (TWh)					
38	Previously Regulated Hydroelectric	39.28	41.11	41.11	-
39	Nuclear	97.70	95.11	94.61	0.99
40	Total	136.98	136.23	135.73	0.99
41	Total Production-Weighted Average Rate (\$/MWh) (line 37 / line 40)	63.28	64.38	62.84	(6.12)

- 1 Average monthly consumption (800 kWh) and average monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Tiered pricing). Typical Consumption includes line losses.
- 2 Based on IESO May 24, 2013 18 Month Outlook. As the 18 Month Outlook did not provide a demand forecast for 2014 or 2015, OPG used the IESO Energy demand forecast for 2013 (141.2 TWh) and assumed the 2014 and 2015 forecasts to be equal to the 2013 forecast (141.2 TWh + 141.2 TWh = 282.4 TWh).
- 3 Typical Bill Impact is line 2 x increase (in \$/MWh) in average OPG rates (payment amounts including riders) from Board Approved EB-2010-0008/EB-2012-0002 to proposed EB-2013-0321. Average Board Approved rates are payment amounts for Prev. Reg. Hydro and Nuclear, respectively, from EB-2010-0008 Payment Amounts Order (Prev. Reg. Hydro from App. B, Table 1, line 3; Nuclear from App. C, Table 1, line 3) plus riders from EB-2012-0002 Payment Amounts Order (Hydroelectric Rider 2013-A from pg. 4, para. 3; Nuclear Rider 2013-A from pg. 5, para. 6), prorated for respective Prev. Reg. Hydro and Nuclear production in 2014-15 Test Period (from Ex. E1-1-1 Table 1, line 3 (Prev. Reg. Hydro) and Ex. E2-1-1 Table 1, line 3 (Nuclear)). Average proposed rates are Test Period amounts for Prev. Reg. Hydro revenue requirement plus Nuclear revenue requirement (from Ex. I1-1-1 Table 1, line 24), plus Test Period amounts for Deferral & Variance Account recovery (from Ex. I1-1-1 Table 1, line 25), plus Test Period revenue from Hydroelectric Rider 2014-A and Nuclear Rider 2014-A, all divided by total Test Period Prev. Reg. Hydro and Nuclear production (from Ex. E1-1-1 Table 1, line 3 (Prev. Reg. Hydro) and Ex. E2-1-1 Table 1, line 3 (Nuclear)). Hydroelectric Rider 2014-A is \$2.02/MWh from EB-2012-0002 Payment Amounts Order, pg. 5, para. 5; Nuclear Rider 2014-A is \$4.18/MWh from EB-2012-0002 Payment Amounts Order, pg. 5, para. 8.

RATE-SETTING FRAMEWORK

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4

1 **1. OVERVIEW**

2
3 This is the first incentive rate-setting (“IR”) application for OPG’s nuclear and hydroelectric
4 generating facilities. In a letter dated February 17, 2015, the OEB indicated that it expected
5 the company’s next payment amounts would be based on the principles outlined in the
6 *Renewed Regulatory Framework for Electricity Distributors* (“RRFE”).¹ The OEB further
7 indicated that the application should include an IR mechanism for the company’s hydroelectric
8 assets. For OPG’s nuclear assets, the OEB set out its view that OPG should take a longer
9 term approach to Custom Incentive Rate-setting (“Custom IR”) that focuses on the parameters
10 of a multi-year cost of service application while incorporating elements of IR.²

11
12 OPG is proposing forms of IR for setting both nuclear and hydroelectric payment amounts. For
13 the company’s hydroelectric assets, OPG’s proposal is closely aligned to the Fourth
14 Generation IR (“4GIRM”) price-cap index method used by most Ontario electricity distributors.
15 For the nuclear assets, OPG’s Custom IR proposal includes a benchmarking-based stretch
16 factor to drive continuous improvement in elements of the company’s operations that can be
17 implemented without jeopardizing safety, reliability, or the execution of the multi-billion dollar
18 nuclear capital work planned for the application period.

19
20 OPG designed this application in direct response to the OEB’s letter, and based on input
21 received from stakeholders. This schedule summarizes the ways in which the application
22 reflects the ratemaking approach set out in the RRFE and elsewhere in OEB policy. The
23 schedule is divided between the company’s proposed frameworks for hydroelectric and
24 nuclear assets.

¹ *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012.

² Letter re: *Incentive Rate-setting for Ontario Power Generation’s Prescribed Generation Assets*, to all participants in EB-2013-0321 and EB-2012-0340, February 17, 2015.

1 This schedule also reviews OPG's proposed annual performance reporting and the company's
2 customer engagement activities.

3
4 **1.1. Stakeholder Consultation**

5
6 In late 2014 and early 2015, OPG held a series of stakeholder information sessions regarding
7 its planned application for 2016 payment amounts. During these information sessions, the
8 company presented OEB Staff and other stakeholders with its proposed rate-setting approach
9 for both hydroelectric and nuclear operations. The consultation consisted of a series of three
10 information sessions during which stakeholders were asked to give feedback on the
11 company's proposed approach. Although OPG ultimately did not file an application for 2016
12 payment amounts, aspects of the current application were discussed in that stakeholdering
13 process. The agendas for these sessions are provided in Ex. A1-7-1 Attachments 1-3.

14
15 OPG also held stakeholder information sessions in connection with the current application on
16 February 8, March 21 and May 19 of 2016. The agendas from these sessions are also
17 provided in Ex. A1-7-1 Attachments 4 -6.

18
19 Following the consultations, OPG made a number of changes to the planned application,
20 including:

- 21 i. Eliminating the proposal to establish hydro base rates using a 2017 forecast test year
22 cost of service review – instead, the filed application escalates existing hydroelectric
23 payment amounts by the proposed price-cap index;
- 24 ii. Eliminating the proposed symmetrical earnings sharing mechanism for nuclear and
25 hydroelectric businesses;
- 26 iii. Eliminating the New Cost of Capital Variance Account proposed to record differences in
27 hydro return on equity during the IR term;
- 28 iv. Modifying the hydroelectric x-factor, increasing the annual productivity adjustment from
29 -1% (as identified by the independent Total Factor Productivity study) to 0%, reflecting
30 OEB policy in the electric distribution sector;

- 1 v. Expanding the application of the nuclear stretch factor applied to include corporate
2 support costs; and
- 3 vi. Expanding the proposed performance reporting metrics to include all of the key
4 hydroelectric performance areas filed in OPG's prior payment amounts application (EB-
5 2013-0321, Ex. F1-1-1, Appendix B) and all measures used in annual nuclear
6 benchmarking.

7

8 **2. HYDROELECTRIC FACILITIES RATE-SETTING PROPOSAL**

9

10 **2.1. Summary of Hydroelectric Rate-setting Proposal**

11

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

16

17 Consistent with the price-cap index methodology in the RRFE, OPG has proposed I- and X-
18 factors to establish the annual price cap adjustment for 2017 to 2021. Consistent with the
19 RRFE, the productivity and stretch factors that comprise the proposed X-factor are based on
20 independent Total Factor Productivity ("TFP") and total-cost benchmarking studies.

21

22 As set out below in Chart 1, the structure of OPG's hydroelectric ratemaking proposal is
23 largely identical to 4GIRM:

24

25

26

27

28

29

30

1

Chart 1 – Summary of Hydroelectric Ratemaking Proposal

Ratemaking Element	4GIRM	OPG Proposal
“Going-In” Rates	Determined in a forward test year cost of service review	Determined in cost of service review of 2014/2015 test year (EB-2013-0321)
Form	Price-cap Index	Price-cap Index
Coverage	Comprehensive (capital and OM&A)	Comprehensive (capital and OM&A)
Annual Adjustment Mechanism	<p>1+(I-X)</p> <p>Inflation: Composite Index. Distribution Industry weighted Labour Index (Ontario AWE) and Non-Labour index (GDP-IPI-FDD)</p> <p>X-factor: Peer group X-factors comprised of:</p> <ol style="list-style-type: none"> 1. Distribution industry TFP growth potential; and 2. a Stretch Factor 	<p>1+(I-X)</p> <p>Inflation: Composite Index. Generation Industry weighted Labour Index (Ontario AWE) and Non-Labour index (GDP-IPI-FDD)</p> <p>X-factor: Peer group X-factors comprised of:</p> <ol style="list-style-type: none"> 1. Hydroelectric generation industry TFP growth potential; and 2. a Stretch Factor
Role of Benchmarking	<ol style="list-style-type: none"> 1. Assess reasonableness of test year cost forecasts 2. Determine stretch factor 	<ol style="list-style-type: none"> 1. Test year review completed in EB-2013-0321 2. Determine stretch factor
Sharing of Benefits	Stretch factor of between 0% and 0.6% based on benchmarking	<p>Stretch factor of between 0% and 0.6% based on benchmarking</p> <p>OPG proposes a stretch factor of 0.3% for the application term, based on the company’s hydroelectric benchmarking</p>

Ratemaking Element	4GIRM	OPG Proposal
Term	Five years	Five years
Incremental and Advance Capital Modules	Available on application	Available on application OPG is not proposing an Advance Capital Module
Treatment of Unforeseen Events	Per OEB policy (<i>Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, EB-2007-0673</i>)	Per OEB policy (<i>Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, EB-2007-0673</i>), with OPG-specific materiality threshold of \$10M
Treatment of Deferral and Variance Accounts	Status quo	Status quo, with addition of a variance account to account for the impact of OEB's decision on OPG's request to adjust the common equity ratio
Performance Reporting / Monitoring and Off-ramps	Annual performance reporting A regulatory review may be initiated if a distributor's annual reporting shows performance outside of the ± 300 basis points ROE dead band, or if performance erodes to unacceptable measures	Annual performance reporting A regulatory review may be initiated if OPG's annual reporting shows performance outside of the ± 300 basis points ROE dead band, or if performance erodes to unacceptable measures

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2.2. OEB & Stakeholder Guidance

2.2.1. OEB Policy

1 With the Niagara Tunnel Project now in service, OPG's regulated hydroelectric generation
2 facilities are in a relatively stable, steady state that is conceptually consistent with a price-cap
3 index form of IR. The company believes that, of the three options set out in the RRFE, the
4 4GIRM approach is best suited to the state of its regulated hydroelectric generation facilities.

5
6 As the RRFE is aimed at rate-making for electricity distributors in Ontario, it is not directly
7 applicable to generators. However, OPG recognizes that many of the objectives and principles
8 addressed in the RRFE can be applied to the generation sector.

9
10 The proposed hydroelectric IR framework deviates from 4GIRM only as is necessary to
11 incorporate material differences between the distribution and hydroelectric generation
12 industries and to transition OPG to IR for the first time.³ Specifically, OPG's proposed model
13 incorporates the following modifications to the 4GIRM methodology:

- 14 1. **Inflation factor:** OPG proposed using the same input sub-indices as the OEB's
15 4GIRM I-factor; however the I-factor is weighted appropriately to reflect the input
16 costs of the hydroelectric generation industry (i.e., not the electric distribution
17 industry) as determined independently by London Economics International LLC
18 ("LEI");
- 19 2. **Productivity Growth:** The independent Total Factor Productivity ("TFP") study
20 reflects growth potential of the hydroelectric generation industry. However,
21 notwithstanding the negative productivity factor identified by the LEI TFP study, OPG
22 is proposing a productivity factor of zero; and
- 23 3. **Stretch factor:** Set once at the beginning of the IR plan term (i.e., not revised
24 annually) to place OPG's hydroelectric benchmarking performance in the context of
25 the OEB's 0% to 0.6% stretch factor range.

³ Reflects an adjustment to the hydroelectric base rate to remove a 2015 nuclear tax loss (discussed in Section 2.3.2) and a new deferral account to reflect the OEB's decision on common equity (discussed in Section 2.6).

1 The RRFE requires an X-Factor to be based on industry TFP growth potential and a stretch
2 factor. In its letter of February 17, 2015, the OEB noted its expectation that OPG's
3 hydroelectric incentive rate-making framework would take into consideration the independent
4 productivity study performed by LEI and filed with the OEB on December 19, 2014. That
5 productivity study reflected information for the 2002 to 2012 period. An updated version of
6 the study including data for 2013 and 2014 is filed as Attachment 1 to this schedule. The
7 TFP study results were substantially the same, as demonstrated in Chart 2:

8
9 **Chart 2 – 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)

10
11 Although LEI's TFP study concludes that a -1% productivity factor is appropriate for OPG's
12 regulated hydroelectric facilities, OPG recognizes that the OEB has declined to accept a
13 negative productivity factor in the context of electricity distribution. OPG therefore proposes a
14 0% productivity factor for the 2017-2021 IR period. This increase to the productivity factor
15 essentially creates an additional 1% stretch factor for OPG's hydroelectric facilities during
16 each year of the IR period, relative to the industry trend identified in the TFP study.

17
18 Total cost benchmarking is an important component of each rate-setting model in the RRFE
19 and plays an important role in OPG's proposed IR frameworks for both hydroelectric and
20 nuclear assets. Under the 4GIRM method, which OPG's hydroelectric IR proposal is based
21 upon, an applicant's benchmark performance is used to determine the stretch factor in the
22 distributor's price-cap index. Similarly, OPG proposes that the hydroelectric stretch factor be
23 determined based on the hydroelectric total cost benchmarking study conducted by Navigant
24 Energy Consulting Inc. ("Navigant"), which is filed as Attachment 2 to this schedule.

25
26 As discussed in section 2.3 below, the proposed 0.3% stretch factor is based on the
27 company's hydroelectric benchmarking performance. In determining the value of the stretch

1 factor, OPG has adopted the same 0% to 0.6% range applied under the RRFE. As OPG's
2 benchmarking results will be submitted and reviewed in this proceeding and not updated
3 over the IRM term, OPG proposes that the stretch factor set in this proceeding remain in
4 effect for the five-year IRM term.

5 6 2.2.2. Filing Guidelines

7
8 The OEB's Filing Guidelines for OPG's prescribed generation facilities are based on a cost of
9 service methodology and are therefore not applicable to a price-cap-based application. OPG
10 has structured the hydroelectric payment amounts evidence on the OEB's 4GIRM Filing
11 Requirements.⁴

12
13 OPG has applied the Filing Requirements as appropriate for the generation industry, as set
14 out in Ex. A1-3-1 Attachment 1. For example, since OPG's payment amounts do not include
15 pass-through amounts, many of the sheets in the OEB's IRM Rate Generator, such as those
16 relating to Retail Transmission Service Rates, are not applicable to OPG. OPG has
17 incorporated the applicable elements of the IRM Rate Generator in Ex. I1-2-1.

18 19 20 21 22 **2.3. Annual Adjustment Mechanism**

23
24 OPG proposes that the company's existing hydroelectric payment amounts be adjusted
25 annually according to a mechanistic price-cap adjustment according to the same formula as
26 used in 4GIRM:

⁴ *Filing Requirements for Electricity Distribution Rate Applications – 2015 Edition for 2016 Rate Applications – Chapter 3: Incentive Rate-Setting Applications*, dated July 16, 2015.

1 **Base Rates x (1 + I – X)**

2
3 In this formula:

- 4 (i) “I” represents generation-industry inflation, determined annually based on a
5 composite inflation index recommended LEI, using the same indices that the
6 OEB uses to adjust rates for electricity distributors. As in 4GIRM, OPG
7 proposes that the I-factor value would be adjusted mechanistically as part of an
8 annual payment amounts adjustment application.

9
10 LEI has calculated a current I-factor value of 1.8% using the most recent
11 Statistics Canada data.⁵

- 12
13 (ii) “X” is the sum of:

- 14 a) a productivity factor, and
15 b) a stretch factor determined by total-cost benchmarking of OPG’s
16 hydroelectric generation facilities.

17
18 As described in greater detail below in section 2.3.3.1, the TFP studies
19 conducted by LEI concluded that a -1% productivity factor would be
20 appropriate, based on productivity trends in the North American hydroelectric
21 generation industry. However, in deference to OEB policy, OPG has increased
22 the proposed productivity factor to zero.

23 Based on a total-cost benchmarking study of OPG’s regulated hydroelectric
24 generation assets by Navigant, OPG proposes a hydroelectric stretch factor of
25 0.3%, consistent with the range of stretch factors applied by the OEB under
26 4GIRM.

27

⁵ Derived from sub-index values as of March 31, 2016.

1 The X-factor would remain consistent over the five-year term of the application. The derivation
2 of the inflation factor and X-factor values are discussed in greater detail in subsections 2.3.1
3 and 2.3.2, respectively.

4
5 2.3.1. Inflation Factor

6
7 OPG retained LEI to recommend an appropriate inflation factor for the company's
8 hydroelectric price-cap framework. LEI recommended a composite index using the same sub-
9 indices that the OEB uses when determining the inflation factor for electricity distributors
10 under 4GIRM:

- 11 (i) Canadian Gross Domestic Product Implicit Price Index – Final Domestic
12 Demand (“GDP-IPI FDD”) from Statistics Canada; and
13 (ii) Average Weekly Earnings for Ontario – Industrial Aggregate (“Ontario AWE”)
14 from Statistics Canada.

15
16 LEI further recommended applying the sub-indices above to the same cost components that
17 the OEB uses when determining the inflation factor for electricity distributors under 4GIRM:

- 18 (i) GDP-IPI FDD is applied to capital costs and non-labour O&M costs; and
19 (ii) Ontario AWE is applied to labour costs.

20
21 LEI's inflation factor analysis was presented to stakeholders during OPG's stakeholder
22 consultation in late 2014 and early 2015. As discussed at the stakeholder consultation, LEI
23 considered other sub-indices that were more relevant to the capital costs OPG would incur.
24 However, LEI found that these alternative indices were historically less stable. Information
25 presented by LEI on the inflation factor at the stakeholder consultations is provided in
26 Attachment 3.

27
28 LEI recommended that OPG's inflation factor follow a 4GIRM-like composite index approach
29 for several reasons:

- 1 (i) It is representative of the various basic categories of inputs that affect OPG
- 2 (labour and non-labour).
- 3 (ii) It captures labour costs that are specific to the Ontario industrial sector.
- 4 (iii) Since it represents inflation trends across many firms and industries, it is
- 5 exogenous to OPG.
- 6 (iv) It is based on data that is readily available from Statistics Canada.
- 7 (v) It can be calculated simply and transparently.
- 8 (vi) It has historically been very stable, leading to more predictable rates.

9

10 OPG expects that the proposed approach will result in more stable payment amounts. Given

11 the relative size of the capital for the generation industry (81%) the capital sub-index has a

12 significant impact on the I-factor, and therefore would result in less stable rates. OPG

13 believes that its customers prefer and the public interest favours more stable rates.

14

15 OPG asked LEI to identify the appropriate weighting between capital, labour, and non-labour

16 costs for the hydroelectric generation industry and specifically for OPG. LEI used the

17 weighting of capital, labour, and non-labour indices that was suggested by its TFP study.

18

19 LEI's analysis produced the following weightings between capital and OM&A costs in Chart 3:

20

21 **Chart 3 – Summary of Hydroelectric I-Factor Weighting**

Sub-index	Weight Assigned	
	Industry	OPG-specific
Capital	81%	88%
OM&A - Non-labour	7%	4%
Total (GDP-IPI FDD)	88%	92%
OM&A - Labour	12%	8%
Total (Ontario AWE)	12%	8%

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In the electricity distribution context, the OEB adopted a weighting of distribution industry sub-indices that was a “reasonable representation for the industry as a whole.”⁶ Similarly, OPG’s proposed annual adjustment mechanism uses generation industry weighting to determine the annual inflation factor adjustment.

Based on labour and non-labour sub-index values as of March 31, 2016, LEI calculated an I-factor of 1.8%. The derivation of this value is set out in Chart 4:

Chart 4 – Summary of Hydroelectric I-Factor Sub-indices, Q1 2016

Year	Inputs and Assumptions										
	Non-Labour GDP-IPI-FDD - National							Labour AWE - All Employees - Ontario			Composite index
	Q1	Q2	Q3	Q4	Annual	Annual % Change	Weight	Annual	Annual % Change	Weight	Annual % Change
2014	112.5	113.2	113.7	114.1	113.375			938.27			
2015	114.3	114.9	115.8	116.2	115.3	1.7%	88%	962.73	2.6%	12%	1.8%

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OPG proposes to make annual adjustments for inflation on the same basis as the OEB does when setting rates for electricity distributors under 4GIRM. As under 4GIRM, OPG’s inflation factor would be updated annually to account for the most current sub-index values. The sub-indices and their weighting would remain constant in each year; only the value of each sub-index would change (i.e., the value of GDP-IPI FDD and Ontario AWE would be updated with the latest Statistics Canada data).

⁶ EB-2010-0379, *Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario’s Electricity Distributors*, corrected on December 4, 2013, p. 9.

1 OPG expects to file annual price-cap adjustment applications in the fall of each year to set the
2 next year's rate. For example, OPG expects to file an application in the fall of 2017 to
3 determine 2018 rates. That 2018 payment amounts adjustment would be based on the values
4 for the GDP-IPI (FDD) and Ontario AWE at the time of those applications.

5
6 2.3.2. "Going in" Rates

7 OPG proposes that the company's current hydroelectric payment amounts as approved in EB-
8 2013-0321 be used as the "going in" rates for the 2017-2021 period, adjusted to correct for the
9 one-time allocation of nuclear tax losses to the hydroelectric business in the prior application.
10 The current payment amounts reflect the OEB's findings in EB-2013-0321 to only allow OPG
11 to recover its cash requirements for pensions and other post employment benefits⁷.

12
13 In its treatment of tax losses in the EB-2013-0321 proceeding, OPG applied the 2015 forecast
14 nuclear tax loss to reduce the 2014 and 2015 nuclear taxable income to \$0. OPG then
15 allocated the remaining unused nuclear tax loss of \$86.7M to the hydroelectric business.⁸ This
16 allowed OPG to reduce hydroelectric payment amounts, giving customers the benefit of the
17 nuclear tax losses immediately, rather than carrying the losses forward to offset future nuclear
18 taxable income.

19
20 To establish the "going-in" rate for IR, the current hydroelectric payment amounts must be
21 adjusted to remove the impact of applying the 2015 nuclear tax loss to the 2015 hydroelectric
22 revenue requirement. Removal of the nuclear tax loss from the approved hydroelectric rate
23 as illustrated in Ex. I1-2-1 Tables 2 and 2a results in a revised "going-in" hydroelectric rate of
24 \$41.09/MWh as derived in Ex. I1-2-1 Table 1a.

25

⁷ EB-2013-0321 Decision With Reasons, Page 87.

⁸ EB-2013-0321, OPG Response to Intervenor Comments on the Draft Payment Amounts Order,
December 12, 2014, page 4.

1 The allocation of specific tax losses from the nuclear to the hydroelectric business unit for
2 ratemaking purposes is necessarily a one-time adjustment to payment amounts intended to
3 provide customers the benefit of the nuclear tax loss sooner than would be the case if they
4 were carried forward within the nuclear business unit. Absent the allocation, the OEB
5 approved hydroelectric base rate in EB-2013-0321 would have been the \$41.09/MWh
6 discussed above, and the \$86.7M would be applied to reduce the nuclear revenue
7 requirements in this application. As customers have received the benefit of the tax losses,
8 these losses are no longer available to reduce nuclear payment amounts in this application.⁹
9 OPG has therefore adjusted the “going in” hydroelectric rates to remove these tax losses.

10
11 2.3.3. X-Factor

12
13 OPG proposes an X-factor composed of two elements: (i) an industry productivity factor, as
14 calculated by LEI’s TFP study of the North American hydroelectric generation industry, and (ii)
15 a stretch factor based on OPG’s hydroelectric benchmark performance.

16
17 2.3.3.1. *Productivity Factor*

18
19 LEI’s TFP study was filed with the OEB as part of the EB-2013-0321 proceeding on December
20 19, 2014 (the “Initial TFP Study”). LEI updated the Initial TFP Study to include 2013 and 2014
21 data (the “Updated TFP Study”). Both the Initial TFP Study and the Updated TFP study
22 yielded a productivity factor of -1%. However, for the reasons described below, OPG is
23 proposing a productivity factor of zero in this application.

24
25 In late 2013, OPG retained LEI to prepare a hydroelectric generation industry productivity
26 study for OPG’s prescribed hydroelectric assets. LEI was responsible for identifying

⁹ Since OPG did not apply to adjust payment amounts for 2016, customers have received a benefit associated with the 2015 nuclear tax losses for an additional year

1 appropriate methodologies of data compilation and peer selection, as well analyzing the data.
2 This subsection briefly reviews LEI's methodology, the peer group selected, and the study's
3 conclusions. The Updated TFP study, which is filed as Attachment 1 to this schedule, sets out
4 each stage of LEI's work in greater detail.

5
6 LEI used an index methodology to calculate the industry TFP, like the approach used in the
7 RRFE.¹⁰ An index-based TFP approach measures the ratio of all outputs to all inputs, where
8 input and output indices are constructed using both quantities and prices of outputs and
9 inputs. LEI selected an indexed approach for a number of reasons: it is relatively simple, easy
10 to communicate and ultimately a robust technique that requires significantly fewer
11 observations than other measuring techniques.

12
13 The selection of inputs and outputs is an important aspect of designing a TFP study. The
14 inputs and outputs used should be those that accurately reflect actual productivity in the
15 industry, and for which data is readily available and quantifiable. For their study, LEI used two
16 inputs: physical capital (measured in MW), and total O&M (measured in dollars). LEI used a
17 single output: generation (measured in MWh). As a measure, generation also benefits from
18 ubiquity; as it is common to every hydroelectric generator, generation data is readily available
19 and data is generally measured consistently across power plants and companies. LEI also
20 found that generation is the most common measure of output in academic and regulatory
21 studies.

22
23 LEI established an appropriate industry peer group based on a "multi-dimensional" set of
24 criteria. Their goal was to identify comparable utilities, while accounting for data-availability
25 issues. They selected firms that have a medium (500-1000 MW) or large (>1000 MW) total
26 hydroelectric capacity. To qualify, peers also needed to have more than one plant, and ideally

¹⁰ *Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, issued November 21, 2013 and corrected on December 4, 2013 (EB-2010-0379).

1 the average age of a peer's hydroelectric fleet would be comparable to OPG's prescribed
2 hydroelectric assets. Peers also needed to have specific hydroelectric operations data
3 available for the period from 2002 to 2012. LEI considered a total of 28 North American peers,
4 ultimately including 17 firms in the Initial TFP Study in the industry group, including OPG. In
5 the Updated TFP Study one firm (Alcoa) was removed as it sold hydroelectric assets in 2012
6 and the remaining hydroelectric capacity was substantially less than the 500 MW capacity
7 criteria used for peer selection. No other changes were made to the peer group.

8
9 LEI considered five Canadian peers for inclusion in the industry group, but ultimately was
10 unable to obtain sufficient data related to the hydroelectric-specific O&M expenses. LEI tried
11 to obtain the necessary data in several forums, including StatsCan and NERC databases,
12 annual reports, regulatory filings and other publicly available information. LEI made repeated
13 information requests to all five utilities, but were unable to obtain the information.
14 Consequently, no other Canadian utilities were included in the industry group.

15
16 LEI calculated TFP results using two methods: average index growth, and a trend regression
17 approach. The results of the Initial TFP Study and the Updated TFP Study are summarized in
18 Chart 5.

19
20 **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)

21
22

1 LEI commented on the results, stating that negative TFP results can be expected for a TFP
2 study on a mature hydroelectric industry.¹¹ During the stakeholder consultation in late 2014
3 and early 2015, LEI explained that a negative productivity factor for the hydroelectric
4 generation industry is expected, given it is an industry with substantially fixed productive
5 capability, fixed capital stock, and increasing operating and maintenance costs that would
6 naturally lead to negative productivity growth.¹²

7
8 The results of the TFP studies notwithstanding, OPG has elected to increase the productivity
9 factor to from negative 1% to zero. OPG believes this approach is consistent with OEB policy.
10 In the electricity distribution context, the OEB has elected not to set rates based on negative
11 productivity growth in the electricity distribution context. In its report on the distribution
12 productivity factor under the RRFE, the OEB stated that it “does not believe it appropriate for a
13 rate setting regime to project and entrench declining productivity expectations into the
14 future.”¹³ The OEB determined that the productivity factor value would be zero, despite the
15 negative result of the industry TFP study.

16
17 While OPG believes that the -1% TFP factor resulting from both the Initial TFP Study and the
18 Updated TFP Study is accurate, it understands the OEB’s policy position and proposes a zero
19 productivity factor in this application.

20
21 In effect, increasing the productivity factor to zero creates an additional 1% stretch factor on
22 OPG’s hydroelectric business during the term of this application. OPG’s performance must
23 exceed the TFP trend identified by LEI in order to meet the reduced rates that result from the
24 hydroelectric price cap index adjustment.

25

¹¹ Updated TFP Study, p. 48

¹² Ex. A1-7-1, Attachment 3, Session notes, p. 4.

¹³ EB-2010-0379, *Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario’s Electricity Distributors*, p. 17.

1 2.3.3.2. *Stretch Factor*

2
3 OPG proposes to use a 0.3% stretch factor based on OPG's performance on independent
4 hydroelectric benchmarking. As described in this section, OPG arrived at this proposal by
5 adopting the range of stretch factors used in the OEB's 4GIRM methodology (i.e., 0%, 0.15%,
6 0.3%, 0.45% and 0.6%), and identifying a stretch factor that corresponds with the company's
7 hydroelectric benchmark performance.

8
9 As required by the OEB's decision in EB-2013-0321, OPG retained Navigant to conduct an
10 independent total-cost benchmarking study of its hydroelectric business.¹⁴ A copy of the
11 hydroelectric benchmarking report is field as Attachment 2 to this schedule.

12
13 Navigant benchmarked approximately 92% of OPG's 2013 costs attributable to its regulated
14 hydroelectric operations against a peer group comprised predominantly of U.S. and
15 Canadian generators that represent approximately 100,000 MW of installed capacity.
16 Facilities comprising the peer group are diverse in size, type and age, and include
17 hydroelectric generation stations with reservoirs, run-of-river generating facilities, and
18 pumped storage stations. Chart 6 summarizes the peer group composition and compares it
19 to OPG's regulated hydroelectric facilities:

20
21 **Chart 6 – Composition of Peer Group and Comparison to OPG Regulated Hydro**

	Peer Group	OPG
No. of Station Groups	222	54
Median Station Age (years)	45	84.5
Median Station Group Size (MW)	152	10
Median Unit Size (MW)	37	5

22

¹⁴ EB-2013-0321, Decision with Reasons (November 20, 2014), pages 17-18.

1 Navigant excluded costs that were unique to OPG’s regulated hydroelectric operations.
 2 Costs not benchmarked include adjustments to centrally held pension and OPEB costs,
 3 IESO non-energy charges, costs attributable to electricity sales and trading, and corporate
 4 business development costs. Navigant separately benchmarked OPG’s regulated hydro
 5 investment costs (i.e., regulatory and sustaining project OM&A and capital investment) and
 6 reliability performance (i.e., availability and EFOR).

7
 8 OPG’s regulated hydroelectric operating costs benchmark in the second quartile relative to
 9 the study’s peer group based on Partial Function Cost. Navigant identified Partial Function
 10 Cost as the key cost metric for benchmarking purposes to assess OPG’s relative
 11 performance to its peers. (The Total Function Cost metric includes Gross Revenue Charges
 12 – a regulatory water and property tax not within OPG’s control and which does not apply to
 13 others in the peer group). With respect to investment, the regulated hydro facilities
 14 benchmark in the second quartile, with marginally lower investment than the median
 15 compared to the peer group. The results of the benchmarking are summarized in Chart 7.

16
 17 **Chart 7 – Hydroelectric Benchmarking Results**

	Partial Function Cost¹⁵ (\$M)* <i>*Key Measure</i>	Total Function Cost¹⁶ (\$M)	Investment¹⁷ (\$M)	Availability (%)	Forced Outage (%)
OPG Regulated Hydro	201	527	140	92.8	1.3
1 st Quartile	114	142	64	95.7	0.3

¹⁵ Partial Function Cost includes costs incurred for hydroelectric station operations, maintenance, waterways and dams, buildings and ground, and HTO & Corporate support costs. Navigant identified Partial Function Cost as the key performance indicator of OPG’s regulated hydroelectric facilities.

¹⁶ Total Function Cost includes Partial Function Cost, as well as costs incurred for Public Affairs and Regulatory which, in the case of OPG, is mostly Gross Revenue Charge payable on hydroelectric production.

¹⁷ “Investment” includes both Capital and Project OM&A expenditures.

Median	203	318	146	90.7	1.3
3 rd Quartile	408	625	444	81.5	4.1

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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.

2.4. Incremental and Advance Capital Module Eligibility

As in 4GIRM, OPG would be eligible to request an Incremental Capital Module ("ICM") funding for qualifying hydroelectric capital projects. Any such request would be prepared pursuant to OEB policy.¹⁸ Although OPG has not included an Advance Capital Module ("ACM") in this application, the company's proposed regulatory framework would permit the use of an ACM or ICM in subsequent applications.

2.5. Unforeseen Events (Z-Factor)

OPG proposes that the OEB's policy on unforeseen events would apply during the term of this application, as set out in OEB policy.¹⁹ OPG proposes that the company's regulatory materiality threshold of \$10 million apply.

2.6. Deferral and Variance Accounts

¹⁸ EB-2014-0219, *Report of the Board: New Policy Options for the Funding of Capital Investments* (Sept. 18, 2014).
¹⁹ *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, July 14, 2008.

1 OPG proposes to continue all existing deferral and variance accounts approved by the OEB
2 as discussed in Ex. H1-1-1. As OPG is not rebasing hydroelectric payment amounts, the
3 impact of any change to the company's common equity ratio approved by the OEB pursuant
4 to OPG's request in Ex. C1-1-1 would be applied through the proposed Hydroelectric Capital
5 Structure Variance Account described in Ex. H1-1-1.

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

9 10 **2.7. Off-Ramp**

11
12 By June 30 of each year, OPG is required to file an analysis of the actual annual regulatory
13 return, after tax on rate base, both dollars and percentages, for the regulated business (i.e.
14 both hydroelectric and nuclear combined).²⁰ This analysis includes a comparison of the
15 regulated business' achieved ROE against the approved ROE included in the payment
16 amounts. OPG proposes that this reporting requirement will be the basis for determining if its
17 actual ROE is outside the +/-300 basis point trigger established by the RRFE for determining
18 whether a regulatory review may be initiated.²¹

19 20 **3. NUCLEAR FACILITIES RATE-SETTING PROPOSAL**

21 22 **3.1. Summary of Nuclear Rate-setting Proposal**

23
24 OPG has endeavoured to develop a form of Custom IR that is both consistent with the OEB's
25 letter of February 17, 2015, and compatible with the state of the company's nuclear business
26 during the 2017-2021 IR period. As described in this schedule and elsewhere in this

²⁰ EB-2010-0008 Decision With Reasons, p. 151..

²¹ RRFE Report, October 18, 2012, p.10 and the references cited therein.

1 application,²² both of OPG's nuclear facilities are entering into a period of significant change.
2 During the IR period, OPG will begin refurbishing the Darlington Nuclear Generating Station.
3 At the same time, the company will carry out the works necessary to extend operations at the
4 Pickering Nuclear Generating Station. Throughout this period, OPG must be able to meet
5 customers' expectations that the company operate safely and reliably, and to continue
6 generating clean, low-cost electricity.

7

8 As there is no prescribed IR regime for OPG's nuclear facilities, OPG has developed a
9 Custom IR framework that is based on the principles set out in the RRFE, the OEB's prior
10 guidance on incentive ratemaking, and on stakeholder feedback. The nuclear Custom IR
11 framework is tied to OPG's performance on the total generating cost benchmarking that
12 underlies the company's gap-based business planning process. The proposed Custom IR
13 framework applies elements of 4GIRM – in particular, a benchmark-based stretch factor – in a
14 manner that is compatible with OPG's regulatory and business context.

15

16 OPG's proposed nuclear Custom IR framework has been informed by various sources,
17 including:

- 18 (i) The OEB's 2012/2013 consultation on incentive rate-making at OPG (the "OEB
19 Consultation")²³;
- 20 (ii) The OEB's Filing Guidelines for OPG (the "Filing Guidelines")²⁴;
- 21 (iii) The principles reflected in the RRFE;
- 22 (iv) application stakeholder consultations²⁵; and
- 23 (v) Other factors including prior OEB decisions, the Government of Ontario's Long-
24 Term Energy Plan, O. Reg. 53/05, and OPG's business planning process.

²² See in particular Ex. A1-3-1, Ex. A1-3-2, and Exhibits D and F.

²³ EB-2012-0340, *Report of the Board: Incentive Rate-making for Ontario Power Generation's Prescribed Generation Assets*.

²⁴ *Filing Guidelines for Ontario Power Generation Inc.*, revised November 11, 2011 (EB-2011-0286).

²⁵ Ex. A1-7-1.

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The major elements of the proposed nuclear Custom IR framework are set out in Chart 8, along with corresponding policy objectives from the RRFE and other sources:

Chart 8 – Summary of Nuclear Custom IR Framework

Policy Objective(s)	Source	Corresponding aspect(s) of Nuclear Rate-making Framework
Adopt a longer-term approach to payment amount-setting based on the parameters for a multi-year Cost of Service application and a Custom IR framework	OEB Consultation Report, p. 9 OEB Letter of February 17, 2015 O. Reg. 53/05 ²⁶	Nuclear Ratemaking proposal includes five future test years with individual forecast revenue requirements. (As noted below, the application layers elements of IR onto this foundation.) Elements of the Custom IR framework are detailed below.
Include meaningful efficiency incentives derived from external benchmarking	RRFE, p. 17	Providing up-front benefit to customers through stretch factor reduction of revenue requirement. Stretch factor applied to revenue requirement arising OM&A costs that are independent of the major projects during the IR period. These stretch reductions are incremental to performance improvements resulting from OPG Nuclear’s gap-based business planning process, discussed in Ex. F2-1-1. Stretch factor was determined by adopting the range of stretch factor values from 4GIRM ²⁷ and applying the range to OEB-approved nuclear total generating cost benchmarking.

²⁶ O. Reg. 53/05, section 6(2)12

²⁷ 0% to 0.6%

Policy Objective(s)	Source	Corresponding aspect(s) of Nuclear Rate-making Framework
<p>Provide tangible benefits and consequences for operating performance</p> <p>Encourage sustainable, year-over-year efficiency gains</p>	<p>OEB Consultation Report, p. 9</p> <p>RRFE, p. 59</p>	<p>Stretch reductions persist year-over-year, incenting OPG to find further savings in each year of the application term, as would occur under 4GIRM.</p> <p>The 100% variable rate design of OPG's payments means that failure to achieve production forecast has direct financial consequences for the company, creating a meaningful incentive to continuously improve productivity.</p>
<p>Be aligned with performance outcomes</p> <p>Performance measures should be directly linked to desired performance outcomes</p>	<p>RRFE, pp. 3, 59</p>	<p>OPG is proposing annual reporting on the company's performance to provide meaningful measures of the company's nuclear performance. The proposed measures reflect identified RRFE performance outcomes.</p> <p>Annual reporting will include all of the measures used in OPG's nuclear benchmarking.</p> <p>Application includes robust evidence of the company's nuclear operations and project forecasts.</p> <p>The application of off-ramps applies to the achieved return on equity for OPG's combined regulated operations as discussed in Section 2.7, above.</p>

Policy Objective(s)	Source	Corresponding aspect(s) of Nuclear Rate-making Framework
It would not be appropriate for OPG’s nuclear assets to move to a pure IR regime based on TFP, input cost indices, Z-factors, and off-ramps before Darlington refurbishment and Pickering closure are complete.	OEB Consultation Report, p. 8	While OPG agrees that it is not appropriate to transition the company’s nuclear assets to a “pure IR” framework at this time, the 100% variable rate design, the proposed stretch factor and performance reporting requirements are meaningful IR elements consistent with the RRFE.

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In 2012 and 2013, the OEB held a consultation to consider how to include elements of incentive regulation within OPG’s rate-making regime. Parties were divided on the appropriate pacing and form of IR for OPG’s nuclear facilities. During the consultation, some stakeholders expressed the view that IR may never become appropriate for nuclear facilities.²⁸ Others accepted that nuclear IR may be more appropriate after the DRP is complete and the Pickering facility has been shut down.

On March 28, 2013, the OEB issued a report on the outcome of the consultation (the “2013 Report”). In the 2013 Report, the OEB stated that:

“the large capital expenditures and reduced production associated with the DRP and the Pickering closure do not favour the implementation of a ‘pure IR regime’ (i.e., one based on TFP with input cost indices, Z-factors, and off-ramps) in the immediate future.”²⁹

The OEB stated that OPG could move toward “a methodology that achieves some of the same objectives as IR” before Darlington Refurbishment and Pickering closure are

²⁸ OEB Consultation Report, p. 5.
²⁹ OEB Consultation Report, p. 8 [emphasis added].

1 complete.³⁰ The proposed nuclear Custom IR framework attempts to strike such a balance,
2 reflecting the fact that OPG's capital and operating costs will vary significantly with the
3 refurbishment of the Darlington facility and the extension of operations at Pickering, but also
4 implementing benchmark-driven stretch reductions in aspects of the company's nuclear
5 operations where it is reasonable to do so.

6
7 The proposed nuclear Custom IR framework reflects the OEB's conclusions. It is based on
8 five individual nuclear revenue requirements, but includes incremental stretch reductions that
9 are sustained, year-over-year, creating a meaningful incentive to continuously improve
10 performance and cost efficiency during the IR period.

11 12 **3.2. Stretch Factor Proposal**

13
14 As described above, any form of incentive regulation proposed for OPG's nuclear assets must
15 be appropriate in the context of the significant programs planned for the company's nuclear
16 facilities during the IR period. OPG proposes a benchmark-based stretch factor that will
17 provide a meaningful performance incentive during the term of this application.

18
19 OPG recognizes the OEB's expectation that an IR mechanism should incent performance
20 improvements, and should be based on measures that are external to the company's
21 forecasts. To achieve this, OPG proposes to apply a benchmark-based stretch factor to
22 revenue requirement attributable to the company's nuclear Base OM&A and allocated
23 corporate support services OM&A.³¹ This reduction is in addition to the performance
24 improvement initiatives reflected in the company's gap-based nuclear business planning
25 process. The proposed stretch reduction has the effect of reducing revenue requirement for
26 these two significant categories of expenditures below forecast.

³⁰ OEB Consultation Report, p. 9.

³¹ Descriptions of nuclear Base OM&A and corporate support services are available at Ex. F2-2-1 and Ex. F3-1-1, respectively.

1 The proposed stretch reduction targets elements of the company's nuclear costs that
2 constitute a significant amount of OPG's nuclear revenue requirement during this application.
3 The stretch factor applies to an average of \$1.7 billion³² or approximately 75% of OPG's total
4 nuclear OM&A in each year of the application.

5

6 As discussed in section 3.2.1 below, OPG is proposing a 0.3% stretch factor. The stretch
7 reduction is cumulative, resulting in a greater reduction to applicable revenue requirement
8 each year of the IR period. As illustrated in Figure 1, the stretch factor grows over the term of
9 the application, resulting in a \$20.4M stretch reduction in 2021, effectively reducing the
10 revenue requirement for Base and Corporate Support OM&A to the level forecast for the prior
11 year.

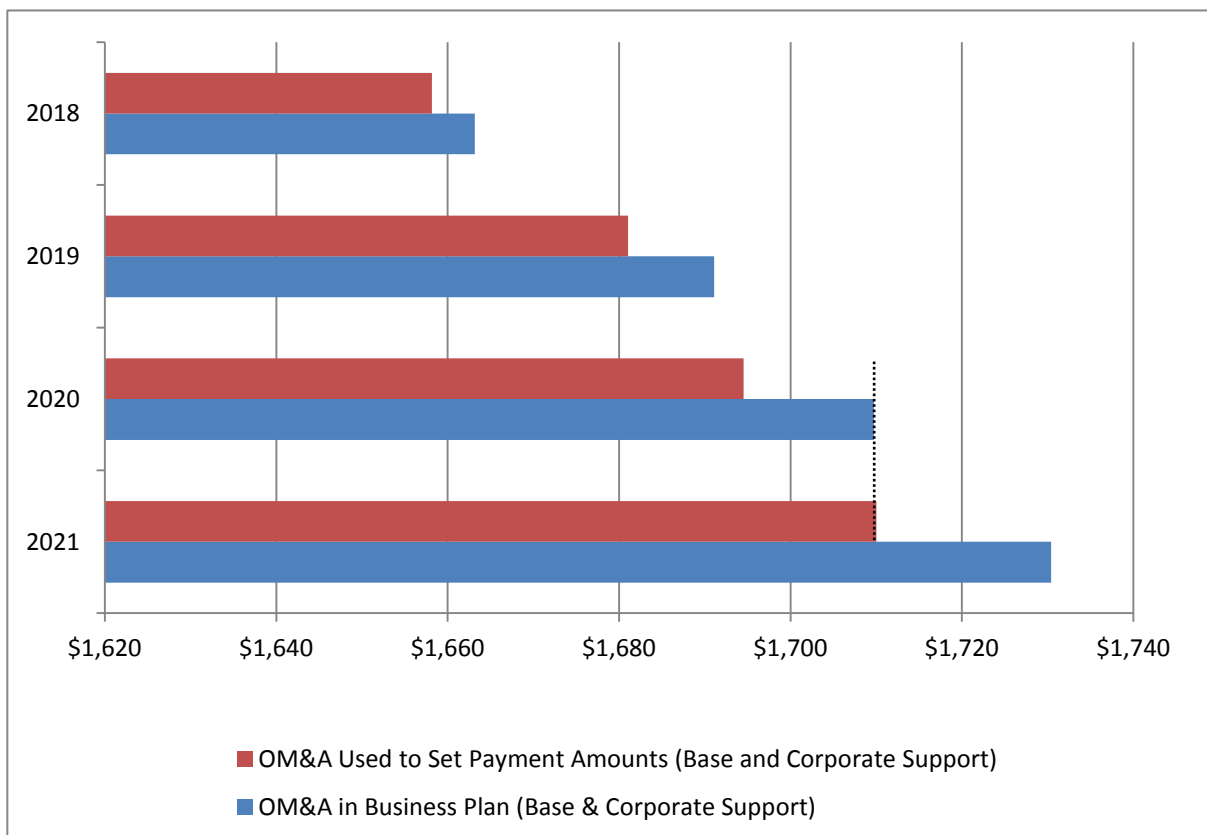
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³² See Chart 10 for annual stretch eligible OM&A costs

1

Figure 1 – Nuclear Stretch Factor Reductions



2

3 OPG views Base OM&A and Corporate Support OM&A as proxies for the overall level of the
4 company's nuclear operating expenditures where it is reasonable to drive efficiencies. OPG
5 does not expect that all elements of these costs can be reduced. For example, many functions
6 within nuclear Base OM&A are related to safety and legislative requirements. Base OM&A
7 includes several critical, regulated functions including safety, emergency preparedness,
8 inspections, operations and maintenance.³³ While these functions are within Base OM&A (and
9 therefore subject to the stretch reduction), OPG will not compromise functions that are

³³ Many of these functions are required for OPG to comply with the *Nuclear Safety and Control Act* (Canada) and are mandated by the CNSC. Nuclear Base OM&A also includes work dealing with environmental issues.

1 mandated by the CNSC or that could otherwise increase safety or environmental risks or the
2 risk of non-compliance with legislated requirements.

3
4 The proposed stretch reductions are in addition to efficiencies and performance improvements
5 within the company's business planning processes. OPG continually strives to improve the
6 company's performance and operational efficiency where it can do so safely within operational
7 requirements (e.g., CNSC requirements) and without affecting reliability. Through the gap-
8 based nuclear business planning process described in Ex. F2-1-1, OPG develops initiatives to
9 meet these goals. The performance initiatives incorporated in the business planning process
10 and the corresponding performance and operational efficiency improvements are reflected in
11 the forecast expenditures in this application.

12
13 As noted above, the stretch factor applies to approximately 75% of OPG's nuclear OM&A.
14 While OPG does not expect to find material efficiencies in the remaining 25% during the term
15 of this application, it will seek to improve performance and reduce costs where it can
16 responsibly do so.

17 18 3.2.1. Derivation of Proposed Stretch Factor

19
20 OPG proposes a stretch factor of 0.3%, which is based on the methodology used by the OEB
21 to set electricity distribution rates. Under the RRFE, distributors may be subject to a range of
22 stretch factors from 0% to 0.6%,³⁴ based on their benchmark performance. OPG has adopted
23 the OEB's range in its proposed ratemaking frameworks for both hydroelectric and nuclear
24 generating facilities.

25

³⁴ Under the RRFE, electricity distributors are assigned to one of five performance cohorts based on their forecast costs relative to econometrically predicted benchmark costs. Based on their determined performance cohort, distributors are assigned a stretch factor of 0%, 0.15%, 0.3%, 0.45% or 0.6%..

1 As set out in the 2015 Nuclear Benchmarking Report, Darlington's Total Generating Cost per
2 MWh performs in the top quartile, and the Pickering facility is in the fourth quartile.³⁵ OPG
3 used a production-weighted average to determine a combined stretch factor value of just
4 below 0.3%. Chart 9 illustrates the derivation of OPG's proposed stretch factor, based on the
5 most recent OEB-approved nuclear production forecast.

6
7

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%

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OPG has reduced the requested payment amounts by 0.3 per cent of the company's nuclear Base OM&A and allocated corporate support OM&A beginning in 2018. The amounts shown in Ex. F2-2-1 reflect the full forecast revenue requirement. The stretch reduction is applied when determining the company's payment amounts in Ex. I1-3-1.

14 In order to emulate the effect of the stretch-factor in the OEB's 4GIRM price-cap framework,
15 OPG has calculated annual stretch reductions such that prior years' reductions are maintained
16 (i.e., reductions to revenue requirement made in 2018 are carried forward to subsequent

³⁵ OPG has used its OEB-approved total generation cost benchmarking performance to determine where the company's nuclear division should fall on the OEB's range of stretch factors. OPG's 2015 Nuclear Benchmarking Report is filed at Ex. F2-1-1, Attachment 1. The Total Generating Cost benchmarking results are on p. 65.

1 years, on the presumption that the company should be incented to find additional savings
 2 each year). Reductions are proposed beginning in 2018, with additional reductions in 2019,
 3 2020, and 2021. This mirrors the operation of the stretch factor under 4GIRM.

4
 5 Chart 10 shows the product of applying the 0.3% stretch factor to Base OM&A and allocated
 6 corporate support OM&A.

7
 8 **Chart 10 – Stretch Reduction Amounts**

(\$M)	2018	2019	2020	2021
Base & Corporate Support OM&A	1,663.2	1,691.1	1,709.7	1,730.4
Stretch Factor	0.3%	0.3%	0.3%	0.3%
Annual Stretch Reduction to Nuclear Revenue Requirement	5.0	10.1	15.2	20.4
Base & Corporate Support OM&A Used to Determine Payment Amounts	1,658.2	1,681.0	1,694.5	1,710.0

9
 10 The total reduction over the term of the application is \$50.6M. Although the 0.3% stretch
 11 reduction is constant, the “snow plow” effect of maintaining prior years’ reductions means that
 12 the \$20.4M reduction in 2021 is a 1.2% reduction to that year’s stretch-eligible OM&A, or a
 13 0.9% reduction to total nuclear OM&A.

14
 15 This stretch reduction is incremental to the performance improvements required to achieve
 16 OPG’s business plan. Customers will benefit from these “up-front” budget reductions, and
 17 OPG will bear the risk of any shortfall.

18
 19 **3.2.2. Productivity Factor is Not Applicable**

20
 21 OPG is not proposing a nuclear industry productivity adjustment as part of the proposed X-
 22 factor. The nature and scale of capital work planned for the IR period mean that past
 23 productivity trends would not be a reasonable indicator of predicted productivity for OPG
 24 during the IR period.

1 **3.3. Annual Adoption of OEB Prescribed ROE**

2 OPG proposes that the company's annual nuclear Return on Equity ("ROE") be the OEB's
3 prescribed ROE as determined by the OEB each year pursuant to the *Report of the Board on*
4 *the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009.

5

6 The five nuclear revenue requirements filed in this application are based on the OEB's
7 prescribed ROE of 9.19 per cent for 2016, which was the most current available at the time of
8 filing.

9

10 As discussed in Ex. C1-1-1, OPG proposes to use the following methodology to establish the
11 ROE for the nuclear business for the 2017 to 2021 period:

- 12 • For the first year of the test period (2017), the ROE will be set using the prevailing
13 ROE specified by the OEB in accordance with the OEB's Cost of Capital Report as of
14 the effective date of the Payments Amount Order;
- 15 • The 2017 ROE will be used to determine the revenue requirement approved by the
16 OEB from 2018 to 2021;
- 17 • For the second through fifth year of the test period (2018 to 2021), the ROE will be
18 set annually using the prevailing ROE specified by the OEB in accordance with the
19 OEB's Cost of Capital Report;
- 20 • The revenue requirement impact of the variance between the forecast ROE approved
21 for 2018 to 2021 in this Application and the actual ROE that the OEB will specify
22 annually for 2018 to 2021 will be recorded in the proposed Nuclear ROE Variance
23 Account, as described at Ex. H1-1-1 Section 6.3.

24

25 **3.4. Operational Effectiveness**

26 "Operational effectiveness" is one of the four outcomes the OEB seeks to promote in the
27 RRFE. The RRFE defines the operational effectiveness outcome as "continuous improvement

1 in productivity and cost performance is achieved; and utilities deliver on system reliability and
2 quality objectives.”³⁶

3
4 Achieving operational effectiveness involves balancing two sets of outcomes: continuously
5 improving processes and practices to provide customers with better value for money, while
6 simultaneously delivering the performance outcomes that customers expect.

7
8 OPG’s nuclear business balances these outcomes in four ways:

- 9 1. A performance-based business planning process that drives the company to achieve
10 safety, reliability, value-for-money, and human performance targets;
- 11 2. Annual benchmarking using an OEB-approved methodology to assess the company’s
12 performance;
- 13 3. Staffing and compensation strategies designed to ensure key resource are available
14 when needed, to minimize risks, and to ensure safe and efficient operations;
- 15 4. Extensive planning to help ensure the Darlington Refurbishment Program (“DRP”) and
16 extended operation of the Pickering Nuclear Generating Station are completed on time
17 and on budget.

18
19 3.4.1. Performance-based Business Planning and Benchmarking

20
21 Through benchmark-driven performance improvement and value-for-money initiatives,
22 OPG’s nuclear business planning process pushes the company to create budgets that reflect
23 continuous improvement in performance and cost efficiency.

24
25 As described in Ex. F2-1-1, benchmark performance is central to OPG’s nuclear business
26 planning process. The company uses annual benchmarking to assess OPG’s performance
27 relative to the industry on a set of key performance indicators, which are divided among the

³⁶ RRFE, page 2.

1 four cornerstones of OPG’s nuclear business: safety, reliability, value for money, and human
2 performance. OPG determines annual performance targets based on the company’s
3 performance on the benchmarked key performance indicators.

4
5 The annual nuclear business planning process starts with internal reviews of the current
6 planning framework, the confirmation and updating of business objectives and priorities,
7 requirements set out in the corporate-wide business planning instructions, a review of the
8 status of operational and performance plans and related capital and OM&A expenditures,
9 and the identification of emerging issues. Out of this process, strategic and performance
10 objectives for OPG nuclear are determined and prioritized.³⁷

11
12 Once it has set performance objectives, OPG employs performance improvement initiatives to
13 achieve the desired outcomes. OPG’s nuclear business plan currently includes initiatives
14 intended to improve reliability, human performance, and value-for money.³⁸ The Nuclear
15 Business Planning and Benchmarking evidence in Ex. F2-1-1 includes three “case studies” of
16 past nuclear performance initiatives that have helped OPG improve its performance in recent
17 years. These are provided at Ex. F2-1-1, section 3.5.

18
19 Ultimately, the company measures and assesses its results through the subsequent round of
20 benchmarking. Based on the benchmark outcomes, OPG may set new performance targets
21 and revise its initiatives accordingly. This performance-based planning process allows OPG to
22 track the company’s results against targets, and to set appropriate targets for each successive
23 year, creating a cycle of continuous performance and cost efficiency improvement.

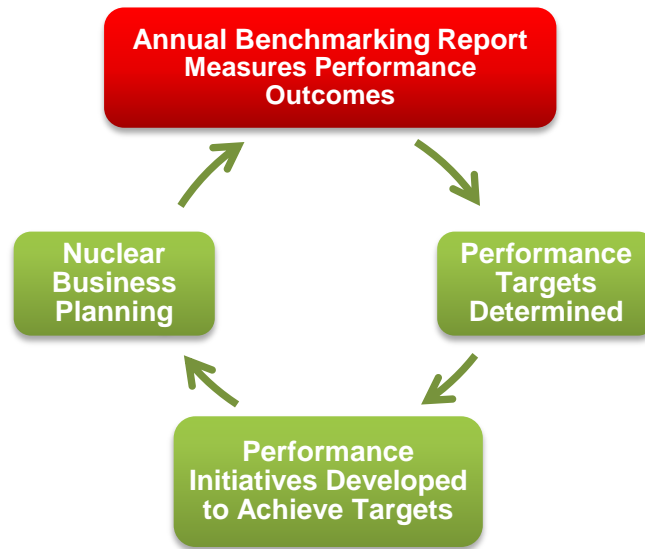
24
25 Figure 2 illustrates OPG’s performance-based nuclear business planning process, at a high
26 level.

³⁷ More information on OPG’s business planning processes is provided in Ex. A2-2-1 and F2-1-1.

³⁸ Some initiatives are intended to address multiple outcomes. For further detail, please see Ex. F2-1-1.

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Figure 2: Nuclear Business Planning Process



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3.4.2. Major Nuclear Performance Initiatives

8 OPG's business plan includes four major nuclear performance initiatives that OPG plans to
9 implement during the IR period:

- 10 i. Human Performance,
- 11 ii. Outage Performance,
- 12 iii. Equipment Reliability, and
- 13 iv. Parts Improvement.

14

15 Details of these initiatives are included in the Nuclear Business Planning and Benchmarking
16 evidence at Ex. F2-1-1.

17

18 OPG's business plan is based on the successful execution of these initiatives. To the extent
19 that OPG does not achieve the targeted benefits from these initiatives, the company's costs
20 and nuclear generation forecast are at risk. OPG may also develop other initiatives during the

1 course of the IR period, depending on the outcomes reflected in the annual nuclear
2 benchmarking report.

3
4 3.4.3. Staffing and Compensation

5
6 In the period prior to this application, OPG has made significant progress in reducing the
7 company's staffing levels and controlling compensations costs. As discussed in Ex. F4-3-1,
8 OPG's Business Transformation project involved restructuring the company around a centre-
9 led model, reducing regular headcount by nearly 2,700 positions between 2011 and 2015,
10 while avoiding severance package costs. Although the Business Transformation initiative has
11 concluded, the company still employs a philosophy of continuous improvement in managing
12 its resources and in regular operations.

13
14 OPG has also been successful in controlling upward pressure on compensation costs. The
15 company has negotiated agreements with both the Power Workers' Union ("PWU") and the
16 Society of Energy Professionals ("Society") that will keep wage escalation below inflation.
17 These agreements run from April 1, 2015 - March 31, 2017 for the PWU, and from January 1,
18 2016 – December 31, 2018 for the Society. Prior to these agreements, typical union salary
19 increases have been in the range of 2% to 3% for OPG and for other large companies in
20 Ontario's electricity sector.

21
22 OPG has also controlled compensation costs for non-union ("Management") employees in
23 several ways. The company froze base salary for Management employees between 2011 and
24 2015. In addition, OPG continues to follow legislated requirements restricting compensation
25 increases to senior Management employees (Vice President and above) and limiting the
26 company's performance-based compensation program.

27
28 In an independent compensation benchmarking study, Willis Towers Watson has confirmed
29 that OPG's overall Total Direct Compensation is now at the market level.

30

1 More information on OPG's compensation, including the Towers Watson benchmarking study,
2 is filed at Ex. F4-3-1.

3 4 3.4.4. Detailed Planning for DRP and Pickering Extended Operations

5
6 A system of continuous improvement is often based on making incremental refinements to
7 recurring processes, year-over-year. The business planning process described above reflects
8 this form of incremental efficiency improvement. In contrast, the DRP and Pickering extended
9 operations are unique, multi-year projects. Given the size and stand-alone nature of these
10 projects, OPG has taken extensive measures to ensure that the projects deliver the best value
11 for Ontario's electricity customers.

12
13 For more information on the efficiencies and cost performance measures incorporated in the
14 DRP, please see Ex. D2-2-1 through Ex. D2-2-10 and Ex. F2-7-1. For Pickering Extended
15 Operations, please see Ex. F2-2-3.

16 17 **4. PERFORMANCE REPORTING**

18
19 OPG understands that the OEB expects utilities to provide meaningful insight into their
20 performance during the course of multi-year applications. Consistent with the RRFE, OPG is
21 proposing to report on a suite of measures that reflect performance on key company
22 outcomes during the term of this application. As discussed in section 4.2, OPG proposes to
23 report annually on the company's measures during the term of this application. Specifically,
24 OPG proposes to report the company's performance on each of the measures identified in
25 section 4.1, which are important inputs to OPG's business planning processes. This reporting
26 would be in addition to OPG's current reporting as directed in EB-2010-0008.

27
28 As discussed in Ex. F2-1-1, OPG uses annual nuclear benchmarking to assess performance
29 against industry peers in the four cornerstones of safety, reliability, value for money and
30 human performance. Benchmarking results contribute to establishing targets to reduce

1 performance gaps or maintain current performance, as appropriate. OPG believes that the
2 company's annual benchmark results will be helpful performance reporting measures for the
3 OEB and stakeholders.

4
5 The proposed benchmark reporting measures are consistent with the RRFE outcome of
6 operational effectiveness (including measures covering system reliability, cost performance
7 and service quality such as safety and environmental performance). These measures reflect
8 outcomes that are both meaningful to customers and important inputs to the company's
9 regular business planning processes. In addition, OPG intends to continue the reporting
10 directed by the OEB in EB-2010-0008 which includes achieved regulatory ROE, the principal
11 financial viability outcome included in the RRFE.

12
13 OPG does not have measurable performance objectives that are analogous to a distributor's
14 mandated conservation and demand management targets or renewable generation
15 connections; consequently OPG is not proposing any specific measures of public policy
16 responsiveness. However, OPG understands that the general RRFE definition of this outcome
17 is that "utilities deliver on obligations mandated by government (e.g., in legislation and in
18 regulatory requirements imposed further to Ministerial directives to the Board)."³⁹ In this
19 regard, OPG is the agent of government/public policy in a direct way, as it is mandated by the
20 Province to support the LTEP and other public policy objectives.

21
22 The RRFE Customer Focus outcome is a significant factor in OPG's planning and operations.
23 OPG is closely engaged with the communities in which it operates, and continues to enhance
24 the role of customer engagement in its business planning process. OPG's customer
25 engagement activities and plans are discussed separately in section 5, below.

26
27

³⁹ RRFE, p. 2.

1 **4.1. Proposed Performance Measures**

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

7

8

Chart 11: Annual Hydroelectric Performance Measures

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

9

1

Chart 12: Annual Nuclear Performance Measures

Nuclear Performance Measures (Separate measures will be filed for Darlington and Pickering Stations)	
Category	Measure
Safety	All Injury Rate (per 200k hours)
	Collective Radiation Exposure (person rem/unit)
	Airborne Tritium Emissions (curies)
	Industrial Safety Accident Rate (#/200k hours)
	Fuel Reliability Index (microcuries /gram)
	2-year Reactor Trip Rate (#/7000 hours)
	3-year Auxiliary Feedwater System Unavailability (#)
	3-year Emergency AC Power Unavailability (#)
	3-year High Pressure Safety Injection Unavailability
Reliability	Forced Loss Rate (%)
	Unit Capability Factor (%)
	Nuclear Performance Index (%)
	On-line Deficient Maintenance Backlog (work orders / unit)
	On-line Corrective Maintenance Backlog (work orders / unit)
	Chemistry Performance Indicator Annual YTD (#)
Cost Effectiveness	Total Generating Cost per Net MWh (\$/MWh)
	Non-Fuel Operating Cost per Net MWh (\$/MWh)
	Fuel Cost per Net MWh (\$/MWh)
	Capital Cost per MW Design Electrical Rating (\$k/MW)
Human Resources	18-month Human Performance Error Rate (#/10k ISAR hours)

2
3

1 **4.2. Annual Performance Reporting Process**

2
3 OPG proposes an annual written process for reporting on the prior year's performance and
4 identifying targets for the following year. Beginning in 2017, OPG would file an updated set of
5 performance measures with the OEB annually. The updated measures would include the
6 prior year's actual performance as well as targets for the new year for each measure.

7
8 OPG believes that these measures will give the OEB and interested parties a clear and
9 meaningful view into the company's operation during the 2017-2021 period. As is the case
10 for electricity distributors, OPG proposes that no rewards or penalties be attached to the
11 company's performance. In OPG's view, annual reporting exists to give the OEB and
12 stakeholders a clear view of OPG's performance during the longer term of this application.
13 The OEB will be able to understand whether OPG is meeting operational targets and
14 financial expectations.

15
16 **5. CUSTOMER ENGAGEMENT**

17
18 **5.1. Overview**

19
20 This section reviews the various ways in which OPG engages with the individuals, businesses
21 and institutions that consume electricity in Ontario and considers customers when planning
22 work and operating its generating facilities. This schedule also describes OPG's ongoing
23 plans to expand the formal role of customer outreach in the company's business planning
24 process.

25
26 The RRFE requires that electricity distributors work to provide services in a manner that
27 responds to identified customer preferences. OPG does not have a direct relationship with
28 electricity consumers, since it sells electricity wholesale into the IESO-controlled market. As a
29 result, OPG does not perform the transactional customer activities that a distributor does.
30 OPG does not manage customer accounts, respond to service calls, or make investment

1 decisions that directly affect the delivery of electricity to individual customers. Nonetheless,
2 the electricity that OPG generates – and how it generates that electricity – affects all
3 Ontarians. In that sense, the ultimate consumers of electricity in the province are all OPG’s
4 customers.

5

6 OPG considers customers’ interests in business planning. As described in this schedule, OPG
7 engages with customers when planning projects, making operational decisions, and
8 participating in communities.

9

10 This schedule summarizes the various forms of customer engagement that OPG executes
11 during the course of its normal business operations, divided into three broad categories, each
12 of which is discussed separately in this schedule:

13

- 14 i. Community Partnerships,
- 15 ii. Indigenous Community Relations, and
- 16 iii. Public Information and Safety Programs.

17

18 In addition to these ongoing forms of community and customer engagement, during the IR
19 term OPG intends to expand its work to identify customers’ preferences and to consider them
20 in its business planning process. To that end, OPG plans to launch an expanded customer
21 engagement program to help inform the company’s business planning. Section 5.6 of this
22 schedule provides more information about the company’s customer engagement plans.

23

24 **5.2. Community Partnerships**

25

26 OPG is a major presence “on the ground” in many communities across the province. OPG
27 coordinates with and attempts to accommodate the needs and preferences of the
28 communities that may be affected by operational decisions or projects. OPG also works in
29 partnership with many Indigenous communities in which the company’s facilities reside.

1 This section describes how OPG works with communities to help ensure that the company's
2 projects are planned and executed in a manner that reflects the preferences of local
3 communities, and that its operations minimally affect local communities.

4
5 5.2.1. Operational Coordination

6
7 OPG considers and accommodates community feedback in various aspects of its regular
8 operations, including the company's ongoing Nuclear Community Advisory Councils,
9 Community Leader , and Waterway Coordination programs.

10
11 5.2.1.1. *Nuclear Community Advisory Councils*

12
13 OPG's Nuclear Generating Stations have a significant role to play in the Clarington and
14 Pickering communities. OPG strives to understand host communities' concerns and to be
15 transparent in providing residents with information about the company's nuclear facilities. To
16 that end, OPG has established Community Advisory Councils ("CAC") for both the Darlington
17 and Pickering generating stations.

18
19 The Nuclear CACs were established in the 1990s, and are comprised of members from a
20 large number of sectors from across the community. CAC membership includes community
21 associations, municipal government, health, environment, education, youth, business and
22 members at large. CAC members live or work in the vicinity of the plants, and serve on a
23 voluntary basis.

24
25 The CACs meet between six and eight times per year. During those meetings, the members
26 receive briefings from OPG staff and other experts. Although meetings focus on environment,
27 public health, safety and economic issues, the topics vary depending on the issues of interest
28 to the community. CAC members have opportunities to question OPG and to discuss what
29 they have heard.

30

1 The CACs are an important bridge between OPG and the communities where the company's
2 Nuclear Generating Stations are located. It allows OPG's senior management to hear directly
3 from members of the community, giving the community a direct connection to the company
4 and allowing the company to better understand and respond to community questions,
5 concerns and preferences.

6
7 *5.2.1.2. Community Leader Engagement*
8

9 In addition to the community engagement processes described above, OPG engages with
10 local leaders in communities where the company's larger generating facilities are located.
11 Engaging with community leaders helps OPG ensure that it has a clear, unbiased perspective
12 on the issues that matter to major segments of the local community.

13
14 OPG identifies local leaders in government, business, academic, media and other sectors that
15 reflect a spectrum of views on OPG's role in the community. Discussions may cover a number
16 of topics, ranging from safety and environmental issues to upcoming company projects at
17 local facilities. In order to encourage interviewees to speak frankly and comprehensively, OPG
18 commits that any discussions will be kept confidential.

19
20 Being qualitative in nature, engagement with community leaders provides directional
21 indication of community views from informed individuals from a spectrum of sectors and
22 interests. OPG's senior management is able to draw upon these views when making business
23 decisions.

24
25 *5.2.1.3. Waterway Coordination*
26

27 OPG's hydroelectric generating stations rely on the same waterways that many Ontarians live
28 near, and rely on for their water supply, work and leisure. OPG operates its hydroelectric
29 generating facilities in coordination with communities and governmental agencies to support
30 public safety during flood events, emergencies and in the course of normal operations. For

1 many rivers, Water Management Plans have been established to account for the needs of the
2 various groups that use and rely on the river. OPG also modifies some of its operations at
3 hydroelectric generating stations to accommodate other users of Ontario's waterways both on
4 an on-going basis and for special events.

5
6 OPG coordinates its use of Ontario waterways with organizations including the Ontario
7 Ministry of Natural Resources and Forestry, local conservation authorities, local municipalities,
8 Indigenous communities, the Federal Department of Fisheries and Oceans, and Parks
9 Canada. In times of extreme watershed conditions, OPG may be able to play a moderating
10 role. In flood-prone conditions, OPG helps to manage the release of water to mitigate risks to
11 local communities (both up-stream and down-stream from the company's generating facility,
12 depending on the location of the flood risk). Similarly, OPG may be called upon during periods
13 of drought to support conservation efforts and aquatic habitat.

14
15 OPG also maintains an extensive Waterway Public Safety Program to mitigate public safety
16 risks associated with the company's facilities. Details of this program and OPG's other public
17 safety measures are described in section 5.5 of this schedule.

18
19 OPG receives requests from users of the waterways regarding special events, such as the
20 Royal Canadian Henley Regatta. Now in its 134th year, the regatta is one of the largest
21 amateur rowing tournaments in North America, and it is held on Martindale Pond in St.
22 Catherine's. In order to support the community and allow the regatta to proceed, OPG
23 reduces flows from its DeCew Falls Generating Station for several hours per day throughout
24 the regatta. Ramping production down and back up is not a trivial endeavour. This process
25 requires multiple safety inspections and coordination with the community. However, OPG
26 shares provincial waterways with customers and local communities. As such, the company
27 takes reasonable steps to support the needs of the customers and communities with which it
28 shares Ontario's waterways.

29
30 5.2.2. Project Planning and Execution

1 OPG's regulated capital projects are often significant endeavours that have the potential to
2 affect local communities in a number of ways.

3
4 OPG's projects have a socioeconomic dimension. Just as the company's large projects can
5 materially add to Ontario's economic growth, its projects can also have a positive effect on the
6 local community's economy.

7
8 In addition, OPG's projects require significant logistical coordination in host communities, such
9 as altering traffic flows or requiring safety-related restrictions on access to areas of land and
10 waterways. Projects often require an influx of personnel, either on a temporary or permanent
11 basis. OPG also takes measures to mitigate risk to a community's environment, archeological
12 record or heritage sites.

13
14 In order to address these various potential effects on host communities, OPG consults with
15 host communities throughout the planning and execution of capital projects. The elements and
16 scale of a project-specific consultation depend on the nature of the project and its potential to
17 affect the local community.

18
19 For example, when OPG plans to carry out sustaining capital work at a generating station, the
20 company assesses the potential for the project to affect the local community and identifies
21 what forms of consultation and information sharing may be required. Each project is different,
22 so OPG makes these assessments on a case-by-case basis.

23
24 For larger projects, OPG's community outreach can be quite broad, including town hall
25 meetings to discuss potential impacts and solicit customer input. The specific forms of
26 outreach vary with the nature of the project, its location, and other factors. Where possible,
27 community feedback will be taken into account and reflected in the project plan. OPG also
28 makes use of dedicated websites for major projects, providing information and soliciting input
29 from the widest possible audience.

30

1 The appropriate form and the extent of community engagement activities will depend on the
2 circumstances of a given project. Not all projects require dedicated consultations; it would not
3 be efficient or cost effective for OPG to hold town hall meetings for smaller projects that occur
4 exclusively within OPG's facilities and have no material impact on the community. When OPG
5 identifies a potential community impact in connection with a smaller project, such as road
6 closures, it takes appropriate measures to inform local residents and businesses. As part of
7 this process, OPG provides contact information for customers who may have questions or
8 concerns.

9 10 **5.3. Academic Collaboration**

11
12 OPG also works with academic and other industry partners to research and promote public
13 safety in connection with electricity generation. By collaborating and sharing existing
14 information with academic researchers, OPG is able to promote public benefits, like flood
15 prevention. By sharing information, OPG can promote innovation and reduce costs for
16 researchers.

17
18 As an example, OPG collaborates with Natural Sciences and Engineering Research Council
19 of Canada ("NSERC") Canada FloodNet, a multi-disciplinary research network that is partly
20 funded by NSERC. FloodNet allows efficient coordination between stakeholders, connecting
21 researchers from across Canada and pooling data from OPG and other industry and
22 government partners. FloodNet is then able to develop enhanced flood forecast tools and
23 flood management capacity, which ultimately reduce the damage, socio-economic impacts
24 and human distress caused by flooding, and help protect community water systems and the
25 environment.

26 27 **5.4. Indigenous Community Relations**

28
29 OPG is committed to building and growing mutually beneficial working relationships with
30 Indigenous communities near its current and future operations. These relationships are built

1 on a foundation of respect for the culture and customs of Indigenous peoples, and established
2 and maintained through ongoing dialogue aimed at preserving openness, transparency and
3 trust.

4
5 Where appropriate, OPG pursues prospective generation-related developments with
6 Indigenous communities that can provide the basis for long-term, mutually beneficial,
7 commercial arrangements.

8
9 OPG's practice of consultation with Indigenous communities pre-dates the statutory duty to
10 consult. OPG's commitment to consultation has been beneficial to both the company and to
11 Indigenous communities. By working to resolve grievances and to build relationships, OPG
12 believes that future projects and continued operation will be able to proceed more efficiently
13 and deliver the best outcomes for Indigenous communities, customers, and the company.

14
15 A copy of OPG's First Nations and Métis Relations Policy is included as Attachment 4.

16 17 **5.5. Emergency Management and Public Safety Programs**

18
19 Public safety is a critical concern for OPG. In addition to the community engagement
20 processes described above, OPG keeps the general public informed about and prepared for
21 emergencies and other safety-related issues through several programs.

- 22
- 23 • Public safety around OPG's dams and hydroelectric generating facilities is critical to
24 OPG. In addition to physical safety measures (e.g., signage, fences, booms and
25 buoys), OPG maintains a proactive dam safety communications program. The
26 company's "Stay Clear, Stay Safe" campaign runs year-round on various media,
27 featuring safety messages tailored to the varying risks between seasons. Designed in
28 coordination with the Centre for Addiction and Mental Health, the campaign targets
29 groups and activities at risk. OPG continues to work closely with the Ontario Provincial
30 Police its public safety campaign.

1 A copy of OPG's recent "Stay Clear. Stay Safe." print brochure is included as
2 Attachment 5. The campaign's television ads can be viewed online at
3 <https://www.youtube.com/user/opgvideos>.
4



5
6 **Figure 3: The logo of OPG's waterway public safety campaign**

- 7
- 8 • Each of OPG's regions has an Emergency Response Plan that is developed and
9 continually maintained in coordination with community leaders (e.g., mayors' offices,
10 Indigenous Communities, MPPs, fire services and other first responders). OPG meets
11 regularly with these community leaders to review the emergency plans and to help the
12 company's community partners conduct their own Hazard Identification and Risk
13 Assessment processes.
 - 14
 - 15 • OPG also conducts annual dam safety exercises. These exercises are more than
16 planning meetings – they involve simulated emergencies that unfold over a number of
17 hours or even multiple days, requiring responses from OPG and other groups. For

1 example, a simulated dam leak could require the OPP to set up barricades and road
2 blocks while OPG’s teams draw down the dam sluice gates or otherwise respond to
3 the simulated emergency. In order to make the simulation effective, OPG may arrange
4 to have individuals attempt to bypass barricades or otherwise complicate the
5 emergency.

- 6
7 • OPG regionalizes its safety signage to help effectively communicate safety hazards to
8 local communities. The signage in Figure 4 is an Ojibway warning used in northern
9 communities, reading “Danger – Dam Ahead – Keep Out”.

10
11 **Figure 4: Ojibway Safety Signage used in Northern Communities**



13
14
15 **5.6. Customer Engagement and Business Planning**

16
17 As Ontario’s largest electricity generator, OPG plays an important role in the economic life of
18 the province and in the daily lives of Ontario families, businesses and institutions, and

1 considers customers' interests when making business decisions. Although OPG has no formal
2 customer engagement obligations, it continues to believe that the company can best maintain
3 the trust of its customers and host communities through business plans that reflect customers'
4 preferences.

5

6 As discussed in Ex. A2-2-1, OPG's business planning process is currently informed by several
7 customer-related factors, including the economic climate, trends in electricity costs and
8 consumers' ability to pay. However, to date, the company has not conducted structured
9 customer outreach expressly intended to inform business planning. OPG believes that a more
10 formal customer engagement process may provide valuable insight into customers'
11 preferences with respect to the company's priorities and plans. OPG intends to develop such
12 a process during the IR period. OPG hopes to build on customer engagement work that other
13 OEB-regulated companies are conducting and, where possible, may look for opportunities to
14 collaborate with other regulated entities to engage with customers more effectively.

15

ATTACHMENTS

- 1
- 2
- 3 Attachment 1: Updated Hydroelectric Total Factor Productivity Study
- 4
- 5 Attachment 2: Hydroelectric Benchmarking Study
- 6
- 7 Attachment 3: London Economics International, Inflation Factor Analysis for OPG's
- 8 Regulated Hydroelectric IRM, December 17, 2014 and January 27,
- 9 2015 stakeholder presentations
- 10
- 11 Attachment 4: OPG First Nations and Métis Relations Policy
- 12
- 13 Attachment 5: "Stay Clear. Stay Safe." Brochure

EMPIRICAL ANALYSIS OF TOTAL FACTOR PRODUCTIVITY TRENDS IN THE NORTH AMERICAN HYDROELECTRIC GENERATION INDUSTRY

Prepared for

Ontario Power Generation Inc.

By



London Economics International LLC

390 Bay Street, Suite 1702

Toronto, ON, M5H 2Y2

February 19, 2016

Julia Frayer
Managing Director

Ian Chow
Senior Consultant

Jarome Leslie
Research Associate

Barbara Porto
Research Associate

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Figure 1. Select Acronyms

AF	Availability Factor
AWE	Average Weekly Earnings
BEA	Bureau of Economic Analysis
BLS	Bureau of Labour Statistics
BPA	Bonneville Power Administration
CA	Canada/Canadian
CMS	Cubic Meters per Second
COS	Cost of Service
DEA	Data Envelopment Analysis
EIA	Energy Information Administration
EUCG	Electric Utility Cost Group
FERC	Federal Energy Regulatory Commission
FF1	FERC Form 1
FDD	Final Domestic Demand
GDP	Gross Domestic Product
GRC	Gross Revenue Charge
HOEP	Hourly Ontario Energy Price
ICE	Intercontinental Exchange
IR	Incentive Ratemaking
IRM	Incentive Rate Mechanisms
ISO	Independent System Operator
LADWP	Los Angeles Department of Water and Power
LEI	London Economics International
MCR	Maximum Continuous Rating
MW	Megawatt
MWh	Megawatt hour
NERC	North American Electric Reliability Corporation
NYPA	New York Power Authority
OEB	Ontario Energy Board
OECD	Organization for Economic Co-operation and Development
O&M	Operations and Maintenance
OM&A	Operations, Maintenance and Administration
OPG	Ontario Power Generation
OLS	Ordinary Least Squares
PEG	Pacific Economics Group
PG	Plant Group
PG&E	Pacific Gas & Electric
PFP	Partial Factor Productivity
PI	Price Index
PJM	Pennsylvania, Jersey, Maryland Power Pool
PPP	Purchasing Power Parity
RRFE	Renewed Regulatory Framework for Electricity
RTO	Regional Transmission Organization

SEPA	Southeastern Power Administration
SERC	Southeastern Electric Reliability Council
SFA	Stochastic Frontier Analysis
SPSC	Semiparametric Smooth Coefficient Model
SNL	SNL Financial
StatsCan	Statistics Canada
SWPA	Southwestern Power Administration
TFP	Total Factor Productivity
TVA	Tennessee Valley Authority
US	United States
WAPA	Western Area Power Administration

1 Executive Summary

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

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

1.1 What is TFP?

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

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

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

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

1.2 What data was used for the TFP study?

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

The data selection and gathering process was the most significant challenge in conducting the TFP study. Primary data sources include FERC Form 1, EIA, US BEA, US BLS, StatsCan, and company public reports, as well as data provided directly by OPG. The final TFP study includes sixteen (16) firms in total: OPG, thirteen (13) US investor-owned firms that file FERC Form 1 data, and two (2) US federal and municipal operators. Data for this study covered a thirteen year period from 2002 through 2014.⁵

1.3 What are the results of the TFP study?

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

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

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

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

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

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

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

results are not viewed in the same way as a benchmarking study. This also means that individual TFP results should not be viewed self-referentially or compared to the industry result.⁷

In the OEB report on Rate Setting Parameters and Benchmarking (EB-2010-0379) issued on November 21, 2013, the Board stated that it will continue with a price cap formula and the use of an I-X regime.⁸ Specifically, the Board has stated it would continue to rely on an index-based approach to determine productivity gains or the X-factor. In this respect, the methodology used by LEI employs an index-based methodology. The results from this study will be useful to inform the productivity growth rate assumptions under an I-X regime.⁹

⁷ The use of an industry rate as opposed to an individual rate is important due to the fact that it has better incentive properties. This is because the regulated firm in question cannot readily influence the result, and also because it reduces data error risk.

⁸ OEB. *Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*. Issued November 21, 2013, corrected December 4, 2013.

⁹ This process through which TFP studies could be used to inform growth rate assumptions under an I-X regime is explained further in section 3.1.

2 Background

Under *Regulation 53/05* pursuant to Section 78.1 of the *Ontario Energy Board Act, 1998*, the OEB's mandate includes setting payments for prescribed assets (nuclear and hydroelectric) of OPG which to date have been under a cost of service ("COS") regulation.¹⁰ In 2012, the OEB started stakeholder consultations to consider incentive regulation options for OPG's prescribed assets. On March 28, 2013, the OEB published a report outlining its policy directive and next steps for implementing IR for OPG's prescribed assets.¹¹ One of these directives to OPG was to file a work plan and a status report for an independent productivity study in the next application to set payment amounts.

To fulfill the OEB mandate, OPG retained LEI in late 2013 to perform an industry productivity study for OPG's prescribed hydroelectric assets. LEI published a report in December 2014, which was filed with the OEB by OPG; this report represents an update to that report. LEI's scope of work included identification of appropriate methodologies of data compilation and peer selection, as well as empirical analysis. This report addresses all sections of the work plan.

¹⁰ OEB. *Ontario Energy Board Act, 1998*. < http://www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98o15_e.htm >

¹¹ OEB. *Incentive Rate-making for Ontario Power Generation's Prescribed Generation Assets EB-2012-0340*. March 28, 2013.

3 Basics of Total Factor Productivity

3.1 What is productivity?

Productivity is the ratio of the quantity of outputs produced by a firm, to the quantity of inputs used by the firm. Productivity growth is a trend variable, based on the year-on-year change in the productivity ratio, or the rate of growth in quantity of outputs relative to the rate of growth in the quantity of inputs. For purposes of IR, and specifically in the design of price caps and revenues caps, regulators are interested in changes in productivity over time. For example, historical productivity growth can inform regulators and the regulated utility on the level of productivity change, to guide the choice of an explicit productivity target or X factor under an I-X price cap or revenue cap.

Note that there are multiple methods for measuring productivity. In a practical sense, productivity measures the output quantity relative to input quantity, while productivity growth defines changes in this measurement over time. Common drivers of increased productivity include technological progress, economies of scale, and scope. When attempting to measure productivity, one would seek to capture as many drivers as possible. It should be noted that while TFP indexing techniques can be relied upon to measure total productivity, a TFP value cannot be decomposed to analyze the individual components or drivers of productivity.

There are also multiple categories of productivity that could be measured – for example, for assessing labour productivity, one would look at the ratio that represents the quantity of labour relative to the quantity of output. Labour productivity is a partial measure of productivity, also known as partial factor productivity (“PFP”). In contrast, a TFP measure would attempt to cover all types of inputs relative to all types of outputs.¹² The distinction between the TFP measure and the PFP measures therefore lies in the number of inputs analyzed – single factor productivity measures (or PFPs) relate output to a single input, whereas TFP considers output relative to all inputs. PFP measures can be misleading if considered in isolation.

Figure 2. Generalized concept of a TFP growth rate

$$\text{TFP growth rate} = \frac{\% \Delta \text{ weighted sum of the quantities of all outputs}}{\% \Delta \text{ weighted sum of the quantities of all inputs}}$$

An industry TFP study measures the changes in overall productivity for the firm and its peers over a specified time period – it is not a benchmarking study, as it does not focus on efficiency levels. In addition, an industry TFP study by definition will not focus on the regulated firm, but rather the industry as a whole. An industry TFP study is backward looking – reporting

¹² OECD. *Measuring Productivity: Measurement of aggregate and industry-level productivity growth*. 2001.

historical growth rates; the industry’s long-term TFP growth rate over the study period timeframe is the primary result or finding of the study.¹³

3.2 Overview of TFP methods

The following section is an overview of the various methods of performing a TFP study. TFP methods can be broadly categorized into deterministic methodologies, which “calculate” TFP, and econometric methodologies, which “estimate” TFP. Figure 3 below gives an overview of some of the methods LEI considered; for more detail see Appendix B Section 9.1.1. LEI chose to use a TFP index method, as discussed further below.

Figure 3. Empirical techniques for estimating TFP

	Non-Frontier technique	Frontier techniques	
Parameters	Index Method	Data Envelopment Analysis ("DEA")	Stochastic Frontier Analysis ("SFA")
Description	Index number measures the ratio of all outputs (weighted by revenue shares) to all inputs (weighted by cost shares)	Linear programming technique which identifies best practice within a sample by fitting a frontier over the top of the data points and measures relative inefficiencies	Same as DEA but following econometric methods to estimate the efficiency frontier
Data needs	Quantity and price data on inputs and outputs for 2 or more firms	Quantity data on inputs and outputs for a sample of firms; price data required to get information on allocative efficiency	Quantity data on inputs and outputs for a sample of firms; price data required to get information on allocative efficiency
Advantages	Relatively simple and robust technique. Can incorporate many inputs and outputs with few observations	Can decompose cost efficiency into component parts, breaking down allocative and technical efficiencies. Can easily handle multiple outputs	Can decompose cost efficiency into component parts, breaking down allocative and technical efficiencies. Accounts for “data noise” (data errors, omitted variables, etc.) and allows for the use of standard statistic tests
Drawbacks	Does not allow for identification of various factors of TFP change such as technical efficiency, scale efficiency, etc.	Requires a large dataset. Sensitive to the way outputs and inputs specified. Can be difficult to explain in a regulatory setting	Requires large sample size for robust estimates. Requires specification of production or cost function. Can be difficult to explain in a regulatory setting

Source: Coelli et al. “A Primer on Efficiency Measurement for Utilities and Transport Regulators.” World Bank Institute. February 2003

¹³ It is preferable to have 10 or more years of growth rate figures; see Section 3.3 for discussion of the appropriate length of TFP study.

TFP index methods are deterministic and do not measure performance relative to an efficient frontier;¹⁴ they measure the ratio of all outputs to all inputs, where input and output indexes are constructed using both quantities and prices of outputs and inputs. Traditionally, TFP indexing can be used to compare rates of change of productivity but not absolute levels (although more complicated multilateral index methods do also allow levels comparisons). The benefits of TFP indexing are that it is a relatively simple, easy to communicate, and robust technique that requires significantly fewer observations than the other measuring techniques, and thus it is often used for regulatory proceedings. TFP indexing is also more transparent when dealing with outliers, unlike DEA and econometric techniques. It is important to note that the TFP index method, because it is a numerical technique as opposed to a statistical technique, does not give a forecast error measure. Therefore, interpreting differences in index values requires qualitative considerations. Finally, LEI notes that the OEB and other regulators are familiar with the index approach,¹⁵ and in the RRFE proceedings the Board stated its preference to continue to rely on productivity factors that were determined using the index-based approach.¹⁶

3.2.1 Selecting an indexing technique

The TFP index methodology requires selection of an indexing technique in order to calculate TFP growth rates. To determine which indexing technique was best suited for TFP calculations, LEI considered Diewert and Nakamura's 2005 review of the four most popular alternate index number formulations: Laspeyres index, Paasche index, Fisher Ideal index, and Törnqvist index (see Appendix B Section 9.1.1 for description of each index).¹⁷ Diewert and Nakamura used the 'axiomatic' approach to the selection of an appropriate index formulation which specifies a number of desirable properties an index formulation should possess: constant quantities test, constant basket test, proportional increase in outputs test, and time reversal test. Only the Fisher Ideal index satisfied all four criteria that an index number method needs to meet.¹⁸

¹⁴ Deterministic methodologies "calculate" TFP values, as opposed to econometric methodologies which "estimate" TFP values. Non-frontier methods assume production is always efficient in their use of existing technology, and equates potential level of production at each moment in time. Non-frontier methods do not provide separate estimates of technical change and efficiency change. Further discussion regarding methods of measuring productivity can be found in Section 9.1.1.

¹⁵ The TFP Index method has also been used in previous industry productivity studies before the OEB, and is a preferred method among practitioners for I-X regimes.

¹⁶ OEB. *Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*. Issued November 21, 2013, corrected December 4, 2013.

¹⁷ Diewert and Nakamura. *Concepts and Measures of Productivity: An Introduction*. 2005.

¹⁸ It should be noted that these four index formulations generally produce very similar results.

Figure 4. Fisher Ideal index

$$\text{Fisher Ideal Index} = \sqrt{(\text{Laspeyres Index}) * (\text{Paasche Index})}$$

The Chained Fisher Ideal index is a geometric mean of the Laspeyres and the Paasche indices (Figure 4).¹⁹ The Fisher Ideal index overcomes the classic ‘index number problem’ suffered by the Laspeyres and Paasche indices, where as one moves further away from the set of prices used, the representative quality of the index decreases (since prices change over time). The Chained Fisher Ideal index overcomes the “index number problem” as follows: instead of using one base observation for the whole period, it calculates the Fisher Ideal index for each period using the previous period’s observation as the base, linking these different calculations together to form an index number series which uses the most representative weights possible for each observation.

Based on the mathematical properties and needs of TFP calculations, the Chained Fisher Ideal index ranked highest and therefore is theoretically superior to all other index methods. For this reason, LEI determined that the Chained Fisher Ideal index was most appropriate for the purposes of this study.

3.2.2 Measuring TFP growth rates

The key finding of an industry TFP study is a numerical estimate of the TFP growth rate over the study period timeframe. LEI employed two methods of measuring TFP growth rates. The first method, referred to as the ‘average growth’ method, calculates the year-on-year changes in the TFP Index and then takes the average of the resulting growth rates over the course of the study period.²⁰ As further outlined in Figure 5, a mathematical equivalent can be calculated by (i) taking the natural logarithm of the ratio of the last TFP index value divided by the first TFP index value, and (ii) then dividing the resulting value by the number of annual year-on-year observations between the start and end year.²¹

Figure 5. Calculating average TFP growth for a study period of 2002-2014

$$\text{Average industry TFP growth} = \ln\left(\frac{\text{2014 industry TFP index}}{\text{2002 industry TFP index}}\right) / 12$$

¹⁹ Indexes are chained by comparing data for each year to the data from the year immediately preceding it (with the exception of the base year). This method provides a more accurate portrayal of year over year growth.

²⁰ Economic Insights. *Total Factor Productivity Index Specification Issues*. December 7, 2009.

²¹ The number of annual changes can be calculated as the number of years for which data is collected as part of the TFP study period minus one. In our example, a study period of 2002-2014 has 13 years of data and (13 - 1 = 12) annual changes over that period.

A second method of obtaining a numerical estimate of the TFP growth rate is referred to as the 'trend regression' method; it is a regression-based method that estimates the linear trend of the TFP index values over the study period timeframe. As outlined in Figure 6, this method is calculated by carrying out a linear regression of the natural logarithm of the TFP index values against the number of years of the study period (starting from 0) and a constant term. The estimated slope of this regression is the average TFP growth rate.²²

Figure 6. Trend regression of TFP growth for a study period of 2002-2014

$$\text{Regress: } \ln(\text{industry TFP index}) = \beta * T + \alpha$$

Where:

β = trend growth rate for the industry TFP index over the study period

T = time in years (0, ...,12)

α = constant term

'Average growth' is the more common method of measuring study-period TFP growth rate, and has been used in previous studies presented before the OEB.²³ The preference of this method can be attributed to the fact that it calculates the actual growth rate of the TFP index values over the course of the study period. However, in certain instances the 'average growth' method can be misleading, most notably when a series exhibits volatility at its endpoints. Because the 'average growth' method tracks the exact growth from start to end, if the endpoints of a series are outliers with respect to the trend then the average method may not give a very good estimate of the underlying TFP trend.

In 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. The trend regression method has been used to calculate trend growth rates in New Zealand and Australia.²⁴ However, because the 'trend regression' method is only a linear estimate of the TFP growth rate, in the case where endpoints are outliers it may not track the actual endpoint to endpoint growth rate as well as the 'average growth' method.

²² Ibid.

²³ For example: PEG. *Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board*. November 2013.

²⁴ For an example of a TFP study using the trend regression method see: Economic Insights. *Electricity Distribution Industry Productivity Analysis: 1996-2008*. September 1, 2009.

Each method has its own set of strengths and weaknesses. For this reason, LEI has presented the results for both methods in Section 6, which we believe is a useful indication of the robustness of the analysis.²⁵

3.3 Appropriate length of TFP study

The main purpose of conducting a TFP study of this nature is to establish industry trends, which are innately long term. Logically, the best method of establishing a trend is by looking at multiple years of data and performance. Multiple years of data limits bias that can be caused by numerical outliers or one-off events that affect performance in any single year. Therefore, a productivity trend should cover a period that extends through a sufficiently long timeframe, 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.

This is especially true for hydroelectric generation businesses, which go through business cycles related to the long lifetime of the assets, and where productivity is also heavily dependent on shorter term, exogenous factors such as hydrology, which can lead to high year-on-year variability in output. The use of a long term data series helps smooth out anomalies associated with one off circumstances, and compensates for year-on-year variability that is observed in data. However, 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 reviewed eighteen previous TFP studies and found that it was common to use data spanning ten years or more for productivity studies.²⁶ Given data availability (see Section 5 for further details), best practices for TFP analysis, and also the context of the hydroelectric business, LEI believes that the thirteen year timeframe of 2002-2014 is appropriate for this study.²⁷ 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

²⁵ Note that the presentation of both methods only refers to the final TFP growth estimate value. In all other instances, such as when estimating quantity sub-index growth rates, only the average TFP growth rate is presented. This is because both methods follow the exact same process, until the final step of calculating the TFP growth rate over the study period timeframe.

²⁶ Data spanned between 10 and 39 years depending on the study. For more information on this portion of the review see Appendix B Section 9.1.3.3.

²⁷ LEI notes that the Pacific Economics Group ("PEG") report on productivity and benchmarking in Ontario, presented to the OEB in November 2013, reviewed data over the 2002-2012 period.

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.

4 TFP inputs and outputs

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

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

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

Figure 7. Calculating the TFP index

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

4.1 TFP study outputs

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

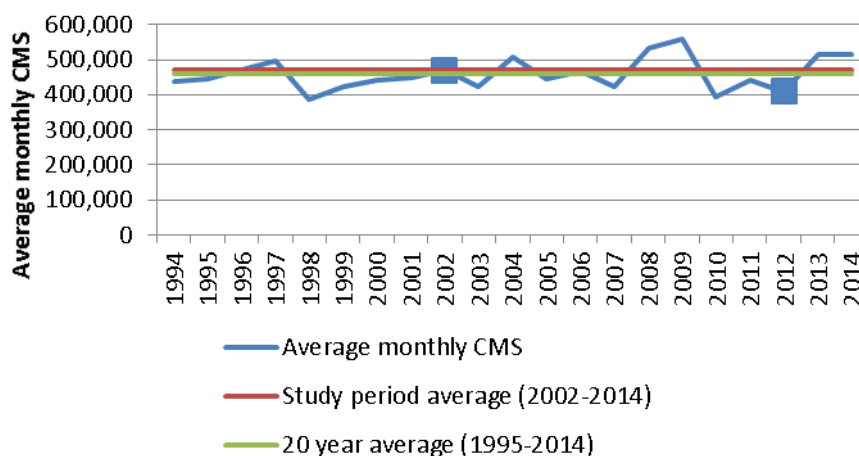
After considering 18 productivity studies on generation, conducted both for academic and regulatory purposes, LEI found that generation was the most common metric chosen for measuring output.²⁸ Generation is an appropriate output because it is the essential output being produced by every power generator.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

²⁸ See Appendix B Section 9.1.3.1 for more detail.

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

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

Figure 8. Historical OPG water flow



Source: Based on information provided directly to LEI by OPG

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

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

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

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

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

4.2 TFP study inputs

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

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

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

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

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

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

4.2.1 O&M input quantities

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

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

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

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

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

For Canadian data, labour O&M price index was based on industrial aggregate average weekly earnings (“AWE”) (reported by *Statistics Canada*; in current dollars, for Canadian utilities, including overtime, seasonally adjusted, for all employees), and the non-labour O&M price index was based on the gross domestic product price index estimate of final domestic demand (“GDP-IPI FDD”) (reported by *Statistics Canada*; implicit price indexes, gross domestic product, final domestic demand, for Canada). For US data, labour O&M price index was based on data gathered from US Bureau of Labor Statistics (“BLS”), and non-labour O&M price index was

based on the GDP-PI data gathered from the US Bureau of Economic Analysis (“BEA”).³¹ Canadian O&M price indices over the TFP study timeframe are presented in Figure 9, while US O&M price indices over the TFP study timeframe are presented in Figure 10.

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

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

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

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

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

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

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

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

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

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

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

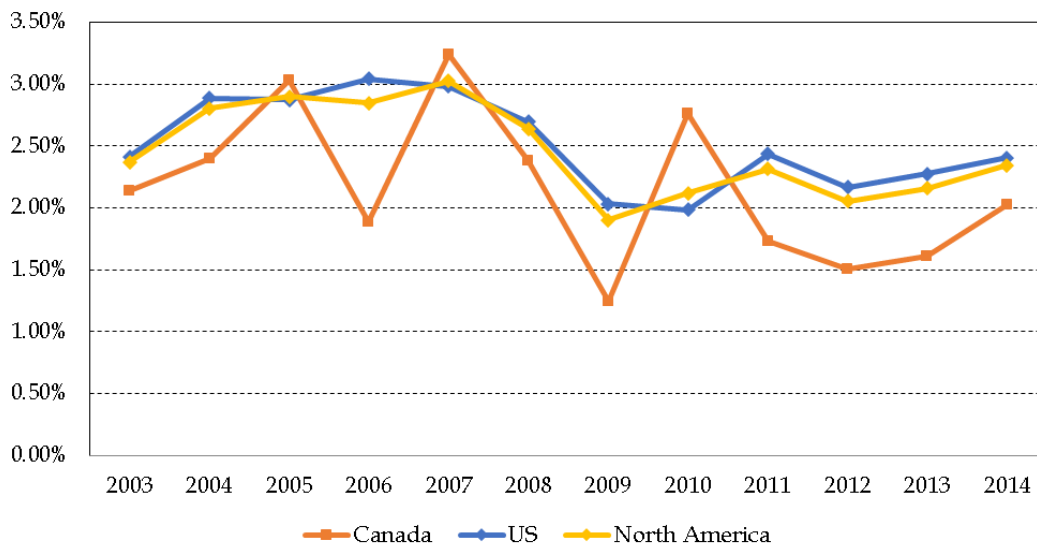
Year	US O&M Price Index	Canadian O&M Price Index	North American O&M Price Index
2002	1.00	1.00	1.00
2003	1.02	1.02	1.02
2004	1.05	1.05	1.05
2005	1.09	1.08	1.08
2006	1.12	1.10	1.12
2007	1.15	1.14	1.15
2008	1.18	1.16	1.18
2009	1.21	1.18	1.20
2010	1.23	1.21	1.23
2011	1.26	1.23	1.26
2012	1.29	1.25	1.28
2013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

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

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

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

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



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

4.2.2 Input share weights

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

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

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

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

Capital input share

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

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

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

Figure 14. Annual implied Capital to Total O&M shares for hydroelectric generation industry³⁶

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

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

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

5 Data for TFP study

Ideally, a hydroelectric industry TFP study would include a large set of peers that are similar in terms of location, capacity, and asset allocation. For the purpose of this study, the peers should include medium to large hydroelectric generators. LEI focused its data research on the United States and Canada due primarily to data availability. As outlined below, LEI considered a total of 28 hydroelectric peers across North America, including 22 in the US and 6 in Canada (including OPG). However, issues with data availability meant that 12 of these peers could not be included in the final industry peer group (and one peer, 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). Of particular note is that with the exception of OPG, no other Canadian firm could be included in the study. In the US, all major utilities are required to submit comprehensive financial and operating reports to the Federal Energy Regulatory Commission (“FERC”) under FERC Form 1 (“FF1”), which is then made publicly available.³⁷ In contrast, no such data bank exists in Canada, and therefore the financial data required for the TFP study from Canadian peers could not be attained either through public resources or directly from the individual utilities. Still, LEI believes that a set of 15 US peers and OPG is sufficient for developing a robust TFP trend.³⁸

5.1 Peer selection

5.1.1 Peer selection criteria

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

³⁷ FERC Form 1 is a regulatory requirement for Major electric utilities, designed to collect financial and operational information on utilities subject to FERC jurisdiction. Major utilities are defined as: having “one million megawatt hours or more; 100 megawatt hours of annual sales for resale; 500 megawatt hours of annual power exchange delivered; or 500 megawatt hours of annual wheeling for others (deliveries plus losses).” FERC Form 1 filings can be found here: <<http://www.ferc.gov/docs-filing/forms/form-1/data.asp>>

³⁸ LEI notes that there is OEB precedent to rely on US data when necessary. See for example Pacific Economic Group report: “Price Cap Index Design for Ontario’s Natural Gas Utilities” (March 2007), which was undertaken under OEB directive. This study used US TFP results to establish TFP growth targets for two Canadian gas utilities (Enbridge Gas Distribution Inc. and Union Gas Limited). Report filed under OEB case number EB-2006-0209, available online at: <http://www.ontarioenergyboard.ca/documents/cases/EB-2006-0209/TFP_study_20070330.pdf>

hydro fleet. Practical considerations relating to the availability of reliable data over the entire timeframe of the study also played an important part in peer selection.³⁹

In addition to meeting the above criteria, peers needed to have data available on the hydroelectric portion of their operations, in order to ensure consistency of data. Inputs and outputs, and therefore productivity, would be completely different for thermal generation, for example. For peers which exclusively operated hydro facilities, this was straightforward. However, a number of peers were excluded from the study because there was no division in reported O&M data between the hydro and non-hydro components of their operations. Peers needed to have annual data on O&M (measured in dollars) and net generation (measured in MWh), for the 2002 through 2014 timeframe. Revenue data was also collected when available, but was estimated when necessary (see Section 5.3 for more detail). The data and peer selection stage of the study provided LEI with plant-level hydro-specific data on annual generation (MWh), capacity (MW), and O&M (dollars), as well as revenues for developing the capital input share.

As discussed in Section 3.3, a thirteen year timeframe was chosen for the study because it is long enough to smooth out anomalies associated with one off circumstances, but not too long that it relies too heavily on “stale” data or periods when data is not available. 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. The end year, 2014, was chosen because this represented the latest available information while LEI was gathering data for this study in late 2015 and early 2016. Considering issues related to data availability and length requirements of a TFP study, LEI determined a study period timeframe of 2002 to 2014 was optimal.

5.1.2 Final peer group

Consistent with above criteria, LEI considered a total of 28 industry peers in North America, including 22 in the United States and 6 in Canada. These consisted of OPG, 14 private US companies that filed FERC Form 1, 2 US municipal utilities, 2 US federal power authorities, 4 US federal power administrations, and five various other Canadian companies.

However, primarily due to lack of certain necessary data, eleven peers could not be included (see more detailed discussions in Sections 5.2.3 and 5.2.4 below). Furthermore, Alcoa which was

³⁹ Note that LEI did not consider the ownership structure of the firm, the regulatory regime under which the firm operated, or the type of energy market in which the firm operated (e.g. bilateral energy versus regional transmission organization (“RTO”) administered energy market, energy-only versus energy and capacity).

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.

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

Figure 15. List of peers included in industry

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

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

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

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

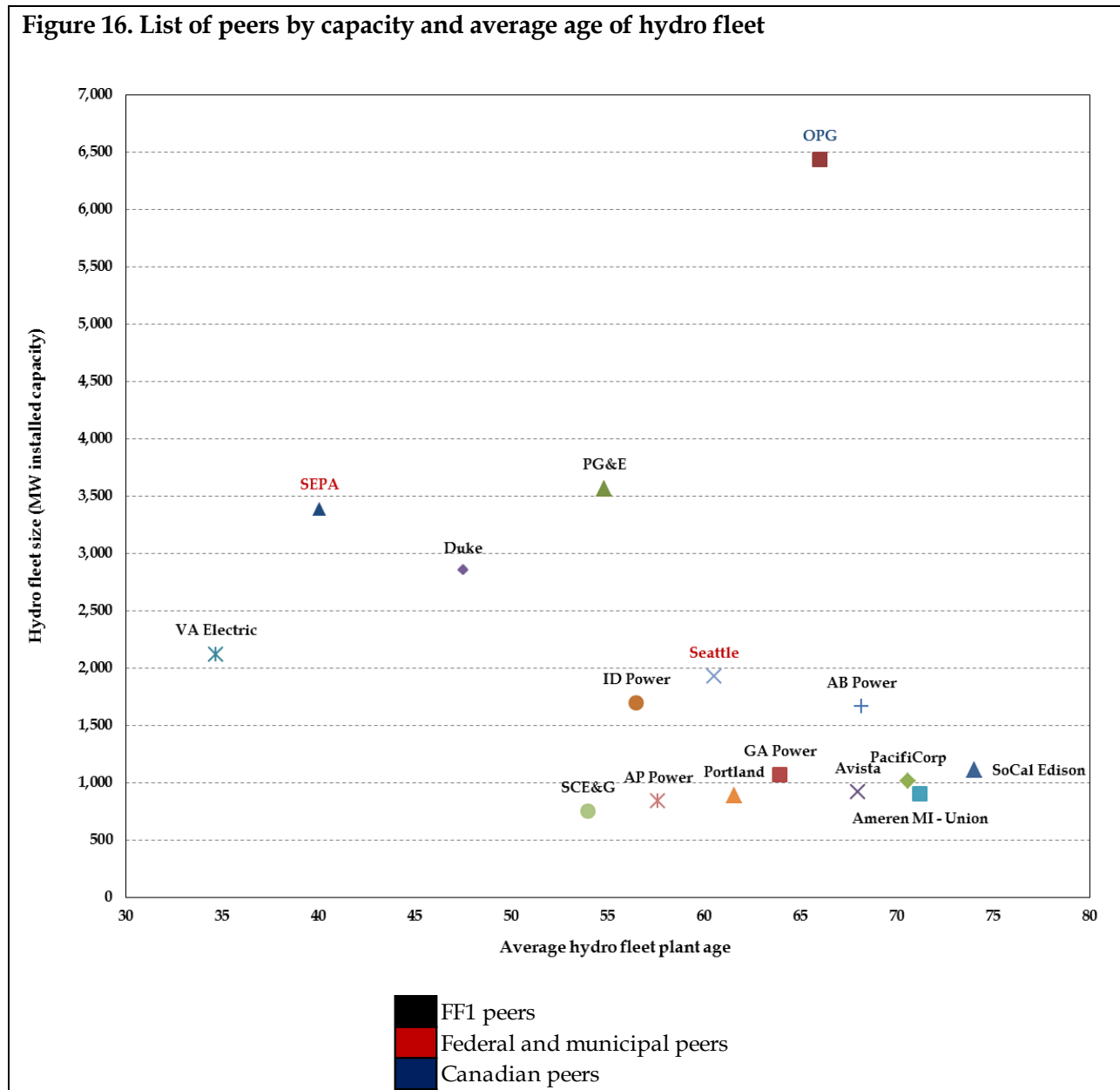
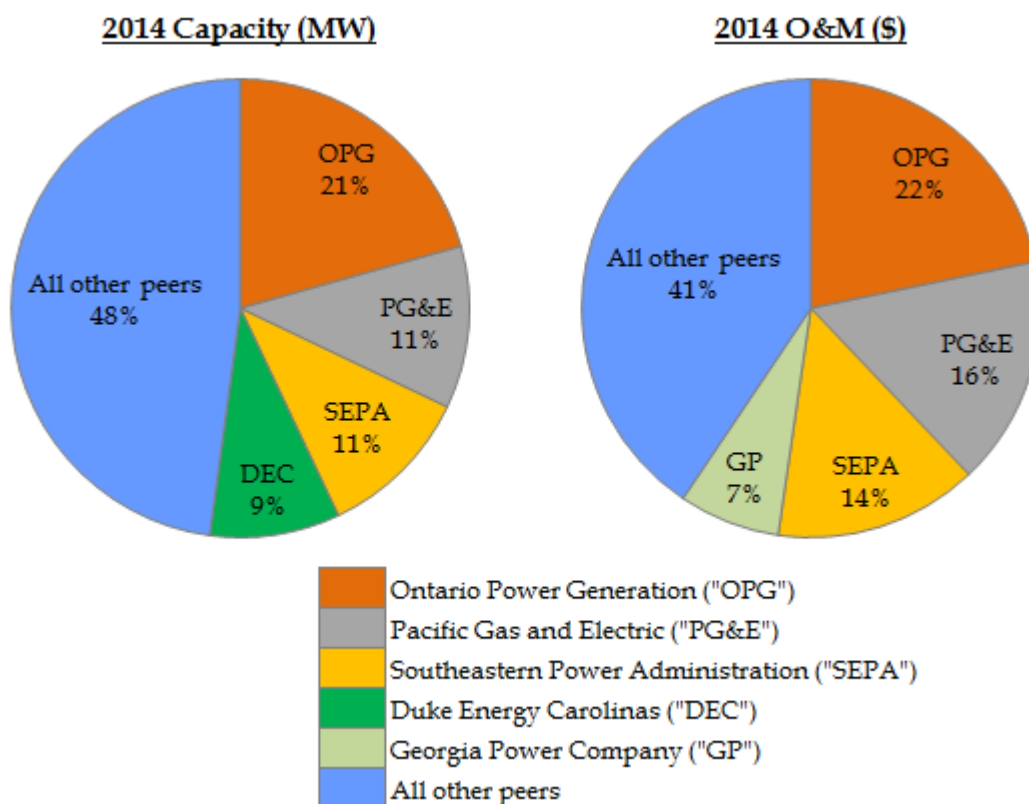


Figure 17. Breakdown of top four peers by 2014 Capacity (MW) and O&M costs (\$) ⁴²



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

5.2 Peer data

LEI considered multiple reputable primary sources for data including FERC Form 1, EIA, StatsCan, US BEA, US BLS, ISO price data, NERC, and company public reports and websites.

⁴² O&M amounts for US peers were converted from US dollars to Canadian dollars using the 2014 OECD PPP for GDP, at a rate of 1.23 Canadian dollars per 1 US dollar. See Section 5.4 for further explanation of conversion process. Further, all O&M values were deflated by their respective indices in order to isolate productivity trends, as previously described in Section 4.2.1.

Although LEI relied mainly on primary sources, data was also sourced and cross checked against third party commercial databases,⁴³ and the confidential EUCG database.⁴⁴

5.2.1 Data provided by OPG

OPG provided LEI with operating and financial data on each of the five hydro plant groups (“PGs”) for the TFP study in January 2016. These figures include net generation, O&M (excluding water rental charges/GRC), and revenue data for the updated study timeframe. Net generation and O&M figures were provided from January 2002 until December 2014.⁴⁵ For revenue, data for January until April 2002 was not available due to markets opening in May 2002 and therefore revenue amounts had to be imputed.⁴⁶

Figure 18. Data provided by OPG

Data provided by OPG	
Operational data	Financial data
<ul style="list-style-type: none"> ▪ Maximum Continuous Rating (MW, plant level) ▪ Net generation (MWh, plant group level) ▪ Plant names and plant info (initial COD, MW, plant type, whether provides ancillary services, etc) 	<ul style="list-style-type: none"> ▪ Total OM&A (\$K, plant group level) <ul style="list-style-type: none"> - Labor OM&A (fully-loaded wages) - Non-labor OM&A ▪ Revenue (\$K, plant group level) ▪ Other costs (\$K, plant group level) <ul style="list-style-type: none"> - NS projects - HTO and corporate costs

⁴³ Including Energy Velocity and SNL Financial.

⁴⁴ While various sources were used to create the dataset used in the final analysis, LEI believes these different sources are comparable because a TFP study is an analysis of trends rather than efficiency levels. Therefore, any potentially unobserved inconsistencies between datasets will not impact results in the same way as they would for a benchmarking study.

⁴⁵ Certain stations were operated by OPG as merchant generating stations, but during the study period were decommissioned so new generating stations could be constructed. These stations include Ear Falls, Healey Falls, Lower Sturgeon, Sandy Falls, Wawaitin and Hound Chute. Data for these sites was removed from the study once the stations were decommissioned.

⁴⁶ Revenue figures for the missing months were estimated by multiplying generation figures for each month by the average monthly HOEP for the same month in 2003-2012 (See Section 5.3 for further discussion on revenue estimations). However, LEI notes that using different estimation methods to calculate OPG’s 2002 revenue between January and April had little to no effect on the final industry TFP results.

5.2.2 FERC Form 1 data

As discussed in Section 5.1 and as presented in Figure 19, LEI identified thirteen large and medium size peers (with hydroelectric portfolios of more than 500 MW) that submit FERC Form 1 annually. FF1 data is submitted by all major electric utilities and is available for large hydro plants. FERC provides guidelines on data requirements, therefore, data sourced from FF1 can be considered reliable. The use of a single data set for this peer group also gives it consistency. FF1 data was used for total O&M costs (non-capital input), nameplate capacity (capital input) and generation (output).

LEI performed adjustments on two companies to correct certain data issues or missing data points in FF1 annual filings. Duke Energy's 2002 FF1 data was missing, so O&M and generation were interpolated for that year based on 2001 & 2003 values. Alabama Power's generation data was missing for 2004, and therefore also required interpolation along the same lines.

As noted in Section 5.2, LEI used a variety of sources and where possible, cross-checked FF1 data with other data sources. However, LEI believes that given the reputation of the publisher, using FF1 data is both reliable and robust.

Figure 19. List of FF1 peers including 2014 capacity, O&M (US \$), and net generation data

Ferc Form 1 peers	Capacity (MW)	O\$M (‘000\$)	Net Generation (MWh)
Pacific Gas and Electric	3,567	113,585	5,740,008
Duke Energy Carolinas, LLC	2,859	32,841	5,008,985
Virginia Electric and Power	2,122	10,617	3,095,734
Idaho Power Company	1,695	33,467	6,097,434
Alabama Power	1,668	37,422	3,892,917
Southern California Edison Company	1,112	27,852	1,543,032
Georgia Power Company	1,071	50,243	1,908,307
PacifiCorp	1,016	31,549	3,595,400
Avista Corporation	921	12,335	4,143,307
Union Electric	904	12,508	1,433,513
Portland General Electric Company	889	25,286	3,165,690
Appalachian Power Company	840	26,933	905,995
South Carolina Electric & Gas Company	750	6,366	613,520

5.2.2.1 Consistency between FF1 and OPG data

LEI attempted to maximize data consistency by using the same data source (FERC Form 1) as much as possible. However, there were still some instances where the method of reporting for primary data differed between industry peers. Most notably was the use of operations, maintenance and administration (“OM&A”) for OPG versus O&M for all other peers. Data provided by OPG was OM&A, but FERC Form 1 data does not report administration costs at the hydroelectric business level.

Although administration costs were included by OPG, they were found by OPG to be relatively flat historically, and were not a sizeable component of the total OM&A, so their inclusion would not measurably impact TFP results. TFP analysis measures change in productivity over time, so if administration costs are trending consistently with O&M costs over time, then OM&A trends can be used as a reasonable proxy for O&M trends. OPG subsequently reviewed administration costs in OPG’s cost of service regulatory filings to the OEB and observed that the trend in administration costs was “flat” and that administration costs were not a significant component of OM&A.⁴⁷ As such, OPG and LEI concluded that the inclusion of administration costs in the OM&A data for OPG (and not in the O&M data for peers) would not materially bias the industry TFP study.

In addition, O&M data was confirmed to be consistent between FF1 and OPG. Figure 20 below shows the list of FF1 O&M line items compared to OPG. Note that data provided by OPG does not include water rental and GRC fees, therefore the “water for power” line item was removed from FF1 O&M costs for consistency.⁴⁸

⁴⁷ Based on OPG's COS filings with the OEB from 2010-2015, on a plant group level.

⁴⁸ The ‘water for power’ line item can be removed because it is a pass-through item and therefore does not affect productivity.

Figure 20. FF1 O&M line items compared to items included in OPG costs

Line item	Included in OPG total O&M costs (without HTO and Corp)
<u>Operation</u>	
535 Operation supervision and engineering	Yes
536 Water for power	No
537 Hydraulic expenses	Yes
538 Electric expenses	Yes
539 Miscellaneous hydraulic power generation expenses	Yes
540 Rents	Yes
<u>Maintenance</u>	
541 Maintenance supervision and engineering	Yes
542 Maintenance of structures	Yes
543 Maintenance of reservoirs, dams and waterways	Yes
544 Maintenance of electric plant	Yes
545 Maintenance of miscellaneous hydraulic plant	Yes

5.2.3 Federal and municipal peer data

Once research into the five Canadian and thirteen FF1 peers had been completed, LEI expanded the search to federal and municipal operators, in order to include as many peers as possible in the industry TFP analysis. Five federal and three municipally owned companies were evaluated for consideration in the industry TFP study. While these operators control sizeable hydroelectric assets, they are not required to file FF1 data, and therefore the data inputs for the TFP study needed to be researched on an individual company basis. The primary data source for this peer set consisted of annual reports and other financial filings published by the companies themselves. Supplementary information was also obtained through direct communication with the companies.

The five federal companies considered for the study were Southeastern Power Administration (“SEPA”), Southwestern Power Administration (“SWPA”), Western Power Administration (“WAPA”), Bonneville Power Administration (“BPA”), and Tennessee Valley Authority (“TVA”). Of these five, only SEPA was included in the final study due to data issues with the other federal companies. For municipal companies, the three that were considered include New York Power Administration (“NYPA”),⁴⁹ Los Angeles Department of Water and Power (“LADWP”), and Seattle City Light (“Seattle”). Of these three, only Seattle was included as part of the final peer set due to data issues with the other municipal companies.

For this TFP study, LEI required data associated only with hydroelectric assets. Published data for TVA and BPA was only available at the company level and did not distinguish between hydro and non-hydro components.⁵⁰ TVA and BPA were not included in the final peer group because they report O&M on a company level, and, for TVA, a sizeable portion of its generation facilities were not hydroelectric. TVA’s hydro component consisted of only around 8.9% of their total generation assets in 2014, as measured in capacity. For BPA, hydro consisted of 82.8% of its 2014 capacity.⁵¹ LEI contacted BPA and TVA for hydro-specific O&M figures, but both firms could not provide breakdowns by specific generation asset types.

SWPA generation facilities were entirely hydro, but O&M from 2003-2005 was either not available or not complete.⁵² According to SWPA, the issue arose because the US Army Corps of Engineers (which runs SWPA’s hydro facilities) experienced issues related to accounting for fixed assets.⁵³ This issue led to the removal of consolidated annual reports for those years from the public record. Because of this three year data gap, SWPA could not be included in the final peer group.

⁴⁹ Although NYPA is a state power authority, it is labeled in this report as municipal for ease of grouping; referring to NYPA as municipal does not affect results or interpretation of results.

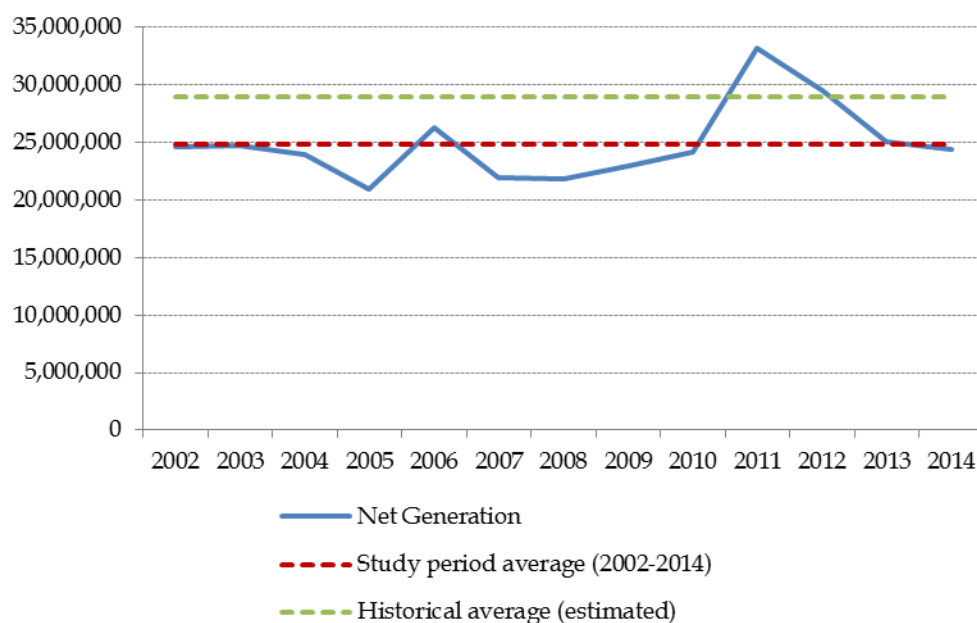
⁵⁰ Based on analysis of primary documents including TVA and BPA’s annual reports, and direct contact with the companies requesting hydro-specific data. TVA’s annual reports can be found here: <<http://www.snl.com/IRWebLinkX/FinancialDocs.aspx?iid=4063363>>, BPA’s annual reports can be found here: <<http://www.bpa.gov/Finance/FinancialInformation/AnnualReports/Pages/default.aspx>>.

⁵¹ Ibid.

⁵² SWPA annual reports can be found here: <<http://www.swpa.gov/annualreport.aspx>>

⁵³ Based on direct conversations with SWPA officials.

Figure 21. WAPA annual generation (MWh) over 2002-2014 period⁵⁴



Source: WAPA annual reports

For WAPA, a complete set of hydro-specific data was obtained through annual reports as well as direct communications with the company.⁵⁵ Net Generation, revenue and O&M costs were adjusted to take into account one coal plant owned by WAPA. O&M costs were further adjusted to remove annual transmission related costs, which were not available in the annual reports but

⁵⁴ Net Generation for the period prior to 2002 was not available for WAPA. However, statements in WAPA’s annual reports (see for example 2008, 2011 and 2012 annual reports available online at: <<http://ww2.wapa.gov/sites/western/newsroom/pubs/Pages/default.aspx>>) refer to a long period of drought from 1999 to 2010, that reduced WAPA’s annual net generation to numbers well below historical average. For example, the 2012 annual report states that 2012 net generation is close to historical average after more than a decade of below average generation due to drought. Based on statements like these, LEI estimated WAPA’s historical generation. LEI notes that WAPA’s annual generation fluctuations also skewed industry TFP results.

⁵⁵ 2002-2014 annual reports for WAPA are not available online. WAPA provided LEI directly with hard copies of their annual reports and statistical appendices for 2002-2014.

were directly provided by WAPA.⁵⁶ However, an 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. As mentioned in its 2012 annual report, WAPA experienced a long term drought condition. Annual generation over the 2002-2014 study period can be seen in Figure 21.⁵⁷ 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.

SEPA is the only federal company that was included in the final peer group. Data for net generation, revenue, and O&M were all available in SEPA's own annual reports.⁵⁸ Unlike the other federal companies, SEPA does not own its own transmission facilities, and therefore O&M figures listed in its annual reports did not need to be corrected. Revenue figures had to be adjusted to take into account sales of "Purchased Power", which is essentially power sold by SEPA but generated by other operators.⁵⁹ This information, provided directly to LEI by SEPA, was subtracted from total revenue to calculate revenue related to the sale of SEPA's hydro power.

Municipal companies, LADWP and NYPA, were not included because their generating facilities were not entirely hydro, and neither provided hydro specific O&M figures. For LADWP, hydro was around 25% of total capacity in 2012. For NYPA, 2012 capacity was about 73% hydro, and data only extended back to 2007.⁶⁰ Given that hydro-specific O&M data could not be gathered, these companies could not be included in the TFP study.

⁵⁶Transmission O&M in 2014 was not provided by WAPA, LEI utilized a 41% transmission O&M portion of total O&M which is consistent with previous years.

⁵⁷ Based on information obtained from WAPA's 2002-2014 annual report and data provided by WAPA.

⁵⁸ SEPA annual reports from 2007-2014 can be accessed here: <<http://energy.gov/sepa/listings/annual-reports>> Hard copy annual reports from 2002-2006 were provided to LEI directly by SEPA.

⁵⁹ Based on direct conversations with SEPA, information contained in annual reports, and information on company website.

⁶⁰ These amounts were obtained from LADWP and NYPA annual reports. LADWP annual reports can be found here: <https://www.ladwp.com/ladwp/faces/ladwp/aboutus/a-financesandreports/a-financialinformation?_adf.ctrl-state=1aardt9i2g_4&_afLoop=419000985723718> and NYPA annual reports can be found here: <<http://www.nypa.gov/financial/>>

Seattle is the only municipal power company that was included in the peer group. Data for net generation and O&M was compiled from information found within Seattle's own annual reports.⁶¹ Seattle's generation facilities are entirely hydroelectric, and therefore generation and O&M data was already in the form necessary for the TFP study. Revenue figures for Seattle had to be estimated, as outlined in Section 5.3.

5.2.4 Canadian peers

In addition to the twenty two US peers above, LEI also considered five Canadian peers: Hydro Quebec, BC Hydro, Newfoundland & Labrador Hydro, Manitoba Hydro, and NB Power. To collect the necessary data, LEI reviewed Canadian databases such as StatsCan and NERC, company annual reports, regulatory filings where available, and other publicly available information for all five companies. While LEI was able to collect most of the operational data, all five companies lacked sufficient publicly-available data related to the appropriate hydro-specific O&M expenses. LEI made repeated information requests to all five companies regarding the appropriate hydro specific O&M costs, but was unable to obtain the information. Therefore, due to lack of necessary data for the TFP study, Canadian peers were ultimately excluded from the final peer list.

5.3 Revenue data estimation

As is discussed in Section 4.2.2, revenues (less O&M costs) are used to estimate capital input shares, which are in turn used to determine appropriate weights (α and $(1-\alpha)$) assigned to the two inputs (Capital and O&M). For all peers with the exception of SEPA, LEI had to perform revenue estimations in some form, because revenue data exclusively from the operation of hydroelectric operations was not obtainable directly from the primary source data.

Revenues for all the FF1 peers were estimated using reported production data and reported wholesale energy prices, because energy sales revenues are not directly reported in FF1. Monthly production data came from the EIA-923 dataset, and LEI used historical monthly ISO zone prices for peers operating within ISO market, or monthly bilateral prices for those in non-ISO markets, based on nearest power price hub traded on ICE.⁶² This same process was carried out to estimate Seattle's revenue.

⁶¹ Seattle annual reports can be found here: <<http://www.seattle.gov/light/pubs/annualrpts.asp>>

⁶² For peers in SERC, posted bilateral prices were utilized. Certain hubs in the Pacific Northwest are not consistently traded, so LEI extrapolated to nearby hubs which were more liquid. Dominion joined PJM in 2005, so ISO

For OPG, revenue data from January 2002 to April 2002 was not available because markets were not yet open; therefore, LEI had to estimate revenues by multiplying net generation for the missing months by the average of 2003-2012 HOEP prices for corresponding months. All other revenue data from April 2002 onwards was provided directly by OPG.⁶³

5.4 Comparing US and Canadian data

As was discussed at the beginning of Section 5, LEI believes that using a peer group of OPG and 15 peers is reasonable. However, one notable difference with respect to data comparability relates to currency differences, as revenue and O&M figures from US peers are measured in US dollars, while for Canadian peers those figures are in Canadian dollars. 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 non-adjusted figures can lead to biases (albeit small) in the TFP results. To adjust for this, LEI inflated all US peer revenue and O&M data by the Purchasing Power Parity (“PPP”)⁶⁴ for Gross Domestic Product (“GDP”) between the US and Canada, as estimated by the OECD.⁶⁵ LEI used the 2014 amount of 1.23 Canadian dollars per 1 US dollar; however, sanity checks using 2002 (start year) and average of 2002-2014 PPP values produced the same industry TFP results.⁶⁶

prices are not available before then; LEI extrapolated based on VACAR zone prices reported in Platts’ Megawatt Daily.

⁶³ Revenue provided by OPG solely represents energy market sales of hydroelectric generation, based on actual settlement with the IESO. It does not reflect any variance accounts, regulatory rate true ups, or any other payments such as Surplus Baseload Generation, Hydroelectric Incentive Mechanism or ancillary services.

⁶⁴ PPP reflects the rate of currency conversion between two countries in relation to the reflective purchasing power of a unit of currency in each country. PPP is much more useful than exchange rates when comparing values between countries, because it is not as volatile.

⁶⁵ LEI chose to inflate US data instead of deflating OPG data because this is a Canadian study. The inflation of US revenue and O&M data did not affect individual TFP results for OPG and 15 US peers, as it only causes a linear shift in data. The effects of the US data inflation can only be seen when comparing US peers with OPG, with the only effect being that US peers make up a larger part of the industry than they would have if data was not adjusted.

6 TFP Results

This section presents TFP results for the industry consisting of 16 peers using a Single Output – Two Input Model as outlined in Section 4, based on plant and company level data collected from 2002 to 2014. We report the TFP trend based on two different growth calculations as outlined in Section 3.2.2. The final result for the industry TFP study ranged from a growth rate of -1.01% (under the ‘average growth’ method) to -1.18% (using the ‘trend regression’ method). Section 6.1 lays out the TFP model used, Section 6.2.1 presents the results from the industry TFP study using the ‘average growth’ method, Section 6.2.2 presents the industry TFP results using the ‘trend regression’ method, and Section 6.3 presents some observations regarding outliers.

6.1 TFP model

Based on LEI’s research and available data (see Section 5 for more detail), LEI used a Single Output – Two Input Model. In this model, the output was generation measured in MWh, and the two inputs were physical capital measured in MW and O&M measured in constant prices. The TFP formula is shown in Figure 22, where:

- the Single Output is measured as Net Generation (MWh) (see discussion in Section 4.1);
- the Two Inputs are Capital measured as Capacity (MW) and Non-capital costs measured as total O&M inputs in constant prices (see discussion in Section 4.2);
- the Capital share is 80% and the O&M share is 20% (see discussion in Section 4.2.2);
- the Labour share of O&M is 63% and the Non-labour share of O&M is 37% (see discussion in Section 4.2.1); and
- the Labour price index and non-labour price indexes are O&M-weighted blends for North American hydroelectric peer industry using Canadian and US labour and non-labour price indexes (see discussed in Section 4.2).

Figure 22. Final TFP index

$$TFP = \frac{\text{Output Quantity}}{\text{Input Quantities}} = \frac{\text{Net Generation}}{20\% * \frac{\text{O\&M Cost}}{(37\%) * (\text{Non - Labour PI}) + (63\%) * (\text{Labour PI})} + 80\% * \text{MW}}$$

In any one year, the TFP Index value is measured as the ratio of total Outputs to total Inputs, using the Chained Fisher Ideal index method discussed in Section 3.2.1. A TFP study’s key finding is the industry’s long-term TFP growth rate; as discussed in Section 3.2.2, this can be measured either by the year-on-year changes in the annual TFP index values over the study timeframe (the ‘average growth’ method), or based on the slope of the linear regression of the TFP index values (the ‘trend regression’ method).

6.2 Industry TFP results

6.2.1 Industry TFP results using the average growth method

The results for the industry TFP study over the 2002-2014 period using the average growth method suggest a TFP growth rate of -1.01%, as summarized in Figure 23.

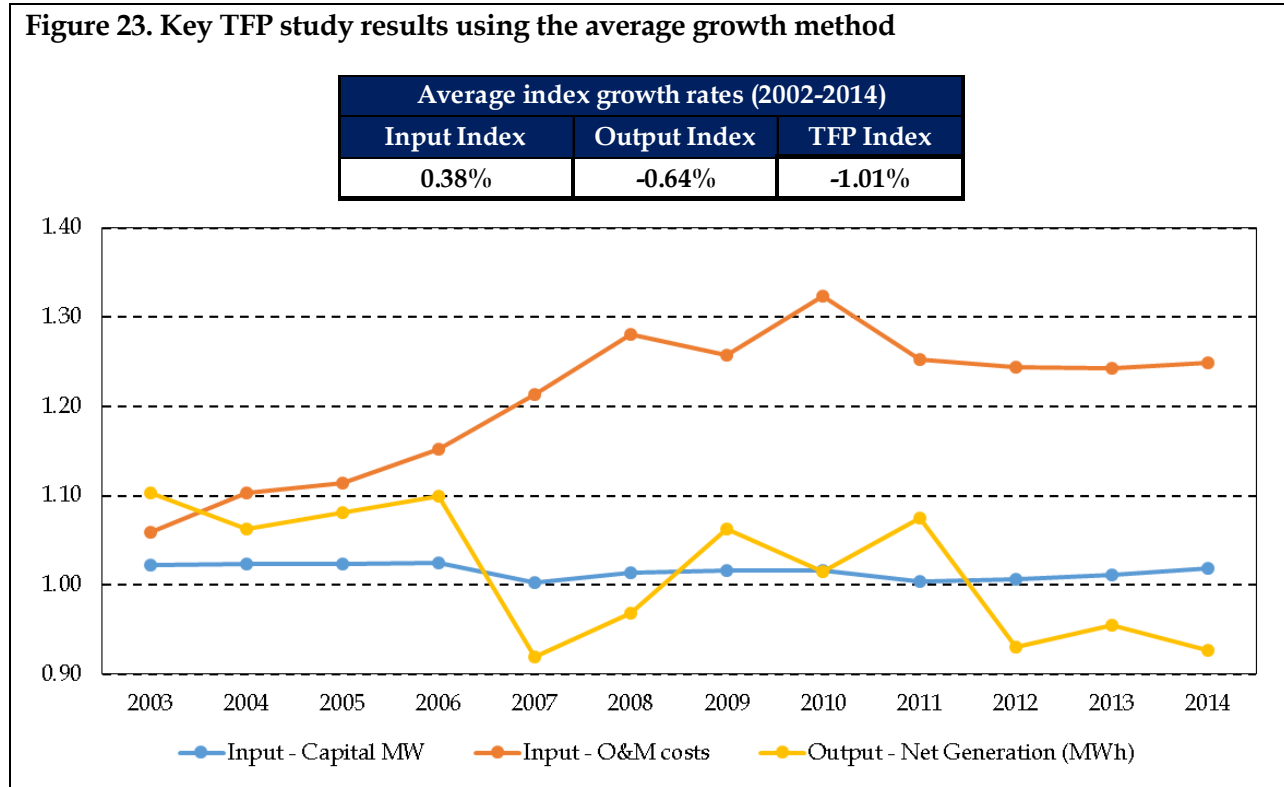


Figure 26, average growth rate for capital inputs measured in MW was 0.15% over the 2002-2014 period, with little year over year fluctuations. This result is to be expected for a mature hydroelectric industry as construction of new generation facilities is infrequent. O&M input growth was higher than capital input at an average rate of 1.85% over the study period, and year over year fluctuations were greater. LEI calculated capital's share of input for this peer set to be on average 80%, and O&M share of input to be 20% (see Section 4.2.2 for more background information on input shares); annual input weights are listed in Figure 24. With more weight assigned to capital, the total input index growth rate is estimated to be 0.38% using the average growth method, and year over year fluctuations are small, as seen in Figure 26.

Figure 24. Annual input weights

Year	Input Weights	
	Capital (MW)	O&M (\$)
2002	85%	15%
2003	88%	12%
2004	86%	14%
2005	88%	12%
2006	86%	14%
2007	82%	18%
2008	84%	16%
2009	78%	22%
2010	75%	25%
2011	76%	24%
2012	67%	33%
2013	75%	25%
2014	76%	24%
AVERAGE	80%	20%

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. Since net generation is the only output, it equals the output index growth rate as measured using the average growth method.⁶⁸

The average input index growth rate of 0.38% and average output index growth rate of -0.64% resulted in an average negative TFP growth rate of -1.01% for the industry over the study period.

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.

⁶⁸ The degree of variability in the output index (see Figure 27) presents a case for calculating growth rates using a trend regression method rather than the average growth method (which is based on trends measured from one endpoint to another endpoint) in order to smooth out the volatility and sensitivity of results to the choice of endpoints. Please see Section 6.2.2 for the results using the trend regression method.

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

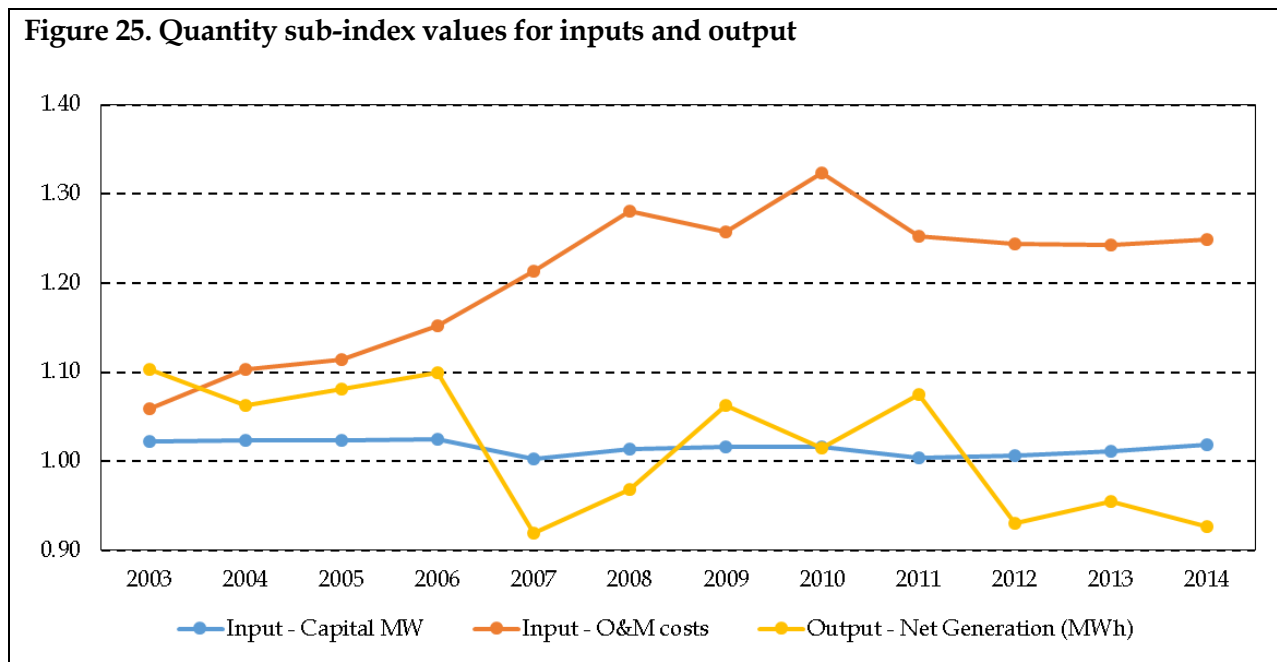


Figure 26. Quantity sub-index growth rates for inputs and output

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

Figure 27. Input, output and TFP index growth rates using the average growth method

Year	Quantity Sub-Index Growth Rates		
	Input Index Growth	Output Index Growth	TFP Index Growth
2002-2003	2.69%	9.80%	7.11%
2003-2004	0.66%	-3.69%	-4.35%
2004-2005	0.07%	1.64%	1.58%
2005-2006	0.62%	1.79%	1.17%
2006-2007	-1.00%	-17.98%	-16.98%
2007-2008	1.78%	5.18%	3.40%
2008-2009	-0.21%	9.40%	9.61%
2009-2010	1.20%	-4.65%	-5.85%
2010-2011	-2.27%	5.69%	7.97%
2011-2012	0.04%	-14.38%	-14.42%
2012-2013	0.34%	2.55%	2.22%
2013-2014	0.61%	-3.00%	-3.60%
AVERAGE	0.38%	-0.64%	-1.01%

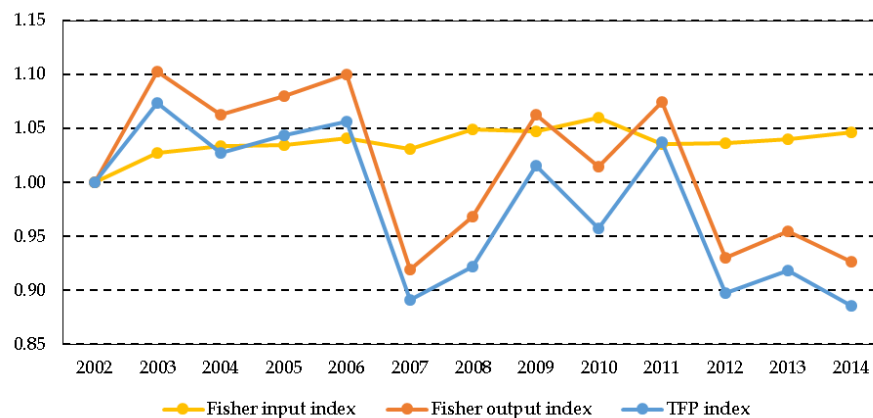
LEI believes that negative TFP trends can be “expected” for mature hydroelectric businesses, because of the fixed production capability, fixed capital stock and rising costs of maintenance through the life cycle of a hydroelectric resource. As discussed earlier in Section 3.1, common drivers of productivity 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).

⁶⁹ Assuming constant water flow levels over the course of the study and given generator design is fixed once the asset is brought into service, unless there are refurbishments that increase output.

6.2.2 Industry TFP results using the trend regression method

The trend regression method estimates the linear trend in the observed TFP index values over time. The slope of the linear regression on the TFP index is the estimate of average TFP growth rate. This method can be useful in establishing average trends in instances where a series exhibits volatility at its endpoints. For the purposes of this study, the year-over-year changes in the output index, visible in Figure 28 below, appears to be the main driver for annual changes in the TFP index value. Such a degree of movement in the output index presents a case for calculating growth using the ‘trend regression’ method.

Figure 28. Fisher input, fisher output, and TFP index values



As discussed in Section 3.2.2, the ‘trend regression’ method estimates TFP growth rate for a study period by first taking the natural logarithm of TFP index values (index values are visible in Figure 28), then carrying out a linear regression of the natural logarithm of the TFP index values against the number of years of the study period (from 0 to 12) and a constant term.

Figure 29 illustrates the final formula for calculating the TFP growth rate using this method, while Figure 30 provides a visual representation of the results from this process; the slope of the line is the estimate of TFP growth rate from 2002-2014 using the ‘trend regression’ method.

Figure 29. Equation of line under ‘trend regression’ method

$$\ln(\text{industry TFP index}) = -1.18\% * T + 5.89\%$$

Where:

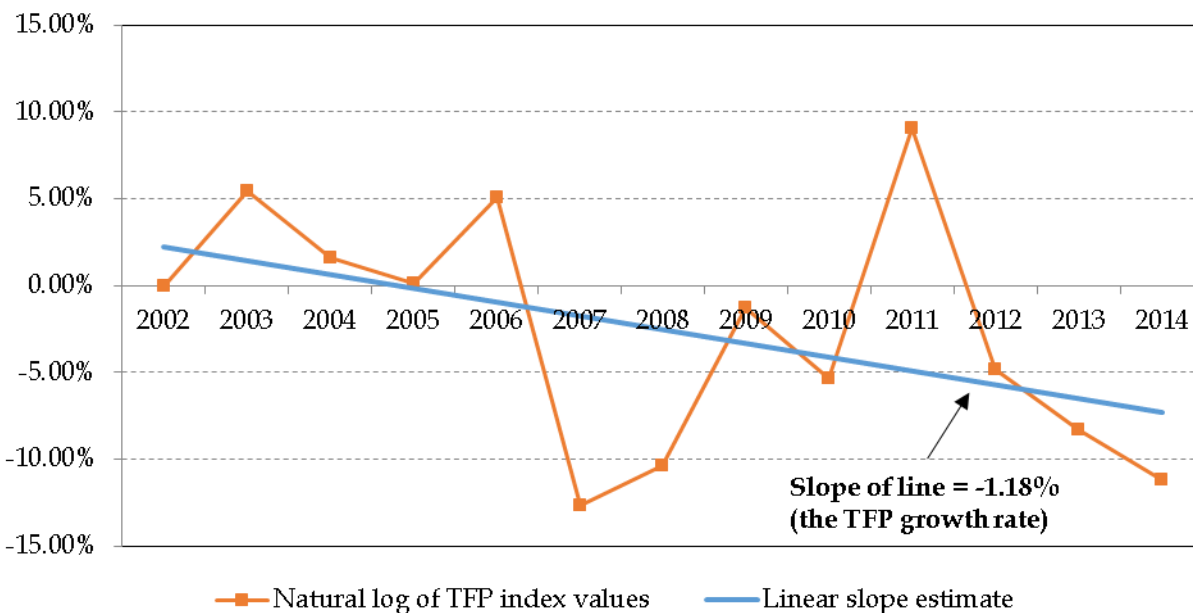
$\ln(\text{industry TFP index})$ = natural logarithm of TFP index values from 2002 – 2014

-1.00% = trend growth rate for the industry TFP index over the study period

T = time in years (0, ...,12)

5.89% = constant term

Figure 30. Natural log of TFP index values and linear slope estimate



This same method of analysis can be carried out on the input and output index values to calculate their respective growth rates under the ‘trend regression method’. As summarized in Figure 31, using the trend regression method, the input index growth rate of 0.22% and the output index growth rate of -0.96% combined into a study-period estimated annual TFP growth rate of -1.18%. Recall, using the average growth method, the input index growth rate of 0.38% and output index growth rate of -0.64% combined into a study-period estimated annual TFP growth rate of -1.01%. Therefore, both methods produce very similar TFP growth rate estimates over the 2002-2014 period.

Figure 31. Key TFP study results using the trend regression method

Industry index growth estimates (2002-2014)		
Input Index	Output Index	TFP Index
0.22%	-0.96%	-1.18%

6.3 Discussion of outlier peers

In a multi-firm analysis of this nature, numerical differences when comparing individual peer TFP growth rates should generally not be given too much significance. The index method is not a statistical technique – the key conclusions should be driven by observed trends and overall trajectories or ranges rather than precise numerical results. Still, in order to identify any potential outlier peers, LEI performed a sanity check by considering whether individual peer results lie within one standard deviation from the mean.

Based on this method of calculation, the upper bound using the ‘average growth’ method was found to be 3.41%% and the lower bound -5.98%. Most of the 16 peers, including OPG and eleven US peers, fall within the “normal” range of average TFP growth rates. However, a total of four peers fall outside the “normal” range; two of these peers are outliers on the positive side, and two are on the negative side. The general cause of outlier status for the four peers was sharp year-over-year changes in net generation for some years during the study period, generally caused by varying water conditions.

Using the ‘trend regression’ method of calculating TFP growth, the upper bound was found to be 2.63% and the lower bound -4.99%. A total of six peers fall outside these standard deviation bounds, three on the positive side and three on the negative side; the remaining ten peers (including OPG) fell within the “normal” TFP range.

LEI notes that although there is some variation in the company-specific results, the industry-level TFP trends are relatively stable and can be concluded to be reliable. The use of two different growth measure calculation methods improves the overall robustness of the industry TFP study – especially as the two methods result in very similar industry TFP results. Most positive and negative outliers were relatively small peers that had a minimal impact on final results. LEI has reviewed outliers, and while it is important to explain the impact outliers could have on the study, these firms should not be excluded. This belief is supported by the skewness of the TFP results after eliminating the outlier peers from their respective growth measure groups, increases from -1.01% to -0.73% using the ‘average growth’ method, and rises from -1.18% to -0.91% using the ‘trend regression’ method.

7 Concluding remarks

On March 28, 2013, the OEB issued a report (EB-2012-0340) outlining its policy directives and next steps for implementing IR for OPG's prescribed assets. In their report, the OEB anticipated that OPG's regulated hydroelectric business will move to an IR regime, and directed OPG to file a work plan and status report for an independent productivity study in the next application to set payment amounts. To fulfill this directive, OPG retained LEI in late 2013 to assist in performing the productivity study on OPG's prescribed hydroelectric assets. This report was written to share findings of LEI's research and TFP study on the North American hydroelectric generation industry.

LEI estimates that, for an industry peer group consisting of OPG and 15 US hydroelectric generators, using data from 2002-2014, the industry TFP growth over the study period timeframe in the range of -1% per annum (more precisely, it is -1.01% using the average growth method and -1.18% using the trend regression method). LEI notes that negative TFP results can be expected for a TFP study on a mature hydroelectric industry. Additionally, LEI cautions against viewing TFP results in the same way as one would a benchmarking study, as well as against comparing individual TFP results to that of the industry. Going forward, LEI believes that this TFP study can be used to inform the productivity growth rate assumptions under the I-X regime.

8 Appendix A: Two-Output model

As discussed in Section 4.1, as a sensitivity test, LEI also constructed a two-input/two-output model for a subset of the industry in its December 2014 TFP study. The two-input/two-output model was built on the dataset of the two-input/one-output model, with the addition of the Availability Factor (“AF”) as a second output, for the 2002-2012 timeframe.⁷⁰

Availability Factor is defined by NERC as “The fraction of a given operating period in which a generating unit is available without any outages.” Because AF data is reported as a percentage, it needs to be converted into a level measure in order to be used as an output. This conversion was done by multiplying the AF percent by the number of hours in a year (8,760), giving a figure that represents annual hourly availability of a generating unit.

Note that NERC AF data was not available for all plants and peers used in the two-input/one-output model. In summary, only 10 out of the 16 peers were included in the two-output/two-input model because there was insufficient data for the remaining 6 firms. The constraint on AF data also led to reduced values of O&M, Generation and Revenue for some of the peers (where AF statistics were not available for some plants).

A major consideration in performing a two-output model is that it required that weights be assigned to each output. Revenue shares were not readily available as most plants are not separately compensated for generation and availability. Therefore, LEI tested different weights for MWh and AF, ranging from every 25% interval from 0% to 100%.

In summary, the two-input/two-output model with 50% weight assigned to Net Generation (MWh) and 50% to AF results in an industry TFP growth rate of -1.34% using the average growth method and -1.11% using the trend regression method. Additional results for this two-input/two-output model are shown in Figure 32. It should be noted that the results for the 100% MWh scenario using this dataset are more negative than the single output model TFP results because the six peers that were dropped generally had higher (more positive) TFP growth rates.

LEI decided against using AF in the final TFP model because adding AF as a second output reduced the size of the peer group from 16 to 10, and because “availability” as an output would already be captured in generation data due to the interrelationship between production and overall annual availability.

⁷⁰ The two-output model has not been updated for 2013-2014 data.

Figure 32. Two-input/two-output model (with smaller peer group due to availability of data)

Model Specifications	Industry TFP growth (2002-2012)	
	Using average growth method	Using trend regression method
Total O&M and Capital vs MWh	-1.63%	-1.29%
Total O&M and Capital vs 75% MWh and 25% AF	-1.48%	-1.20%
Total O&M and Capital vs 50% MWh and 50% AF	-1.34%	-1.11%
Total O&M and Capital vs 25% MWh and 75% AF	-1.19%	-1.02%
Total O&M and Capital vs AF	-1.05%	-0.94%

9 Appendix B: Lessons learned and challenges through review of economic literature on productivity studies

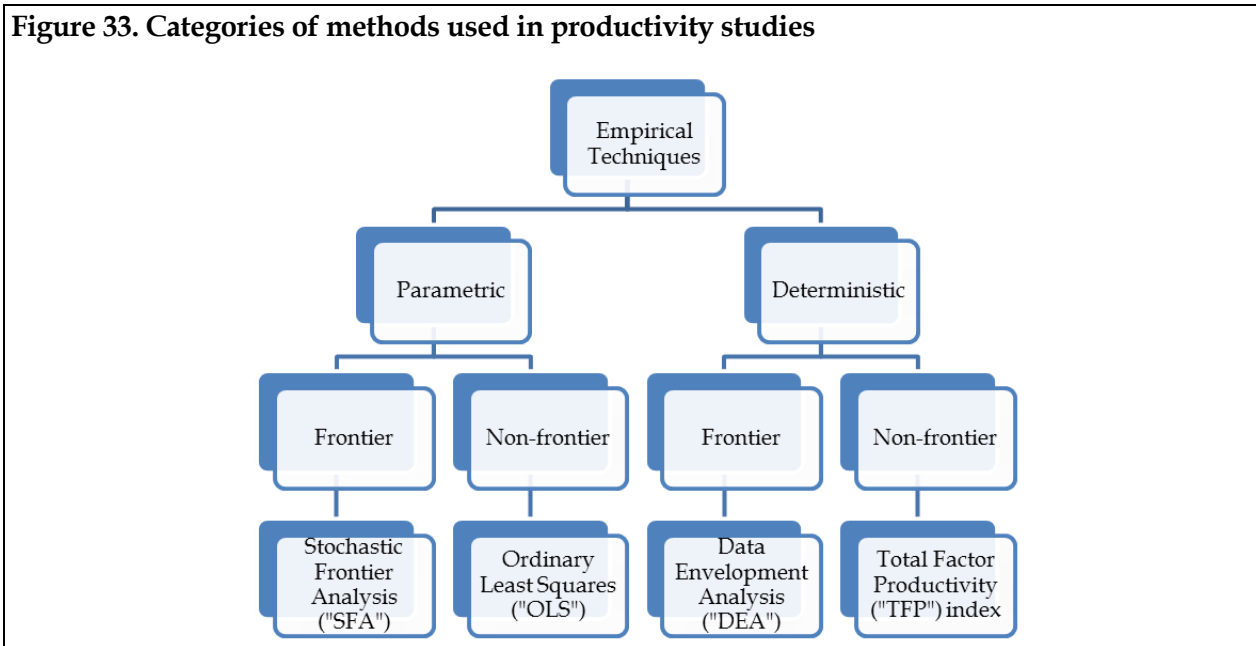
As part of the research phase of this study, LEI reviewed a number of previous studies that analyzed productivity of generation, distribution, transmission sectors, or electricity sector as a whole. For each study, data used, method employed, TFP composition (inputs and outputs), and study conclusions were summarized. This section presents the key findings of the review.

9.1.1 Methods for measuring productivity

The following section is an introduction to the various methods in performing a TFP study, specifically methods seen in the review: stochastic frontier analysis (“SFA”), Data Envelopment Analysis (“DEA”), and TFP indexes. They can be broadly categorized into deterministic methodologies, which “calculate” TFP, and econometric methodologies (which are also known as parametric methods), which “estimate” TFP.

TFP study methods can also be categorized into frontier and non-frontier. Frontier methods assume that production units do not fully use existing technology. These methods are able to break productivity growth down into technical change and efficiency change; technology changes can push the frontier upwards, while efficiency changes are productivity improvement, given the same technology. On the other hand, non-frontier methods assume that production is always efficient, and equates potential level of production at each moment in time. These methods do not separately estimate technical change and efficiency change.

Figure 33. Categories of methods used in productivity studies



First introduced by Charnes et al in 1978, DEA is a linear programming technique which identifies best practice within a sample by fitting a frontier over the top of the data points; relative efficiencies are measured from less efficient firms with respect to the frontier. As seen in

the review, it is a method which is more popular in academic studies of generating units, given the amount of detail it can provide, which is discussed further below. It is often used with a Malmquist index, which measures productivity change between two points in time.

Figure 34. Common Indexing Techniques

Laspeyres Index:

- Named for French economist Etienne Laspeyres
- Indexation method in which all input and output values are weighted at base year prices to ensure consistent price comparisons
- Becomes an increasingly inappropriate methodology as the time interval and/or price variability increases

Paasche Index:

- Named for German economist Hermann Paasche
- Indexation method similar to the Laspeyres method except that all input and outputs are value at their end of period prices to ensure price consistency
- Also becomes increasingly inappropriate as the time interval increases and/or the price variability increases

Fisher Index:

- Named for American Economist Irving Fisher
- Attempts to minimize the inaccuracies inherent in the Paasche and Laspeyres methods of price indexation by weighting all input and output prices by the geometric mean of base year and end of period prices
- The geometric mean involves the square root of the product of base year and end of period prices
- In a TFP period scenario, a Fisher Indexation TFP calculation can also be calculated as the geometric mean of the TFP calculations resulting from Paasche and Laspeyres indexation techniques

Törnqvist index:

- Attributed to Finnish economist Leo Törnqvist and is commonly used in TFP studies
- Approximates the Fisher indexation method whereby indexes are formed by each component's weighted geometric mean, relative to a base year, in which weights are equal to the components average cost share
- Typically analyzed in logarithmic format

Malmquist Index:

- Initially introduced in: "Multilateral Comparisons of Output, Input and Productivity Using Superlative Index Numbers", by Douglas W. Caves, Laurits R. Christensen and W. Erwin Diewert in 1982 but named for Swedish economist Sten Malmquist
- Parametric method that uses techniques similar to DEA to construct an efficient frontier which changes annually, thus measuring productivity relative to the previous year
- Classifies efficiency into technical change and efficiency change aspects
- One advantage is that it does not require price or cost information so is often in used when there are data limitation

One of the most important benefits is that the DEA is able to decompose cost efficiency into component parts, breaking down allocative and technical efficiencies. Technical efficiencies can be in turn decomposed into scale and pure technical efficiencies. This allows researchers to identify the best role models and make recommendations on improving efficiency. As well, it is

not required to specify the functional form of the production relationship, and depending on the which version of DEA is used, it is often not necessary to specify prices or weights for inputs and outputs. Specifying weights is often one of the more challenging aspects of measuring productivity.⁷¹ Finally, this method can easily deal with multiple inputs and outputs.

In terms of weaknesses, DEA is particularly sensitive to error in measurement error for frontier firms, since DEA uses these firms to derive efficiency. DEA also requires a large dataset, where a rough rule of thumb is that the number of observations needs to be at least three times the sum of the number of outputs and inputs to get worthwhile results. Finally, DEA has not typically been used to determine X-factors in regulatory proceedings, which can be related to them being difficult to explain, being regarded as a 'black box', and poor experiences with DEA by the regulators in the early years.

TFP index methods measure the ratio of all outputs to inputs, where input and output indexes are constructed using both quantities and prices of outputs and inputs. Traditionally, it can be used to compare rates of change of productivity but not absolute levels, though more recent developments have overcome this shortcoming. Benefits are that it is a relatively simple and robust technique, and thus it is often used for regulatory proceedings. As well, index number methods can incorporate many inputs and outputs with few observations. However, it requires values for all outputs and inputs. As well, it is not able to break down efficiencies into its component parts, such as scale efficiency or technical efficiency.

SFA is an econometric method which recognizes that some of the difference between a firm's actual costs and the line of best fit are due to random events rather than inefficiency. Like DEA, SFA is also able to break down efficiencies into its component parts, such as scale efficiency or technical efficiency. Finally, it is able to separate the error term in the stochastic production function into two elements - genuine inefficiency and random fluctuations.

In terms of disadvantages, SFA is an econometric method, which is generally more complex, difficult to communicate, and require significant data. They are therefore not typically used as frequently by experts performing productivity studies for ratemaking or other regulatory purposes. Rather, they are more often used in academic studies.⁷² Furthermore, they require specification of production or cost function, and although they recognize randomness in the line of best fit, if there are in fact no measurement errors in the sample, some inefficiency would be regarded as noise.

⁷¹ The cost efficiency version of DEA requires specification of output and input weights in the DEA data set.

⁷² OECD. *Measuring Productivity: Measurement of aggregate and industry-level productivity growth*. 2001.

9.1.2 Selecting the index TFP method

In order to choose the optimal TFP method, LEI reviewed eighteen TFP studies on electricity generation companies and distribution utilities, and has summarized the lessons learned in this section. Four different methodologies for measuring productivity were used in the studies reviewed which cover the most common methodologies. In order to summarize the studies reviewed, LEI aggregated information from all 13 generator academic studies, 1 government consultation and 4 regulatory productivity studies.⁷³ Many methods were reviewed for measuring productivity, but TFP index methods are most popular for regulatory purposes; although DEA is widely used for academic generation studies, its advantages are not useful in regulatory proceedings.

It is clear that DEA and TFP index methods are the most common in the utility industry. It is also clear that academic studies favour DEA. Multiple academic studies highlighted DEA's ability to break down inefficiencies and offer more detailed analysis, which allowed researchers to identify role models and make recommendations on improving efficiency. This is also an advantage for using SFA. However, these advantages are not particularly relevant for regulatory purposes, and the breakdown of efficiency into technical and allocative is not important for setting an X-factor. From this perspective, no method has a clear advantage in terms of results, which may explain why the DEA method was not seen in our selected regulatory studies.

It is important to note as well that both DEA and SFA are generally complex and difficult to communicate conceptually. The issue of complexity is particularly true in the case of econometric (and semiparametric) methods such as SFA and SPSC. These more complex methods are more often used in academic studies for their various benefits discussed above. However, because they can be difficult to explain in layman terms and are considered a 'black box', DEA, SFA and SPSC methods are not often used in government consultations and regulatory studies. Index methods on the other hand are easier to communicate because people can more easily understand the concept of taking weighted averages of output and input quantities, which is an advantage for regulators. This is one of the explanations for the popularity of index methods in regulatory work.

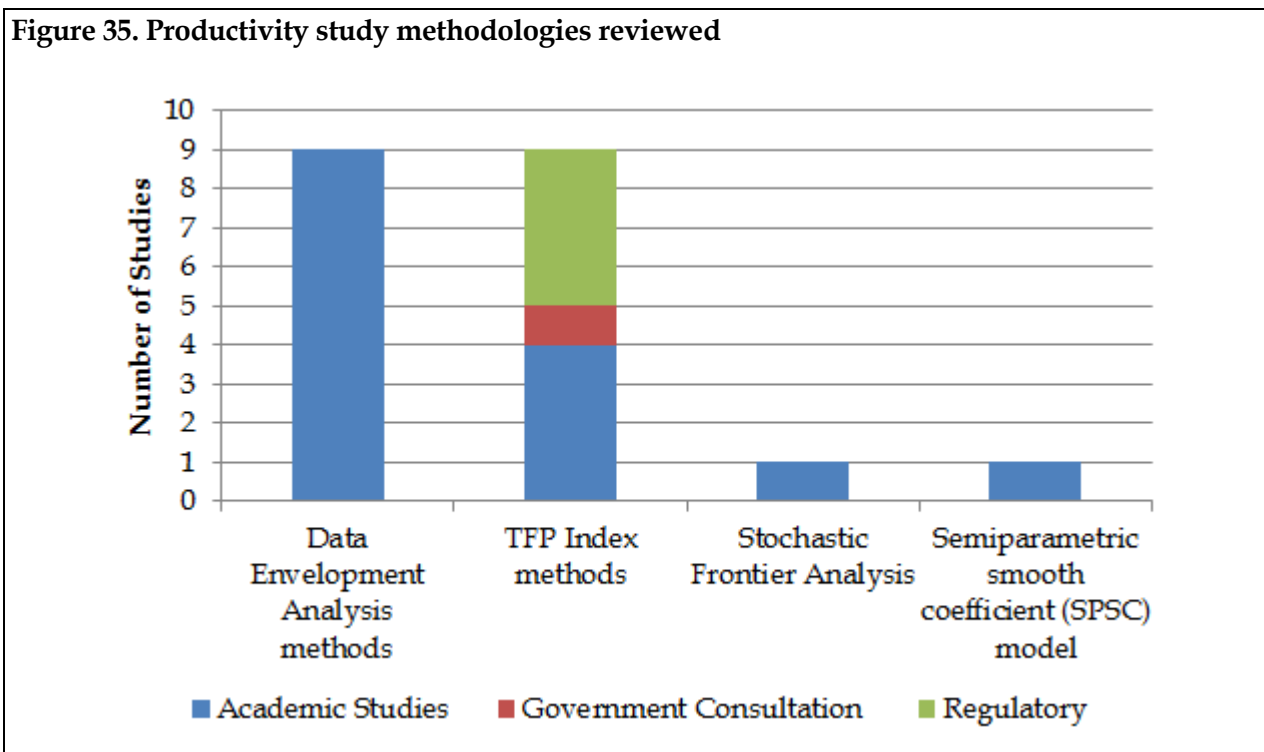
Data wise, it is also important to note that DEA is very observation intensive. For sensible results using DEA, with a reasonable number of outputs and inputs, one needs many observations, which may prove to be an issue within OPG's peer group. Index number methods, on the other hand, can incorporate many outputs and inputs with only a few observations. Finally, index number methods are also somewhat less sensitive to outlier observations and data errors, or at least the effects are more immediately obvious with index number methods.

⁷³ Note that some studies used multiple methods.

To summarize, the indexing method is less complex, easier to communicate, and requires significantly less data than the other measuring techniques. While DEA and TFP methods are both commonly used for the electricity industry, DEA is less practical from a regulatory perspective, given its primary advantage is limited in value for setting an X-factor, it requires more data, and it is difficult to communicate. The indexing method, due to its transparency and relative simplicity, is most often the method of choice for productivity studies performed for regulatory purposes. Furthermore, in Ontario, the OEB has used the index methods for distributors. For these reasons, LEI believes the Index method is the optimal choice for measuring TFP in this study.

9.1.3 Selecting a TFP method: Review of previous studies

In order to choose the optimal TFP method, LEI reviewed eighteen TFP studies on electricity generation companies and distribution utilities, and has summarized key lessons learned in this section (for more detail see Section 9.1.2). TFP index methods were most popular for regulatory purposes, while DEA was widely used for academic generation studies but less so for regulatory proceedings.



While DEA and TFP methods are both commonly used for the electricity industry, DEA is less practical from a regulatory perspective, given its primary advantage is limited in value for setting an X-factor, it requires more data, and it is difficult to communicate. The indexing method, due to its transparency and relative simplicity, is most often the method of choice for productivity studies performed for regulatory purposes. Furthermore, in Ontario, the OEB has

used the index methods for incentive regulation of distributors. For these reasons, LEI believes the Index method is the optimal choice for measuring TFP in this study.

9.1.3.1 Outputs used in TFP studies

As part of the review of 18 other productivity studies, LEI also looked at what outputs were commonly used. Despite the differences between the studies as far as methods and subject matter, there were many similarities in what was used as outputs. LEI has aggregated the parameters used by the studies related to generation, leaving out any transmission and distribution companies, as they have completely different parameters. This is summarized in Figure 36 and Figure 37 below. The most common output is energy generation in MWh, as that is what is being produced by every power plant. LEI also notes that generation data is readily available and can be consistently measured across a peer group. In two fossil fuel studies, pollutants were captured as a negative output; however, this will not be applicable to hydroelectric plants.

Figure 36. Outputs used in generation productivity studies

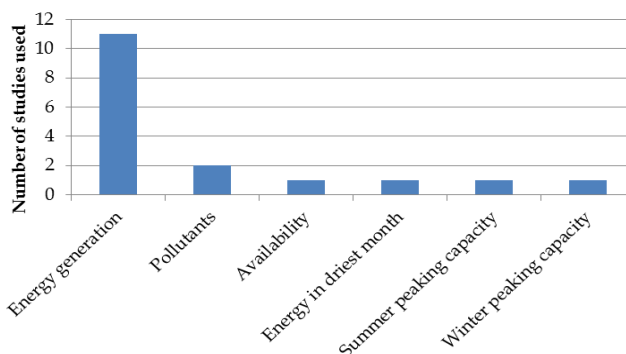


Figure 37. Example of outputs used in generation productivity studies

Outputs	Examples
Power Produced	<ul style="list-style-type: none"> • Generation (MWh) • Output in specific periods (e.g., to support resource adequacy)
Ancillary Services	<ul style="list-style-type: none"> • Reactive support/voltage control • Automatic Generation Control • Black start • Reliability must-run
Reliability	<ul style="list-style-type: none"> • Availability • Forced outage rates
Other Services	<ul style="list-style-type: none"> • Sale of ancillary services • Water management • Added flexibility to system

9.1.3.2 Inputs used in TFP studies

A review of the inputs used in eighteen previous productivity studies can be seen in Figure 38 and Figure 39 below. The most common input observed for generation related productivity studies was capacity (as a measure of capital). Specifically, capacity in MW is very commonly used as a proxy measure. Capital can also be measured using replacement cost, but is much less common – in fact, nearly every study used capacity as a measure of capital. Further discussion on physical as compared to monetary measures of capital can be found in Appendix C Section 10.

Figure 38. Inputs used in generation productivity studies

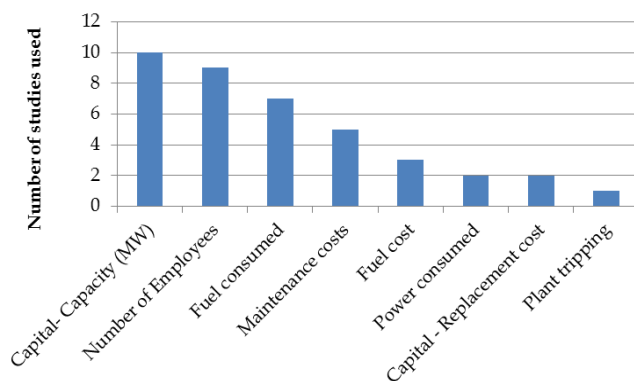


Figure 39. Example of inputs used in generation productivity studies

Inputs	Examples
Capital	<ul style="list-style-type: none"> Physical measure: Plant Capacity (MW) Monetary measure: Depreciated or replacement value of capital stock
Operations and Maintenance	<ul style="list-style-type: none"> Operations and Maintenance (O&M) without labour costs Operations and Maintenance (O&M) with labour costs
Labour Employed	<ul style="list-style-type: none"> Number of Employees Wages (\$)
Other Costs	<ul style="list-style-type: none"> Power consumed Environment and regulatory

The second most common input is number of employees, which captures the labour involved in power production. LEI decided against using number of employees in favour of O&M costs due to data limitations (employee figures were not readily available for all US peers). Labour costs were captured already in O&M costs and also in the input price indices. Another important

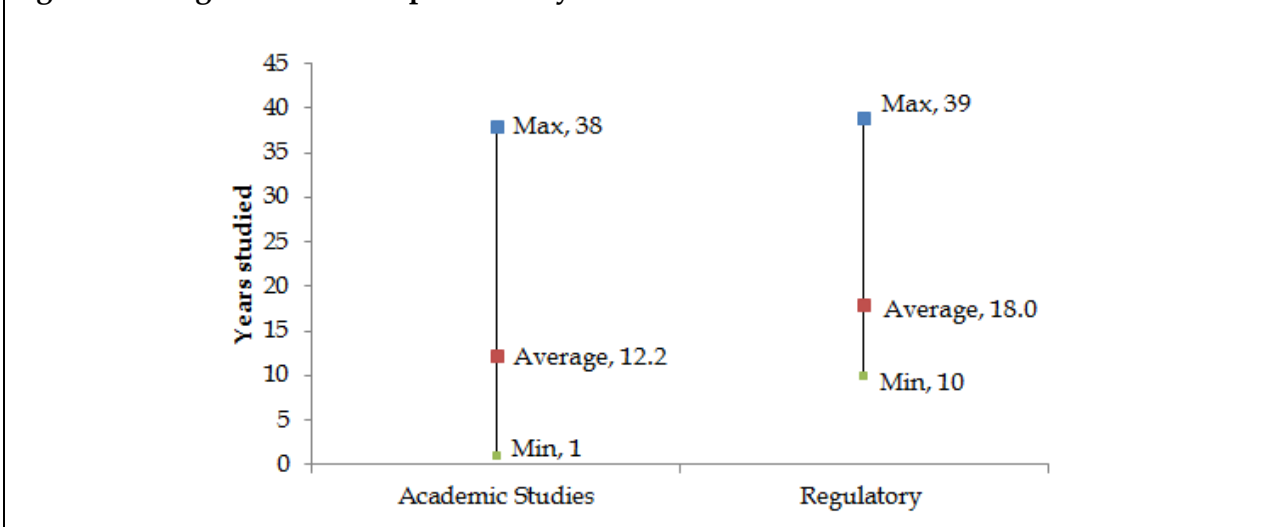
input is fuel, whether it is captured by fuel consumed (often in joules), power consumed (in MWh) or in terms of annual fuel costs. However, this method is more important when looking at thermal generation plants, and is not relevant the context of a hydroelectric TFP study.⁷⁴

9.1.3.3 Length of TFP studies

LEI reviewed eighteen TFP studies sourced from academia as well as TFP studies performed for regulatory filings to aid in the determination of an appropriate period of study; Figure 40 shows the range in study period timeframe.

It is clear from the studies reviewed that a set of data which spans ten years or more is common for productivity studies. Although some academic studies have very short study periods, this can often be attributed to the purpose of the study, which is to make conclusions about the productivity method, rather than making a conclusion about productivity trends (which must be backed by a sufficiently large dataset). This can be observed in the fact that regulatory studies all used a study period of over 10 years.⁷⁵

Figure 40. Length of reviewed productivity studies



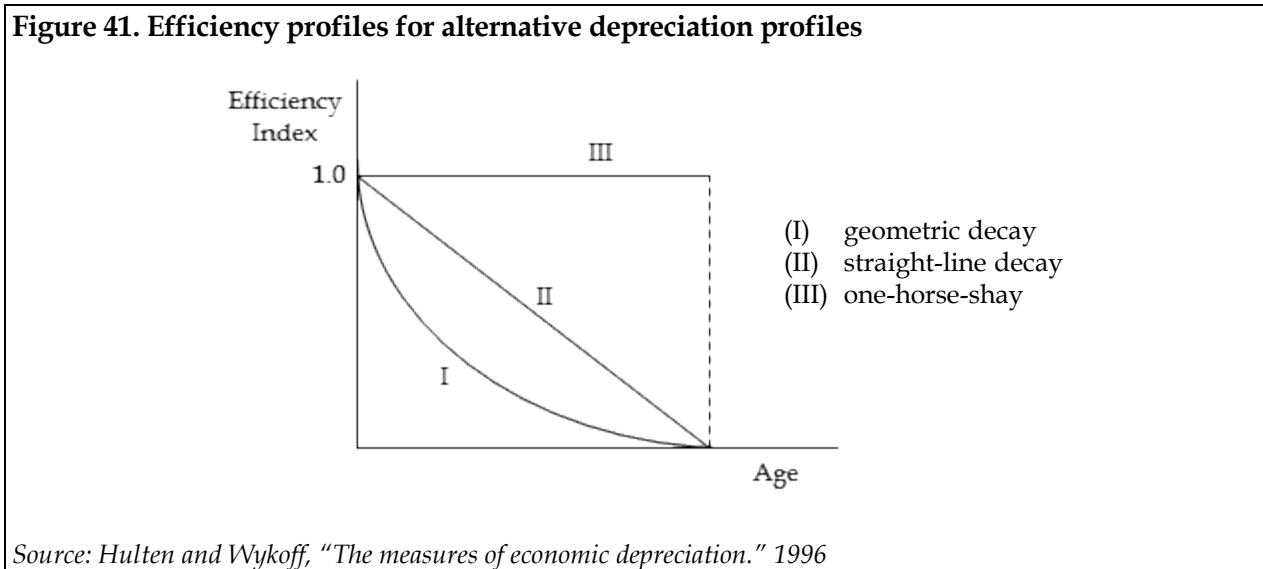
⁷⁴ ‘Water for power’ or water rental rates are more of flow-through items in the regulatory arrangement of hydroelectric operators and therefore do not affect productivity.

⁷⁵ LEI notes that the Pacific Economics Group (“PEG”) report on productivity trends for Ontario electricity distributors, presented to the OEB in November 2013, also estimated TFP trends over the 2002-2012 period

10 Appendix C: Capital input quantities, physical or monetary approach

Selecting the appropriate inputs and outputs is a key part of a TFP study. As discussed in Section 4, for the hydroelectric business, one of the important inputs to production is capital. There are two possible methods for estimating capital input quantities: a physical method and a monetary method. The monetary method uses depreciated asset values in constant price dollar terms while the physical method uses physical indicators such as MW of capacity.

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. However, depreciated asset value methods do suffer from certain analytical subjectivity. For example, in order to approximate the capital input quantity under the monetary approach, one needs to employ a depreciation assumption – typically studies use either a declining balance or straight line depreciation assumption. 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, as illustrated in Figure 41 below.



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 given the changes in corporate structures and ownership as a result of deregulation and restructuring. The data necessary includes: benchmark capital stock, capital additions since the base year, approved rate of return since the base year, and rate of depreciation. Generally, because measurement of capital depends on a benchmark of capital stock, many more years of data are required beyond the official start year of the TFP analysis in order to allow for an accurate capital measure under the monetary approach. Based on industry practice, a significant number of years of data is typically required (above and beyond the TFP

study timeframe) in order to estimate the capital input quantities. For example, in the electricity distribution sector, PEG used a capital benchmark year of 1989.⁷⁶

In contrast, the physical method is straightforward if the capital input of the business can be adequately measured using physical proxies. For the generation-related TFP studies, it is common to use the installed capacity (in terms of MWs) to represent the capital input of the business. This is a readily available metric and comparably measured across companies and over time. Therefore, using the physical method of measuring capital (i.e. plant capacity in MW) was selected as the appropriate method for the purposes of this study.

⁷⁶ PEG. *Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board*. Issued November 2013. http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2010-0379/EB-2010-0379_Final_PEG_Report_20131111.pdf

Hydro Benchmarking Study

Presented to:

Ontario Power Generation Inc.

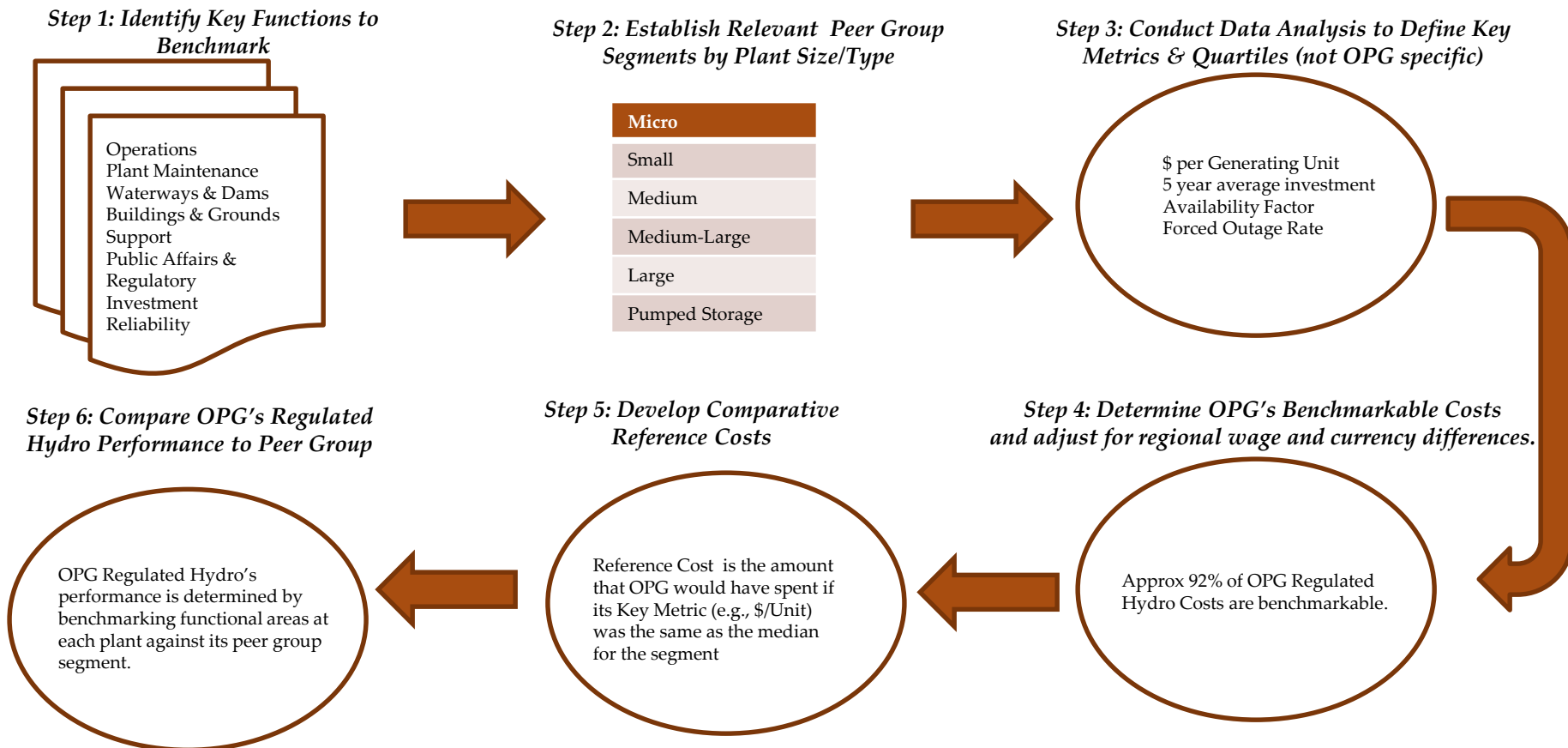


August 17, 2015 FINAL



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



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

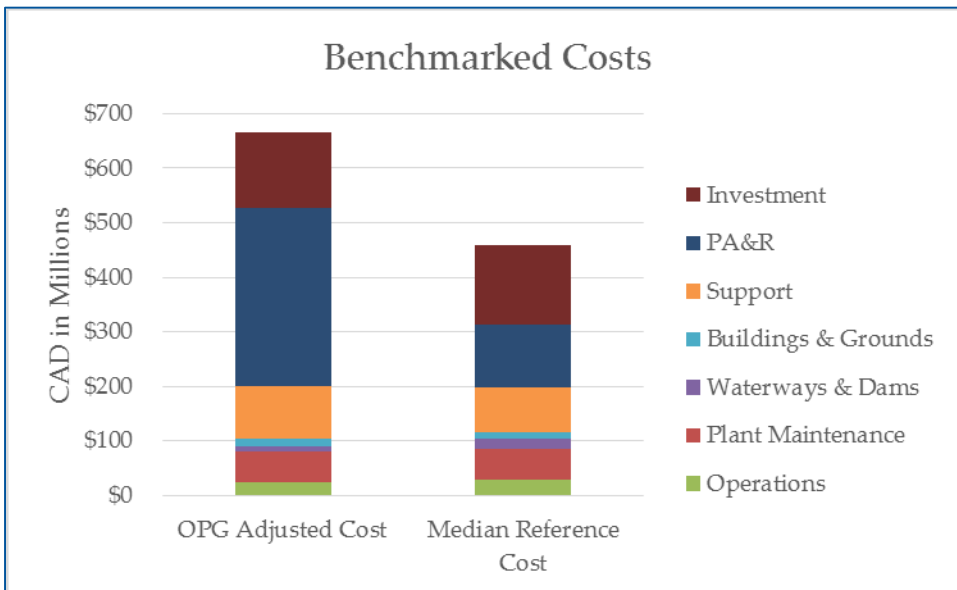
- » OPG’s cost performance by functional area and reliability metric are shown in the table below.
- » The Partial Function⁽²⁾ metric is considered by Navigant to be the key cost metric for benchmarking purposes because it includes the functions that are regularly performed at all hydro plants.
- » The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

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

Top Quartile
Second Quartile
Third Quartile
Bottom Quartile

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

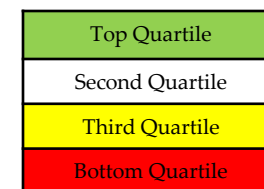
On the key Partial Function cost metric, benchmarked costs were lower than the Reference Cost.



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

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

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



OPG Regulated Hydro had Partial Function Costs that were 99% of the Median Reference Cost.

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Cost Category	OPG Adjusted Costs as a % of Reference Cost
Operations	82%
Plant Maintenance	92%
Waterways & Dams	54%
Buildings & Grounds	120%
Support	117%
<i>Partial Function</i>	99%
Public Affairs & Regulatory	284%
<i>Total Function</i>	166%
Investment	96%
<i>Total Costs Benchmarked</i>	144%

- » OPG's PA&R costs are significantly higher than the median at most locations and is the primary driver for OPG's higher than median total costs.⁽¹⁾

(1) The largest components of OPG's regulated Hydro electric 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.

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Program History / Peer Group Composition

» Navigant's Annual GKS Hydro Benchmarking Program

- The program was initiated in 1994 and has been run annually since then.
- Data base is cumulative, utilizing the most recent data for each station, or groups of stations, in the data base.
- As improvements in the measurement framework and methodologies were implemented, all data in the data base was recast accordingly. Data is adjusted annually for inflation.
- In addition to the cost comparisons, Navigant also maintains a comprehensive practices data base of leading performers.

» Peer Group Composition

- The data base includes over 450 stations owned by 42 companies, comprised of 1,600 units that represent ~100,000 MW of installed capacity.
- Participants are predominately from the United States and Canada.
- The peer group is diverse in size, type of facility and age, and includes a mix of run of river, reservoir and pumped storage stations.
- The stations are grouped into approximately 222 station groups excluding OPG. Study results are presented on a station group basis. Most station groups consist of a single plant.

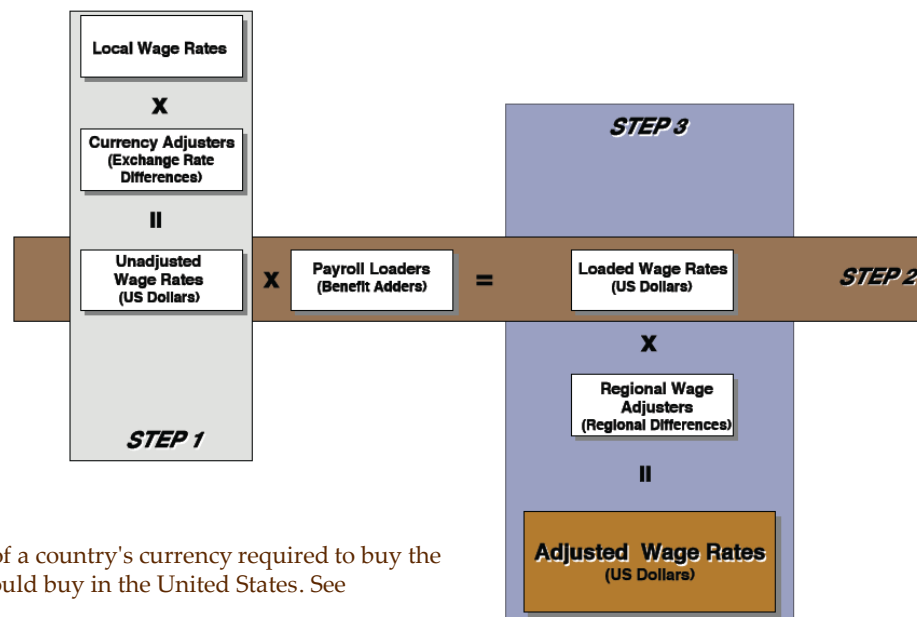
	Peer Group	OPG
# of Station Groups	222	54
Median Station Age	45 years	84.5 years
Median Station Group Size	152 MW	10 MW
Median Unit Size	37 MW	5 MW

» Unit Costs

- Cost measures quantify the cost of each function, on a comparable unit-of-output basis, across the panel participants.
- Cost adjustments are made to account for Purchasing Power Parity (PPP)⁽¹⁾ and differences in regional wages.
- All other differences, such as station type, capacity or unit size, and age are dealt with by grouping similar stations together for comparisons.

» Service Level Measures

- Service level measures are calculated to quantify how well the function is accomplishing its goals.
- In plant maintenance, for example, forced outage rate and availability factor are used as measures of how well the stations have been maintained.



(1) The Purchasing Power Parity (PPP) conversion factor is the number of units of a country's currency required to buy the same amount of goods and services in the domestic market as a U.S. dollar would buy in the United States. See <http://data.worldbank.org/indicator/PA.NUS.PPPC.RF> for details.

Functions Benchmarked

Function	Definition	Primary Metric
Operations	All activities associated with the day-to-day operations of station	\$/Unit
Plant Maintenance	All activities associated with the maintenance of rotating equipment and non-rotating electrical components of the plant up to the headgate or final valve	\$/MWh
Waterway & Dam Maintenance	All activities associated with the maintenance of the waterways, dams, and penstocks up stream of the headgate or final valve	\$/MW
Buildings & Grounds Maintenance	All activities associated with the maintenance of non-production facilities	\$/MW
Investment	Major projects undertaken to restore a facility to its original design or operating and maintenance characteristics, provide additional capacity, or improve operating and maintenance characteristics	\$/MW
Support	All services (excluding engineering) provided by plant or off-site personnel who support hydro or whose costs are allocated to the hydro business	\$/MW
Public Affairs & Regulatory	All activities associated with managing regulatory, environmental, and community issues and providing services required by the water use franchise	\$/MW
Total Function Cost	All of the above except Investment	\$/MWh
Partial Function Cost	All of the above except Investment and PA&R	\$/MWh
Availability Factor	% of the period that the plant was available for generation	%
Forced Outage Rate	FOR = (hours unit out due to forced outage + hours unit out due to start-up failure) / (service hours + hours units out due to forced outage + hours out due to start-up failure).	%

Functions Not Benchmarked

Function	Definition	CAD in Millions
Adjustments to Pension/OPEB Related Costs	Adjustments to centrally held pensions and Other Post Employment Benefits (OPEB) obligations resulting from actuarial valuations based on demographics, projected interest rates, discount rates and return on investment. Note, current obligations for pensions and OPEB are included in the benchmarked costs.	\$38.7
IESO Non-Energy Charges	Non energy charges for withdrawal of electricity from the IESO grid. Includes transmission charges, debt retirement charge, rural or remote electricity rate protection charge, administration fee, OPA fees, uplift charges and Global Adjustment.	\$7.3
Electricity Sales & Trading	Costs for coordinating the offering of OPG's generation into the IESO market. Includes outage planning and strategies to optimize production based on market price signals and to manage generation risks.	\$3.8
Corporate Business Development	Costs for exploring the concept and definition of major generation development projects as well as other business development initiatives.	\$1.9
All Other		\$7.6
	Total Costs Excluded from Benchmarking	\$59.3

These cost categories are not benchmarked because they are not available and/or don't apply for the peer group. They have explicitly been excluded from the hydro benchmarking program as originally designed and subsequently confirmed by the program participants.

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Operations Cost

(Thousands of USD/Unit)	Total	Micro Hydro, Staffed	Micro Hydro, Automated	Small Hydro, Automated	Medium Hydro, Automated	Med-Large, Automated	Large Hydro, Automated	Pumped Storage, < 150 MW
Total OPG Regulated Hydro	87	13	37	71	100	163	303	146
Minimum	*	13	6	16	24	74	96	124
1 st Quartile	*	132	28	71	80	155	165	179
Median	*	203	42	95	108	211	241	202
3 rd Quartile	*	258	76	158	215	320	503	256
Maximum	*	288	432	1,324	1,057	713	1,002	432
Average	*	187	69	166	191	253	347	231

- » On average, OPG Regulated Hydro had lower than median Operations cost in all segments except for Large Hydro, Automated.
- » OPG Regulated Hydro had top quartile Operations performance in the Micro Hydro/Staffed, Small Hydro Automated, and Pumped Storage <150 MW segments.

Top Quartile
2 nd Quartile
3 rd Quartile
Bottom Quartile

* No single set of quartile and median values apply to groups of plants that cover multiple segments, since the reference costs vary for each segment.

Plant Maintenance Cost

(USD/MWh)	Total	Micro Hydro, Station Age >45 yrs	Small Hydro, Station Age >45 yrs	Medium Hydro, Station Age >45 yrs	Med-Large, Station Age >45 yrs	Large Hydro, Station Age >45 yrs	Low Use, <100 MW	Low Use, >100 MW	Pumped Storage, <150 MW
Total OPG Regulated Hydro	1.41	6.53	1.40	1.88	1.44	0.67	1.95	4.07	42.93
Minimum	*	1.72	0.63	0.69	0.65	0.49	0.95	1.17	1.54
1 st Quartile	*	3.57	1.71	1.22	0.68	0.71	2.03	2.32	4.04
Median	*	5.72	2.23	1.95	1.65	0.82	3.44	4.07	5.31
3 rd Quartile	*	9.33	2.93	2.84	1.98	1.09	12.13	4.89	16.41
Maximum	*	22.13	23.59	13.20	2.48	1.75	41.95	7.84	311.99
Average	*	7.28	3.29	2.67	1.46	0.96	9.05	3.93	47.73

- » On average, OPG Regulated Hydro had lower than median Plant Maintenance cost.
- » OPG Regulated Hydro had top quartile Plant Maintenance performance in the Small and Large Hydro >45 years old and Low Use <100 MW segments.
- » OPG Regulated Hydro had bottom quartile Plant Maintenance performance in the Pumped Storage <150 MW segment.

Top Quartile
2 nd Quartile
3 rd Quartile
Bottom Quartile

* No single set of quartile and median values apply to groups of plants that cover multiple segments, since the reference costs vary for each segment.

Waterways & Dams Maintenance Cost

(Thousands of USD/MW)	Total	Plant Size <200 MW	Plant Size 200-500 MW	Plant Size >500 MW
Total OPG Regulated Hydro	1.2	2.3	0.6	0.5
Minimum	*	0.1	0.2	0.1
1 st Quartile	*	2.2	0.8	0.6
Median	*	4.1	1.3	1.0
3 rd Quartile	*	10.2	2.7	1.4
Maximum	*	74.2	6.9	3.1
Average	*	8.5	2.2	1.1

- » On average, OPG Regulated Hydro had lower than median WW&D Maintenance Cost in all segments.
- » OPG Regulated Hydro had top quartile WW&D Maintenance performance overall and in the 200-500 MW and >500 MW segments.

Top Quartile
2 nd Quartile
3 rd Quartile
Bottom Quartile

* No single set of quartile and median values apply to groups of plants that cover multiple segments, since the reference costs vary for each segment.

Buildings & Grounds Maintenance Cost

(Thousands of USD/MW)	Total
Total OPG Regulated Hydro	1.9
Minimum	0.0
1 st Quartile	0.7
Median	1.6
3 rd Quartile	4.3
Maximum	77.0
Average	4.3

- » On average, OPG Regulated Hydro had higher than median Buildings & Grounds Maintenance cost.
- » A potential reason for higher B&G costs is that OPG operates regulated hydroelectric facilities across a large territory spanning the entire province and must maintain a significant portfolio of roads and bridges.

Top Quartile
2 nd Quartile
3 rd Quartile
Bottom Quartile

Support Cost

(USD)	Median Reference Cost M\$	K\$/MW	Adjusted Cost M\$	Variance M\$
Total OPG Regulated Hydro	66.2	11.8	77.3	11.1
Minimum	*	0	*	n/a
1 st Quartile	*	4.3	*	n/a
Median	*	10.1	*	n/a
3 rd Quartile	*	23.2	*	n/a
Maximum	*	317.3	*	n/a
Average	*	22.7	*	n/a

- » On average, OPG Regulated Hydro had higher than median Support Cost.
- » OPG’s Total Adjusted Support Costs were \$11.1 million higher than the Median Reference Cost.

Top Quartile
2 nd Quartile
3 rd Quartile
Bottom Quartile

* No single set of quartile and median values apply to multiple regions, since each region has its own set of values.

Partial Function Cost

(USD/MWh)	Total	Micro Hydro	Small Hydro	Medium Hydro	Med-Large	Large Hydro	Low Use, <100 MW	Low Use, >100 MW	Pumped Storage <150 MW
Total OPG Regulated Hydro	5.01	27.09	6.65	7.53	4.08	2.25	8.93	15.34	101.36
Minimum	*	5.96	3.51	1.41	1.73	0.63	4.31	4.77	6.68
1 st Quartile	*	13.45	5.76	4.04	3.08	2.08	9.61	7.68	14.18
Median	*	23.77	8.43	4.84	4.59	2.84	10.46	12.26	25.12
3 rd Quartile	*	37.25	15.17	8.29	5.67	4.96	27.37	15.48	47.18
Maximum	*	374.94	105.20	48.53	9.00	10.06	182.19	31.45	1,014.12
Average	*	35.93	13.84	7.77	4.80	3.52	33.26	13.54	153.37

- » On average, OPG Regulated Hydro had lower than median Partial Function Cost in the Low Use <100 MW, Small Hydro, Medium-Large Hydro, and Large Hydro segments.
- » On average, OPG Regulated Hydro had bottom quartile Partial Function Cost performance in the Pumped Storage <150 MW segment.

Top Quartile
2 nd Quartile
3 rd Quartile
Bottom Quartile

* No single set of quartile and median values apply to groups of plants that cover multiple segments, since the reference costs vary for each segment.

Public Affairs & Regulatory Cost

(Thousands of USD/MW)	Total
Total OPG Regulated Hydro	40
Minimum	0
1 st Quartile	3
Median	14
3 rd Quartile	27
Maximum	153
Average	20

- » On average, OPG Regulated Hydro had bottom quartile PA&R Cost performance.

Top Quartile
2 nd Quartile
3 rd Quartile
Bottom Quartile

Total Function Cost

(USD/MWh)	Total	Micro Hydro	Small Hydro	Medium Hydro	Med-Large	Large Hydro	Low Use, <100 MW	Low Use, >100 MW	Pumped Storage <150 MW
Total OPG Regulated Hydro	13.19	30.59	11.30	12.20	10.91	13.23	13.33	20.11	106.40
Minimum	*	6.04	4.12	2.23	1.78	0.68	4.49	5.77	8.42
1 st Quartile	*	20.95	10.02	4.33	6.48	5.85	12.52	9.02	17.11
Median	*	28.01	15.68	7.56	8.97	8.72	14.40	19.12	30.64
3 rd Quartile	*	41.25	22.75	14.47	11.61	12.35	35.19	22.15	53.59
Maximum	*	380.64	183.44	72.13	18.88	20.88	384.82	31.86	1,593.48
Average	*	40.93	22.70	11.99	9.37	9.26	59.79	17.01	229.47

- » On average, OPG Regulated Hydro had higher than median Total Function Cost in all segments except for Small Hydro and Low Use <100 MW.
- » OPG Regulated Hydro had bottom quartile Total Function Cost performance in the Large Hydro and Pumped Storage <150 MW segments.

Top Quartile
2 nd Quartile
3 rd Quartile
Bottom Quartile

* No single set of quartile and median values apply to groups of plants that cover multiple segments, since the reference costs vary for each segment.

Investment Cost

(Thousands of USD/MW)	Total	16-40 years old	41-65 years old	>65 years old
Total OPG Regulated Hydro	17	18	12	34
Minimum	*	1	0	1
1 st Quartile	*	5	7	12
Median	*	10	14	33
3 rd Quartile	*	17	31	136
Maximum	*	95	277	688
Average	*	14	30	91

- » On average, OPG Regulated Hydro had higher than median Investment cost in the 16-40 years old and >65 years old segments.
- » OPG Regulated Hydro had bottom quartile Investment cost performance in the 16-40 years old segment.

Top Quartile
2 nd Quartile
3 rd Quartile
Bottom Quartile

Availability Factor

(%)	Total	Micro Hydro, Station Age >45 yrs	Small Hydro, Station Age <45 yrs	Small Hydro, Station Age >45 yrs	Medium Hydro, Station Age >45 yrs	Med-Large	Large Hydro, Station Age >45 yrs	Low Use, <100 MW	Low Use, >100 MW	Pumped Storage, <150 MW
Total OPG Regulated Hydro	92.8%	80.5%	96.4%	91.3%	87.6%	92.2%	94.6%	85.7%	97.0%	82.1%
Maximum	100.0%	99.8%	100.0%	99.1%	98.5%	99.6%	95.4%	100.0%	99.6%	93.8%
1 st Quartile	95.7%	97.9%	95.9%	94.5%	94.3%	93.6%	91.0%	97.0%	97.2%	84.1%
Median	90.7%	91.2%	92.9%	91.4%	89.1%	90.1%	84.1%	92.6%	83.6%	78.4%
3 rd Quartile	81.5%	73.3%	86.5%	84.7%	82.3%	86.7%	77.2%	85.9%	78.5%	75.3%
Minimum	2.6%	6.7%	74.9%	25.4%	70.7%	68.4%	68.4%	75.0%	63.8%	35.5%
Average	86.6%	84.0%	90.7%	86.2%	87.5%	89.3%	83.1%	90.6%	85.5%	75.9%

- » On average, OPG Regulated Hydro had top quartile Availability Factor performance in the Small Hydro <45 years old and Large Hydro >45 years old segments.
- » OPG Regulated Hydro had bottom quartile Availability Factor performance in the Low Use <100 MW segment.

Top Quartile
2 nd Quartile
3 rd Quartile
Bottom Quartile

Forced Outage Rate

(%)	Total	Micro Hydro, Station Age >45 yrs	Small Hydro, Station Age <45 yrs	Small Hydro, Station Age >45 yrs	Medium Hydro, Station Age >45 yrs	Med-Large	Large Hydro, Station Age >45 yrs	Low Use, <100 MW	Low Use, >100 MW	Pumped Storage, <150 MW
Total OPG Regulated Hydro	1.3%	6.4%	1.5%	3.5%	1.0%	1.7%	0.4%	4.3%	0.2%	1.7%
Minimum	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	1.7%
1 st Quartile	0.3%	0.4%	0.6%	0.2%	0.2%	0.3%	0.4%	1.7%	0.1%	6.0%
Median	1.3%	1.8%	1.5%	1.0%	0.7%	0.4%	2.8%	4.3%	1.6%	13.0%
3 rd Quartile	4.1%	5.9%	3.8%	1.9%	2.3%	0.9%	11.6%	7.2%	4.8%	21.8%
Maximum	99.2%	93.0%	9.1%	50.8%	35.5%	17.6%	17.6%	55.6%	23.8%	74.7%
Average	5.4%	7.6%	2.6%	3.7%	2.4%	1.8%	6.2%	8.7%	5.0%	19.6%

- » On average, OPG Regulated Hydro had top quartile Forced Outage Rate performance in the Large Hydro >45 years old and Pumped Storage <150 MW segments.
- » OPG Regulated Hydro had bottom quartile Forced Outage Rate performance in the Micro Hydro >45 years old, Small Hydro >45 years old, and Medium-Large Hydro segments.

Top Quartile
2 nd Quartile
3 rd Quartile
Bottom Quartile

1	Executive Summary
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OPG has several areas where its benchmarked costs were notably greater than the Reference Costs .

- » OPG’s Regulated Hydro, Public Affairs & Regulatory (PA&R) costs were 284% of the Reference Cost. However, these costs are not controllable because they are primarily comprised of GRC.
- » At the segment level, OPG’s benchmarked costs were higher than the 3rd quartile Reference Cost (i.e., within 4th quartile) in the following areas:

Segments	Functions where Benchmarked Costs were Bottom Quartile	Potential Reasons (in addition to having a high Benefits Multiplier)
Pumped Storage, <150 MW	Plant Maintenance	Sir Adam Beck PGS is older, of a more complex design and had a lower capacity factor than the segment median ⁽¹⁾
All segments	Public Affairs & Regulatory	High Gross Revenue Charges
16-40 years old	Investment	Arnprior has smaller Station Capacity and Average Unit Size than the segment median ⁽²⁾

(1) Plant Maintenance Cost in \$/MWh increases with station age and decreases with increasing capacity factor. In 2013, Sir Adam Beck PGS (OPG’s only station in the <150 MW Pumped Storage segment) was 55 years old and had a 4.5% capacity factor, compared to the segment medians of 39 years old and 9.3% capacity factor.

(2) Investment Cost in \$/MW increases with decreasing Station Capacity and Average Unit Size. In 2013, Arnprior (OPG’s only station in the 16-40 Years Old segment) has a Station Capacity of 82 MW and Average Unit Size of 41 MW, compared to the segment medians of 204 MW and 55 MW.

OPG has several areas where its benchmarked costs were notably less than the Reference Costs.

- » OPG's Regulated Hydro Waterways & Dams Maintenance costs were 54% of the Reference Cost.
- » At the segment level, OPG's benchmarked costs were lower than the 1st quartile Reference Cost (i.e., within 1st quartile) in the following areas:

Segments	Functions where Benchmarked Costs were in the Top Quartile	Potential Reasons
Micro Hydro/Staffed, Small Hydro Automated, and Pumped Storage <150 MW	Operations	Low overtime & contractor %, Fewer Units per Station Group
Small and Large Hydro >45 years old and Low Use <100 MW	Plant Maintenance	Low overtime & contractor %, Higher capacity factors
200-500 MW, >500 MW	WW&D Maintenance Cost	Low overtime & contractor %

1	Executive Summary
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Database Station Listing (1 of 2)

Company	Station Group Name
AES-Brazil	Agua Vermelha
AES-Brazil	Bariri
AES-Brazil	Barra Bonita
AES-Brazil	Caconde
AES-Brazil	Euclides da Cunha
AES-Brazil	Ibitinga
AES-Brazil	Limoeiro
AES-Brazil	Mogi-Guaçu
AES-Brazil	Nova Avanhandava
AES-Brazil	Promissao
Algonquin Power Company	Eastern Quebec Region
Algonquin Power Company	New England Region
Algonquin Power Company	New York Region
Algonquin Power Company	Ontario Region
Algonquin Power Company	Western Canada Region
Algonquin Power Company	Western Quebec Region
BC Hydro	Ash River
BC Hydro	Bridge River 1-2
BC Hydro	Cheakamus
BC Hydro	Clowhom
BC Hydro	GM Shrum
BC Hydro	John Hart
BC Hydro	Jordan River
BC Hydro	Kootenay Canal
BC Hydro	Ladore
BC Hydro	Lake Buntzen One
BC Hydro	Mica
BC Hydro	Peace Canyon
BC Hydro	Revelstoke
BC Hydro	Ruskin
BC Hydro	Seton
BC Hydro	Seven Mile
BC Hydro	Stave Falls
BC Hydro	Strathcona
BC Hydro	Wahleach
BC Hydro	Whatshan
California Dept. of Water Resources	Banks
California Dept. of Water Resources	Chrisman
California Dept. of Water Resources	Devil Canyon
California Dept. of Water Resources	Dos Amigos
California Dept. of Water Resources	Gianelli PS
California Dept. of Water Resources	Hyatt
California Dept. of Water Resources	Mojave Siphon
California Dept. of Water Resources	Pearblossom
Central Arizona Project	Mark Wilmer Pumping Plant
Central Arizona Project	Salt Gila Pumping Plant
Central Arizona Project	Waddell Pump/Generating Plant
Chelan County PUD	Lake Chelan
Chelan County PUD	Rock Island 1st Powerhouse
Chelan County PUD	Rock Island 2nd Powerhouse

Company	Station Group Name
Chelan County PUD	Rocky Reach
Churchill Falls (Labrador) Corp.	Churchill Falls
Columbia Power Corporation	Arrow Lakes
Columbia Power Corporation	Brilliant Dam
Columbia Power Corporation	Brilliant Expansion
Exelon Power Generation	Conowingo
Exelon Power Generation	Muddy Run
FortisBC	FortisBC Hydro
Grant County PUD	Priest Rapids-Wanapum
Great Lakes Power, Ltd.	Maggie
Great Lakes Power, Ltd.	Michipicoten
Great Lakes Power, Ltd.	Montreal
Great Lakes Power, Ltd.	Sault
Guangzhou Pumped Storage Power Station	Guangzhou Pumped Storage
Hydro-Quebec	Beaumont
Hydro-Quebec	Grand-Mere
Hydro-Quebec	La Gabelle
Hydro-Quebec	La Tuque
Hydro-Quebec	Rapide-Blanc
Hydro-Quebec	Shawinigan 2A/2B
Hydro-Quebec	Shawinigan 3
Hydro-Quebec	Trenche
Iberdrola	Duero
Iberdrola	Jucar
Iberdrola	La Muela
Iberdrola	Sil
Iberdrola	Villarino
Kings River Conservation District	Pine Flat Power Station
Landsvirkjun	Blanda
Landsvirkjun	Laxa
Landsvirkjun	Sigalda
Landsvirkjun	Sog
Los Angeles Dept. of Water & Power	Aqueduct
Los Angeles Dept. of Water & Power	Castaic 55
Los Angeles Dept. of Water & Power	Castaic Pump
Los Angeles Dept. of Water & Power	Owens System
Los Angeles Dept. of Water & Power	The Creek System
Meridian Energy	Manapouri
Meridian Energy	Waitaki River System
Metropolitan Water District	Etiwanda
Metropolitan Water District	Gene
Mighty River Power	Mighty River Power Hydro
New York Power Authority	Blenheim-Gilboa
New York Power Authority	Lewiston
New York Power Authority	NYP&A Small Hydro
New York Power Authority	Robert Moses
New York Power Authority	St. Lawrence
Newfoundland & Labrador Hydro	Bay D'Espoir
NextEra Energy Resources	Androskoggin River
NextEra Energy Resources	Kennebec River

Company	Station Group Name
NextEra Energy Resources	Saco River
Northern California Power Agency	Collierville
Northern California Power Agency	Collierville-Spicer
Northern California Power Agency	New Spicer Meadows
Nova Scotia Power, Inc.	Nova Scotia Small Hydro
Nova Scotia Power, Inc.	Wreck Cove
Oklahoma Municipal Power Authority	Kaw
Ontario Power Generation	Abitibi Canyon
Ontario Power Generation	Aguasabon
Ontario Power Generation	Alexander
Ontario Power Generation	Amrrior
Ontario Power Generation	Auburn
Ontario Power Generation	Barrett Chute
Ontario Power Generation	Big Chute
Ontario Power Generation	Big Eddy
Ontario Power Generation	Bingham Chute
Ontario Power Generation	Calabogie
Ontario Power Generation	Cameron Falls
Ontario Power Generation	Caribou Falls
Ontario Power Generation	Chats Falls
Ontario Power Generation	Chenaux
Ontario Power Generation	Coniston
Ontario Power Generation	Crystal Falls
Ontario Power Generation	DeCew Falls ND1
Ontario Power Generation	DeCew Falls NF23
Ontario Power Generation	Des Joachims
Ontario Power Generation	Elliott Chute
Ontario Power Generation	Eugenia Falls
Ontario Power Generation	Frankford
Ontario Power Generation	Hagues Reach
Ontario Power Generation	Hanna Chute
Ontario Power Generation	High Falls
Ontario Power Generation	Indian Chute
Ontario Power Generation	Kakabeka Falls
Ontario Power Generation	Lakefield
Ontario Power Generation	Lower Notch
Ontario Power Generation	Manitou Falls
Ontario Power Generation	Matabitchuan
Ontario Power Generation	McVittie
Ontario Power Generation	Merrickville
Ontario Power Generation	Meyersburg
Ontario Power Generation	Mountain Chute
Ontario Power Generation	Otter Rapids
Ontario Power Generation	Otto Holden
Ontario Power Generation	Pine Portage
Ontario Power Generation	R.H. Saunders
Ontario Power Generation	Ragged Rapids
Ontario Power Generation	Ranney Falls
Ontario Power Generation	Seymour
Ontario Power Generation	Sidney

Database Station Listing (2 of 2)

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 Attachment 2

Company	Station Group Name
Ontario Power Generation	Sills Island
Ontario Power Generation	Silver Falls
Ontario Power Generation	Sir Adam Beck I
Ontario Power Generation	Sir Adam Beck II
Ontario Power Generation	Sir Adam Beck PGS
Ontario Power Generation	South Falls
Ontario Power Generation	Stewartville
Ontario Power Generation	Stinson
Ontario Power Generation	Trethewey Falls
Ontario Power Generation	Whitedog Falls
Portland General Electric	East Side Hydro
Portland General Electric	West Side Hydro
Puget Sound Energy	Baker River
Puget Sound Energy	Electron Project
Sacramento Municipal Utility District	SMUD Hydro
Safe Harbor Water Power Corp.	Safe Harbor Station
Scottish Power	Cruachan
Seattle City Light	Boundary
Seattle City Light	Skagit
Southern California Edison	Big Creek Pumped Storage
Southern California Edison	Big Creek System
Southern California Edison	Bishop System
Southern California Edison	East End System
Southern California Edison	Kaweah/Tule System
Southern California Edison	Kern System
Tacoma Utilities	Cowlitz
Tacoma Utilities	Cushman
Tacoma Utilities	Nisqually
Tennessee Valley Authority	Boone
Tennessee Valley Authority	Chickamauga
Tennessee Valley Authority	Douglas
Tennessee Valley Authority	Fontana
Tennessee Valley Authority	Fort Patrick Henry
Tennessee Valley Authority	Kentucky
Tennessee Valley Authority	Raccoon Mountain
Tennessee Valley Authority	Watauga Station
Tennessee Valley Authority	Wilson
TransAlta Utilities	Alberta Small Hydro
TransAlta Utilities	BC Small Hydro
TransAlta Utilities	Bighorn
TransAlta Utilities	Bow Valley
TransAlta Utilities	Brazeau
TransAlta Utilities	Ontario Small Hydro
TransCanada	Deerfield River System
TransCanada	Lower Connecticut River System
TransCanada	Upper Connecticut River System
Turlock Irrigation District	Don Pedro
Turlock Irrigation District	TID Small Hydro
U. S. Bureau of Reclamation (Mid-Pacific)	Tracy
U.S. Army Corps of Engineers (ASE - Mobile)	Allatoona

Company	Station Group Name
U.S. Army Corps of Engineers (ASE - Mobile)	Buford
U.S. Army Corps of Engineers (ASE - Mobile)	Carters
U.S. Army Corps of Engineers (ASE - Mobile)	J. Woodruff
U.S. Army Corps of Engineers (ASE - Mobile)	Millers Ferry
U.S. Army Corps of Engineers (ASE - Mobile)	R. F. Henry
U.S. Army Corps of Engineers (ASE - Mobile)	W.F. George
U.S. Army Corps of Engineers (ASE - Mobile)	West Point
U.S. Army Corps of Engineers (ASE - Nashville)	Barkley
U.S. Army Corps of Engineers (ASE - Nashville)	Center Hill
U.S. Army Corps of Engineers (ASE - Nashville)	Cheatham
U.S. Army Corps of Engineers (ASE - Nashville)	Cordell Hull
U.S. Army Corps of Engineers (ASE - Nashville)	Dale Hollow
U.S. Army Corps of Engineers (ASE - Nashville)	J. Percy Priest
U.S. Army Corps of Engineers (ASE - Nashville)	Laurel
U.S. Army Corps of Engineers (ASE - Nashville)	Old Hickory
U.S. Army Corps of Engineers (ASE - Nashville)	Wolf Creek
U.S. Army Corps of Engineers (ASE - Savannah)	Hartwell
U.S. Army Corps of Engineers (ASE - Savannah)	J.S. Thurmond
U.S. Army Corps of Engineers (ASE - Savannah)	R.B. Russell
U.S. Army Corps of Engineers (ASE - Wilmington)	J.H. Kerr
U.S. Army Corps of Engineers (ASE - Wilmington)	Philpott
U.S. Army Corps of Engineers (Portland)	Bonneville
U.S. Army Corps of Engineers (Portland)	Cougar
U.S. Army Corps of Engineers (Portland)	Detroit / Big Cliff
U.S. Army Corps of Engineers (Portland)	Green Peter / Foster
U.S. Army Corps of Engineers (Portland)	Hills Creek
U.S. Army Corps of Engineers (Portland)	John Day
U.S. Army Corps of Engineers (Portland)	Lookout Point / Dexter
U.S. Army Corps of Engineers (Portland)	Lost Creek
U.S. Army Corps of Engineers (Portland)	The Dalles
U.S. Army Corps of Engineers (Seattle)	Albeni Falls
U.S. Army Corps of Engineers (Seattle)	Chief Joseph
U.S. Army Corps of Engineers (Seattle)	Libby
U.S. Army Corps of Engineers (Walla Walla)	Dworshak
U.S. Army Corps of Engineers (Walla Walla)	Ice Harbor
U.S. Army Corps of Engineers (Walla Walla)	Little Goose
U.S. Army Corps of Engineers (Walla Walla)	Lower Granite
U.S. Army Corps of Engineers (Walla Walla)	Lower Monumental
U.S. Army Corps of Engineers (Walla Walla)	McNary
U.S. Bureau of Reclamation (Idaho)	Anderson Ranch
U.S. Bureau of Reclamation (Idaho)	Black Canyon
U.S. Bureau of Reclamation (Idaho)	Boise Diversion
U.S. Bureau of Reclamation (Idaho)	Chandler
U.S. Bureau of Reclamation (Idaho)	Green Springs
U.S. Bureau of Reclamation (Idaho)	Minidoka
U.S. Bureau of Reclamation (Idaho)	Palisades
U.S. Bureau of Reclamation (Idaho)	Roza
U.S. Bureau of Reclamation (Lower Colorado)	Davis Dam
U.S. Bureau of Reclamation (Lower Colorado)	Hoover Dam
U.S. Bureau of Reclamation (Lower Colorado)	Parker Dam

Company	Station Group Name
U.S. Bureau of Reclamation (Mid-Pacific)	Carr
U.S. Bureau of Reclamation (Mid-Pacific)	Folsom
U.S. Bureau of Reclamation (Mid-Pacific)	Keswick
U.S. Bureau of Reclamation (Mid-Pacific)	New Melones
U.S. Bureau of Reclamation (Mid-Pacific)	Nimbus
U.S. Bureau of Reclamation (Mid-Pacific)	Shasta
U.S. Bureau of Reclamation (Mid-Pacific)	Spring Creek
U.S. Bureau of Reclamation (Mid-Pacific)	Trinity
U.S. Bureau of Reclamation (PN)	Grand Coulee (Pump Storage)
U.S. Bureau of Reclamation (PN)	Grand Coulee LPH
U.S. Bureau of Reclamation (PN)	Grand Coulee RPH
U.S. Bureau of Reclamation (PN)	Hungry Horse
U.S. Bureau of Reclamation (PN)	New Grand Coulee
U.S. Bureau of Reclamation (Upper Colorado)	Blue Mesa
U.S. Bureau of Reclamation (Upper Colorado)	Crystal
U.S. Bureau of Reclamation (Upper Colorado)	Flaming Gorge
U.S. Bureau of Reclamation (Upper Colorado)	Fontenelle
U.S. Bureau of Reclamation (Upper Colorado)	Morrow Point
U.S. Bureau of Reclamation (Upper Colorado)	Upper/Lower Molina
Virginia Power	Bath County

Total Cost Segments

Group 1

Micro Hydro

Average Station Capacity less than 30 MW
Average Unit size less than 15 MW

Group 2

Small Hydro

Average Station Capacity less than 150 MW

Group 3

Medium Hydro

Average Station Capacity equal to or greater than 150 MW but less than 400 MW

Group 4

Medium-Large Stations

Average Station Capacity equal to or greater than 400 MW but less than 700 MW

Group 5

Large Hydro Stations

Average Station Capacity equal to or greater than 700MW

Group 6

Low Use Stations

Stations with a long-term capacity factor less than 20%

Group 7

Pumped Storage Stations

All Stations

Group 8

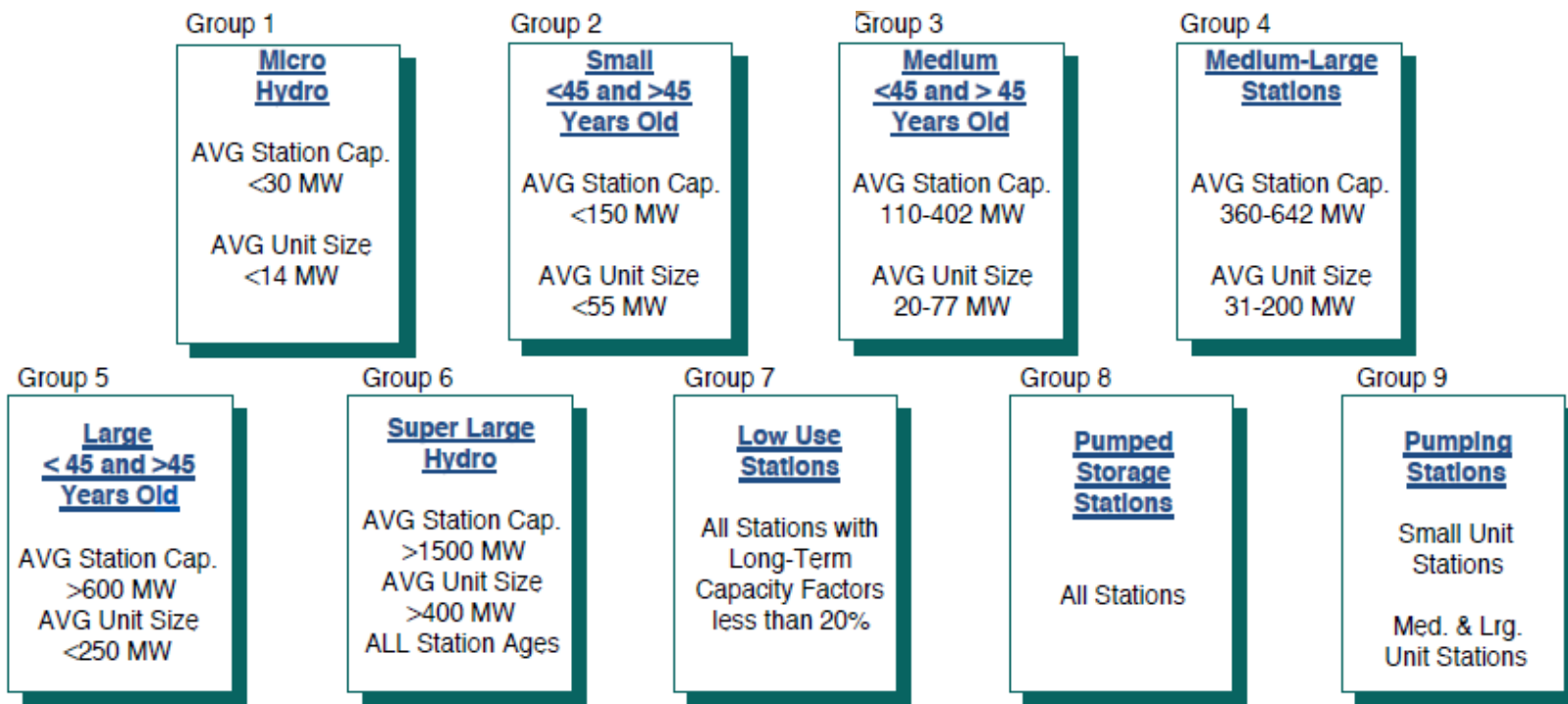
Pumping Stations

All Stations

Operations Segments

Group 1	Group 2	Group 3	Group 4	Group 5	Group 6	Group 7
<u>Micro Hydro Units</u>	<u>Small Hydro Units</u>	<u>Medium Hydro Units</u>	<u>Medium -Large Hydro Units</u>	<u>Large Hydro Units</u>	<u>Super Large Hydro Units</u>	<u>Pumped Storage Units</u>
Average Unit Sizes ≤10 MW	Average Unit Sizes 11-29 MW	Average Unit Sizes 30-64 MW	Average Unit Sizes 65-100 MW	Average Unit Sizes 100-250 MW	Average Unit Sizes Greater than 400 MW	Small Stations <150 MW Units Large Stations >150 MW Units
Conventional Stations ONLY	Conventional Stations ONLY	Conventional Stations ONLY	Conventional Stations ONLY	Conventional Stations ONLY	Conventional Stations ONLY	

Plant Maintenance Segments



Waterways & Dams Maintenance Segments

Group 1

Small Stations

Station Group MW
Capacity
Less than 200 MW

Conventional & Pumped
Storage Stations

Group 2

Medium-Sized Stations

Station Group MW
Capacity
200-500 MW

Conventional & Pumped
Storage Stations

Group 3

Large Stations

Station Group MW
Capacity
Greater Than 500 MW

Conventional & Pumped
Storage Stations

Buildings & Grounds Maintenance Segments

All Station Groups

All Station Groups,
regardless of capacity,
including both
Conventional and
Pumped Storage
Stations

Investment Segments



Support Segments

All Station Groups

All Station Groups,
regardless of capacity,
including Conventional,
Pumped Storage and
Pumping Stations

Public Affairs & Regulatory Segments

All Station Groups

All Station Groups,
regardless of capacity,
including both
Conventional, Pumped
Storage and Pumping
Stations

Cost Metric Definitions

Function	Key Metric	Reference Cost ⁽¹⁾
Operations	Operations Cost per Generating Unit	(Segment Median in \$/Unit) x (# of Generating Units in the station group)
Plant Maintenance	Plant Maintenance Cost per MWh generated	(Segment Median in \$/MWh) x (MWh generated by the station group)
Waterway & Dam Maintenance	WW&D Cost per MW of capacity	(Segment Median in \$/MW) x (MW capacity of the station group)
Buildings & Grounds Maintenance	B&G Cost per MW of capacity	(Segment Median in \$/MW) x (MW capacity of the station group)
Investment	Investment Cost per MW of capacity	(Segment Median in \$/MW) x (MW capacity of the station group)
Support	Support Cost per MW of capacity	(Segment Median in \$/MW) x (MW capacity of the station group)
Public Affairs & Regulatory	PA&R Cost per MW of capacity	(Segment Median in \$/MWh) x (MW capacity of the station group)
Total Cost	Total Cost per MWh generated	Sum of the above
Total Function Cost	Total Cost per MWh generated	Total Cost less Investment
Partial Function Cost	Total Cost per MWh generated	Total Cost less Investment and PA&R

(1) The Reference Cost is the amount that OPG would have spent if its Key Metric was the same as the segment median for each function. For example, if a plant had the same Operations \$/Unit as the median in its Operations segment, the same Plant Maintenance \$/MWh as the median in its Plant Maintenance segment, etc. for all other functions, then its Total Cost would be equal to the Reference Cost.

Performance Metric Definitions

Weighted Forced Outage Rate

- Measure that compares the forced outage hours to service hours, as follows:
 - $FOR = (\text{hours units out due to forced outage} + \text{hours out due to start-up failure}) / (\text{service hours} + \text{hours unit out due to forced outage} + \text{hours out due to start-up failure})$
 - Does not include planned maintenance extending beyond planned periods
 - Service hours does not include hours where unit was on standby but available. It does include all modes of operations (spinning, regulation, pump, generate).
- Service, forced outage and start-up failure hours are weighted by unit capacities to determine a Station Group weighted rate.

Weighted Availability Factor

- Measure that compares the hours that the units were available for service, as follows:
 - $\text{Availability} = 1 - [\text{Outage hours of ALL types} / 8760]$
- Outage hours are weighted by unit capacities to determine a Station Group weighted rate

Abbreviations

B&G	Buildings & Grounds
FTE	Full-Time Equivalent
GKS	Generation Knowledge Service
GRC	Gross Revenue Charges
IESO	Independent Electricity System Operator
MW	Megawatt
MWh	Megawatt-hour
OPEB	Other Post Employment Benefits
OPG	Ontario Power Generation
PA&R	Public Affairs & Regulatory
WW&D	Waterways & Dams
WAF	Weighted Availability Factor
WFOR	Weighted Forced Outage Rate

OPG Station Groups Benchmarked

Station Group	Ops Seg	Fully Staffed or Automated	Maint Seg	WW&D Seg	Total Cost Seg	Inv Seg
Abitibi Canyon	3A	A	2B	2	2	4
Aguasabon	1	A	2A	1	1	3
Alexander	1	A	2A	1	1	4
Arnprior	2	A	8A	1	8A	2
Auburn	1M	A	2M	1	1M	4
Barrett Chute	2	A	8A	1	8A	3
Big Chute	1M	A	2M	1	1M	4
Big Eddy	1M	A	2M	1	1M	4
Bingham Chute	1M	FS	2M	1	1M	4
Calabogie	1M	A	2M	1	1M	4
Cameron Falls	1	A	2A	1	1	4
Caribou Falls	2	A	2A	1	1	3
Chats Falls	1	A	2B	1	2	4
Chenau	1	A	2A	1	1	3
Coniston	1M	A	2M	1	1M	4
Crystal Falls	1M	A	2M	1	1M	4
DeCew Falls 1	1M	A	2M	1	1M	4
DeCew Falls ND23	3A	A	2B	1	1	4
Des Joachims	2	A	2C	2	2ML	3
Elliott Chute	1M	A	2M	1	1M	4
Eugenia Falls	1M	A	2M	1	1M	4
Frankford	1M	A	2M	1	1M	4
Hagues Reach	1M	A	2M	1	1M	4
Hanna Chute	1M	A	2M	1	1M	4
High Falls	1M	A	2M	1	1M	4
Indian Chute	1M	A	2M	1	1M	4
Kakabeka Falls	1M	A	2M	1	1M	4

Station Group	Ops Seg	Fully Staffed or Automated	Maint Seg	WW&D Seg	Total Cost Seg	Inv Seg
Lakefield	1M	A	2M	1	1M	4
Lower Notch	3B	A	8B	2	8B	3
Manitou Falls	1	A	2A	1	1	3
Matabitchuan	1M	A	2M	1	1M	4
McVittie	1M	A	2M	1	1M	4
Merrickville	1M	A	2M	1	1M	4
Meyersburg	1M	A	2M	1	1M	4
Mountain Chute	3A	A	8A	1	8A	3
Otter Rapids	2	A	2B	1	2	3
Otto Holden	2	A	2B	2	2	3
Pine Portage	2	A	2B	1	1	3
Ragged Rapids	1M	A	2M	1	1M	4
Ranney Falls	1M	A	2M	1	1M	4
Saund	3A	A	5	3	3	3
Seymour	1M	A	2M	1	1M	4
Sidney	1M	A	2M	1	1M	4
Sills Island	1M	A	2M	1	1M	4
Silver Falls	2	A	2A	1	1	3
Sir Adam Beck 1	2	A	2C	2	2ML	4
Sir Adam Beck 2	3A	A	5	3	3	3
Sir Adam Beck PGS	4A	A	4A	1	4A	3
South Falls	1M	A	2M	1	1M	4
Stewartville	2	A	8A	1	8A	3
Stinson	1M	A	2M	1	1M	4
Trethewey Falls	1M	A	2M	1	1M	4
Whitedog Falls	1	A	2A	1	1	3

Segment Codes

Operations Segments	
1MFS	Micro FS
1MA	Micro Auto
1FS	Small FS
1A	Small Auto
2FS	Med FS
2A	Med Auto
3AFS	Medium-Large FS
3AA	Medium-Large Auto
3BFS	Large FS
3BA	Large Auto
4A	Pumped Storage <150 MW
4B	Pumped Storage >150 MW

Plant Maintenance Segments	
1M	Micro <45 Years Old
2M	Micro >45 Years Old
1A	Sml<45 Years Old
2A	Sml>45 Years Old
1B	Med<45 Years Old
2B	Med>45 Years Old
1C	Med-Lrg<45 Years Old
2C	Med-Lrg>45 Years Old
3	Large<45 Years Old
5	Large>45 Years Old
4A	Pumped Storage <150 MW
4B	Pumped Storage >150 MW
8A	Low Use <100 MW
8B	Low Use >100 MW

WW&D Maintenance Segments	
1	Small
2	Medium
3	Large

Investment Segments	
1	<15 Years Old
2	16-40 Years Old
3	41-65 Years Old
4	>65 Years Old

Partial and Total Function Cost Segments	
1M	Micro
1	Small
2	Med
2ML	Med-Lrg
3	Large
4A	Pumped Storage <150 MW
4B	Pumped Storage >150 MW
8A	Low Use <100 MW
8B	Low Use >100 MW

Key CONTACTS



Bruce Hamilton, Project Manager
Director
Vancouver, WA
503.476.2711
bruce.hamilton@navigant.com

Megan Kuc
Senior Consultant
Chicago, IL
312.583.6925
megan.kuc@navigant.com

Wayne Leonard
Senior Consultant
Vancouver, WA
360.828.4004
wayne.leonard@Navigant.com

Dale Probasco
Managing Director
Chicago, IL
612.868.5955
dprobasco@navigant.com

Todd Williams
Managing Director
Toronto, ON
647.288.5204
twilliams@navigant.com

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Filed: 2016-05-27
EB-2016-0152
Exhibit: A1-3-2
Attachment 3
Page 1 of 17

London Economics International LLC

Inflation Factor Analysis for OPG Regulated Hydroelectric IRM

prepared for stakeholder consultations

Julia Frayer, Ian Chow
December 17, 2014



How is inflation applied in an incentive regulation mechanism (IRM)?

- ▶ OPG asked LEI to recommend an appropriate inflation (“I”) factor for an I–X IRM approach for OPG hydroelectric assets
- ▶ “Economists use the term ‘inflation’ to denote an ongoing rise in the general level of prices quoted in units of money” (White. *The Concise Encyclopedia of Economics*. 2008)
- ▶ Under the TFP–based I–X approach, assumptions for an inflation factor (I–factor) and inflation trends are necessary
 - I must be used to inflate rates per the I–X formula annually
 - The choice of the I–factor also impacts the X factor
 - I–factor applied in the rate formula is usually based on the actual inflation trend for the previous period, but longer term historical trends are useful in understanding and evaluating different indices
 - Application of the previous period inflation factors results in a lag, which depends on when data is published
- ▶ Although a single consumer price index (“CPI”) or producer price index (“PPI”) could be used as the I–factor, LEI recommends that OPG consider an I–factor based on more specific inflation indices that represent different inputs to OPG’s hydroelectric business

Ontario has used both input and output-based inflation factors through different generations of IRM for electricity distributors

1G IRM
(2001–2006)

Input Price Index – Weighted average of 3 components: Price of labour, price of materials, and price of capital (weights based on latest available data, applied to all utilities)

- Given the volatility, only 50% of Price of capital is accounted for in the IPI

2G IRM
(2007–2009)

Gross Domestic Product Implicit Price Index for Final Domestic Demand (GDP–IPI–FDD) – Broad macroeconomic (output) measure, takes into account cost of capital equipment; less controversial and easier to implement

3G IRM
(2009–
)

Gross Domestic Product Implicit Price Index for Final Domestic Demand (GDP–IPI–FDD) – OEB recognized that there may be differences in input price trends for the industry and the broader economy; however, for simplicity assumed that the Input Price Differential was zero

4G IRM

Choice of 3 regulatory options with 2 inflation index options:

- 4G Incentive Ratemaking – **composite index**
- Custom Incentive Ratemaking – **custom index**
- Annual Incentive Ratemaking Index – **composite index**

For the composite index, the OEB decided on a 2-factor approach, using Average Weekly Earnings for the labour sub-index, and Canada GDP IPI FDD for the non-labour sub-index, as the capital sub-index was found to be overly volatile

Selection of inflation indices for the I factor should be done on the basis of objective criteria

1. Relevance to utility costs

Does it closely reflect the utility's observed cost pressures?

2. Exogeneity

Is the utility a large component of the index?

3. Source reliability

Does the index come from a reliable source?

4. Data availability

Does the index rely on readily available, public data?

5. Index simplicity

Is the index generally accepted by ratepayers and easy to calculate and understand?

6. Index stability

Are the year-over-year changes in the index relatively stable and not overly volatile?

LEI recommends a composite inflation index for OPG's hydroelectric generation business under IRM

- ▶ A composite inflation index is where an index is composed of other sub-indices for key inputs, which reflect different inflation trends for different cost categories

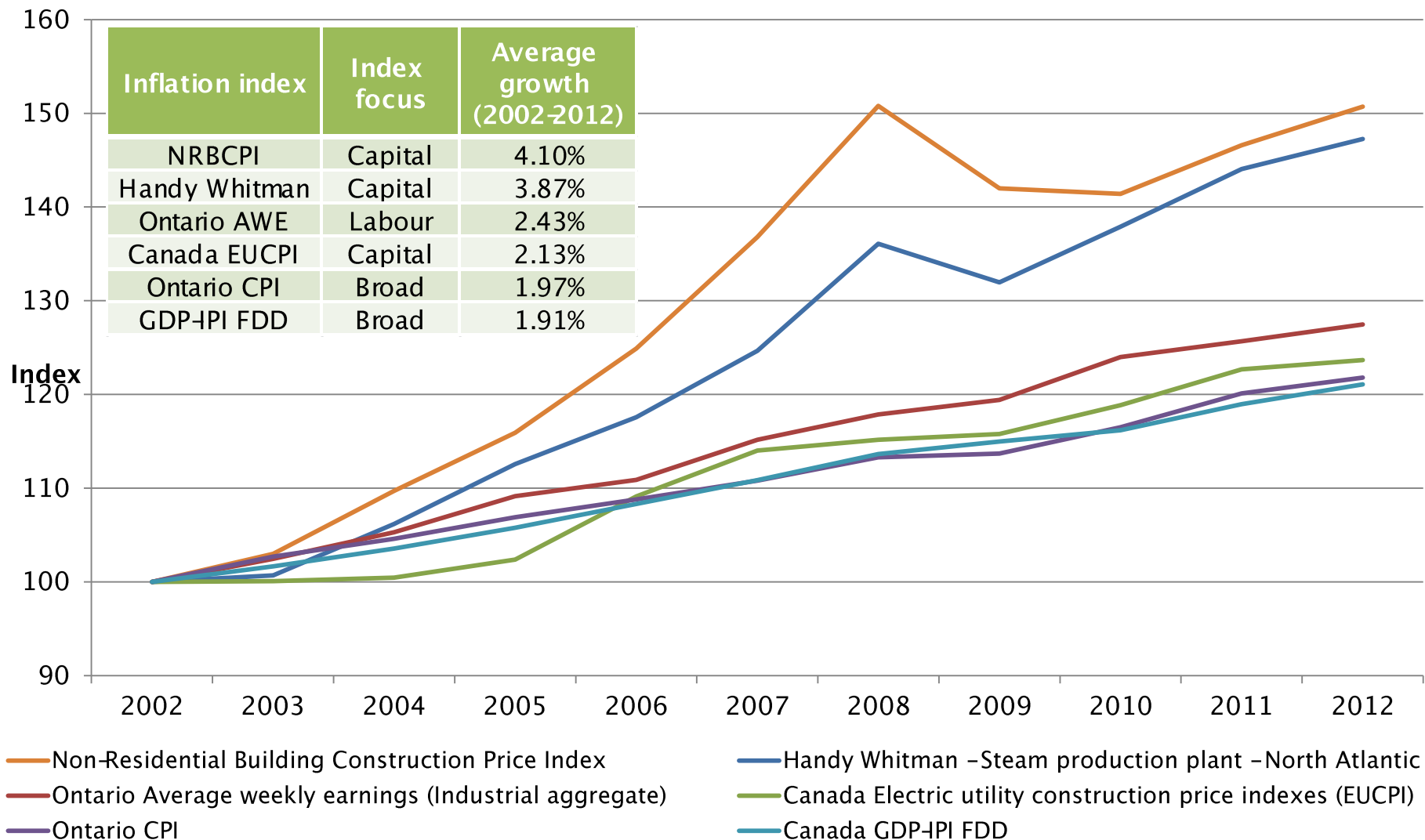
$$I = \alpha (\text{Labour inflation}) + \beta (\text{Non - labour inflation}) + \delta (\text{Capital inflation})$$

where α , β and δ represent weights

- ▶ The criteria of relevance to OPG's unit cost pressures is best achieved with a customized inflation index
 - OEB has concurred and recently modified its policies to utilities to propose customized input-focused inflation indices
- ▶ A customized inflation index need not be complex, especially if there are publicly available indices available
 - OEB has moved to a composite two-factor inflation index in 4G IRM for electricity distributors

Historically, different indices used to measure inflation of labour, non-labour and capital for utility operators have differing trends and sensitivities to economic cycles

Historical inflation indices and average historical growth (2002-2012)





Choice of inflation index options should be evaluated against six criteria, weighted by importance (where 1 is most important)

	CPI	GDP-IPI FDD	Customized composite index (with tailored capital index, e.g., IPPI or NRBCPI)	Customized composite index (with GDP-IPI FDD as proxy for capital)
1. Relevance to utility costs				
2. Exogeneity			*	
3. Data availability			**	**
4. Source reliability			**	**
5. Index simplicity	***		****	****
6. Index stability				
Indicative overall score (weighted)				

* If industry is small and regulated firm is a major respondent for the industry there may be a "bias" if its costs drive the index

** Assuming individual sub indices come from StatCan

*** Requires adjustment then of the X factor

**** Requires weights

Preferred
 Partially favorable
 Unfavorable

LEI recommends a two-factor composite index which uses AWE for labour, and GDP-IPI FDD for non-labour and capital

► Labour: *Statistics Canada's* Average Weekly Earnings (“AWE”) index for Ontario industrial aggregate

- AWE shows the average financial return from paid employment to inflate labour costs
- Multiple consultants (LEI, PEG) and regulators (AUC, OEB) recommend the use of average weekly earnings for a labour price sub index

► Non-Labour and Capital: Canadian Gross Domestic Product Implicit Price Index – Final Domestic Demand (“GDP-IPI FDD”)

- GDP-IPI FDD applies to all final domestic demand, so it broadly covers many industrial inputs, and measures the price changes of the whole economy
- The OEB has already approved the application of GDP-IPI FDD on non-labour and capital for electricity distributors
- **Non-Labour:** Multiple consultants have successfully recommended GDP-IPI FDD for a non-labour sub index (including OEB electricity distribution IRM, LEI in Alberta proceedings and PEG’s 2013 report)
- **Capital:** GDP-IPI FDD ranked as the best alternative in terms of data availability, reliability, simplicity, exogeneity and stability

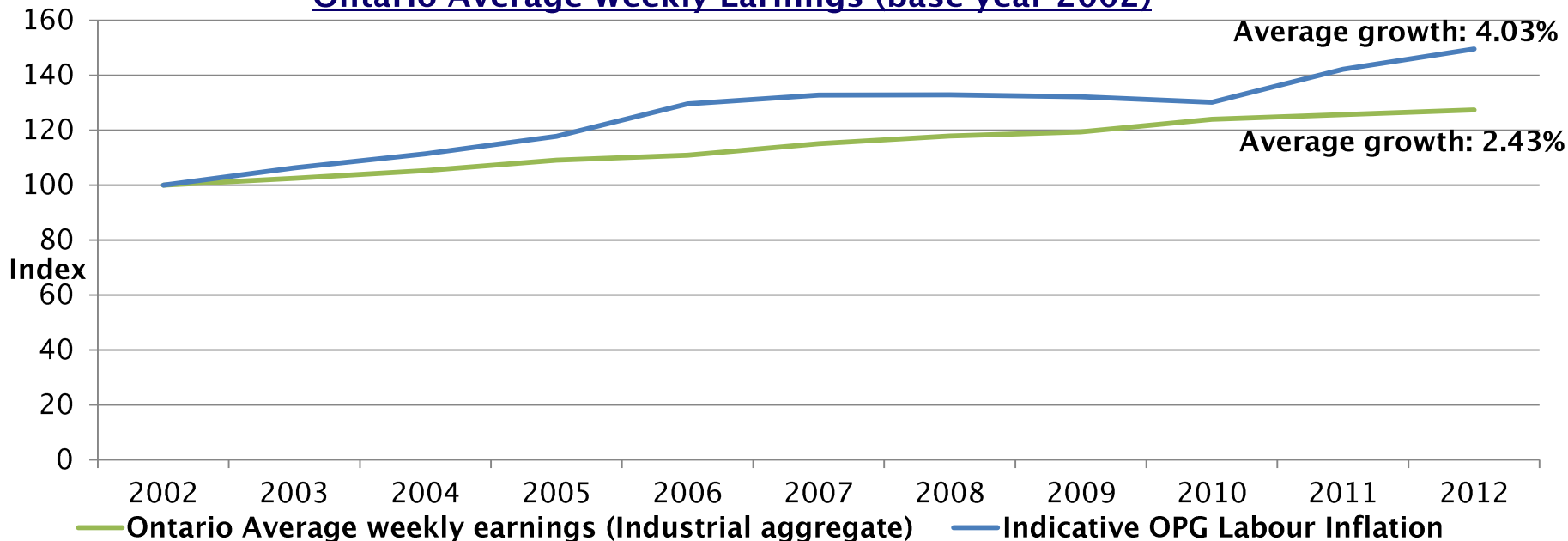


The average weekly earnings index for the utility sector is a reliable and relevant measure of labour cost inflation

- ▶ LEI recommends Statistics Canada’s average weekly earnings (AWE) index for Ontario industrial aggregate, which shows the average financial return from paid employment to inflate labour costs
- ▶ Average growth in OPG labour costs per FTE from 2002 to 2012 was 4.03%, which is greater than the average AWE growth rate of 2.43%

Criteria	AWE
1. Relevance to utility costs	✓
2. Exogeneity to the firm	✓
3. Data availability	✓
4. Source reliability	✓
5. Index simplicity	✓
6. Index stability	✓

Ontario Average Weekly Earnings (base year 2002)



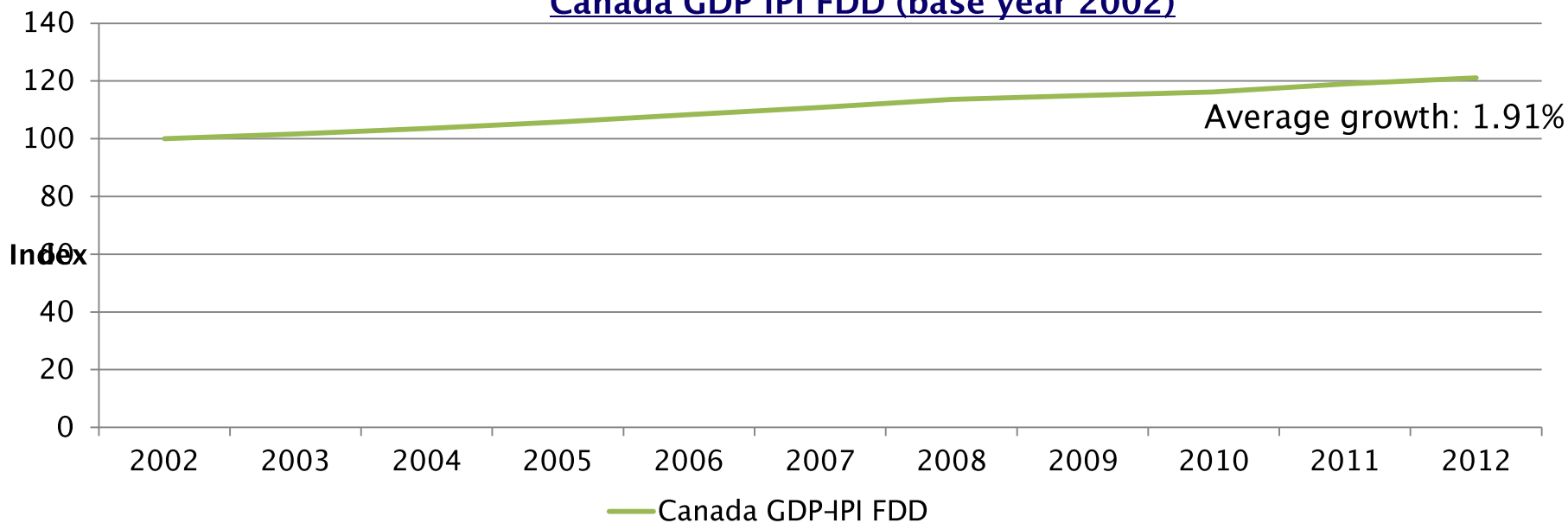


Canadian GDP-IPI FDD applies to inflation trends in procurement of various industrial services and materials (non-labour costs)

- ▶ Canadian GDP-IPI FDD is an index which measures the price changes of the whole economy (GDP)
- ▶ Non-labour costs cover procurement of various services and materials
 - GDP-IPI FDD applies to all final domestic demand, so it broadly covers many industrial inputs

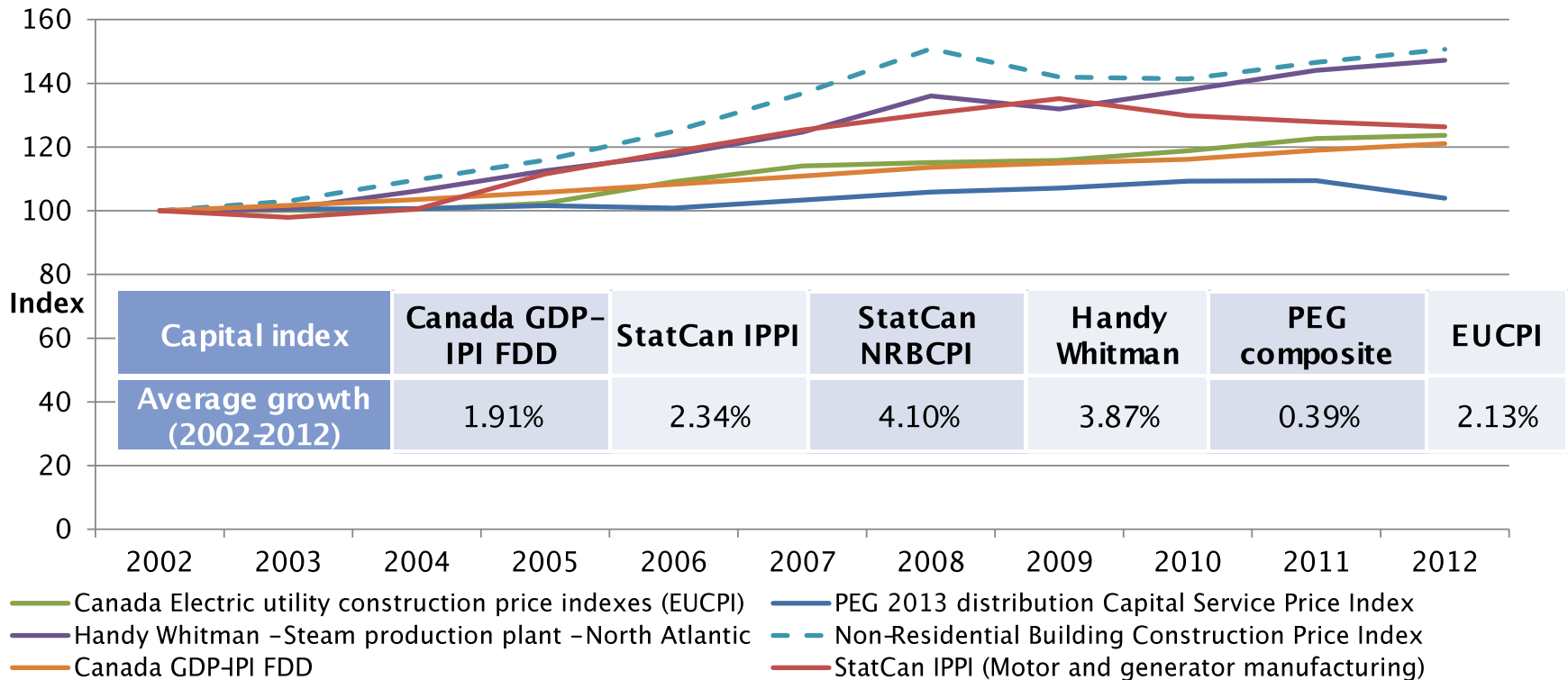
Criteria	GDP IPI FDD
1. Relevance to utility costs	✓
2. Exogeneity to the firm	✓
3. Data availability	✓
4. Source reliability	✓
5. Index simplicity	✓
6. Index stability	✓

Canada GDP IPI FDD (base year 2002)



GDP–IPI FDD for capital inflation maintains exogeneity of the index, yields more stable rates, and is simpler for ratepayers to understand, while still being relevant to utility costs

- ▶ LEI evaluated a variety of options for the capital inflation index; relevance and exogeneity are the more important criteria – but simplicity, stability, data availability, and reliability are also important to consider
- ▶ Although a tailored capital index such as StatCan Industrial Product Price Index (IPPI) or Non–residential Building Construction Price Index (NRBCPI) are relevant to the key capital components of a hydroelectric generation business, historical data shows that such indices are sensitive to economic cycles

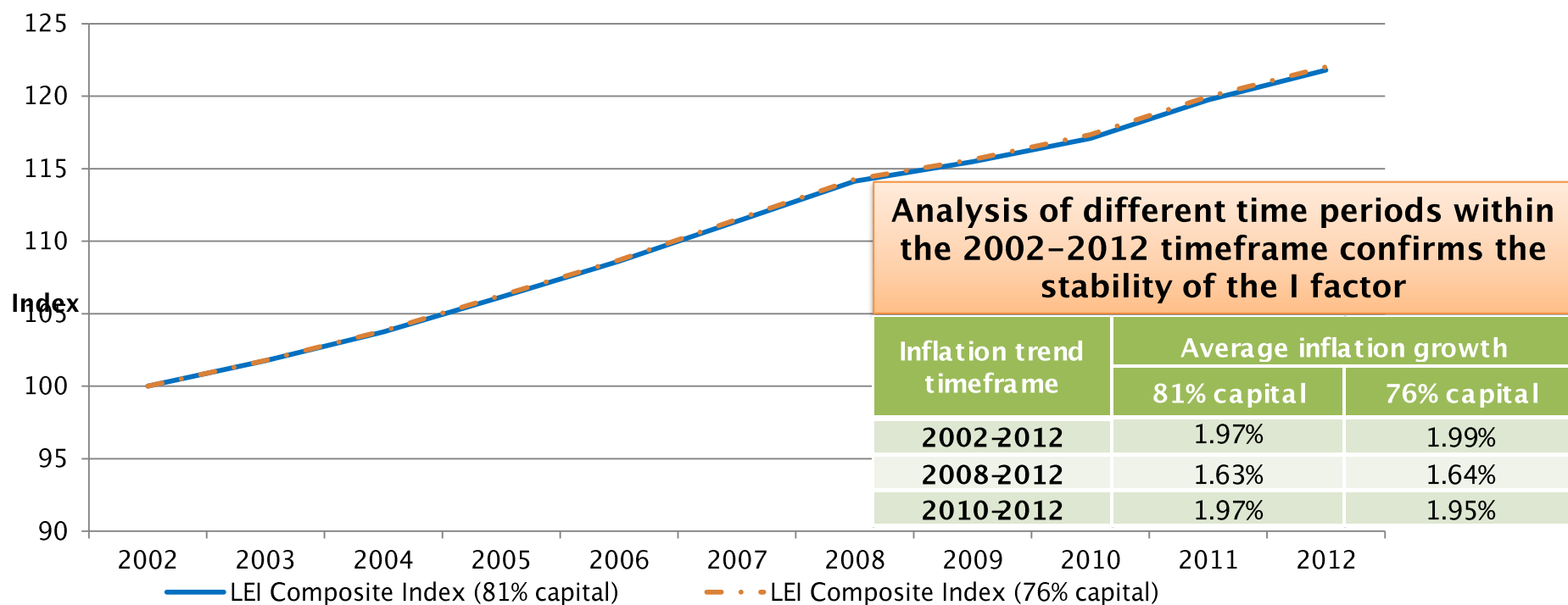




LEI's composite inflation index has an average historical growth of 1.97% from 2002 through 2012

- ▶ The composite index is weighted sum of capital, labour and non-labour (material) indices using average industry cost shares (and labour share suggested by the EUCG database)
 - For RRFE, the OEB chose to use industry weightings because it was “a more reasonable representation for the industry as a whole

Industry Weights	Capital	Labour	Non-labour	Composite inflation index
(2002-2012)	81%	12%	7%	$I = 12\%(AWE) + 7\%(GDP-IPI\ FDD) + 81\%(GDP-IPI\ FDD)$
(2008-2012)	76%	15%	9%	$I = 15\%(AWE) + 9\%(GDP-IPI\ FDD) + 76\%(GDP-IPI\ FDD)$





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**Second information session:
Inflation Factor Analysis for OPG's Regulated
Hydroelectric IRM**

prepared for stakeholder consultation

Julia Frayer, Ian Chow, Adam Hariri
January 22, 2015

OPG asked LEI to recommend an appropriate inflation index or “I-factor” for an I-X IRM approach

- ▶ **“Economists use the term ‘inflation’ to denote an ongoing rise in the general level of prices quoted in units of money” (White. *The Concise Encyclopedia of Economics*. 2008)**
- ▶ **Within an I-X IRM regime, the I-factor compensates for rising unit costs of inputs, while X-factor compensates for productivity trends (e.g., how inputs converted to outputs)**
 - The choice of the I-factor also impacts the setting of the X-factor
 - Unlike a X-factor, where a value is usually set for the duration of the IRM cycle, only the I-factor component indices are set and the values are updated annually based on reported indices
 - I-factor values are recalculated based on the actual inflation trend for the previous period
 - Application of the previous period inflation factors results in a lag, which depends on when data is published

LEI recommends a composite inflation index for OPG's hydroelectric generation business

- ▶ **Theory:** A composite inflation index is built from other indices that reflect inflation trends for different inputs/cost categories

$$I = \alpha (\text{Labour inflation}) + \beta (\text{Non-labour inflation}) + \delta (\text{Capital inflation})$$

where α , β and δ represent weights

- ▶ **Regulatory Precedent:** In 3GIRM for electricity distributors, OEB had relied on GDP-IPI for I-factor, but more recently the policy under 4GIRM has been modified to allow for a composite index
- ▶ **Practical:** LEI recommends a composite index similar to OEB's 4GIRM for electricity distributors
 - It is relevant, as it represents the basic categories of inputs (labour, non-labour), and labour is specifically for the Ontario industrial sector
 - It is exogenous to OPG since it represents inflation trends across many firms and many industries (for GDP-IPI)
 - It is both reliable and readily available, based on data published by Statistics Canada
 - It is relatively simple to put together given the input price shares that were developed for the TFP study
 - LEI's recommended I-factor has historically been very stable

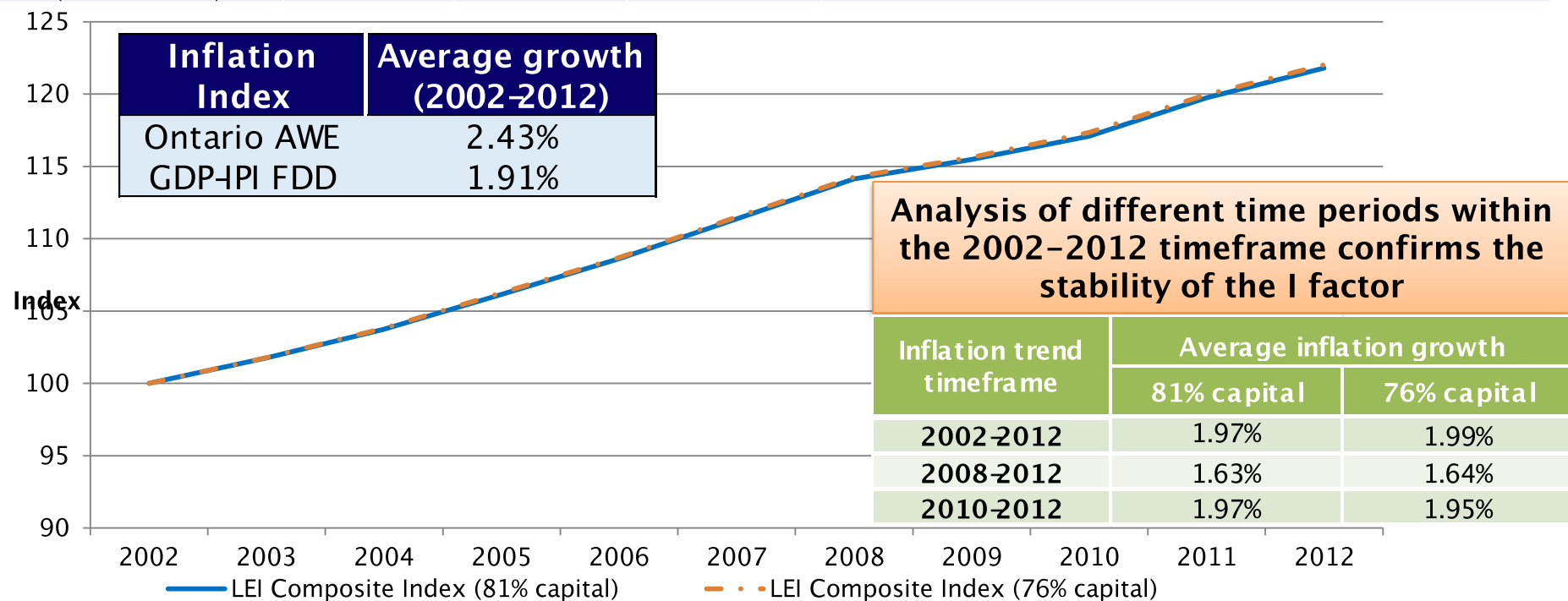


LEI's composite inflation index has an average historical growth of 1.97% from 2002 through 2012

► The composite index is weighted sum of capital, labour, and non-labour (material) indices using average industry cost shares as suggested by LEI's work in the industry TFP study

- For RRFE/4GIRM, the OEB chose to use industry weightings because it was "a more reasonable representation for the industry as a whole" (Source: December 2013 Board Report under EB-2010-0379)

Industry Weights	Capital	Labour	Non-labour	Composite inflation index
(2002-2012)	81%	12%	7%	$I = 12\%(AWE) + 7\%(GDP-IPI\ FDD) + 81\%(GDP-IPI\ FDD)$
(2008-2012)	76%	15%	9%	$I = 15\%(AWE) + 9\%(GDP-IPI\ FDD) + 76\%(GDP-IPI\ FDD)$



LEI employs industry average input weights developed in the TFP study for its recommended composite I-factor for OPG

- ▶ An industry average weight allows for the use of an exogenous I-factor that is representative of industry conditions
 - Using industry trends over firm-specific trends has OEB precedent
 - Using OPG-specific weights rather than industry weights to calculate the composite I-factor leads to a slight decrease from 1.97% to 1.95% for the 2002–2012 period

Index	Method of estimating weights	Weight assigned	
		Industry	OPG
Capital	Average of capital weights over 2002–2012 period (for industry)	81%	88%
O&M	Average of O&M weights over 2002–2012 period (for industry)	19%	12%
Labour	O&M weight * EUCG labour share (for industry)	19% * 62% = 12%	12% * 64% = 8%
Non-labour	O&M weight * EUCG non-labour share (for industry)	19% * 38% = 7%	12% * 36% = 4%

- ▶ Determining weights using more recent data (rather than the 11-year average from the TFP study) would not materially change the I-factor

Index	Data years	Capital	Labour	Non-labour	Composite inflation index
Industry	(2010–2012)	72%	18%	10%	I = 2.00%
OPG	(2010–2012)	82%	11%	7%	I = 1.97%

Internal Use Only		
Document Number: OPG-POL-0027		Revision Number: R004
Usage Classification: Information	Sheet Number: N/A	Page: 1 of 1

Title: FIRST NATIONS AND MÉTIS RELATIONS POLICY

Policy Statements: Ontario Power Generation (OPG) is committed to building long term, mutually beneficial working relationships with First Nations and Métis communities proximate to its present and future operations.

OPG is committed to developing these relationships on a foundation of respect for the languages, customs, and political, social and cultural institutions of First Nations and Métis communities. OPG acknowledges the aboriginal and treaty rights of First Nations and Métis communities as recognized and affirmed in the Constitution Act 1982.

OPG's commitments are made on its own behalf, and not on behalf of the Crown or any other government agency. (Section 53.1(2) of *the Electricity Act, 1998*).

Requirements: OPG shall continue its efforts to reach mutually satisfactory resolution of grievances with respect to past generation-related development.

OPG shall pursue, where appropriate, prospective generation-related developments with First Nations and Métis communities that can provide the basis for long term mutually beneficial commercial arrangements.

OPG's operational business plans shall be developed with a view to implementing this policy in the following areas:

- Community relations and outreach;
- Capacity building support within communities; and
- Employment/Business Contracting opportunities.

OPG shall ensure that the execution of this policy is consistent with its commercial mandate and the Memorandum of Agreement with its Shareholder.

Accountabilities: The Vice-President, Corporate Relations and Communications is accountable for the development and maintenance of a program that achieves the requirements of the policy, including reporting to the Board on OPG's overall performance.

The Operating Unit and Function leaders are accountable for the effective implementation of the First Nations and Métis program within their respective organizations.

Definitions: Aboriginal peoples of Canada include the Indian, Inuit and Métis peoples of Canada (Constitution Act 1982, Section 35).

Approval: Board of Directors **Date:** December 13, 2012

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STAY CLEAR. STAY SAFE.

Around dams, hydroelectric stations and surrounding waterways.





Stay clear. Stay safe.

Around dams, hydroelectric

stations and surrounding waterways.

Getting too close to dams and hydroelectric stations is always dangerous. A spot that seems calm and safe one moment can turn into a dangerous surge of rising and fast-flowing water – quickly and often without any warning.

Obey all signs, booms and barriers.

Most facilities are remotely-controlled by operators many kilometres away. They open or close dams, to help manage river flows, and start or stop generators throughout the day and night as demand for electricity changes.

This may result in frequent, rapid and dangerous changes in water levels and flows; changes that can harm those who venture too close.

Be especially careful near waters above and below dams and hydroelectric stations.



Remotely-operated dam gates can quickly turn calm waters or dry riverbeds into dangerous flows.

At a generating station, water from above the dam runs through the station and then surges out to join the main stream of the river.

In areas above and below dams, fast-moving water creates dangerous turbulence and strong undercurrents, which are not always apparent from the calm-looking surface waters.

For your own protection, stay clear, stay safe.

**STAY
CLEAR.
STAY
SAFE.**



What happens when you fail to stay clear, stay safe?



Before



After

This is a very dangerous spot and should be avoided. Areas inside warning signs, buoys and booms are extremely dangerous. Stay clear of them.

The same spot just minutes later. Remotely operated gates at the dam release large volumes of water that could leave you stranded, swamp your boat or put you in the grip of an undertow.

Be Alert!

Even if you can't see a generating station or dam, waterways upstream and downstream can still be affected by its operations. It's important to be aware of the potential dangers caused by changing flows, and stay clear of waters near stations and dams.

Dams and hydroelectric stations are not recreation areas.

Do not treat hydroelectric facilities as fishing holes, boating areas or swimming areas.

These areas are not safe for any recreational activities, including camping, picnicking or even winter activities such as snowmobiling or cross-country skiing.

Put safety first. When travelling on unfamiliar paths or waterways, plan your trip ahead.

For your own safety near a dam or hydroelectric station, make sure you:

- Obey ALL warning signs, fences, buoys, booms and barriers. They are put there to protect you. The areas inside are dangerous, so stay clear. Some signs have pictures that show the consequences of not staying clear.
- Stay well back from the edge of waters above and below dams and hydroelectric stations.
- Never stand below a dam, or anchor or tie your boat there. Rapidly changing water levels and flows can swamp your boat or pull you into an undertow.
- Stay off dams or hydroelectric station structures, unless OPG has clearly indicated where it is safe to walk or drive.
- Avoid snowmobiling, cross-country skiing, skating or ice fishing on rivers or lakes near dams and generating stations.
- Don't risk walking onto a river or lake around dams and generating stations where the ice may be thin due to the current. Changing water levels can crack the ice, leaving it weak and unstable.



! Don't find yourself on thin ice. Winter brings more dangers.

Ice forming near a dam or hydroelectric station can be thinner and less consistent than ice in other locations because of changing water flows beneath.

TRESPASSING ON OPG PROPERTY IS ILLEGAL.

TO ENSURE YOUR SAFETY,

TRESPASSERS CAN BE CHARGED.



Teach children to Stay Clear and Stay Safe.

Be sure to tell children exactly where they can and cannot go, and make sure you are nearby and can see them at all times. For their safety, teach them what the signs and other barriers mean.

As a rule remember to:

- Stay out of dry or calm riverbeds below dams. They can quickly change into rapidly flowing waterways with dangerous currents.
- Stay a safe distance outside of warning signs, buoys, booms and barriers and be alert for changes in water levels.
- Stay away from the edge of a waterway where footing may be slippery.
- Don't wade into moving water.
- When swimming, fishing, boating or paddling in a river, be aware of the water level and check upstream frequently for any sign of increasing currents or rising water. If the water level is rising or the flow is speeding up, get out of the water or move your boat downstream. Obey all signs and barriers.

*The area between booms
and dams is very dangerous.
Stay Clear!*



Stay Clear. Stay Safe!

We take pride in operating our facilities safely, in a manner that respects the environment and the rights of other users of the waterways.

Please respect the hazards near our dams and stations, and obey all warning signs, booms, buoys, and barriers. They are there for your protection.

*For information, please visit
www.stayclearstaysafe.ca*

ONTARIO POWER
GENERATION
opg.com

1 **NUCLEAR RATE SMOOTHING AND**
2 **MID-TERM PRODUCTION REVIEW**

3
4 **1.0 PURPOSE**

5 This evidence sets out OPG’s proposals for smoothing nuclear payment amounts during the
6 2017 to 2021 test period, and for a mid-term review of the nuclear production forecast for the
7 second half of the test period.

8
9 **2.0 NUCLEAR RATE SMOOTHING**

10 **2.1 Overview**

11 OPG proposes that annual nuclear base payment amounts reflect a constant 11 per cent per
12 year rate increase during the 2017 to 2021 test period (the “smoothed rate”). OPG further
13 proposes that a deferral account be established to record the difference between the total
14 annual nuclear revenue requirement approved by the OEB starting in 2017 and the portion of
15 that revenue requirement each year that produces the proposed annual 11 per cent payment
16 amount increase when combined with the OEB approved nuclear production forecast for the
17 corresponding year.

18
19 OPG’s proposal is intended to mitigate rate impact and volatility beginning January 1, 2017
20 and ending when the Darlington Refurbishment Program ends (the “deferral period” as
21 defined in O. Reg. 53/05, s. 0.1 (1)). The rate impact and volatility in the test period are
22 driven by reduced production as Darlington units are taken out of service to be refurbished,
23 partially offset by production at the Pickering generating station in 2021 due to the plan to
24 extend operations, and costs associated with the Darlington Refurbishment Program
25 (“DRP”). OPG’s proposal is consistent with the amendments to O. Reg. 53/05 (the
26 “regulation”), which came into force as of January 1, 2016 and are filed as Ex. A1-6-1,
27 Attachment 1.

1 OPG proposes an 11 per cent annual smoothed rate increase for the 2017 to 2021 period,
2 which would result in a cumulative deferred revenue requirement of approximately \$1.6B¹
3 based on OPG's proposed revenue requirement, including reductions from the nuclear
4 stretch factor adjustment.² This proposed rate increase would result in stable payment
5 amount increases during the first five years of the deferral period, while supporting adequate
6 levels for OPG's credit metrics.

7

8 The average residential customer bill impact of OPG's rate proposals is slightly less than 0.7
9 per cent annually or approximately \$1.05 on a typical monthly residential customer bill each
10 year. If OPG were to propose a constant nuclear base rate increase that recovered the entire
11 proposed nuclear revenue requirement for the 2017 to 2021 period, that rate increase would
12 be approximately 15 per cent per year, and the customer bill impact would be over 1.2 per
13 cent annually or approximately \$1.85 on a typical monthly residential customer bill each year.

14

15 **2.2 Requirements of O. Reg. 53/05**

16 Ontario Regulation 53/05 sets out certain processes and parameters that OPG and the OEB
17 must follow regarding the smoothing of OPG's nuclear payment amounts during the deferral
18 period.³

19

20 The regulation requires that, for each year of the deferral period, the OEB must approve a
21 nuclear revenue requirement and must also determine a portion of that approved revenue
22 requirement to defer.⁴ The OEB is required to make this decision with the aim of stabilizing
23 year-over-year changes in payment amounts.⁵ Ontario Regulation 53/05 confirms that rate
24 smoothing applies when determining the amount of revenue requirement to defer and that
25 the OEB's approval of OPG's nuclear revenue requirement is not restricted by rate
26 smoothing.⁶

¹ Annual deferred amounts provided in Chart 4. The deferred amount excludes interest of approximately \$0.28B based on OPG's annual long-term debt rates discussed in Ex. C1-1-2.

² Ex. I1-3-1, Table 1, line 5.

³ O. Reg. 53/05 defines the deferral period which commences January 1, 2017 and ends when the Darlington Refurbishment Project ends.

⁴ O. Reg. 53/05, s. 5.5 (1).

⁵ O. Reg. 53/05, s. 6 (2), sub-para. 12 (i).

⁶ O. Reg. 53/05, s. 6 (2), sub-para. 12 (iii).

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Pursuant to the regulation, OPG is required to establish a rate smoothing deferral account (“RSDA”) 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 that year.⁷

Ontario Regulation 53/05 also requires OPG to record interest on the balance of the RSDA at the OEB approved long-term-debt rate for OPG, compounded annually.⁸

Ontario Regulation 53/05 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.⁹ 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 (the “recovery period”).¹⁰

2.3 Rate Smoothing Considerations

While O. Reg. 53/05 establishes certain processes and parameters governing the establishment of smoothed nuclear payment amounts, the OEB is required to apply its judgement in order to set a smoothed rate that is just and reasonable. In developing its rate smoothing proposal, OPG considered the objectives of the OEB and the Renewed Regulatory Framework for Electricity Distributors (“RRFE”) performance outcomes.¹¹ With these factors in mind, OPG developed a set of considerations that informed its rate smoothing proposal.

⁷ O. Reg. 53/05, s. 5.5 (1).

⁸ O. Reg. 53/05, s. 5.5 (2).

⁹ O. Reg. 53/05, s. 6 (2), para. 12 (ii).

¹⁰ O. Reg. 53/05, s. 6 (2), para. 12 (iv)

¹¹ *Ontario Energy Board Act, 1998*, section 1(1), in particular, “to protect the interests of consumers with respect to prices” and “to facilitate the maintenance of a financially viable electricity industry.” OPG considered the RRFE objectives of Customer Focus and Financial Performance relevant to the setting of smoothed rates.

1 FINANCIAL PERFORMANCE

2 1) Financial Viability (Leverage and Cash Flow Impacts): This criterion focuses on
3 maintaining levels for the company's credit metrics that are adequate to support an
4 investment grade credit rating, and ensuring sufficient cash flow to support the
5 company's debt and interest obligations. As discussed in Ex. C1-1-2, OPG forecasts
6 issuing \$4B in long-term debt over the 2017 to 2021 period. An investment grade
7 credit rating is critical to OPG's ability to obtain cost effective financing.

8
9 OPG used two financial metrics to gauge the potential impact of rate smoothing
10 alternatives on the above objectives: Debt-to-Earnings Before Interest Taxes
11 Depreciation and Amortization ("EBITDA") ratio and the Funds from Operations
12 ("FFO") Adjusted Interest Coverage ratio. The Debt-to EBITDA ratio is used by
13 Standard and Poor's as a measure of financial risk. A forecast Debt-to-EBITDA ratio
14 of greater than 5.5 indicates a high level of financial risk, which could lead to a credit
15 rating downgrade. The FFO Adjusted Interest Coverage ratio is reported in OPG's
16 external financial filings (i.e., Management Discussion and Analysis) as an indicator of
17 OPG's ability to support the level of debt by meeting interest obligations from
18 operating cash flows. OPG's target threshold for this ratio is a minimum of three
19 times. OPG's rate smoothing proposal reflects the company's best attempt to stay
20 within the above thresholds while taking into account the other considerations

21
22 CUSTOMER FOCUS

23 2) Rate Stability: Ontario Regulation 53/05 provides that the OEB's rate-smoothing
24 decisions should be made "with a view to making more stable the year-over-year
25 changes in the payment amount."¹² In an environment of escalating revenue
26 requirements and decreasing production, stability implies a constant rate change
27 each year of the deferral period. Stability during the RSDA recovery period¹³ would be
28 similarly achieved using the same rate change each year. For customers, stability
29 would allow them to better predict the impact of OPG generation on their electricity

¹² O. Reg. 53/05 Section 12(i)

¹³ O. Reg. 53/05 requires recovery over a period not to exceed ten years, beginning at the end of the deferral period. OPG assumes a 10 year period given the magnitude of the peak account balance

1 bills. For OPG, stable rate changes would improve the predictability of cash flows at a
2 time when the DRP and the end of commercial operations at the Pickering station are
3 expected to reduce production while drawing on OPG's financial resources. OPG's
4 proposal reflects a constant rate change during the first five years of the deferral
5 period and was developed by considering rate impacts over the full deferral and
6 recovery periods, as discussed below.

7
8 3) Long-term Perspective: As a substantial portion of the revenue requirement will be
9 deferred for future collection, the rates set in one period will necessarily affect rates to
10 be established in the future. These future rate effects should be considered when
11 setting rates for the test period, in order to avoid creating abrupt rate swings in the
12 future. Rates should be reasonable considering the entire cost deferral and recovery
13 cycle. For example, a smoothed rate that is too low during the deferral period will
14 result in large rate increases during the recovery period. The opposite is also true.

15
16 4) Post-Recovery Transition: A rate smoothing proposal should attempt to minimize rate
17 transition issues on completion of RSDA recovery. OPG's costs and production are
18 expected to be in a steady state on completion of the smoothing account recovery
19 period (i.e., the "new normal"). The average forecast unsmoothed rate (i.e., the rate
20 excluding any rate smoothing recoveries) from 2032 to 2036 is approximately
21 \$120/MWh (discussed in section 2.4). Ideally, the smoothed rate at the end of the
22 recovery period should not differ substantially from the steady state rate. This would
23 avoid abrupt rate changes following the end of the recovery period.

24
25 5) Intergenerational Equity: The fundamental concept of smoothing is that costs incurred
26 in one period are deferred for recovery in a future period. Ontario Regulation 53/05
27 supports this treatment, and provides that costs deferred for recovery will earn OPG's
28 long-term debt interest rate compounded annually as determined by the OEB. The
29 smoothed rate should balance the customer bill impacts of deferred recovery with the
30 carrying costs that will ultimately be borne by customers in subsequent periods as a
31 result of that deferral.

6) Customer Bill Impact: The four Customer Focus considerations discussed above all affect the short-term and long-term impact on customer bills. The magnitude of the customer bill impact over the full deferral and recovery period should be reasonable in the circumstances.

2.4 Rate Smoothing Alternatives

Ontario Regulation 53/05 requires the OEB to set smoothed annual payment amounts by deferring specific amounts of approved nuclear revenue requirement. In this application the OEB is setting a smoothing rate for the 2017 to 2021 period, and revenue requirement and production information for this period is required to do so. The amount of revenue requirement to be deferred each year is the net amount resulting from OEB decisions on the annual nuclear production forecasts, annual nuclear revenue requirements, and the rate of annual increase in nuclear base payment amounts. The revenue requirement and production forecasts¹⁴ proposed in this application are summarized in Chart 1. Rate smoothing alternatives are provided at the end of this section.

Chart 1
Nuclear Revenue Requirement and Production

	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

Ontario Regulation 53/05 requires the OEB to authorize recovery of the balance in the RSDA over a period not to exceed ten years.¹⁵ As the magnitude of the costs being deferred is in the billions of dollars, OPG's smoothing proposal assumes RSDA recovery over the maximum ten year period.

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

¹⁴ Production forecast details for Darlington and Pickering are provided in Ex E2-1-1 Table 1. Revenue Requirement values are net of stretch factor reductions, as presented in Ex. I1-3-1 Table 1.

¹⁵ O. Reg. 53/05 section 6 (2), subparagraph 12 (iii).

1 production for the entire deferral and recovery period is necessary context for the rate
 2 smoothing proposal. While it is not possible to forecast revenue requirement and production
 3 out 20 years with a high degree of accuracy, below OPG provides its current view of the
 4 approximate longer-term revenue requirement and production forecasts, along with indicative
 5 average rates that would result for the 2021-2036 period absent rate smoothing.

6
 7 **Chart 2**
 8 **Five-Year Revenue Requirement, Production and Average Rate**
 9 **(Absent Rate Smoothing)**

	2017-2021	2022-2026	2027-2031	2032-2036
Anticipated Revenue Requirement (\$BN)	\$ 17.0	\$ 18.1	\$ 18.2	\$ 17.1
Anticipated Production (TWh)	188	130	136	141
Average Rate (\$/MWh)	\$ 90	\$ 139	\$ 135	\$ 121

10
 11
 12 The average rate (absent rate smoothing) for the 2032 to 2036 period reflects both the
 13 planned completion of the DRP and assumed completion of activities and costs associated
 14 with the planned end of commercial operations at Pickering. OPG believes that the average
 15 forecast 2032 to 2036 rate is a reasonable proxy for the rate that will prevail after the cost
 16 deferral and recovery cycle (i.e., the “new normal”). To minimize the impact of transitioning to
 17 non-smoothed rates after the RSDA is recovered over the assumed ten year period, the final
 18 rate in the recovery period should be similar to the post-transition rate (i.e., approximately
 19 \$120/MWh forecast above).

20
 21 The following chart provides a summary of the outcomes from a range of rate smoothing
 22 alternatives. The alternatives reflect a constant annual rate increase for the ten year deferral
 23 period during which the DRP is forecast to be completed, and the resulting constant annual
 24 rate change required to recover amounts deferred and carrying costs over the following ten
 25 year recovery period. For each alternative, OPG has provided the approximate peak RSDA
 26 account balance, an estimate of the total interest accumulated in the RSDA to the end of the
 27 recovery period, projected credit metrics during the deferral period, the rate change both in
 28 \$/MWh and percentage terms on transition to the steady state rate following the recovery

1 period (i.e., approximately \$120/MWh), and an estimated average monthly customer bill
 2 impact over the full deferral and recovery periods.

3
 4
 5

Chart 3
Smoothing Alternatives – Outcomes

2017 - 2021 Rate Increase	12.0%	11.0%	10.0%	9.0%	8.0%
2022- 2026 Rate Increase	12.0%	11.0%	10.0%	9.0%	8.0%
2027 - 2035 Rate Increase	(6.4)%	(3.4)%	(0.3)%	2.6%	5.4%
Peak Account Balance (\$B)	\$2.4	\$3.5	\$5.0	\$6.9	\$9.5
2017 - 2036 Total Interest (\$B)	\$0.7	\$1.6	\$3.0	\$4.5	\$5.9
Interest Cost / Deferred Revenues Ratio	0.2	0.5	0.8	0.9	0.9
FFO Interest Coverage > = 3* (2017-2021) / (2022-2026)	3.7 / 6.3	3.6 / 5.3	3.5 / 4.5	3.5 / 3.9	3.4 / 3.3
DEBT to EBITA < = 5.5* (2017-2021) / (2022-2026)	6.1 / 5.1	6.2 / 5.3	6.3 / 5.5	6.3 / 5.7	6.4 / 6.0
Transition Impact: 2037 Rate Change (\$/MWh / %)	\$26/MWh / 27%	\$2/MWh / 2%	\$(28)/MWh / (19%)	\$(60)/MWh / (33%)	\$95/MWh / (44%)
Average Bill Impact: 2017-2036 (%)	0.2%	0.3%	0.4%	0.6%	0.8%
Average Bill Impact: 2017-2036 (\$ / month)	\$0.24	\$0.42	\$0.65	\$0.90	\$1.16

6
 7

*Weakest Ratio

8 **2.5 Application of the Criteria and OPG’s Proposal**

9 Based on its assessment of the alternatives above, using the considerations described in
 10 section 2.3, OPG proposes an 11 per cent annual nuclear base rate increase for the 2017 to
 11 2021 period. A discussion of the rationale OPG applied to evaluate each option for each of

- 1 i. Financial Viability (Leverage and Cash Flow Impacts): Higher values for the FFO
2 Adjusted Interest Coverage ratio and lower values for the Debt to EBITDA credit metric
3 reduce financial risk to OPG. OPG applied “financial viability” as a threshold criterion to
4 identify the range of potentially acceptable rate smoothing alternatives shown in Chart
5 3. OPG assessment was based on at least one of the two metrics cited above being
6 within threshold at all times during each of the two 5-year deferral periods (i.e., 2017 to
7 2021 and 2022 to 2026).
- 8 ii. Long-Term Perspective: The assessment was based on the size of the average
9 change in rates during the recovery period (closer to 0 per cent is better).
- 10 iii. Post-Recovery Transition: The assessment was based on the size of the change in
11 rates at the end of the recovery period (smaller is better) to the forecast steady state
12 rate of approximately \$120/MWh.
- 13 iv. Intergenerational Equity: The assessment was based on the ratio of total interest costs
14 to total amounts deferred (total interest / total amounts deferred). The lower the ratio,
15 the lower the cost of deferring revenue under that alternative. Intergenerational equity
16 involves striking a balance between the benefits of deferring revenue and the costs of
17 the deferral; therefore OPG’s assessment placed value on a ratio that best reflects this
18 balance (i.e., neither the highest nor the lowest ratio).
- 19 v. Customer Bill Impact: The assessment was based on average customer monthly bill
20 impacts for the entire deferral and recovery period. Consistent with the Rate Stability
21 criterion, the impact was determined using a constant rate increase during the deferral
22 period (i.e., both 2017 to 2021 and 2022 to 2026) and a constant rate change during
23 the recovery period (2027 to 2036) as identified in Chart 3. Lower customer bill
24 impacts are better.

25
26 In OPG’s assessment, the 11 per cent smoothing is the best alternative as it was either the
27 best or second best on four of the five considerations above, and no worse than third best on
28 the remaining consideration. The proposed nuclear payment amounts proposed in Ex. I1-3-1
29 have been determined based on this level of deferred recovery. OPG therefore proposes to
30 defer the collection of approximately \$1.6B in nuclear revenue requirements for 2017 through

1 2021, which is the sum of the deferred revenue requirement amounts for those years shown
2 in Chart 4.

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4
5

Chart 4

OPG Proposed Deferred Nuclear Revenue Requirement¹⁷

	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
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)

6
7

3.0 MID-TERM PRODUCTION REVIEW

9 OPG seeks approval of a mid-term production review in the first half of 2019 (i.e., prior to
10 July 1, 2019) for:

- 11 1) an update of the nuclear production forecast and consequential updates to nuclear fuel
12 costs underpinning the payment amounts for the final two-and-a-half years of the five-
13 year application period (July 1, 2019 to December 31, 2021); and
- 14 2) disposal of applicable audited deferral and variance account balances (most accounts
15 would reflect amounts accumulated over the period January 1, 2016 to December 31,
16 2018) as well as any remaining unamortized portions of previously approved amounts
17 with recovery period extending beyond December 31, 2018.

18

3.1 Rationale for Mid-Term Review

20 In this application, OPG has provided a nuclear production forecast that covers the full five-
21 year period from January 1, 2017 to December 31, 2021. The company's nuclear production
22 forecast and forecasting process are described in detail in Ex. E2-1-1. The production forecast
23 is based on a set of current assumptions that are challenging to meet, with the risk of

¹⁷ Proposed Revenue Requirement per Ex I-1-1 Table 2
Forecast Production per Ex E-2-1 Table 1
Smoothed Rate determined by escalating the existing \$59.29 approved nuclear payment amount from EB-2013-0321 by 11% each year
Smoothed Revenue determined by applying the Smoothed Rate to the Forecast Production
Deferred Revenue calculated as the difference between the Proposed Revenue Requirement and the Smoothed Revenue

1 deviations from forecast increasing into the second half of the application. OPG's mid-term
2 review application will include the revised production forecast underpinning its latest approved
3 business plan for the period July 1, 2019 to December 31, 2021 (the "mid-term production
4 forecast"). The mechanics of the mid-term review proposal are discussed in section 3.2.

5
6 Substantial uncertainty exists relating to events that could result in substantial impacts on
7 OPG's production in the latter half of OPG's five-year application. Circumstances could result
8 in substantially higher or lower production than currently forecast. If production is higher than
9 forecast, customer bills would be unnecessarily inflated (i.e., the higher production would
10 result in a credit balance in the proposed Mid-term Nuclear Production Variance Account, to
11 be refunded to customers in the next payment amount application). If production is lower than
12 forecast, OPG may not recover its revenue requirement. Mitigating this risk benefits both
13 customers and the company.

14
15 OPG expects that the nuclear production forecast that will be included in its future approved
16 business plans will reflect an increased level of certainty related to events that may affect
17 production during the second half of the test period, providing a sufficiently robust basis for
18 setting reasonable production performance targets for the second half of the test period that
19 would be fair to both customers and OPG.

20
21 As discussed during consultation with stakeholders, several factors make it extremely difficult
22 to accurately forecast OPG's annual nuclear production over the five-year period covered by
23 this application:

- 24 i. Public Policy Changes: Changes to public policy, especially the Government of
25 Ontario's Long Term Energy Plan ("LTEP") could impact OPG's nuclear production. In
26 particular, a change to the refurbishment schedule for future units at the Darlington
27 generating station could materially alter OPG's production schedule within the period
28 of this Application.
- 29 ii. Pickering Extended Operations: Canadian Nuclear Safety Commission ("CNSC")
30 approval is still required and, as discussed in Ex. F2-2-3, OPG has not yet completed

- 1 work necessary to confirm that the Pickering units would be fit to operate beyond
2 2020.
- 3 iii. Execution of Darlington Refurbishment Program: If refurbishment of the first unit at
4 Darlington is completed earlier or later than scheduled, production may vary. In
5 addition, there is a risk that the post-refurbishment forced loss rate at Darlington may
6 vary from OPG's current forecast. These factors have the potential to materially
7 decrease or increase production, depending on the circumstances.
- 8 iv. Regulatory Requirements and Approvals: OPG's nuclear facilities are subject to
9 significant regulatory oversight. Changing requirements and work required to comply
10 with existing requirements have the potential to affect OPG's nuclear production
11 forecast.
- 12 v. Aging Facilities: The risk of unplanned outages increases as units begin to approach
13 their end of life, in particular for Pickering given on-going work on asset condition
14 assessment and fuel channel work and pending CNSC licence renewals.

15

16 OPG expects that it will be better able to assess these and other risks, and their potential
17 effect on production, at the time of the proposed mid-term review.

18

19 The mid-term review of nuclear production is also consistent with the rate-smoothing
20 requirements in O. Reg. 53/05 and would protect both customers and OPG. The regulation
21 requires the OEB to determine revenue requirements for the nuclear facilities for each year
22 on a five-year basis, and to determine the portion of the approved revenue requirement to be
23 recorded in the RSDA.¹⁸ Subject to the OEB concluding that rates are no longer just and
24 reasonable pursuant to Section 78.1 of the Act, the regulation does not entitle the OEB to
25 revisit those approved revenue requirement amounts during the five years. However, while
26 the revenue requirement must be determined on a five-year basis, no such limitation exists
27 for the determination of production.

28

29 The production forecast is a critical element of OPG's rate-setting framework given OPG's
30 rate structure. As noted in Ex. E2-1-1, there are a number of factors that could materially

¹⁸ O. Reg. 53/05, sub-paragraphs 6(2)12 (i) and (ii).

1 impact OPG's production which are too uncertain to predict with reasonable precision. Given
2 the relatively long term of this application and the uncertainty of nuclear production during
3 that period, a mid-term review of nuclear production and related fuel costs for the second half
4 of the application term (i.e., July 1, 2019 to December 31, 2021) would help address the
5 forecast uncertainty inherent in OPG's production forecast as it looks further into the future
6 and provides a basis to set reasonable production performance targets for the second half of
7 the application term.

8
9 In general, it is more difficult to forecast events further in the future. This difficulty increases
10 further when the subject matter of the forecast is inherently uncertain. Since the inception of
11 regulation by the OEB, there have been a number of variances between OEB approved and
12 actual production. It has proven difficult to forecast nuclear production in the past where
13 OPG's Pickering and Darlington facilities were operating in a comparatively steady state
14 compared to the operating circumstances that will be facing these facilities during the
15 application period. Even with a mid-term review, the proposed ratemaking methodology will
16 result in a significant increase in production forecast risk compared to previous applications.¹⁹

17
18 As discussed in Ex. A1-3-2, a completely variable rate provides a strong financial incentive to
19 OPG to achieve or surpass the OEB approved production forecast, thereby increasing the
20 quality of service (e.g., increased availability, reduced EFOR) provided to customers. The
21 approved production forecast is effectively a performance target with financial rewards and
22 penalties.

23 24 **3.2 Mechanics of Mid-Term Production Review**

25 OPG proposes to file an application to review the company's updated nuclear production
26 forecast and associated fuel costs in the first quarter of 2019. The scope of this application
27 would be limited to a review of OPG's nuclear production forecast for the period from July 1,
28 2019 to December 31, 2021, any consequential revisions to forecast fuel costs, and the
29 disposition of audited December 31, 2018 balances in deferral and variance accounts

¹⁹ In previous applications, OPG's payment amounts have been based on forecast production of two years or less.

1 including any remaining unamortized portions of previously approved amounts with recovery
2 periods extending beyond December 31, 2018. OPG does not propose to re-open any other
3 elements of this Application in the mid-term review.

4

5 The application will present the impact of the production variance from July 1, 2019 to
6 December 2021. The production variance will be the difference between: (i) the nuclear
7 production forecast approved in this Application and, (ii) the nuclear production forecast
8 proposed by OPG in the mid-term review application. The annual production variance will be
9 multiplied by the net of the approved smoothed nuclear payment amount and the average
10 fuel cost in the approved revenue requirement for the applicable year. The amounts
11 determined above will be recorded in the proposed Mid-Term Nuclear Production Variance
12 Account described in Ex H1-1-1.

DRIVERS OF DEFICIENCY

1.0 PURPOSE

This evidence presents the major drivers of revenue deficiency for the nuclear facilities over the 2017-2021 period as determined in Ex. I1-1-1 Table 3.

2.0 OVERVIEW

The revenue deficiency for the nuclear facilities over the 2017-2021 period is driven in largely equal parts by (i) lower nuclear production, which reflects the commencement of Darlington refurbishment outages and outage days related to Pickering Extended Operations¹, and (ii) increases in revenue requirement relative to the annual average of the 2014 and 2015 revenue requirement approved in EB-2013-0321.

The largest drivers of changes in revenue requirement are described below, the largest of which is the Darlington Refurbishment Program (“DRP”). The annual revenue deficiency impact of the production and revenue requirement drivers are detailed in Chart 1 and explained in section 3.0 below.

3.0 DRIVERS OF DEFICIENCY FOR THE NUCLEAR FACILITIES

3.1 Lower Production

Relative to the annual average of the OEB-approved nuclear production for 2014 and 2015, forecast nuclear production declines by 9.7TWh for 2017, 9.3TWh for 2018, 8.8TWh for 2019, 10.4TWh for 2020, and 12.4TWh for 2021. The comparison of production forecasts in Ex. E2-1-2 identifies the drivers of production forecast changes. The primary drivers of lower production are the units taken out of service for DRP,² and the incremental outage requirements resulting from Pickering Extended Operations between 2017 and 2020.

¹ The overall impact of Pickering Extended Operations is to increase production in the 2017-2021 test period relative to the original planned end of commercial operations in 2020. Pickering Extended Operations is a driver of deficiency relative to 2014/15 payment amounts due to decreased production and increased costs in 2017-2020 in order to execute outages to enable extension.

² Unit 2 in 2016, Unit 3 in 2020 and Unit 1 in 2021.

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3.2 Darlington Refurbishment (42 per cent of revenue requirement impact)

The DRP impacts primarily reflect an increase in the cost of capital and depreciation expense, and related income taxes resulting from rate base in-service additions for refurbishment capital projects. OPG forecasts over \$700M in such rate base additions over the 2016-2019 period, and approximately \$4.8B in 2020 when Unit 2 returns to service.³ The DRP impacts also include DRP-related nuclear OM&A expenses, which are related to the removal activities associated with existing structures or facilities including re-tube and feeder replacement and waste management costs.⁴

3.3 Pickering Extended Operations Enabling Costs (10 per cent of revenue requirement impact)

The positive economic evaluations of Pickering Extended Operations from OPG and the IESO are provided at Ex. F2-2-3. Forecast OM&A expenses to 2020 to enable Pickering Extended Operations are another driver of the higher revenue requirement relative to EB-2013-0321 approved levels. These costs total \$292M over the 2017 to 2020 period as presented in Ex. F2-2-3 Chart 2.

3.4 Impact of Changes in Nuclear Station End-of-Life Dates on Nuclear Liabilities (13 per cent of revenue requirement impact)

Accounting changes in nuclear station end-of-life dates⁵ impact OPG's nuclear decommissioning and nuclear used fuel and waste management liability ("nuclear liabilities") costs. As further discussed in Ex. C2-1-1 and detailed in Ex. C2-1-1 Table 5, the net impact (for both prescribed and Bruce facilities and including associated income taxes) relates to the increase in the nuclear asset retirement obligation ("ARO") and corresponding increase in nuclear asset retirement costs ("ARC") of approximately \$2.3B recorded by OPG at the end of 2015. This increase was primarily driven by the extension of the accounting service life for the Bruce B nuclear units to recognize the Province's December 2015 announcement of an updated refurbishment agreement between the IESO and Bruce Power L.P. The net increase

³ Ex. D2-2-10.
⁴ Ex F2-7-1 Table 1, footnote 1.
⁵ Effective December 31, 2015. Discussed in Ex. F4-1-1.

1 in the revenue requirement consists of an increase related to the Bruce facilities (through a
2 reduction in Bruce Lease net revenues) and a decrease related to the prescribed nuclear
3 facilities.

4
5 **3.5 Remaining Depreciation and Amortization Expense (13 per cent of revenue**
6 **requirement impact)**

7 Remaining nuclear depreciation and amortization expense is the change in depreciation and
8 amortization expense excluding that related to DRP and nuclear liability costs, which are
9 discussed above. Remaining nuclear depreciation and amortization expense for prescribed
10 facilities (including the associated tax gross-up) is forecast to be higher over the 2017-2020
11 period, reflecting nuclear operations capital in-service additions to rate base. Depreciation
12 and amortization expense declines significantly in 2021, as Pickering reaches the facility's
13 assumed end of life date of December 31, 2020. Depreciation and amortization expense is
14 presented in Ex. F4-1-1.

15
16 **3.6 Outage OM&A Expenses (7 per cent of revenue requirement impact)**

17 Forecast nuclear outage OM&A expenses⁶ are higher in the test period, primarily due to a
18 number of planned outages in accordance with OPG's aging and life cycle management
19 programs, in addition to and separate from the refurbishment of the Darlington units. The
20 outage work in 2017-2019 effectively replaces two scheduled planned outages for Unit 2 in
21 2016 and 2019 which would otherwise have been undertaken absent Unit 2 refurbishment.
22 In addition, Pickering's outage OM&A expenses in 2020 include costs for preparatory work
23 for a 2021 Vacuum Building Outage ("VBO") (planned every 12 years) and the outage OM&A
24 forecast in 2021 includes expenditures associated with a six-unit VBO. Additional detail on
25 outage activities and costs is provided in Ex. F2-4-1 and Ex. F2-4-2.

26
27 **3.7 Remaining/Other OM&A Expenses (15 per cent of revenue requirement impact)**

28 Remaining/Other OM&A expenses changes in OM&A expenses that do not include DRP-
29 related increases in OM&A, Pickering Extended Operations enabling costs or nuclear outage
30 costs. The primary driver of an increase in remaining/ other OM&A is an increase in nuclear

⁶ Other than enabling costs for Pickering Extended Operations discussed in section 3.6 above.

1 base OM&A costs mainly due to labour cost escalation reflecting collective agreement
2 provisions. Nuclear base OM&A costs are presented in Ex. F2-2-1 and Ex. F2-2-2.
3 Compensation and benefits are discussed in Ex. F4-3-1.

4
5 **3.8 Fuel Costs (-8 per cent of revenue requirement impact)**

6 Fuel costs discussed here exclude those related to the nuclear liabilities adjustment
7 discussed above. The forecast decrease in fuel costs for the prescribed nuclear facilities over
8 the 2017-2021 period reflects lower generation, as discussed above, and lower fuel bundle
9 costs. The lower forecast fuel bundle costs are primarily due to lower cost of uranium
10 concentrate partially offset by higher prices for conversion services and fuel bundle
11 manufacturing. Nuclear fuel costs are discussed in Ex. F2-5-1 and Ex. F2-5-2.

12
13 **3.9 Other (8 per cent of revenue requirement impact)**

14 The "Other" revenue requirement driver category includes a number of factors. The two main
15 causes of the increase in this cost driver are a decline in non-energy revenue and lower
16 Bruce Lease net revenues (other than the impact of the 2015 nuclear liabilities adjustment
17 and station end-of-life changes discussed in section 3.4). The decline in non-energy
18 revenues is primarily the result of lower heavy water sales due to the depletion of inventory.
19 Lower Bruce Lease net revenues are due to a combination of factors including lower forecast
20 lease revenues and higher used fuel expenses, which are partially offset by higher forecast
21 service revenue. Non-energy revenue is discussed in Ex. G2-1-1 and Ex. G2-1-2, Bruce
22 Lease net revenues are discussed in Ex. G2-1-1

23
24 The remaining costs in this category consist of a residual increase in the cost of capital and
25 associated tax gross-up, lower property taxes and residual fluctuations in income taxes not
26 included in the drivers discussed above. The residual increase in the cost of capital and
27 associated taxes is mainly due to increases in the non-DRP components of component of
28 rate base from forecast in-service additions at Darlington. Taxes are discussed in Ex. F4-2-1
29 and cost of capital is discussed in Ex C1-1-1, C1-1-2 and C1-1-3.

1

Chart 1: Nuclear Deficiency for 2017 - 2021 Period

Line No		(\$M) 2017	(\$M) 2018	(\$M) 2019	(\$M) 2020	(\$M) 2021	Reference
1	EB-2013-0321 Average Approved 2014 & 2015 Revenue Requirement	2,834.0	2,834.0	2,834.0	2,834.0	2,834.0	Note 1a
2	Revenue at EB-2013-0321 Payment Amount (\$59.29/MWh)	2,258.9	2,280.9	2,313.9	2,214.8	2,097.9	Note 2a
3	Lower Production (line 1 - line 2)	575.2	553.1	520.2	619.2	736.1	
	Changes in Revenue Requirement:						
4	Darlington Refurbishment	78.0	29.5	(6.6)	542.3	574.0	Note 3a
5	Pickering Extended Operations Enabling Costs	25.6	55.3	107.1	104.3	0.0	Ex. F2-2-3 Chart 2
6	Impact of Changes in Nuclear Station End-of-Life Dates on Nuclear Liabilities	31.8	36.2	42.2	129.7	132.2	Ex. C2-1-1 Table 5, line 17
7	Remaining Depreciation and Amortization Expense (other than lines 4 & 6)	99.9	136.9	143.7	132.4	(141.7)	Note 4a
8	Outage OM&A Expenses (other than line 5)	75.8	59.8	29.9	12.2	11.8	Note 5a
9	Remaining/Other OM&A Expenses (other than lines 4, 5, 6 and 8)	62.2	84.7	93.9	89.6	103.6	Note 6a
10	Fuel Costs (other than line 6)	(49.8)	(47.8)	(37.5)	(41.4)	(56.7)	Note 7a
11	Other	32.6	66.3	88.4	(13.2)	52.5	Note 8a
12	Total Change in Revenue Requirement (lines 4 through 11)	355.9	420.9	461.1	956.0	675.8	
13	Total Revenue Deficiency (line 3 + line 12)	931.1	974.0	981.2	1,575.2	1,411.9	Ex. I1-1-1 Table 3, line 5

Notes

1a Ex. I1-1-1 Table 2, Line 11

OEB APPROVED		
2014	2015	AVERAGE
2,790.4	2,877.6	2,834.0

2a

REDUCED PRODUCTION	2017	2018	2019	2020	2021
Test Period Production (Ex. E2-1-1 Table 1, line 3, cols. (e) to (i)) (TWh)	38.1	38.5	39.0	37.4	35.4
Nuclear Base Payment Amount (EB-2013-0321 Payment Amount Order, App D, line 3) (\$/MWh)	\$59.29	\$59.29	\$59.29	\$59.29	\$59.29
Forecast Revenue (\$M)	2,258.9	2,280.9	2,313.9	2,214.8	2,097.9

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Note	Driver of Revenue Requirement Change	EB-2016-0152	EB-2013-0321 <i>(references shown are to EB-2016-0152 exhibits unless otherwise noted)</i>
3a	Impact of Darlington Refurbishment Program (DRP)	DRP revenue requirement impact comprises:	
		OM&A Expenses Ex. F2-1-1 Table 1, line 5, cols. (e) to (i)	OM&A Expenses Ex. H1-1-1 Table 11a, Table to Note 1, col. (a), line 4a
		Cost of Capital (Ex. B3-1-1 Table 1, line 9, cols. (f) and (i) and line 16 (cols. (c),(f) and (i)) x Ex. C1-1-1 Tables 1-5 col. (c), line 8)	Cost of Capital Ex. H1-1-1 Table 11a, Table to Note 6, col. (c), line 3b
		Depreciation Ex. F4-1-1 Table 2, line 2, cols. (e) to (i)	Depreciation Ex. H1-1-1 Table 11a, Table to Note 6, col. (c), line 5b
		Income Tax [(Ex. B3-1-1 Table 1, line 9, cols. (f) and (i) and line 16, cols. (c), (f) and(i) x Ex. C1-1-1 Tables 1-5, col. (b), line 5 x Ex. C1-1-1 Tables 1-5, col. (c), line 5) + Ex. F4-1-1 Table 2, line 2, cols. (e) to (i), less Ex. F4-2-1 Table 3b, Note 3] x 25% / (1-25%)	Income Tax (Ex. H1-1-1 Table 11a, Table to Note 6, col. (c), lines 4b+ 5b-6b) x 25% / (1-25%)
4a	Impact of Other Depreciation and Amortization Expense	Impact of Other Depreciation and Amortization Expense is calculated as:	
		Total Depreciation Ex. I1-1-1 Table 1, line 17, cols. (a) to (e)	Total Depreciation and Amort. Ex. I1-1-1 Table 2, line 4, (cols. (a)+(b))/2
		Less: Darlington Refurbishment Depreciation Ex. F4-1-1 Table 2, line 2, cols. (e) to (i)	Less: Darlington Refurbishment Depreciation Ex. H1-1-1 Table 11a, Table to Note 6, col. (c), line 5b
		Less: Impact of Changes in Station EOL dates on Nuclear Liabilities Ex. C2-1-1 Table 5, line 1, cols. (a) to (e) less cols. (f) to (j)	
5a	Increase in Outage OM&A Expenses	Outage OM&A expenses are calculated as:	
		Total Outage OM&A Ex. F2-4-1 Table 1, line 7, cols. (e) to (i)	Total Outage OM&A EB-2013-0321: Ex. F2-4-1 Table 1, line 6 (cols. (e)+(f))/2
		Less: Pickering Extended Operations Enabling Costs (Outage OM&A) Ex. F2-2-3 Chart 2, line 5	
6a	Other OM&A Expenses	Other OM&A Expenses are calculated as:	
		Total OM&A Expenses Ex. I1-1-1 Table 1, line 15, cols. (a) to (e)	Total OM&A Expenses Ex. I1-1-1 Table 2, line 2 (cols. (a)+(b))/2
		Less: Outage OM&A As calculated in Note 5a	Less: Total Outage OM&A EB-2013-0321: Ex. F2-4-1 Table 1, line 6 (cols. (e)+(f))/2
		Operations Enabling Costs Line 5	
		OM&A Expenses Ex. F2-1-1 Table 1, line 5, cols. (e) to (i)	OM&A Expenses Ex. H1-1-1 Table 11a, Table to Note 1, col. (a), line 4a
		Less: Impact of Changes in Station EOL dates on Nuclear Liabilities Ex. C2-1-1 Table 5, line 3, cols. (a) to (e) less cols. (f) to (j)	
7a	Decrease in Fuel Costs	Fuel Costs are calculated as:	
		Total Fuel Expense Ex. I1-1-1 Table 1, line 16, cols. (a) to (e)	Total Fuel Expense Ex. I1-1-1 Table 2, line 3 (cols. (a)+(b))/2
		Less: Impact of Changes in Station EOL dates on Nuclear Liabilities Ex. C2-1-1 Table 5, line 2, cols. (a) to (e) less cols. (f) to (j)	
8a	Other	Impact of Other is calculated as:	
		Total Revenue Requirement Ex. I1-1-1 Table 1, line 24, cols. (a) to (e)	Total Revenue Requirement Ex. I1-1-1 Table 2, line 11 (cols. (a)+(b))/2
		Less: Revenue requirement change factors identified Notes 3a to 7a + Line 5 + Line 6	Less: Revenue requirement change factors identified Notes 3a to 7a

Note	Driver of Revenue Requirement Change	EB-2016-0152	EB-2013-0321 <i>(references shown are to EB-2016-0152 exhibits unless otherwise noted)</i>
3a	Impact of Darlington Refurbishment Program (DRP)	DRP revenue requirement impact comprises:	
		OM&A Expenses Ex. F2-1-1 Table 1, line 5, cols. (e) to (i)	OM&A Expenses Ex. H1-1-1 Table 11a, Table to Note 1, col. (a), line 4a
		Cost of Capital (Ex. B3-1-1 Table 1, line 9, cols. (f) and (i) and line 16 (cols. (c),(f) and (i)) x Ex. C1-1-1 Tables 1-5 col. (c), line 8)	Cost of Capital Ex. H1-1-1 Table 11a, Table to Note 6, col. (c), line 3b
		Depreciation Ex. F4-1-1 Table 2, line 2, cols. (e) to (i)	Depreciation Ex. H1-1-1 Table 11a, Table to Note 6, col. (c), line 5b
		Income Tax [(Ex. B3-1-1 Table 1, line 9, cols. (f) and (i) and line 16, cols. (c), (f) and(i) x Ex. C1-1-1 Tables 1-5, col. (b), line 5 x Ex. C1-1-1 Tables 1-5, col. (c), line 5) + Ex. F4-1-1 Table 2, line 2, cols. (e) to (i), less Ex. F4-2-1 Table 3b, Note 3] x 25% / (1-25%)	Income Tax (Ex. H1-1-1 Table 11a, Table to Note 6, col. (c), lines 4b+ 5b-6b) x 25% / (1-25%)
4a	Impact of Other Depreciation and Amortization Expense	Impact of Other Depreciation and Amortization Expense is calculated as:	
		Total Depreciation Ex. I1-1-1 Table 1, line 17, cols. (a) to (e)	Total Depreciation and Amort. Ex. I1-1-1 Table 2, line 4, (cols. (a)+(b))/2
		Less: Darlington Refurbishment Depreciation Ex. F4-1-1 Table 2, line 2, cols. (e) to (i)	Less: Darlington Refurbishment Depreciation Ex. H1-1-1 Table 11a, Table to Note 6, col. (c), line 5b
		Less: Impact of Changes in Station EOL dates on Nuclear Liabilities Ex. C2-1-1 Table 5, line 1, cols. (a) to (e) less cols. (f) to (j)	
5a	Increase in Outage OM&A Expenses	Outage OM&A expenses are calculated as:	
		Total Outage OM&A Ex. F2-4-1 Table 1, line 7, cols. (e) to (i)	Total Outage OM&A EB-2013-0321: Ex. F2-4-1 Table 1, line 6 (cols. (e)+(f))/2
		Less: Pickering Extended Operations Enabling Costs (Outage OM&A) Ex. F2-2-3 Chart 2, line 5	
6a	Other OM&A Expenses	Other OM&A Expenses are calculated as:	
		Total OM&A Expenses Ex. I1-1-1 Table 1, line 15, cols. (a) to (e)	Total OM&A Expenses Ex. I1-1-1 Table 2, line 2 (cols. (a)+(b))/2
		Less: Outage OM&A As calculated in Note 5a	Less: Total Outage OM&A EB-2013-0321: Ex. F2-4-1 Table 1, line 6 (cols. (e)+(f))/2
		Operations Enabling Costs Line 5	
		OM&A Expenses Ex. F2-1-1 Table 1, line 5, cols. (e) to (i)	OM&A Expenses Ex. H1-1-1 Table 11a, Table to Note 1, col. (a), line 4a
		Less: Impact of Changes in Station EOL dates on Nuclear Liabilities Ex. C2-1-1 Table 5, line 3, cols. (a) to (e) less cols. (f) to (j)	
7a	Decrease in Fuel Costs	Fuel Costs are calculated as:	
		Total Fuel Expense Ex. I1-1-1 Table 1, line 16, cols. (a) to (e)	Total Fuel Expense Ex. I1-1-1 Table 2, line 3 (cols. (a)+(b))/2
		Less: Impact of Changes in Station EOL dates on Nuclear Liabilities Ex. C2-1-1 Table 5, line 2, cols. (a) to (e) less cols. (f) to (j)	
8a	Other	Impact of Other is calculated as:	
		Total Revenue Requirement Ex. I1-1-1 Table 1, line 24, cols. (a) to (e)	Total Revenue Requirement Ex. I1-1-1 Table 2, line 11 (cols. (a)+(b))/2
		Less: Revenue requirement change factors identified Notes 3a to 7a + Line 5 + Line 6	Less: Revenue requirement change factors identified Notes 3a to 7a

OVERVIEW OF OPG

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1.0 PURPOSE

This evidence provides an overview of OPG, including a summary of its mandate, objectives, key assets, corporate governance and organization. OPG's nuclear and regulated hydroelectric businesses are described in Ex. A1-4-2 and Ex. A1-4-3, respectively.

2.0 CORPORATE OVERVIEW

OPG is an electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG's focus is on the effective stewardship of generation assets owned by the people of Ontario. This is achieved by focusing on: (i) the safe, reliable operation of its facilities including the avoidance of harm to employees, contractors, and the public at large, (ii) the management of these facilities by maintaining a strong focus on delivering value for money and (iii) adhering to the highest standards of corporate citizenship, including a commitment to environmental and social objectives.

As part of its business, OPG owns and operates both regulated and unregulated generation facilities. OPG's regulated generation facilities consist of two nuclear generating stations with a total generation capacity of 6,606 MW and 54 regulated hydroelectric generating stations with a total generation capacity of 6,425 MW, for a combined regulated generation capacity of 13,031 MW.

While not regulated facilities, the Bruce A and B Generating Stations have an impact on the calculation of the payment amounts. These stations are owned by OPG and leased on a long-term basis to Bruce Power L.P. The revenues from the lease, net of costs, are used to reduce the payment amounts for the regulated facilities.

The locations of the regulated facilities and other OPG facilities are illustrated on the map provided as Attachment 1.

1 In 2015, OPG's regulated facilities generated a total of 74.7 TWh, representing
2 approximately 55 per cent of the total electricity generated in the Province of Ontario (137.0
3 TWh). The nuclear facilities generated 44.5 TWh and the regulated hydroelectric facilities
4 generated 30.2 TWh, or approximately 60 per cent and 40 per cent of OPG's total regulated
5 energy production, respectively. Further details on the regulated facilities are provided in Ex.
6 A1-4-2 and Ex. A1-4-3.

7

8 In addition to generating electricity for sale to the IESO-administered market, OPG's
9 regulated assets sell ancillary products to the IESO markets, including operating reserve,
10 voltage control/reactive support, black start capability, and automatic generation control.
11 Revenues associated with sales of ancillary products from the regulated facilities are
12 discussed in Exhibit G - Other Revenues.

13

14 **3.0 OPG GOVERNANCE AND ORGANIZATION**

15 OPG's Board of Directors ("OPG Board") is appointed by the shareholder. The OPG Board
16 currently has 15 members, who bring substantial expertise in managing large businesses,
17 managing and operating nuclear stations, managing capital-intensive companies, and
18 overseeing regulatory, government, and public relations. The OPG Board has established
19 the following committees to focus on areas critical to OPG's success:

20

- 21 • **Audit and Risk Committee:** The Audit and Risk Committee is responsible for the
22 integrity, quality and transparency of OPG's financial information, the adequacy of the
23 financial reporting process, the systems of internal controls, and OPG's related
24 principles, policies and procedures which management has established. The
25 Committee is responsible for the oversight of the Company's regulatory filings,
26 financial statements, and other annual disclosures. The Committee also provides
27 oversight of the performance of the OPG Pension Fund, the Used Fuel Segregated
28 Fund and the Decommissioning Segregated Fund. Additionally, the Committee is
29 responsible for the oversight of enterprise-wide risk and associated risk management
30 activities. The Committee reviews management's assessment of the principal risks to

1 achieving the Company's strategic and business plan objectives and the strategies
2 for monitoring and responding to these risks.

- 3
- 4 • **Compensation, Leadership and Governance Committee:** The Compensation,
5 Leadership and Governance Committee provides oversight of OPG's human
6 resources and compensation policies and practices, including Chief Executive Officer
7 ("CEO") objectives and compensation, disclosure on compensation and human
8 resources matters, leadership talent review, succession planning, labour negotiations
9 and human resources policies. The Committee also oversees the OPG Board's
10 governance program and practices to ensure alignment with corporate governance
11 best practices, including annually reviewing and assessing the OPG Board's system
12 of corporate governance.
 - 13
 - 14 • **Generation Oversight Committee:** The Generation Oversight Committee is
15 responsible for the oversight of safe, secure and efficient operations of OPG's
16 generating facilities. The Committee is responsible for reviewing significant
17 operational, transactional and strategic risks against business plan objectives.
18 Additionally, the Committee oversees the development, risk management, financing
19 and execution of new and existing generation projects. The Committee is responsible
20 for reviewing the results of assessments by regulators and/or independent oversight
21 organizations, including proposed remediation programs. The Committee ensures
22 that OPG's generating facilities comply with nuclear, health and safety, and
23 environmental laws and regulations.
 - 24
 - 25 • **Darlington Refurbishment Committee:** The Darlington Refurbishment Committee is
26 responsible for the oversight of the Darlington Refurbishment Project. The Committee
27 is responsible for retaining external independent oversight advisors and reviewing
28 results and/or major findings from external assessments and management's
29 proposed remediation programs and plans. The Committee monitors progress of the
30 refurbishment project against the final approved execution scope, budget and
31 schedule as well as project risks and associated mitigation plans.

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OPG's senior management team is led by OPG's President and CEO, who is also a member of the OPG Board. The leaders of the nuclear and regulated hydroelectric business units report to the President and CEO. The organization and management of the nuclear and the regulated hydroelectric business units, which are the subject of this Application, are described in greater detail in Ex. A1-4-2 and Ex. A1-4-3, respectively.

Also reporting directly to the President and CEO are the various functions that provide support to the operational business units. These include Business and Administrative Services, Finance, People and Culture, and Law. Please refer to the organizational chart provided in Ex. A1-5-1 for further detail.

4.0 OPG's MANDATE AND OBJECTIVES

In addition to being governed by the various policies in areas such as safety, Code of Business Conduct, disclosure and the environment, OPG is subject to the terms of a Memorandum of Agreement between the Shareholder and OPG, dated July 17, 2015 (the "Memorandum of Agreement"), which sets out the Shareholder's expectations regarding OPG's mandate, governance framework, generation performance and investment, financial framework and communications. The Memorandum of Agreement confirms that OPG will operate as a business enterprise with a commercial mandate, governed in principle and at first instance by an independent Board of Directors. The Memorandum of Agreement is provided in Attachment 2.

The Memorandum of Agreement further states that the Shareholder may at times direct OPG to undertake special initiatives, which will be communicated as written declarations by way of a Unanimous Shareholder Agreement, or Declaration, in accordance with section 108 of the *Business Corporations Act* (Ontario) and made public. Copies of the shareholder directives that OPG has received are posted on OPG's website at:

<http://www.opg.com/about/management/open-and-accountable/Pages/shareholder-directives.aspx>.

LIST OF ATTACHMENTS

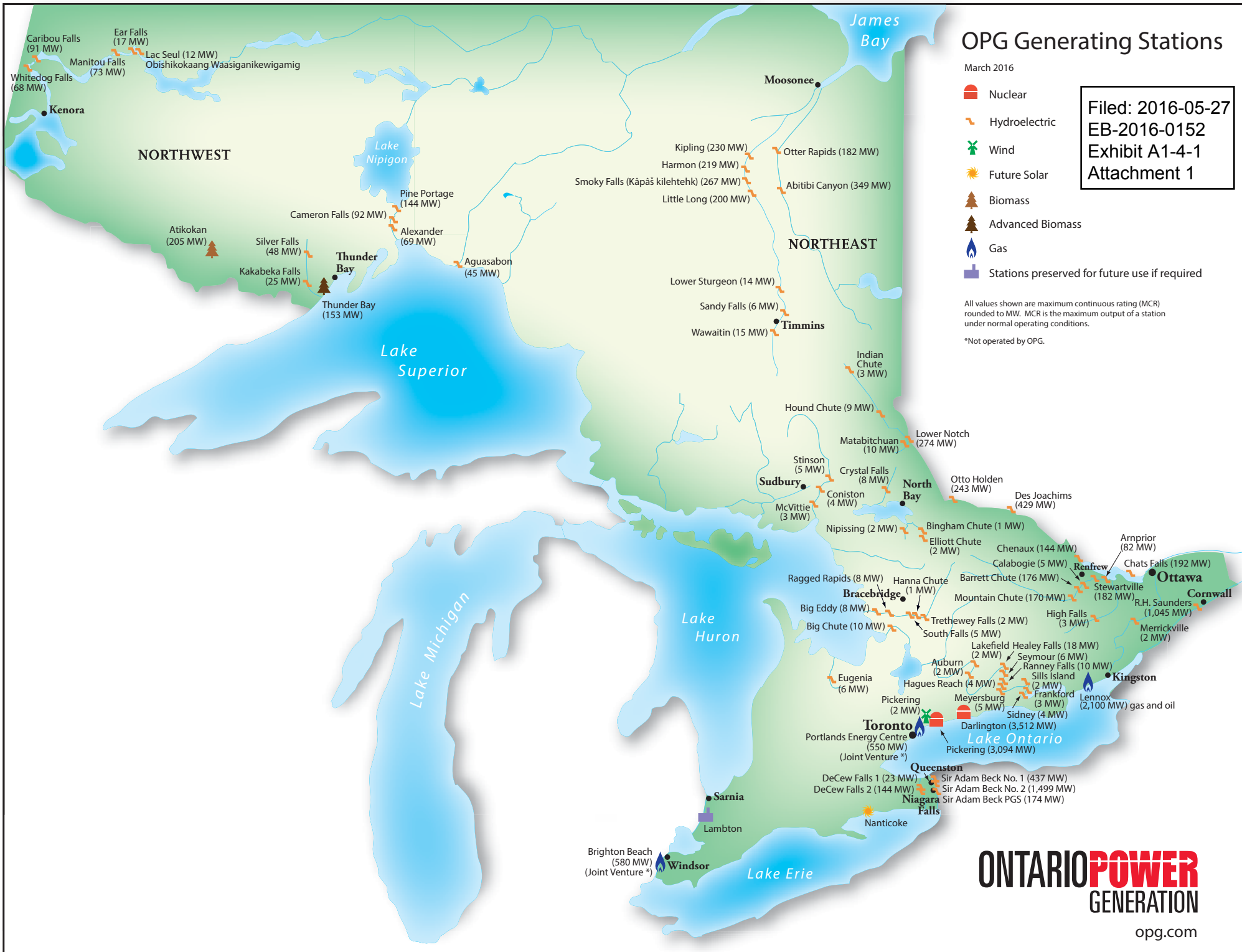
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3 Attachment 1: Map showing locations of the regulated facilities and other OPG
4 facilities

5

6 Attachment 2: Memorandum of Agreement between the Shareholder and OPG



OPG Generating Stations

March 2016

- Nuclear
- ⚡ Hydroelectric
- ✚ Wind
- ☀ Future Solar
- 🌲 Biomass
- 🌲 Advanced Biomass
- 🔥 Gas
- Stations preserved for future use if required

Filed: 2016-05-27
 EB-2016-0152
 Exhibit A1-4-1
 Attachment 1

All values shown are maximum continuous rating (MCR) rounded to MW. MCR is the maximum output of a station under normal operating conditions.

*Not operated by OPG.

ONTARIO POWER
 GENERATION

opg.com

MEMORANDUM OF AGREEMENT

BETWEEN

Her Majesty the Queen in right of Ontario, as represented by the
Minister of Energy (the "Shareholder" or "Minister")

And

Ontario Power Generation, Inc. ("OPG")

MEMORANDUM OF AGREEMENT

BETWEEN

Her Majesty the Queen in right of Ontario as represented by the Minister of Energy (the "Shareholder" or "Minister")

And

Ontario Power Generation, Inc. ("OPG") or the "Corporation"

WHEREAS OPG is a business corporation incorporated under the *Business Corporations Act* (Ontario) (BCA).

AND WHEREAS The Minister, on behalf of Her Majesty in right of Ontario, may acquire and hold shares of OPG, and has primary policy responsibility for the overall legislative and regulatory framework, established primarily under the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998*, and the applicable regulations, within which OPG must conduct its business operations .

NOW THEREFORE the parties hereto have agreed as follows.

1 DEFINITIONS/INTERPRETATION

1.1 The following terms shall have the meanings ascribed to them herein:

"Corporation" means "Ontario Power Generation Inc."

"EA" means the "*Electricity Act, 1998*" and its regulations and the phrase "the Act" has a corresponding meaning.

"Deputy Minister" means the Deputy Minister of Energy, a public servant appointed by the Lieutenant Governor in Council under the auspices of section 4 of the *Ministry of Energy Act, 2011*;

"Ministry" means the Ministry of Energy;

"Minister" means the Minister of Energy appointed by the Lieutenant Governor in Council under the auspices of the *Executive Council Act* (Ontario) and includes reference to such other member of the Executive Council as may be assigned the administration of the *Ministry of Energy Act, 2011* (Ontario) under the *Executive Council Act* (Ontario);

"MOA" means this Memorandum of Agreement, including any and all appendixes attached hereto;

"BCA" means *Business Corporations Act* (Ontario);

"OEBA" means the *Ontario Energy Board Act, 1998* and its regulations, codes, or orders of the Ontario Energy Board, as applicable;

"OPG Board Chair" means the member of the Corporation's Board of Directors which is appointed by the Minister pursuant to a unanimous shareholder resolution made in writing, and who is designated by the Minister as Chair;

“Shareholder” means Her Majesty the Queen, in Right of the Province of Ontario, as represented by the Minister of Energy who holds all of the issued shares of the Corporation on behalf of the Crown, and “sole shareholder” shall have the same meaning.

2. PURPOSE OF THIS MEMORANDUM OF AGREEMENT

The parties hereto agree and acknowledge that the purpose of this MOA is as set out below:

- 2.1 To serve as the basis of agreement between OPG and its sole Shareholder on mandate, governance, performance, and communications of OPG.
- 2.2 To establish the accountabilities and relationships solely between OPG and the Shareholder. In its discretion, the Shareholder may waive or deem compliance of OPG’s obligations as appropriate in the circumstances.
- 2.3 To promote a positive and co-operative working relationship between OPG and the Shareholder.

3 GOVERNANCE OF OPG

- 3.1 Under the OBCA, the OPG Board of Directors is responsible for supervising the management of the business affairs and operations of the Corporation, including a fiduciary duty to act honestly and in good faith with a view to the best interests of the Corporation and to exercise the skill as well as a standard of care and diligence that a reasonably prudent person would exercise in similar circumstances. As such, the Corporation operates as a business enterprise with a commercial mandate, governed in principle and at first instance by an independent Board of Directors who is responsible for the appointment of the President and Chief Executive Officer. The President and Chief Executive Officer and management are responsible for the day-to-day operations of the company.
- 3.2 The Minister shall be responsible for appointing or re-appointing, in a timely manner and following consultation with the Chair, as appropriate, the directors of OPG pursuant to the process established by the Public Appointments Secretariat and securities regulators’ National Policy on Corporate Governance Guidelines.
- 3.3 As a reporting issuer of debt securities, OPG is subject to the disclosure standards and requirements of the *Securities Act* (Ontario) and shall make such disclosures as may be required.
- 3.4 As set out in subsection 53.1(2) of the EA, OPG and its subsidiaries are not agents of the Crown for any purpose, despite the Crown Agency Act.
- 3.5 OPG shall operate in an accountable and transparent manner with regard to the Corporation’s governance, management, administration and operations. In this regard, OPG is subject to a number of statutes and Treasury Board/Management Board of Cabinet directives. A list of applicable statutes and directives is set out in Appendix 1 attached hereto.
- 3.6 Notwithstanding the foregoing, the Shareholder may at times direct OPG to undertake special initiatives. Such directives shall be written declarations by way of a Unanimous Shareholder

Agreement and/or Declarations and resolutions, in accordance with section 108 of the OBCA, which shall be made public by OPG within a reasonable timeframe by publishing such agreements, declarations and resolutions on the Corporation's website.

3.7 Unless otherwise directed by the Shareholder or statute, OPG shall operate in Ontario in accordance with the highest corporate standards, including but not limited to the highest corporate standards in the areas of corporate governance and social responsibility. OPG shall continue to benchmark its corporate governance practices against the securities regulators' National Policy on Corporate Governance Guidelines, as well as other leading governance organizations, as appropriate.

4 MANDATE

4.1 The objects of OPG include, in addition to any other objects, owning and operating a diversified portfolio of generation assets and facilities.

4.2 OPG shall leverage its assets and expertise to generate new revenues on a commercially sound basis, including the making of strategic investments and acquisitions in the electricity sector, as well as in related business opportunities inside and outside Ontario, on its own or in partnership as appropriate, for the benefit of the Corporation and the Shareholder.

4.3 OPG shall continue to operate as a respected, publicly-owned electricity generation enterprise and to operate its assets efficiently and cost-effectively, and to deliver value both to Ontario's ratepayers and taxpayers.

4.4 OPG shall ensure that it conducts its operations in full compliance with all laws and regulations and serves as a model in regard to public and employee safety, environmental practices, corporate citizenship, community engagement and First Nations and Métis relations.

4.5 OPG shall undertake generation development projects in support of the Province's electricity planning initiatives, including the Long Term Energy Plan, as may be updated from time to time.

4.6 OPG shall support the Province of Ontario's efforts to fulfill the Crown's constitutional duty to consult and accommodate Aboriginal peoples, where that duty arises in relation to OPG generation projects, by carrying out those procedural aspects of the Crown's consultation obligations that are delegated in writing to OPG by the Province, including the Ministry.

4.7 The Province of Ontario and the Ministry supports the role of public power and mitigating electricity prices in Ontario and in doing so:

- a. mandates that OPG maintain itself as a strong, viable public power component of the electricity sector at an appropriate scale and with generation portfolio diversity to ensure long-term operational and financial sustainability and to support OPG long term liabilities; and
- b. mandates that OPG plan and operate its generation facilities based upon good utility practice recognizing safety, legal, regulatory, environmental and market factors.

- 4.8 OPG shall support the Province's economic development objectives where feasible, including generating financial benefits that remain within the Province of Ontario.
- 4.9 OPG shall serve the public interest and operate in a way that achieves a commercial rate of return, moderates overall electricity prices, and supports the efficient operation of the electricity market.
- 4.10 OPG shall earn a commercial rate of return and generate sufficient cash in order to maintain an investment grade credit rating, and service its borrowing needs for operations and projects; as well as supporting the opportunity to access public debt markets in the future. Any significant new generation approved by the Board of Directors and agreed to by the Shareholder may receive financial support from the Province of Ontario, if and as appropriate.
- 4.11 Subject to any unanimous shareholder declaration or resolution, OPG shall be permitted to participate in all energy-related procurements in Ontario.
- 4.12 OPG shall inform the Shareholder of any solar and wind developments or projects that the Corporation intends to undertake or assume, including the sources of the Corporation's financing, before undertaking or assuming such developments or projects.
- 4.13 Where appropriate, OPG shall pursue prospective generation related developments with First Nations and Métis communities that can provide the basis for long term mutually beneficial commercial arrangements.
- 4.14 Acknowledging sections 3.1 and 3.4 of this MOA, OPG will act in the interests of both OPG and the Shareholder in entering into potential settlements of material Aboriginal claims or grievances or material arrangements with communities potentially affected by OPG generation development. Unless otherwise agreed to with the Shareholder, OPG will pursue such agreements or arrangements so that the Shareholder benefits equally from releases from liability and indemnifications obtained by OPG in relation to damage caused by the construction, operation and development of OPG facilities. Nothing in this MOA will require OPG to pursue releases for matters for which the Shareholder may be solely liable.

5 REPORTING REQUIREMENTS

- 5.1 OPG and the Shareholder will ensure timely sharing of information sharing on major developments and issues that may impact the business of OPG or the interests of the Shareholder. Major developments and issues include planned acquisition of energy assets and/or assumption of existing power supply contracts, proposed settlements of material Aboriginal peoples' claims or grievances relating to OPG facilities, and proposed arrangements with communities affected by OPG generation development.
- 5.2 OPG shall report to the Shareholder, on an immediate basis, where a material human safety or system reliability issue arises.

5.3 Every year OPG shall develop and submit a rolling 3-5 year business plan to the Shareholder for review and concurrence.

- a. Once approved by OPG's Board of Directors, OPG's annual business plan will be submitted to the Minister for concurrence.
- b. The annual business plan shall include 3 -5 year performance targets based on operating and financial results as well as major project execution. It shall also include a 3 - 5 year investment plan for new projects.
- c. OPG shall include objectives for operational efficiency improvements in its business plan.
- d. Staff from the Ministry will review OPG's annual business plan in a timely manner.
- e. The Deputy Minister shall advise and assist the Minister on any responsibilities associated with the approval of OPG's annual business plan.
- f. OPG shall respond to any comments or requests for further information on the annual business plan, made by the Minister, Deputy Minister or Ministry staff in a timely manner.
- g. Concurrence will be subject to the appearance of OPG's business plan before Treasury Board.

5.4 Within 90 days after the end of each fiscal year, as required by subsection of 53.4 (1) of the EA, OPG shall submit to the Minister an annual report on its affairs during that fiscal year.

- a. In a timely manner in advance of the submission of the annual report to the Minister, OPG will provide a draft copy of the annual report for Ministry staff to review.
- b. Ministry staff will review the draft annual report in a timely manner, and may request additional information from OPG, as necessary.

5.5 OPG shall provide, in a timely manner, quarterly and year-end financial reports for the Ministry's review prior to filing with the OSC, and in particular:

- a. year-end financials, which include News Release, MD&A and Audited Financial Statements whose content is prescribed by the securities regulators' National Instrument 51-102; and,
- b. the Annual Information Form and Statement of Executive Compensation, whose content is prescribed by securities regulators' National Instrument NI 51-102.

5.6 OPG shall provide briefings to senior officials of the Ministry on OPG's operational and financial performance against plan.

5.7 OPG shall provide reports and information to the Ministry of Finance, as required, from time to time, as per subsection 53.4 (4) of the EA. Reports and information requests from the Ministry of Finance shall be made through the Ministry of Energy.

- 5.8 The OPG Board Chair shall report to the Minister annually on the effectiveness of this MOA. Such report shall be provided to the Minister in writing within 90 days after the end of each fiscal period.
- 5.9 OPG shall provide to the Minister quarterly status updates on its response to the recommendations set out in the Auditor General's 2013 Report.

6 PERFORMANCE EXPECTATIONS

6.1 Operational Expectations

- 6.1.1 OPG shall operate its generating assets safely, efficiently and cost-effectively, and in accordance with all applicable safety and environmental regulations and standards.
- 6.1.2 OPG shall pursue cost-effective and efficient operational improvements that maintain the reliability of operations, the safety and security of OPG assets, employees and the public.
- 6.1.3 OPG shall undertake periodic benchmarking appropriate for its operations and type of assets, including as part of its submissions to the OEB.
- 6.1.4 OPG shall operate its Ontario based portfolio of generation assets in a manner that contributes to Ontario's and Canada's environmental objectives.
- 6.1.5 OPG shall ensure that a system is in place for the creation, collection, maintenance, and disposal of records in accordance with corporate policy, guidelines and best practices.
- 6.1.6 OPG shall make information targeted to the general public available in French where it meets a need to do so.
- a. Recognizing that OPG's direct interaction with the public is often limited to regional or host community communications or broader public safety, OPG shall make information available in French only if reasonable in the circumstances.
 - b. For greater clarity, OPG shall provide the following services and products in French: advertising, news releases and educational materials where it meets a need to do so. As well, public safety communications, annual financial reports and educational materials will be provided in French and French speaking spokespersons will be made available as required for public and media interaction. French language products will be listed under a specific heading on the OPG web site.
 - c. This list shall be reviewed by OPG annually.
- 6.1.7 OPG shall support the province of Ontario in implementing its policy of putting conservation first by pursuing energy efficiency improvements in its operations where

economic. OPG shall identify a lead for reporting on its energy efficiency improvements to liaise with the Ministry on a regular basis.

OPG shall also continue to report on its energy efficiency results in its annual Sustainable Development Report.

6.2 Financial Expectations

- 6.2.1 As an OBCA Corporation and reporting issuer with a commercial mandate, OPG shall operate on a financially sustainable basis, earning a commercial rate of return in order to be able to service its current and future liabilities, to support the appropriate level of capital spending and to maintain or increase the value of its assets for its Shareholder.
- 6.2.2 OPG shall finance project investments and its operations in a prudent and cost-effective manner.

6.3 Compensation

- 6.3.1 OPG shall annually inform the Shareholder about its compliance with applicable legislation and regulations governing employee compensation.

7 LABOUR NEGOTIATIONS

- 7.1 In advance of commencing discussions for the renewal of its collective agreements with its unions, OPG shall seek advice from the Ministry on Provincial policy direction and relevant fiscal considerations affecting labour negotiations in the broader public and/or energy sectors.
- 7.2 When a collective agreement has been negotiated and ratified, OPG shall inform the Ministry of the results and details of the collective agreement in a timely manner.

8 COMMUNICATIONS

- 8.1 The OPG Board of Directors and the Minister shall meet as needed to enhance mutual understanding of interrelated strategic matters.
- 8.2 OPG's Board Chair, OPG's President and Chief Executive Officer and the Minister shall meet on an as needed basis.
- 8.3 OPG's President and Chief Executive Officer and the Deputy Minister shall meet on a regular and as needed basis on matters of mutual importance.
- 8.4 OPG's senior management and Ministry senior officials shall meet on a regular and as needed basis to discuss new and ongoing issues, discuss strategic business objectives and OPG's performance, and to clarify expectations or to address emergent issues.

- 8.5 The Shareholder shall specifically seek OPG's input on electricity policies that may impact OPG, when and as appropriate.
- 8.6 OPG's communications shall include promotion and awareness of electricity generation and efficiency where appropriate to increase public understanding of energy consumption and support the Ministry's efforts.
- 8.7 OPG shall consult with the Ministry, as appropriate, on key communication issues that may affect the Ministry or OPG. OPG shall keep the Ministry informed, as appropriate, of the key communication issues in a timely manner, and in advance if it is possible or appropriate to do so, having regard to the seriousness of the key communication issue.
- 8.8 In all other respects, OPG shall communicate with government ministries and agencies in a manner typical for an Ontario Corporation of its size and scope to ensure a timely flow of information.

9 TERM OF THIS AGREEMENT

- 9.1 The MOA shall be in effect for not more than five years from the date of execution.
- 9.2 The Shareholder and the OPG Board Chair shall renew or revise this MOA by the expiry date, or earlier, as required.
- 9.3 The Shareholder and the OPG Board Chair shall reaffirm this MOA for continuance with a change in either the Minister or Chair, and such reaffirmation may be done by letter and such letter shall be considered part and parcel of this Agreement as if the party or parties reaffirming the MOA had duly signed and executed an amendment to the MOA.
- 9.4 This MOA shall be posted publicly on OPG's website.

SIGNATURES

Original signed by:

2015/05/20

Bernard Lord
Board Chair
Ontario Power Generation, Inc.

Date

Original signed by:

2015/07/17

Honourable Bob Chiarelli
Minister of Energy

Date

APPENDIX 1: STATUTES OF PARTICULAR APPLICATION

Auditor General Act

Broader Public Sector Accountability Act, 2010

Business Corporations Act

Electricity Act, 1998

Freedom of Information and Protection of Privacy Act

Ontario Energy Board Act, 1998

Public Sector Compensation Restraint to Protect Public Services Act, 2010

Public Sector Expenses Review Act, 2009

Public Sector Salary Disclosure Act, 1996

Public Sector and MPP Accountability and Transparency Act, 2014

APPENDIX 2: APPLICABLE TB/MBC/MOF DIRECTIVES

Compensation Arrangements Compliance Report Directive
Perquisites Directive
Procurement Directive
Travel, Meal and Hospitality Directive
Ministers' Staff Commercial Transactions Directive

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OVERVIEW OF REGULATED HYDROELECTRIC FACILITIES

1.0 PURPOSE

This evidence describes the regulated hydroelectric facilities. It also identifies the regulations, agreements and programs key to these facilities.

2.0 DESCRIPTION OF REGULATED HYDROELECTRIC FACILITIES

A total of fifty-four OPG hydroelectric generating stations are subject to OEB regulation. These facilities are operated and maintained by five Operations Groups: Niagara Operations (formerly Niagara Plant Group), Eastern Operations (formerly Ottawa/St. Lawrence Plant Group), Northeast Operations (formerly Northeast Plant Group), Northwest Operations (formerly Northwest Plant Group) and Central Operations (formerly Central Hydro Plant Group). The Operations Groups are responsible for operation and maintenance of regulated hydroelectric stations as well as OPG's thermal stations.

Hydroelectric facilities typically include: generating equipment (i.e., turbines, generators, transformers, protections and controls, etc.), related civil works (powerhouses, dams, headworks, spillways and water conveyance canals and tunnels), and the facilities required to operate and maintain the generating stations (control rooms, work centres, and headquarters).

Chart 1 presents information on OPG's regulated hydroelectric stations.

1
 2
 3

Chart 1
Regulated Hydroelectric Facilities General Information

Plant Group	Generating Station	Number of In-Service Units	Net In-Service Capacity (MW)	Original Unit In-Service Dates	
Niagara Operations	Sir Adam Beck I	8	436	1922 – 1930	
	Sir Adam Beck II	16	1,499	1954 – 1958	
	Sir Adam Beck PGS	6	174	1957 – 1958	
	DeCew Falls I	4	23	1898	
	DeCew Falls II	2	144	1948	
Eastern Operations	R.H. Saunders	16	1,045	1958 – 1959	
	Arnprior	2	82	1976-1977	
	Barrett Chute	4	176	1942-1968	
	Calabogie	2	5	1917	
	Mountain Chute	2	170	1967	
	Stewartville	5	182	1948-1969	
	Chats Falls (OPG owns 4 of 8 units)	4	96	1931-1932	
	Chenau	8	144	1950-1951	
	Des Joachims	8	429	1950-1951	
	Otto Holden	8	243	1952-1953	
	Central Operations	Auburn	3	2	1911-1912
		Big Chute	1	10	1909-1919 (rebuilt 1993)
		Big Eddy	2	8	1941
		Bingham Chute	2	1	1923-1924
		Coniston	3	4	1905-1915
Crystal Falls		4	8	1921	
Elliot Chute		1	2	1929	
Eugenia Falls		3	6	1915-1920	
Frankford		4	3	1913	
Hagues Reach		3	4	1925	
Hanna Chute		1	1	1926	
High Falls		3	3	1920	
Lakefield		1	2	1928	
McVittie		2	3	1912	
Merrickville		2	2	1915-1919	
Meyersberg	3	5	1924		

	Nipissing	2	0	1909
	Ragged Rapids	2	8	1938
	Ranney Falls	3	10	1922-1926
	Seymour	5	6	1909
	Sidney	4	4	1911
	Sills Island	2	2	1900
	South Falls	3	5	1916-1925
	Stinson	2	5	1925
	Trethewey Falls	1	2	1929
Northeast Operations	Abitibi Canyon	5	349	1933-1959
	Otter Rapids	4	182	1961-1963
	Lower Notch	2	274	1971
	Matabitchuan	4	10	1910
	Indian Chute	2	3	1923-1924
Northwest Operations	Aguasabon	2	47	1948
	Alexander	5	69	1930-1958
	Cameron Falls	7	92	1920-1958
	Caribou Falls	3	91	1958
	Kakabeka Falls	4	25	1906-1914
	Manitou Falls	5	73	1956-1958
	Pine Portage	4	145	1950-1954
	Silver Falls	1	48	1959
	Whitedog Falls	3	68	1958

1

2 **2.1 Niagara Operations**

3 The Niagara Operations (“NAO”) includes three Sir Adam Beck facilities and two Decew Falls
 4 facilities. A map showing these facilities is provided as Attachment 1.

5

6 The Sir Adam Beck facilities include Sir Adam Beck I Generating Station (“Sir Adam Beck I”),
 7 Sir Adam Beck II (“Sir Adam Beck II”), Pump Generating Station (“PGS”) and associated
 8 structures such as tunnels, the open cut canal and the International Niagara Control Works
 9 structure (also known as International Control Dam), as well as the PGS Reservoir. Water
 10 conveyance structures (i.e., tunnels and canals) divert water from the upper Niagara River to
 11 the Sir Adam Beck plants. Water is discharged from the plants into the lower Niagara River.
 12 Under a Memorandum of Understanding between OPG and the New York Power Authority

1 (“NYPA”), OPG and NYPA equally share the costs associated with Joint Works at Niagara
2 (including the International Control Dam).

3

4 The DeCew Falls facilities include DeCew Falls I, DeCew Falls II and associated water
5 conveyance structures such as Intakes 1 and 2, and the Waterworks canal. Water
6 conveyance structures divert water from the Welland Ship Canal, through Lake Gibson and
7 Lake Moodie, to the DeCew generating stations. Water discharged from the plants flows
8 through the Twelve Mile Creek to Lake Ontario.

9

10 The Niagara Operations facilities (Sir Adam Beck and DeCew Falls) are controlled from a
11 single control centre located at Sir Adam Beck I.

12

13 **2.2 Eastern Operations**

14 Eastern Operations (“EO”) operates ten regulated hydroelectric generating stations. The EO
15 headquarters is located in Renfrew. The regulated stations include RH Saunders Generating
16 Station, and the Ottawa River and Madawaska River stations. A map showing the locations
17 of these facilities is provided as Attachment 2.

18

19 R.H. Saunders Generating Station (“R.H. Saunders”) is a 16-unit hydroelectric station on the
20 St. Lawrence River at Cornwall, Ontario. R.H. Saunders is connected to the 16-unit St.
21 Lawrence - Franklin D. Roosevelt Generating Station, which is owned and operated by the
22 New York Power Authority (“NYPA”). Together, the two stations span the entire St. Lawrence
23 River. Associated structures include: the powerhouse, dams, headworks, dykes, bridges, and
24 ice booms. Under a Memorandum of Understanding between OPG and NYPA, OPG and
25 NYPA equally share the costs associated with Joint Works at the St. Lawrence facilities
26 (including the Iroquois Control Dam and Long Sault Dam, headworks, dykes, and the
27 Barnhart Island bridge). The RH Saunders Generating Station has its own work centre and
28 control centre.

29

30 There are four generating stations on Ottawa River (Otto Holden, Des Joachims, Chenaux,
31 and Chats Falls) and there are five generating stations on the Madawaska River (Mountain

1 Chute, Barrett Chute, Calabogie, Stewartville, and Arnprior). The Ottawa River and
2 Madawaska River stations are maintained from six work centres, and are remotely operated
3 from a control centre located at Chenaux Generating Station.

4
5 The Chat Falls Generating Station on the Ottawa River is jointly owned with Hydro Quebec.
6 There eight units and joint works (dams, sluices and bridges) associated with the Chats Falls
7 Generating Station (“GS”). Four generating units are owned by OPG, and four are owned by
8 Hydro Quebec. OPG operates and maintains the entire station through an Operating
9 Services agreement with Hydro Quebec.

10 11 **2.3 Central Operations**

12 Central Operations (“CO”) operates twenty-five regulated hydroelectric generating stations.
13 The regulated CO stations are located on ten river systems in the centre of the Province
14 (Beaver River, Mississippi River, Muskoka River, Otonabee River, Rideau River, Severn
15 River, South River, Sturgeon River, Trent River, and Wanapitei River).

16
17 The CO headquarters is located in North Bay. The CO generating stations are maintained
18 from four work centres, and they are remotely operated from a control centre located at the
19 North Bay headquarters. A map showing the locations of these facilities is provided as
20 Attachment 3.

21 22 **2.4 Northeast Operations**

23 Northeast Operations (“NEO”) operates five regulated hydroelectric stations: two on the
24 Abitibi River (Abitibi Canyon and Otter Rapids); two on the Montreal River (Indian Chute and
25 Lower Notch); and one on the Matabitchuan River (Matabitchuan).

26
27 NEO headquarters is located in Timmins. The regulated NEO generating stations are
28 maintained from two work centres, and are remotely operated from a control centre located
29 in Timmins. A map showing the locations of these facilities is provided as Attachment 4.

30 31 **2.5 Northwest Operations**

1 Northwest Operations (“NWO”) operates nine regulated generating stations: one on the
2 Aquasabon River (Aguasabon); two on the English River (Manitou Falls and Caribou Falls);
3 two on the Kamanistikwia River (Silver Falls and Kakabeka Falls); three on the Nipigon River
4 (Pine Portage, Cameron Falls, and Alexander); and one on the Winnipeg River (Whitedog
5 Falls).

6
7 The NWO headquarters is located in Thunder Bay. The NWO generating stations are
8 maintained from four work centres and are remotely operated from a control centre located at
9 the Thunder Bay headquarters. A map showing the locations of the NWO facilities is
10 provided as Attachment 5.

11

12 **3.0 KEY HYDROELECTRIC REGULATIONS, AGREEMENTS AND PROGRAMS**

13 OPG’s regulated hydroelectric facilities are subject to international treaties between Canada
14 and the United States, federal and provincial legislation and regulatory requirements, as well
15 as several contractual arrangements with third parties. Collectively these regulations,
16 agreements and programs result in additional costs and program needs with respect to the
17 operation and management of the regulated facilities.

18

19 This section provides an overview of:

- 20 • Regulations, treaties and agreements with regard to water rights for the regulated
21 hydroelectric facilities.
- 22 • Agreements with other utilities/generators related to operational
23 requirements/guidelines, joint works, water sharing, water diversions, and
24 compensation settlements.
- 25 • Dam and public safety governance and programs.
- 26 • First Nations and Metis Relations.

27

28 A summary of the legislative and regulatory framework applicable to OPG’s regulated
29 facilities is provided at Ex. A1-6-1.

30

31 **3.1 Water Rights**

1 3.1.1 Regulation of Water Rights

2 Rights to and restrictions on the use of water are determined by international treaties
3 between Canada and the United States, together with the application of interprovincial
4 agreements, federal and provincial legislation, common law as it pertains to real property and
5 riparian rights, as well as the terms and conditions of certain leases and permits with and
6 from the Government of Canada and the Province of Ontario. Water management plans
7 authorized by the Ontario Ministry of Natural Resources and Forestry prescribe water
8 elevation and flow limits for many of Ontario's major rivers.

9
10 3.1.2 International Boundary Rivers

11 Through a series of agreements between the Government of Canada and the Province of
12 Ontario, OPG has been granted the right to exercise Canada's rights with respect to the
13 construction, maintenance, and operation of hydroelectric generating facilities on the Niagara
14 and St. Lawrence Rivers under the *Boundary Waters Treaty of 1909*, the *Niagara Diversion*
15 *Treaty of 1950*, the *Niagara Development Act of 1951*, and the *International Rapids Power*
16 *Development Agreement Act of 1952*.

17
18 The *Boundary Waters Treaty of 1909* governs all boundary waters between Canada and the
19 United States. Water rights on both the Niagara and St. Lawrence Rivers are subject to this
20 treaty. The Treaty created the International Joint Commission ("IJC") to help prevent and
21 resolve disputes over the use of boundary waters between Canada and the United States.
22 The IJC established the International Niagara Board of Control to oversee water level
23 regulation on the Niagara River, and the International St. Lawrence River Board of Control to
24 ensure Lake Ontario outflows meet IJC requirements, including dependable flow for
25 hydropower and adequate depths for navigation on the St. Lawrence River.

26
27 The *Niagara Diversion Treaty of 1950* between Canada and the United States, among other
28 things, determines the priority of use for the waters flowing out of Lake Erie (Niagara River
29 and Welland Canal), sets minimum flow requirements over Niagara Falls, and provides for
30 the allotment of the waters available for power generation. It also recognizes that certain

1 diversion waters are to be excluded from determination of the power generation water
2 allotment.

3
4 The International Niagara Committee (“INC”) was created by the Governments of Canada
5 and the United States pursuant to the *Niagara Diversion Treaty of 1950* to determine and
6 report the amounts of water available for purposes of the Treaty, including water used for
7 power diversions at Niagara. The INC is independent of the IJC, but works in collaboration
8 with the IJC’s International Niagara Board of Control.

9
10 The *Niagara Parks Act* (Ontario) provides the Niagara Parks Commission with the authority
11 to grant certain rights to use the waters of the Niagara River for purposes of power
12 generation. By agreement executed February 2005, the Niagara Parks Commission granted
13 OPG sole rights to take water from the Niagara and Welland Rivers for purposes of power
14 generation until December 31, 2056.

15
16 The DeCew Falls stations use water that is conveyed through the Welland Canal from Lake
17 Erie under an agreement between OPG and the St. Lawrence Seaway Management
18 Corporation that has been renewed through June 30, 2038.

19
20 **3.1.3 Interprovincial Rivers**

21 Four of OPG’s hydroelectric generating stations are located on the Ottawa River which
22 forms the provincial boundary between Ontario and Quebec. The *Ottawa River Water*
23 *Powers Act, 1943*, (concurrent legislation, Ontario and Quebec) authorized the water power
24 developments at OPG’s Otto Holden GS, Des Joachims GS, and Chenaux GS sites on the
25 Ottawa River. The fourth station, Chats Falls GS, is owned jointly by OPG and Hydro
26 Quebec. The four generating stations are subject to water power lease agreements with the
27 Ontario Ministry of Natural Resources and Forestry.

28
29 “An Agreement Respecting Ottawa River Basin Regulation” dated March 2, 1983, between
30 the Governments of Canada, Ontario, and Quebec, established the Ottawa River Regulation

1 Planning Board and Secretariat to oversee the integrated management of the waters within
2 the Ottawa River basin. OPG participates as a member of the Board.

3
4 Whitedog Falls GS is located on the Winnipeg River which flows from the Lake of the Woods
5 in northwestern Ontario to Lake Winnipeg in Manitoba. Manitou Falls GS and Caribou Falls
6 GS are located on the English River which is a major tributary to the Winnipeg River just east
7 of the Manitoba-Ontario provincial border. These three generating stations are subject to
8 water power lease agreements with the Ontario Ministry of Natural Resources and Forestry.

9
10 Concurrent Federal and Provincial (Ontario and Manitoba) legislation, authorized regulation
11 of the waters of the Lake of the Woods, Lac Seul, the English and Winnipeg Rivers, control
12 of flows, and utilization of water diverted from the Lake St. Joseph. The Lake of the Woods
13 Control Board is the regulating authority for managing these waters.

14 15 3.1.4 Provincial Rivers

16 Forty-one of OPG's regulated hydroelectric generating stations are located on seventeen
17 interior Ontario rivers (see sections 2.3 to 2.6). Tenure at thirty-one of these sites is
18 authorized by water power lease agreements with the Ontario Ministry of Natural Resources
19 and Forestry, or licence agreements with Parks Canada. The remaining ten of these sites are
20 owned by OPG.

21
22 In addition, OPG holds eight Crown Leases and twenty-seven Licences of Occupation,
23 issued by the Ontario Ministry of Natural Resources and Forestry, that provide additional
24 land tenure and flooding rights for facilities associated with the regulated hydroelectric
25 generating stations.

26
27 Water management plans, authorized by the Ontario Ministry of Natural Resources and
28 Forestry, exist for fourteen of the seventeen interior rivers and prescribe flow and water level
29 elevation limits. The other three rivers (Rideau, Trent, and Severn) fall under federal
30 jurisdiction and are not subject to Ontario Water Management Plans.

31

1 **3.2 Agreements with Other Utilities**

2 OPG also has agreements with the New York Power Authority, Hydro Quebec, Manitoba
3 Hydro, and H2O Power LP to address issues such as operational requirements/guidelines,
4 cost sharing and management of joint works, water utilization, and settlement of
5 water/energy transactions.

6

7 **3.3 Dam Safety and Waterways Public Safety**

8 3.3.1 Dam Safety

9 There are 202 dams and special hydraulic structures associated with OPG's regulated
10 hydroelectric stations. Of these, 25 dams are associated with OPG's stations in the Niagara
11 Plant Group and two dams are associated with R.H. Saunders. A further 175 dams are in the
12 Eastern Operations, Central Operations, Northeast Operations, and Northwest Operations.

13

14 In Canada, dams come under provincial jurisdiction, with the exception of dams situated in
15 boundary waters, on canals (i.e., Trent-Severn Waterway ("TSW") and the Rideau Canal),
16 and those owned by the Government of Canada. The majority of OPG's dams fall within the
17 jurisdiction of the Province of Ontario, or through Parks Canada for dams located on the
18 TSW or Rideau Canal however the structures on the Ottawa River are also regulated by the
19 Province of Quebec. OPG provides regular submissions to the Province of Quebec to
20 demonstrate that these structures remain in compliance with the Act and Regulation.

21

22 The Province of Ontario currently governs dams under the *Lakes and Rivers Improvement*
23 *Act* ("LRIA"), administered by the Ministry of Natural Resources and Forestry ("MNRF").
24 Sections 14 and 16 of the Act require MNRF's approval for activities such as the
25 construction, alteration, improvement, or repair of dams. In August 2011, the Province of
26 Ontario issued new Technical Guidelines for Approval under the LRIA. These Guidelines are
27 not formal regulations. However, they do form the standards to which dams in Ontario are
28 expected to comply. Transport Canada also has regulatory approval authority over OPG
29 dams under the Navigation Protection Act as they may relate to alternations of the dams or
30 approved works (e.g. safety booms, buoys etc.)

31

1 For dams located on the Trent Severn Waterway and the Rideau Canal system, OPG is
2 required to meet Parks Canada dam safety criteria issues in 2010, primarily as it applies to
3 upgrading structures.

4
5 While the regulatory regime in Ontario continues to develop, OPG has well-established
6 programs based on the Canadian Dam Association (“CDA”) – Dam Safety Guidelines (2013)
7 and the CDA Guidelines for Public Safety Around Dams (2011), as well as other industry
8 guidelines that are, in many respects, a model for emerging standards and regulatory
9 requirements. OPG’s Safe Operations Policy, approved by the OPG Board, and associated
10 Dam Safety Program Management Document directs that dams be designed, constructed,
11 operated and maintained in a manner that meets all regulatory requirements or, in the
12 absence of regulations, the safety guidelines published by the CDA or other industry best
13 practice.

14
15 Pursuant to OPG’s dam safety program, dam safety reviews are completed periodically for
16 all dams owned and operated by OPG.

17
18 **3.3.2 Waterways Public Safety**

19 Since 2002, OPG has developed a number of technical documents concerning public safety
20 around dams, as well as materials to educate the public and raise awareness of the hazards
21 associated with dams and hydroelectric facilities. Currently there are no regulations covering
22 public safety around dams, beyond the federal requirements administered by Transport
23 Canada under the *Navigation Protection Act* (2014) or *Canada Shipping Act* (2001) and the
24 associated regulations. Transport Canada’s involvement in public safety is primarily the
25 installation of safety measures (e.g. safety booms, buoys) and enforcement of restrictions to
26 navigation. However, the Province of Ontario has issued a Best Management Practice
27 document in August 2011 to guide owners on improvements to safety around dams. In
28 addition the Canadian Dam Association issued Guidelines for Public Safety Around Dams in
29 October 2011.

1 In the absence of government regulations, OPG has developed a Waterways Public Safety
2 Program to guard the public from risks associated with its dams and hydroelectric stations.
3 The program includes: installation of physical control measures (e.g., booms, buoys, fencing,
4 signage, audible alerts), operating procedures, and employee training requirements. A major
5 element of the program is public education. For example, OPG has worked diligently to
6 establish a “Stay Clear - Stay Safe” message. OPG actively engages other agencies such as
7 the MNRF, Ontario Provincial Police, St. John’s Ambulance, Life Saving Society, the Ontario
8 Waterpower Association, and numerous other stakeholders in water safety education to
9 partner in delivering the message to the public.

10

11 **3.4 Indigenous Relations**

12 Ontario Power Generation’s hydroelectric assets are widely dispersed throughout Ontario.
13 Many of the stations and dams are in close proximity to various Aboriginal communities. This
14 proximity to dams and generating stations has had direct and indirect effects on some First
15 Nations communities during initial construction and from on-going operations.

16

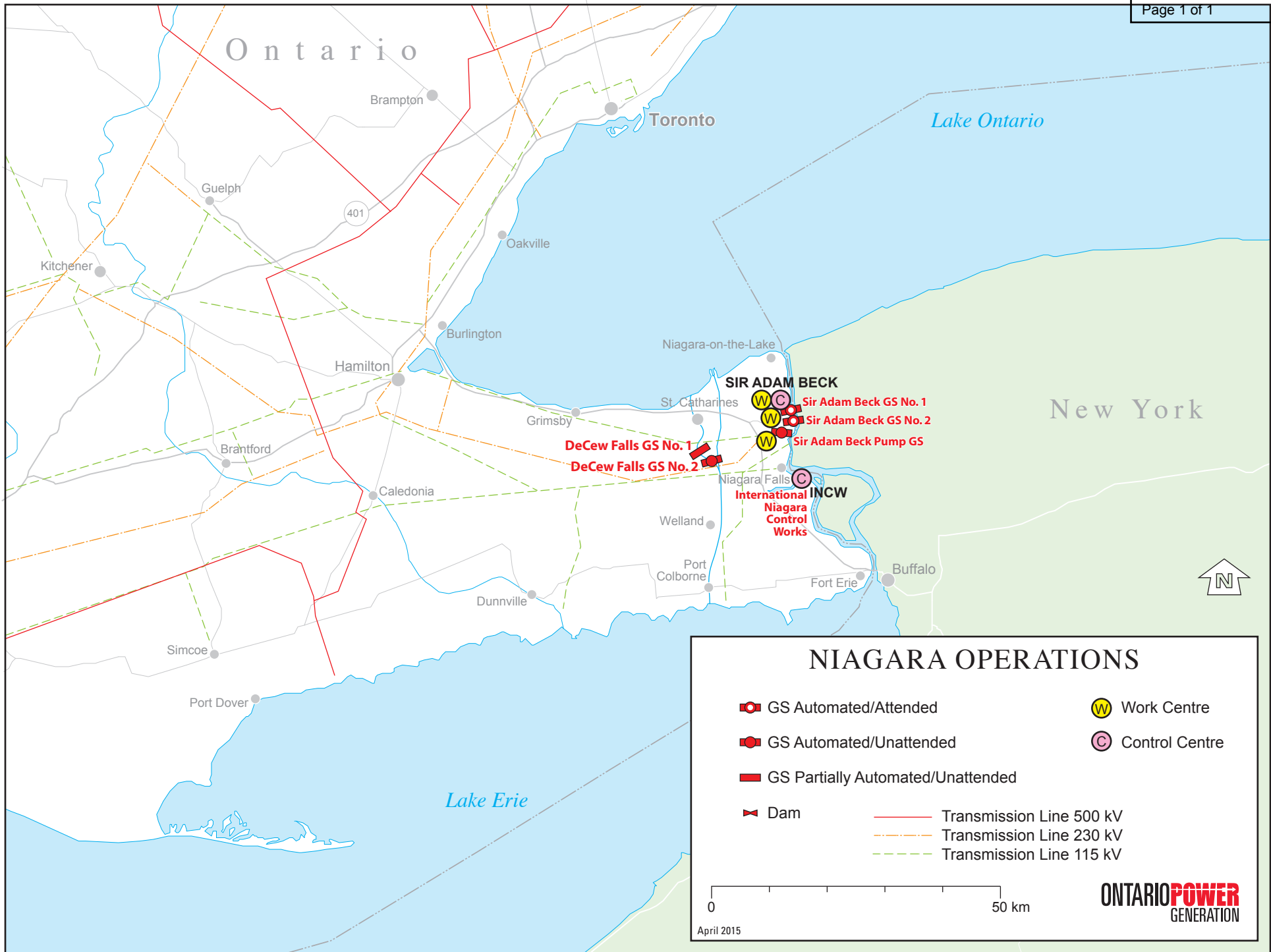
17 OPG has engaged in a past grievance settlement program since 1992 to address some of
18 these effects on Aboriginal Communities. The program is voluntary and non-adversarial. The
19 successful outcome is a negotiated settlement acceptable to both parties. Within OPG,
20 executive approval is required to enter into a settlement agreement. The program is backed
21 by the OPG Board level Policy on First Nations and Metis Relations.

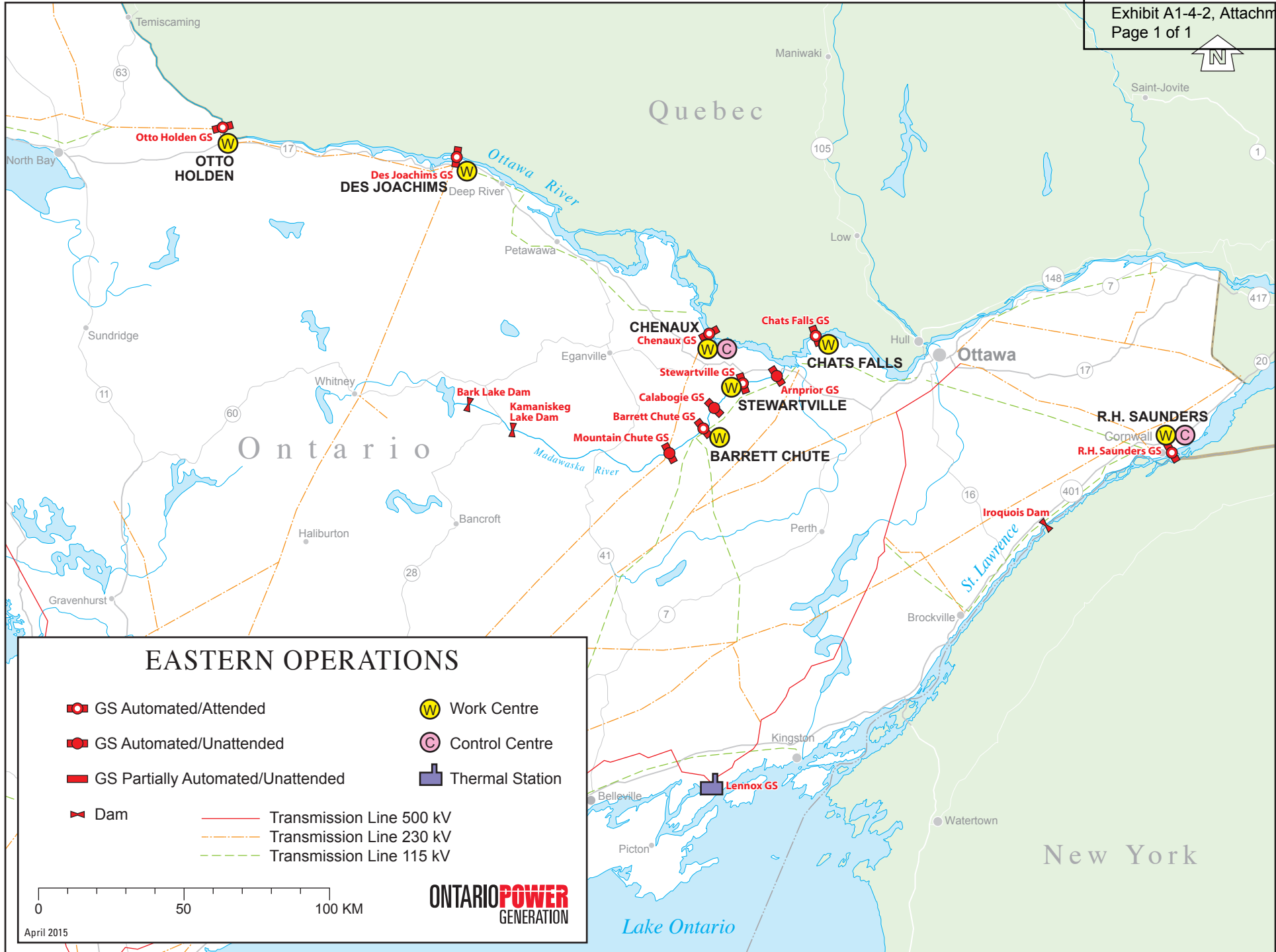
22

23 To date, OPG (and formerly Ontario Hydro) has completed 23 settlements with First Nation
24 communities across Ontario.

ATTACHMENTS

- 1
- 2
- 3 Attachment 1: Niagara Operations - Overview
- 4
- 5 Attachment 2: Eastern Operations - Overview
- 6
- 7 Attachment 3: Central Operations - Overview
- 8
- 9 Attachment 4: Northeast Operations - Overview
- 10
- 11 Attachment 5: Northwest Operations - Overview





EASTERN OPERATIONS










- GS Automated/Attended
- GS Automated/Unattended
- GS Partially Automated/Unattended
- Dam
- Work Centre
- Control Centre
- Thermal Station
- Transmission Line 500 kV
- Transmission Line 230 kV
- Transmission Line 115 kV

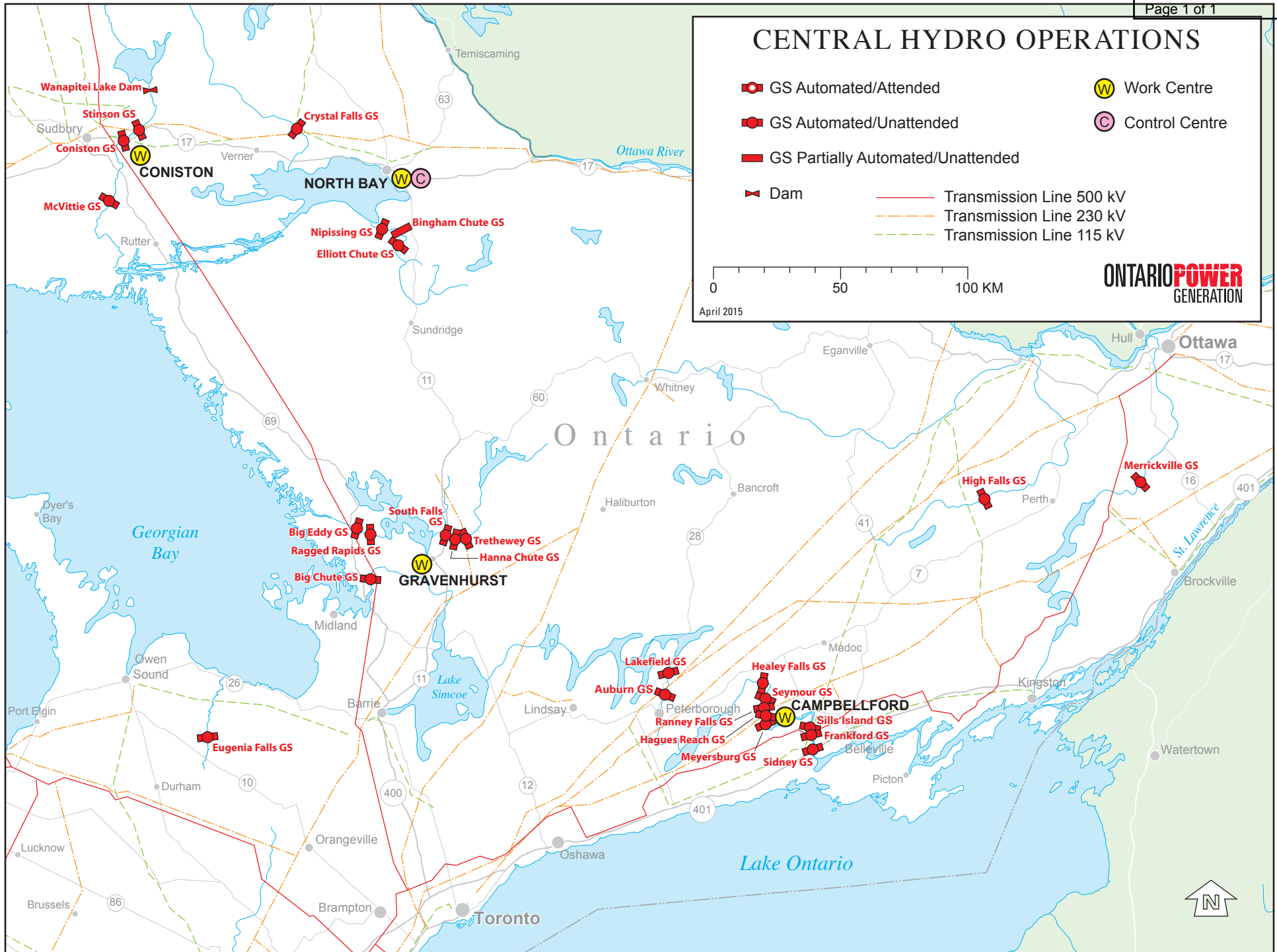
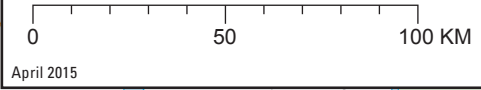
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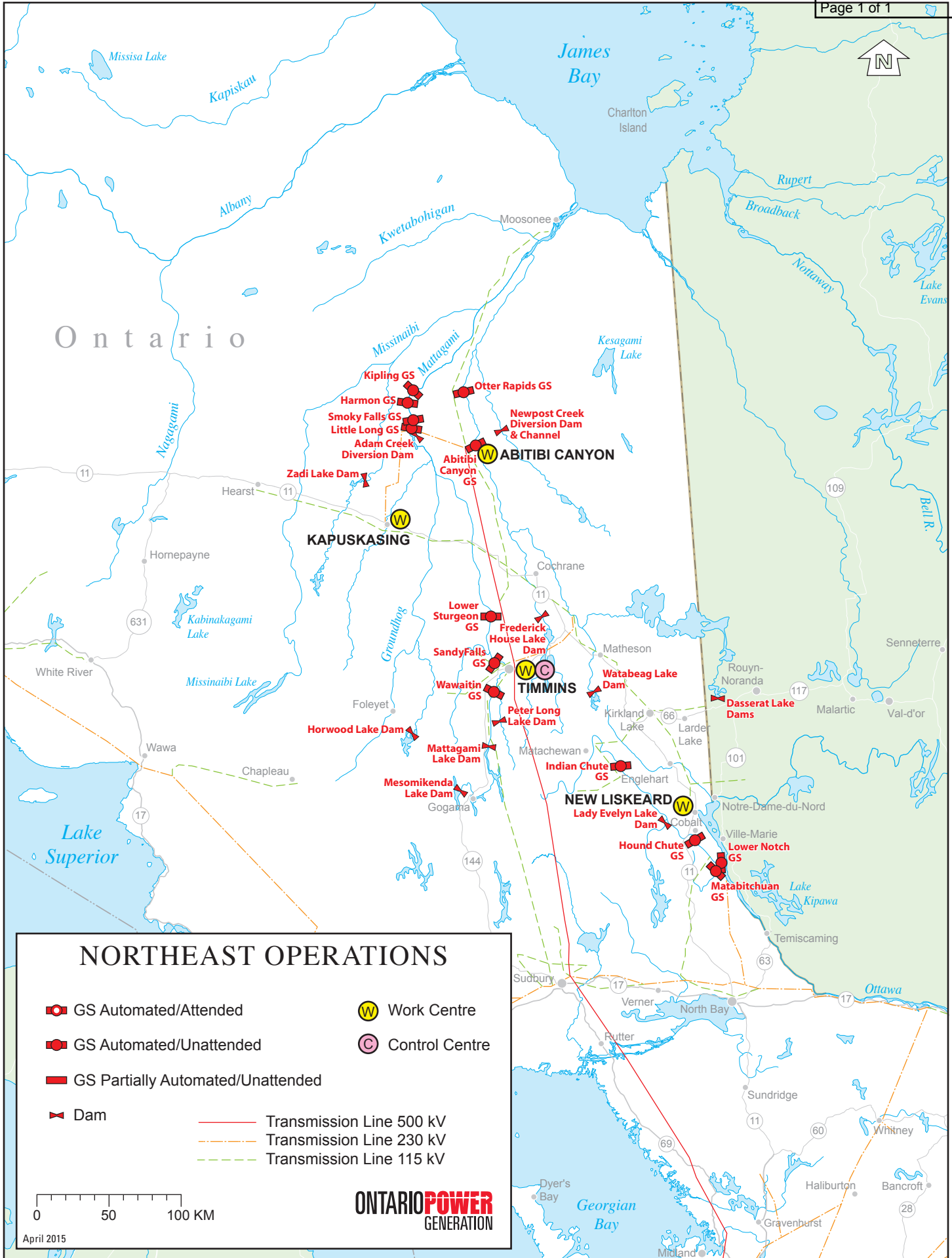


April 2015

CENTRAL HYDRO OPERATIONS

-  GS Automated/Attended
-  GS Automated/Unattended
-  GS Partially Automated/Unattended
-  Dam
-  Work Centre
-  Control Centre
-  Transmission Line 500 kV
-  Transmission Line 230 kV
-  Transmission Line 115 kV





NORTHEAST OPERATIONS

- GS Automated/Attended
- GS Automated/Unattended
- GS Partially Automated/Unattended
- Dam
- Work Centre
- Control Centre
- Transmission Line 500 kV
- Transmission Line 230 kV
- Transmission Line 115 kV

0 50 100 KM



April 2015



OVERVIEW OF NUCLEAR FACILITIES

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1.0 PURPOSE

This evidence describes OPG's nuclear facilities and sets out an overview of OPG's nuclear mandate, objectives, organization, and governance framework.

The evidence is substantially the same as Ex. A1-4-3 submitted in OPG's last rates application (EB-2013-0321) with the exception of an update to section 3.0, Nuclear Organization.

2.0 OPG'S NUCLEAR GENERATING FACILITIES

OPG's nuclear generating facilities consist of Pickering Generating Station ("Pickering") and Darlington Generating Station ("Darlington") (collectively, the "nuclear generating stations").

All of OPG's nuclear generating stations are based on CANDU technology, a pressurized-heavy-water reactor using natural-uranium technology developed in Canada. CANDU reactors are unique in their use of natural uranium, deuterium oxide (heavy water) as a moderator/coolant, on-line refueling capability and two shut down safety systems. These plants serve as base load resources as they have been designed to operate at full power. Chart 1 below provides basic information about the nuclear generating stations.

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Chart 1

Nuclear Generating Stations Basic Information

	Pickering		Darlington
	Units 1 and 4¹	Units 5-8	Units 1-4
In-service dates	1971 - 1973	1983 - 1986	1989 - 1992
Net in-service capacity	1,030 MW	2,064 MW	3,512 MW
Number of units in-service and size in MW's	2 x 540	4 x 540	4 x 934

4 1 Pickering Units 2 and 3 were laid up in 1997 and have been placed into a safe store condition for eventual
5 dismantling.

6

7 While OPG's ten nuclear units are based on CANDU principles, they reflect three
8 generations of design philosophy and technology with Pickering Units 1 and 4, Pickering 5 to
9 8, and Darlington built in the 1960s, 1970s, and 1980s respectively. This results in significant
10 variations among the three nuclear stations, including technology system components and
11 overall design.

12

13 Planning is underway to extend the safe operation of Pickering, whereby all six units at
14 Pickering would operate until 2022, at which point two units would be shut down and the
15 remaining four units would operate until 2024 (referred to as "Pickering Extended
16 Operations"). Further details regarding Pickering Extended Operations is provided in Ex. F2-
17 2-3.

18

19 Darlington will be undergoing refurbishment over the period 2016-2025, as discussed in Ex.
20 D2-2-1 and Ex. F2-7-1.

21

22 **3.0 NUCLEAR ORGANIZATION**

23 The nuclear organization is led by the President, OPG Nuclear and Chief Nuclear Officer (per
24 OPG's organizational chart shown in Ex. A1-5-1). The operating groups within the nuclear

1 organization are described below (all reporting to the President, OPG Nuclear and Chief
2 Nuclear Officer).

- 3
- 4 • **Darlington and Pickering Stations** – led by the Senior Vice President Darlington
5 and Senior Vice President Pickering and focused on the operation, maintenance, and
6 performance of Pickering and Darlington.
- 7 • **Nuclear Engineering** – led by the Senior Vice President, Nuclear Engineering and
8 Chief Nuclear Engineer and focused on plant safety and reliability by provision of
9 various engineering services (e.g., design engineering, component engineering,
10 station engineering).
- 11 • **Fleet Operations and Maintenance** – led by the Vice President, Fleet Operations
12 and Maintenance and focused on driving improvement across the Nuclear fleet.
- 13 • **Security and Emergency Services** – led by the Vice President, Security and
14 Emergency Services and responsible for provision of security services for all of OPG
15 including nuclear sites and facilities, as well as ensuring compliance with all CNSC
16 security requirements.
- 17 • **Inspection and Maintenance Services** – led by the Vice President, Inspection and
18 Maintenance Services and responsible for providing inspection and maintenance
19 services to Darlington and Pickering facilities.
- 20 • **Decommissioning and Nuclear Waste Management** – led by the Senior Vice
21 President, Decommissioning and Nuclear Waste Management, and responsible for
22 the ongoing long-term management of nuclear waste produced by its operations,
23 including low and intermediate level radioactive waste and used fuel. Also
24 responsible for the planning and conduct of decommissioning of all OPG owned and
25 operated nuclear facilities. This includes oversight on the Pickering Extended
26 Operations project and management of the overall planning for the end of commercial
27 operations at Pickering. Further details on nuclear waste management and
28 decommissioning including the funding of nuclear liabilities are provided in Exhibit C2.
- 29 • **Nuclear Projects** – led by the Senior Vice President, Nuclear Projects and
30 responsible for managing the planning and development of all projects in Nuclear.

1 This includes major refurbishment projects at Darlington, as discussed in greater
2 detail in Ex. D2-2-1.

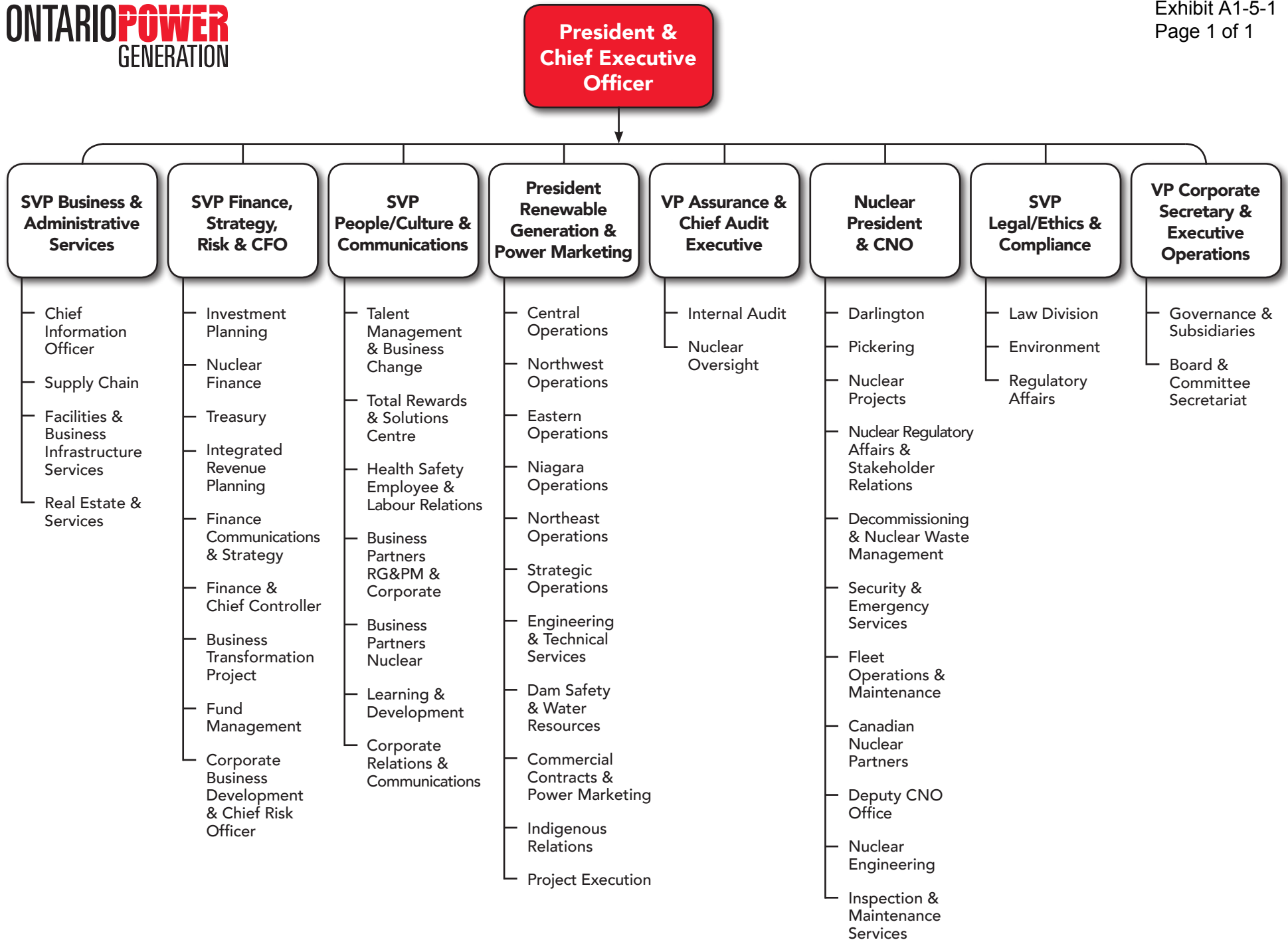
3
4 A more detailed description of the roles and responsibilities of the various operating groups
5 in the Nuclear organization is provided in Attachment 1 to Ex. F2-2-1.

6 7 **4.0 NUCLEAR OBJECTIVES**

8 OPG Nuclear has the following cornerstone major focus areas with the purpose of making
9 the existing nuclear facilities more dependable, predictable, and cost effective:

- 10 • **Safety:** The Safety cornerstone makes nuclear safety, employee safety and
11 environmental safety (e.g., radiation) the overriding priorities. It requires that all laws
12 and industry/regulatory expectations are met, activities are performed conservatively
13 and responsibly, and that business decisions are made with the full knowledge of the
14 risks and potential impacts.
- 15 • **Human Performance/Leadership:** The Human Performance/Leadership
16 cornerstone recognizes that minimizing individual fallibility and organizational
17 programs/processes is the basis for operational excellence.
- 18 • **Reliability:** The Reliability cornerstone requires that OPG operate, maintain and
19 engineer the nuclear facilities such that equipment, performance, availability and
20 output are optimized.
- 21 • **Value for Money:** The Value for Money cornerstone delivers solutions that are the
22 best combination of cost, quality and performance.

23
24 These cornerstone major focus areas are the basis for the establishment of performance
25 targets and key initiatives during the benchmarking and business planning process, as
26 discussed in Ex. F2-1-1.



SUMMARY OF LEGISLATIVE FRAMEWORK

1.0 PURPOSE

The purpose of this evidence is to provide a summary of the extensive legislative and regulatory framework as well as other government requirements that govern OPG and apply to OPG's regulated facilities. The evidence also summarizes relevant best practices and guidelines to which OPG adheres, particularly in matters where regulations are under development.¹

2.0 INTRODUCTION

OPG is subject to provincial and federal legislation and regulations, including the decisions of administrative tribunals or other regulatory bodies whose powers are derived from such legislation or regulations (e.g., the Ontario Labour Relations Board, the Independent Electricity System Operator ("IESO"), and the Canadian Nuclear Safety Commission ("CNSC")), and to Canada's international obligations under certain international treaties (e.g., regarding international boundary waters and nuclear safeguards). Compliance with the legislative framework can drive the need for certain programs and capital and non-capital expenditures, and impact on OPG's operations.

3.0 ONTARIO ENERGY BOARD ACT

The *Ontario Energy Board Act, 1998* ("Act"), when read in conjunction with Ontario Regulation 53/05 (Attachment 1), as made under the Act, as amended ("Regulation"), establishes that OPG is a prescribed generator for the purposes of Section 78.1 of the Act (Attachment 2). The combination of the Act and the Regulation provide that OPG is entitled to receive just and reasonable payments, subject to specific rules in the Regulation, with respect to the output from the prescribed generating facilities.

¹ This evidence is substantially the same as that filed in EB-2013-0321, with the following exceptions: the addition of discussion of amendments to Ontario Regulation 53/05 in section 3; the removal of the discussion for the regulated hydroelectric facilities; modification to legislation regarding nuclear civil liability in section 7.2; and modification to legislation regarding security for nuclear facilities in section 7.5.

1 The Regulation was amended effective as of January 1, 2016. The amendments reduce
2 volatility in OPG's regulated nuclear payment amounts during and following the execution of
3 the Darlington Refurbishment Program, while permitting an orderly recovery of prudently
4 incurred costs. The amendments establish and define the function of a rate smoothing
5 deferral account in respect of OPG's nuclear facilities, ensure the recovery of costs and firm
6 financial commitments in respect of the Darlington Refurbishment Program, and establish the
7 need for the Darlington Refurbishment Program. OPG's nuclear rate smoothing proposal is
8 discussed in Ex. A1-3-3.

9
10 **4.0 ELECTRICITY ACT**

11 Part IV.1 of the *Electricity Act, 1998* applies directly to OPG. The provisions set out in this
12 Part of the *Electricity Act, 1998* establish the objects of OPG as well as certain obligations on
13 OPG to provide reports to its shareholder.

14
15 **5.0 ELECTRICITY MARKETS**

16 Under authority granted to it by the *Electricity Act, 1998*, the IESO administers and ensures
17 compliance with the Market Rules for the Ontario Electricity Market (the "Market Rules"). All
18 of OPG's prescribed generating facilities are registered in the IESO-controlled markets and
19 are therefore required to comply with all applicable Market Rules.

20
21 **6.0 OEB LICENCE**

22 OPG holds an Electricity Generation Licence (EG-2003-0104) from the OEB, which is valid
23 until October 30, 2023 (the "Licence"). The Licence can be found in Attachment 3. The
24 Licence applies to all generating stations that are owned or owned and operated by OPG,
25 including the prescribed facilities. The Licence obligates OPG to comply with all applicable
26 provisions of the Act, the *Electricity Act, 1998*, all regulations under these acts, and all
27 applicable Market Rules. The Licence further obligates OPG to enter into agreements for the
28 supply of energy or ancillary services where the IESO deems necessary for the purpose of
29 maintaining the reliability and security of the IESO-controlled electricity grid. Ancillary
30 services provided by the nuclear facilities are discussed in Ex. G2-1-1.

1 **7.0 REGULATED HYDROELECTRIC FACILITIES**

2 OPG's regulated hydroelectric facilities are subject to international treaties between Canada
3 and the United States; federal and provincial regulatory and legislative requirements; and
4 common law as it pertains to riparian interests, waterways, and real property. The key
5 regulatory obligations and constraints applicable to the regulated hydroelectric facilities are
6 highlighted below.

7

8 **7.1 Water Rights and Usage**

9 Relevant legislation and agreements include:

- 10 • *Public Lands Act* (Ontario);
- 11 • *Lakes and Rivers Improvement Act* (Ontario);
- 12 • *Niagara Parks Act* (Ontario);
- 13 • *Boundary Waters Treaty of 1909 between Great Britain and the United States*
14 (sanctioned by the Parliament of Canada);
- 15 • *Niagara Diversion Treaty of 1950* between Canada and the United States;
- 16 • *Niagara Development Act, 1951* (Ontario);
- 17 • Agreement between OPG and the Niagara Parks Commission, February 2005;
- 18 • *International Rapids Power Development Agreement Act, 1952*, between Canada and
19 Ontario;
- 20 • *St. Lawrence Development Act, 1952 (No. 2)* (Ontario);
- 21 • *Dominion Water Power Act* and *Dominion Water Power Regulations* (Canada);
- 22 • *Ottawa River Water Powers Act, 1943* (Ontario and Quebec);
- 23 • Agreement Respecting Ottawa River Basin Regulation, 1983 (Canada, Ontario,
24 Quebec) pertaining to management and regulation of the waters within the Ottawa
25 River basin;
- 26 • Agreement Concerning the Revision of the Rent for the Water Powers of the Ottawa
27 River, executed 1995 (Quebec, Ontario, Hydro Quebec, and Ontario Hydro);
- 28 • *Lake of the Woods Control Board Act* (Canada, 1921, and Ontario, 1922);
- 29 • *Tripartite Agreement (Canada, Ontario, and Manitoba), 1922*, pertaining to control of
30 upper waters of the Winnipeg River;
- 31 • *Lac Seul Conservation Act, 1928* (Canada and Ontario);

- 1 • *Lake of the Woods Control Board Amendment Act, 1958* (Canada, Ontario, and
2 Manitoba);
- 3 • *Manitoba-Ontario Lake St. Joseph Diversion Agreement Authorization Act, 1958*
4 (Manitoba, Ontario, Manitoba Hydro-Electric Board, and Hydro-Electric Power
5 Commission of Ontario);
- 6 • *Electricity Act, 1998*, section 92.1, which addresses the gross revenue charge;
- 7 • Water Power Leases and Water Power Lease Agreements, Crown Leases and
8 Licences of Occupation with Ontario Ministry of Natural Resources;
- 9 • Licences with Parks Canada for facilities on the Trent River and Rideau Canal;
- 10 • Lease agreement with St. Lawrence Seaway Management Corporation for diversion
11 of water from the Welland Ship Canal for utilization at DeCew Falls; and
- 12 • Agreements between OPG and other utilities/generators (New York Power Authority,
13 Manitoba Hydro, Hydro Quebec, H2O Power LP) related to operational
14 requirements/guidelines, joint works, water sharing, water diversions, and
15 compensation settlements.

16 17 **7.2 Dam Safety**

18 OPG's Safe Operations Policy and the associated Dam Safety Program Management
19 document require that all OPG dams be designed, constructed, operated and maintained in
20 accordance with all regulations. In the absence of a specific regulation, the Canadian Dam
21 Association ("CDA") Dam Safety Guidelines (2013), the CDA Guidelines for Public Safety
22 Around Dams (2011), or other appropriate industry standards shall apply. These guidelines
23 and OPG's internal standards provide guidance on dam safety covering inspections, testing
24 of flow control equipment, emergency preparedness planning, periodic reviews of safety and
25 other aspects considered critical for ensuring the safety of the regulated hydroelectric
26 facilities and their operations.

27
28 In Ontario, provincial legislative authority over dams is exercised through the *Lakes and*
29 *Rivers Improvement Act* and the supporting Regulation 454/96. In August 2011, the Province
30 of Ontario enhanced the direction to dam owners with the provision of new Technical
31 Guidelines for Approval under the *Lakes and Rivers Improvement Act*.

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In Quebec, provincial legislative authority over dams is exercised through the *Quebec Dam Safety Act* and the supporting Quebec Dam Safety Regulation. This covers OPG facilities on the Ottawa River.

The Government of Canada exercises authority over dams through the *Navigation Protection Act* and the *Canada Shipping Act, 2001*, including associated Regulations. These acts apply to OPG in relation to the construction of new dams, alterations to existing dams, and the administration of “approved works”, such as safety booms and exclusion zones associated with OPG’s measures to manage public safety. The Government of Canada has jurisdiction over all boundary waters as well as waters associated with canals. As well as operating the Sir Adam Beck facilities on the Niagara River and the R.H. Saunders facility on the St. Lawrence River, OPG also operates a number of structures on the Trent Severn Waterway (“TSW”) and the Rideau Canal which come under Federal jurisdiction. In the case of the OPG facilities located on the TSW and Rideau Canal, the guidelines OPG is required to follow are administered by Parks Canada’s Dam Safety Directive (2009).

Relevant dam safety guidelines and legislation include:

- CDA Dam Safety and Public Safety Around Dams Guidelines;
- *Lakes and Rivers Improvement Act* (Ontario);
- Province of Ontario Dam Safety Technical Guidelines;
- *Navigation Protection Act* (Canada);
- *Canada Shipping Act* and the Vessel Operation Restriction Regulations;
- International Joint Commission regulation of the Niagara and St. Lawrence Rivers, pursuant to the *Boundary Waters Treaty of 1909*;
- Quebec Dam Safety Act and Dam Safety Regulation;
- Quebec Civil Protection Act; and
- Directive for Dam Safety Program of Parks Canada Dams and Water-Retaining Structures.

1 **7.3 Environmental**

2 The environmental legislation and best practice standards that impact OPG's regulated
3 hydroelectric facilities include:

- 4 • *Fisheries Act* (Canada);
- 5 • *Conservation Authorities Act* (Ontario);
- 6 • *Clean Water Act, 2006* (Ontario);
- 7 • *Environmental Assessment Act* (Ontario);
- 8 • *Environmental Protection Act* (Ontario);
- 9 • *Great Lakes Protection Act, 2015* (Ontario);
- 10 • *Ontario Water Resources Act*,
- 11 • *Endangered Species Act, 2007* (Ontario);
- 12 • *Migratory Birds Convention Act* (Canada);
- 13 • *Species at Risk Act* (Canada); and
- 14 • ISO 14001 Environmental Management System standard, to which OPG has
15 corporate registration.

16

17 **7.4 Other**

18 OPG's regulated hydroelectric facilities are also subject to relevant municipal by-laws that
19 apply locally, as well as to more generally applicable legislative and regulatory requirements
20 such as in areas that include:

- 21 • Technical standards and safety including corresponding regulations and codes,
22 particularly in respect of fuel storage tanks;
- 23 • Heritage;
- 24 • Dangerous goods transportation;
- 25 • Occupational health and safety;
- 26 • Employment standards;
- 27 • Labour relations; and
- 28 • Freedom of information.

29

30

1 **8.0 NUCLEAR GENERATING FACILITIES**

2 **8.1 Nuclear Operations and Materials**

3 OPG's nuclear operations are subject to the jurisdiction of the Canadian Nuclear Safety
4 Commission ("CNSC"), an independent federal government agency that derives its powers
5 from, and is responsible for administering, ensuring compliance with and enforcing the
6 *Nuclear Safety and Control Act* (Canada), which is described below. Several of the key
7 regulatory regimes that are uniquely applicable to OPG's nuclear facilities are discussed
8 below.

9

10 The *Nuclear Safety and Control Act* (Canada) is intended to limit the risks to national
11 security, health and the safety of persons and the environment that are associated with the
12 development, production and use of nuclear energy, as well as to limit risks associated with
13 the production, possession and use of nuclear substances, certain equipment and certain
14 related information. This act also implements measures to which Canada has agreed
15 respecting international control of the development, production and use of nuclear energy,
16 including the non-proliferation of nuclear weapons and nuclear explosive devices. In addition,
17 this act establishes the CNSC and delineates its powers.

18

19 The CNSC's regulatory control extends to regulating all aspects of site selection,
20 construction, operation and maintenance (including refurbishment for life extension), and
21 decommissioning of nuclear facilities.

22

23 The CNSC exercises its mandate in respect of OPG's nuclear operations largely by means of
24 the issuance of operating licences and amendments, as well as through continuous
25 monitoring and inspections to ensure compliance with operating licences, relevant standards
26 and applicable regulations. The regulator issues requests for action and information on a
27 routine basis in the order of 400 pieces of correspondence per station per year. Operating
28 licences, which must be renewed approximately every five to ten years for the generating
29 stations (or ten years in respect of certain nuclear waste facilities), impose numerous
30 conditions and constraints on OPG, including obligations to comply with Regulatory
31 Documents issued by the CNSC and various external standards and codes (e.g., National

1 Building Code, National Fire Code, CSA Standards). The CNSC has issued a number of
2 Regulatory Documents for nuclear power plants, including for example, ones relating to
3 maintenance programs, reliability programs, aging management, safety analysis, and
4 emergency preparedness.

5
6 For refurbishment of nuclear power plants for life extension, the regulatory process and
7 CNSC expectations have been documented in Regulatory Document 2.3.3 *Periodic Safety*
8 *Reviews*, (which superseded RD-360, *Life Extension of Nuclear Power Plants*) (see Ex. D2-
9 2-1, Attachments 3 and 4). This document outlines expectations for, and CNSC acceptance
10 of, *Periodic Safety Reviews* against modern codes and standards, including requiring a
11 safety factor review, a global assessment report, and the ensuing integrated implementation
12 plan for the corrective actions and safety improvements. Regulatory control by the CNSC is
13 exercised through amended operating licences by including licence conditions that have to
14 be met.

15
16 The CNSC also issues Guidance Documents that provide direction to licensees and
17 applicants on how to meet the requirements set out in the CNSC's regulations, Regulatory
18 Documents, and licences. It is OPG's practice to incorporate the directions from these
19 Guidance Documents into the design and operating documents for its nuclear generating
20 stations.

21
22 Although the above-mentioned conditions and constraints do not impose a limiting date for
23 continued operation of a nuclear facility, OPG must maintain compliance in order to ensure
24 that the nuclear facility is fit for service and continued operation.

25
26 OPG holds two Power Reactor Operating Licences from the CNSC, which allow for the
27 operation of Pickering and Darlington nuclear generating stations, as well as separate
28 licences that authorize the operation of nuclear waste management facilities. OPG also
29 maintains regulated certificates for radioactive material transportation packages, and
30 licences for the possession, transport, and import/export of certain radioactive materials.

1 OPG also maintains a licence for the preparation of site of a new nuclear power plant at the
2 Darlington site.

3
4 In addition to the resources and costs associated with compliance with the conditions in
5 these licences, the application process for each licence, including significant amendments or
6 renewal, requires extensive preparation and the conduct of public hearings involving CNSC
7 staff and intervening stakeholders. OPG is required to pay a licence fee to the CNSC each
8 year, under the CNSC's Cost Recovery Fees Regulations, which in effect covers the CNSC's
9 costs of staff and resources to administer the licence including compliance activities and
10 inspections. The CNSC's also has significant power to regulate licensing under the *Nuclear
11 Safety and Control Act*. OPG's nuclear facilities are required to operate in accordance with
12 numerous regulations under this act, including:

- 13 • General Nuclear Safety and Control Regulations;
- 14 • Class 1 Nuclear Facilities Regulations;
- 15 • Packaging and Transport of Nuclear Substances Regulations;
- 16 • Nuclear Security Regulations;
- 17 • Radiation Protection Regulations;
- 18 • Nuclear Substances and Radiation Devices Regulations;
- 19 • Class II Nuclear Facilities and Prescribed Substances Regulations;
- 20 • Nuclear Non-proliferation Import and Export Control Regulations; and
- 21 • CNSC Cost Recovery Fees Regulations.

22
23 A person or organization may only possess or dispose of nuclear substances, or construct,
24 operate and decommission nuclear facilities in accordance with the terms of a licence issued
25 by the CNSC. Licence terms incorporate the applicable requirements set out in the
26 regulations.

27
28 It is a fundamental principle of nuclear regulation that the licensee, in this case OPG, bears
29 responsibility for the safe operation of nuclear facilities. The CNSC sets safety objectives in
30 areas such as radiation protection, physical site security, and the transport of radioactive
31 materials. OPG is required to design, implement, monitor, and continually improve upon its

1 extensive programs in each of these critical areas. The CNSC audits OPG's performance
2 against these objectives, continually monitors OPG's safety performance and reports
3 annually to Parliament with an assessment of licensee performance in all areas of nuclear
4 safety. The delivery and continual improvement of these programs represent a significant
5 cost driver for OPG in respect of the regulated nuclear facilities.

6 7 **8.2 Civil Liability**

8 OPG is subject to the *Nuclear Liability Act* (Canada), which governs civil liability for nuclear
9 damage in Canada. On February 26, 2015, the federal *Nuclear Liability and Compensation*
10 *Act* under Bill C-22 received Royal Assent, and will come into force by order of the Governor
11 in Council. Once in force, it will replace and repeal the *Nuclear Liability Act* (Canada). The
12 new legislation increases OPG's risk management costs, which are centrally-held and, in
13 turn, directly assigned to Nuclear (see Ex. F4-4-1).

14 15 **8.3 Nuclear Waste Management**

16 The *Nuclear Safety and Control Act* provides the CNSC with authority over nuclear waste
17 from a health, safety and environmental protection perspective. The CNSC licenses all of
18 OPG's waste management facilities. OPG is also subject to the *Nuclear Fuel Waste Act*
19 (Canada) which addresses the long-term handling and disposal of used nuclear fuel.

20
21 Coincident with the formation of OPG on April 1, 1999, OPG and the Province of Ontario
22 entered into the Ontario Nuclear Funds Agreement ("ONFA"). The ONFA is an agreement
23 that generally establishes the responsibilities for funding OPG's nuclear waste management
24 and decommissioning liabilities, which were inherited from Ontario Hydro. The ONFA is
25 discussed in greater detail in Ex. C2-1-1.

26 27 **8.4 Environmental**

28 Projects associated with OPG's nuclear facilities, including the nuclear waste management
29 facilities, can be subject to requirements for the preparation of environmental assessments
30 under the *Canadian Environmental Assessment Act* (Canada). In addition, nuclear
31 operations are subject to a wide range of environmental legislation and regulation, both

1 federal (e.g., *Fisheries Act*, *Canadian Environmental Protection Act*, *Transportation of*
2 *Dangerous Goods Act*, *Species at Risk Act*) and provincial (e.g., *Environmental Protection*
3 *Act*, *Ontario Water Resources Act*, *Endangered Species Act*, 2007), along with the
4 associated costs of compliance and the need to respond to rapidly changing regulatory
5 requirements in these areas. OPG's nuclear generating facilities also operate in accordance
6 with the ISO 14001 Environmental Management System standard.

7
8 **8.5 Other**

9 Beyond the nuclear-specific federal requirements described above, two pieces of provincial
10 legislation apply in respect of the security personnel associated with OPG's nuclear
11 generating facilities. These are the *Police Services Act* (Ontario) and the *Security for*
12 *Electricity Generating Stations and Nuclear Generating Stations Act* (Ontario). Pursuant to
13 Bill 35, the *Security for Electricity Generating Stations and Nuclear Generating Stations Act*
14 (Ontario) replaced the *Public Works Protection Act* (Ontario) on June 24, 2015, and the
15 *Public Works Protection Act* (Ontario) was concurrently repealed.

16
17 OPG's nuclear facilities are also subject to applicable legislation and regulations in areas
18 such as public access to information (Ontario or, indirectly as an affected third party,
19 Canada), occupational health and safety (Ontario), employment standards (Ontario) and
20 labour relations (provincial and federal), shipping and hazardous products as well as relevant
21 municipal by-laws.

22

ATTACHMENTS

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- Attachment 1: Ontario Regulation 53/05
- Attachment 2: Section 78.1 of the OEB Act
- Attachment 3: OPG Electricity Generation Licence

Ontario Energy Board Act, 1998
Loi de 1998 sur la Commission de l'énergie de l'Ontario

ONTARIO REGULATION 53/05
PAYMENTS UNDER SECTION 78.1 OF THE ACT

Consolidation Period: From January 1, 2016 to the [e-Laws currency date](#).

Last amendment: O. Reg. 353/15.

This Regulation is made in English only.

Definition

0.1 (1) In this Regulation,

“approved reference plan” means a reference plan, as defined in the Ontario Nuclear Funds Agreement, that has been approved by Her Majesty the Queen in right of Ontario in accordance with that agreement;

“Darlington Refurbishment Project” means the work undertaken by Ontario Power Generation Inc. in respect of the refurbishment, in whole or in part, of some or all of the generating units of the Darlington Nuclear Generating Station;

“deferral period” means the period beginning on January 1, 2017, and ending when the Darlington Refurbishment Project ends;

“nuclear decommissioning liability” means the liability of Ontario Power Generation Inc. for decommissioning its nuclear generation facilities and the management of its nuclear waste and used fuel;

“nuclear facilities” means the nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2;

“Ontario Nuclear Funds Agreement” means the agreement entered into as of April 1, 1999 by Her Majesty the Queen in right of Ontario, Ontario Power Generation Inc. and certain subsidiaries of Ontario Power Generation Inc., including any amendments to the agreement. O. Reg. 23/07, s. 1; O. Reg. 353/15, s. 1.

(2) For the purposes of this Regulation, the output of a generation facility shall be measured at the facility’s delivery points, as determined in accordance with the market rules. O. Reg. 312/13. s. 1.

Prescribed generator

1. Ontario Power Generation Inc. is prescribed as a generator for the purposes of section 78.1 of the Act. O. Reg. 53/05, s. 1.

Prescribed generation facilities

2. The following generation facilities of Ontario Power Generation Inc. are prescribed for the purposes of section 78.1 of the Act:

1. The following hydroelectric generating stations located in The Regional Municipality of Niagara:

i. Sir Adam Beck I.

ii. Sir Adam Beck II.

iii. Sir Adam Beck Pump Generating Station.

iv. De Cew Falls I.

v. De Cew Falls II.

2. The R. H. Saunders hydroelectric generating station on the St. Lawrence River.

3. Pickering A Nuclear Generating Station.

4. Pickering B Nuclear Generating Station.

5. Darlington Nuclear Generating Station.

6. As of July 1, 2014, the generation facilities of Ontario Power Generation Inc. that are set out in the Schedule. O. Reg. 53/05, s. 2; O. Reg. 23/07, s. 2; O. Reg. 312/13, s. 2.

Prescribed date for s. 78.1 (2) of the Act

3. April 1, 2008 is prescribed for the purposes of subsection 78.1 (2) of the Act. O. Reg. 53/05, s. 3.
4. REVOKED: O. Reg. 312/13, s. 3.

Deferral and variance accounts

5. (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records capital and non-capital costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecasts as set out in the document titled "Forecast Information (as of Q3/2004) for Facilities Prescribed under Ontario Regulation 53/05" posted and available on the Ontario Energy Board website, that are associated with,

- (a) differences in hydroelectric electricity production due to differences between forecast and actual water conditions;
 - (b) unforeseen changes to nuclear regulatory requirements or unforeseen technological changes which directly affect the nuclear generation facilities, excluding revenue requirement impacts described in subsections 5.1 (1) and 5.2 (1);
 - (c) changes to revenues for ancillary services from the generation facilities prescribed under section 2;
 - (d) acts of God, including severe weather events; and
 - (e) transmission outages and transmission restrictions that are not otherwise compensated for through congestion management settlement credits under the market rules. O. Reg. 23/07, s. 3.
- (2) The calculation of revenues earned or foregone due to changes in electricity production associated with clauses (1) (a), (b), (d) and (e) shall be based on the following prices:

- 1. \$33.00 per megawatt hour from hydroelectric generation facilities prescribed in paragraphs 1 and 2 of section 2.
- 2. \$49.50 per megawatt hour from nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 3.

(3) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

(4) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A Nuclear Generating Station, including those units which the board of directors of Ontario Power Generation Inc. has determined should be placed in safe storage. O. Reg. 23/07, s. 3.

- (5) For the purposes of subsection (4), the non-capital costs include, but are not restricted to,
- (a) construction costs, assessment costs, pre-engineering costs, project completion costs and demobilization costs; and
 - (b) interest costs, recorded as simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

5.1 REVOKED: O. Reg. 312/13, s. 3.

Nuclear liability deferral account

5.2 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under 78.1 of the Act, the revenue requirement impact of changes in its total nuclear decommissioning liability between,

- (a) the liability arising from the approved reference plan incorporated into the Board's most recent order under section 78.1 of the Act; and
- (b) the liability arising from the current approved reference plan. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 23/07, s. 3.

5.3 REVOKED: O. Reg. 312/13, s. 3.

Nuclear development variance account

5.4 (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under section 78.1 of the Act, differences between actual non-capital costs incurred and firm financial commitments made and the amount included in payments made under that section for planning and preparation for the development of proposed new nuclear generation facilities. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 27/08, s. 1.

Darlington refurbishment rate smoothing deferral account

5.5 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the commencement of the deferral period, the difference between,

- (a) the revenue requirement amount approved by the Board that, but for subparagraph 12 i of subsection 6 (2) of this Regulation, would have been used in connection with determining the payments to be made under section 78.1 of the Act each year during the deferral period in respect of the nuclear facilities; and
- (b) the portion of the revenue requirement amount referred to in clause (a) that is used in connection with determining the payments made under section 78.1 of the Act, after determining, under subparagraph 12 i of subsection 6 (2) of this Regulation, the amount of the revenue requirement to be deferred for that year in respect of the nuclear facilities. O. Reg. 353/15, s. 2.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account at a long-term debt rate reflecting Ontario Power Generation Inc.'s cost of long-term borrowing that is determined or approved by the Board from time to time, compounded annually. O. Reg. 353/15, s. 2.

Rules governing determination of payment amounts by Board

6. (1) Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. O. Reg. 53/05, s. 6 (1).

(2) The following rules apply to the making of an order by the Board that determines payment amounts for the purpose of section 78.1 of the Act:

1. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the variance account established under subsection 5 (1) over a period not to exceed three years, to the extent that the Board is satisfied that,
 - i. the revenues recorded in the account were earned or foregone and the costs were prudently incurred, and
 - ii. the revenues and costs are accurately recorded in the account.
2. In setting payment amounts for the assets prescribed under section 2, the Board shall not adopt any methodologies, assumptions or calculations that are based upon the contracting for all or any portion of the output of those assets.
3. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5 (4). The Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 15 years.
4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs and firm financial commitments incurred in respect of the Darlington Refurbishment Project or incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,
 - i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or
 - ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.
- 4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,
 - i. the costs were prudently incurred, and

- ii. the financial commitments were prudently made.
5. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., the Board shall accept the amounts for the following matters as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors of Ontario Power Generation Inc. before the effective date of that order:
 - i. Ontario Power Generation Inc.'s assets and liabilities, other than the variance account referred to in subsection 5 (1), which shall be determined in accordance with paragraph 1.
 - ii. Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations.
 - iii. Ontario Power Generation Inc.'s costs with respect to the Bruce Nuclear Generating Stations.
 6. Without limiting the generality of paragraph 5, that paragraph applies to values relating to,
 - i. capital cost allowances,
 - ii. the revenue requirement impact of accounting and tax policy decisions, and
 - iii. capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2.
 7. The Board shall ensure that the balance recorded in the deferral account established under subsection 5.2 (1) is recovered on a straight line basis over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the account, based on the following items, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.,
 - i. return on rate base,
 - ii. depreciation expense,
 - iii. income and capital taxes, and
 - iv. fuel expense.
 - 7.1 The Board shall ensure the balance recorded in the variance account established under subsection 5.4 (1) is recovered on a straight line basis over a period not to exceed three years, to the extent the Board is satisfied that,
 - i. the costs were prudently incurred, and
 - ii. the financial commitments were prudently made.
 8. The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.
 9. The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.
 10. If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear generation facilities referred to in paragraphs 3, 4 and 5 of section 2.
 11. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc. that is effective on or after July 1, 2014, the following rules apply:
 - i. The order shall provide for the payment of amounts with respect to output that is generated at a generation facility referred to in paragraph 6 of section 2 during the period from July 1, 2014 to the day before the effective date of the order.
 - ii. The Board shall accept the values for the assets and liabilities of the generation facilities referred to in paragraph 6 of section 2 as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors before the making of that order. This includes values relating to the income tax effects of timing differences and the revenue requirement impact of accounting and tax policy decisions reflected in those financial statements.

12. For the purposes of section 78.1 of the Act, in setting payment amounts for the nuclear facilities during the deferral period,
 - i. the Board 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 made under section 78.1 of the Act with respect to the nuclear facilities,
 - ii. the Board shall determine the approved revenue requirements referred to in subsection 5.5 (1) and the amount of the approved revenue requirements to be deferred under subparagraph i on a five-year basis for the first 10 years of the deferral period and, thereafter, on such periodic basis as the Board determines,
 - iii. for greater certainty, the Board's determination of Ontario Power Generation Inc.'s approved revenue requirement for the nuclear facilities shall not be restricted by the yearly changes in payment amounts in subparagraph i,
 - iv. the Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5.5 (1), and the Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 10 years commencing at the end of the deferral period, and
 - v. the Board shall accept the need for the Darlington Refurbishment Project in light of the Plan of the Ministry of Energy known as the 2013 Long-Term Energy Plan and the related policy of the Minister endorsing the need for nuclear refurbishment. O. Reg. 23/07, s. 4; O. Reg. 27/08, s. 2; O. Reg. 312/13, s. 4; O. Reg. 353/15, s. 3.
7. OMITTED (PROVIDES FOR COMING INTO FORCE OF PROVISIONS OF THIS REGULATION). O. Reg. 53/05, s. 7.

SCHEDULE

1. Abitibi Canyon.
2. Alexander.
3. Aquasabon.
4. Arnprior.
5. Auburn.
6. Barrett Chute.
7. Big Chute.
8. Big Eddy.
9. Bingham Chute.
10. Calabogie.
11. Cameron Falls.
12. Caribou Falls.
13. Chats Falls.
14. Chenaux.
15. Coniston.
16. Crystal Falls.
17. Des Joachims.
18. Elliott Chute.
19. Eugenia Falls.
20. Frankford.
21. Hagues Reach.
22. Hanna Chute.
23. High Falls.

24. Indian Chute.
25. Kakabeka Falls.
26. Lakefield.
27. Lower Notch.
28. Manitou Falls.
29. Matabitchuan.
30. McVittie.
31. Merrickville.
32. Meyersberg.
33. Mountain Chute.
34. Nipissing.
35. Otter Rapid.
36. Otto Holden.
37. Pine Portage.
38. Ragged Rapids.
39. Ranney Falls.
40. Seymour.
41. Sidney.
42. Sills Island.
43. Silver Falls.
44. South Falls.
45. Stewartville.
46. Stinson.
47. Trethewey Falls.
48. Whitedog Falls.

O. Reg. 312/13, s. 5.

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Ontario Energy Board Act, 1998

S.O. 1998, CHAPTER 15 Schedule B

Payments to prescribed generator

78.1 (1) The IESO shall make payments to a generator prescribed by the regulations with respect to output that is generated by a unit at a generation facility prescribed by the regulations. 2014, c. 7, Sched. 23, s. 7.

Payment amount

(2) Each payment referred to in subsection (1) shall be the amount determined in accordance with the order of the Board then in effect. 2014, c. 7, Sched. 23, s. 7.

(3) REPEALED: 2014, c. 7, Sched. 23, s. 7.

Board orders

(4) The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment. 2004, c. 23, Sched. B, s. 15.

Fixing other prices

(5) The Board may fix such other payment amounts as it finds to be just and reasonable,

- (a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or
- (b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Burden of proof

(6) Subject to subsection (7), the burden of proof is on the applicant in an application made under this section. 2004, c. 23, Sched. B, s. 15.

Order

(7) If the Board on its own motion or at the request of the Minister commences a proceeding to determine whether an amount that the Board may approve or fix under this section is just and reasonable,

- (a) the burden of establishing that the amount is just and reasonable is on the generator; and
- (b) the Board shall make an order approving or fixing an amount that is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Application

(8) Subsections (4), (5) and (7) apply only on and after the day prescribed by the regulations for the purposes of subsection (2). 2004, c. 23, Sched. B, s. 15.




Electricity Generation Licence

EG-2003-0104

Ontario Power Generation Inc.

Valid Until

October 30, 2023



Jennifer Lea

Counsel, Special Projects

Ontario Energy Board

Date of Issuance: October 31, 2003

Date of Last Amendment: February 11, 2011 (expires April 30, 2011)

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

Commission de l'énergie de l'Ontario
C.P. 2319
2300, rue Yonge
27e étage
Toronto ON M4P 1E4

LIST OF AMENDMENTS

Board File No. Date of Amendment

EB-2005-0245	April 25, 2005
EB-2006-0042	April 10, 2006
EB-2006-0007	June 23, 2006
EB-2006-0110	September 12, 2006
EB-2008-0054	May 7, 2008
EB-2008-0114	June 24, 2008
EB-2008-0107	October 2, 2008
EB-2009-0319	November 10, 2009 (corrected December 3, 2009)
EB-2010-0027	March 18, 2010
EB-2010-0267	November 30, 2010
EB-2011-0020	February 11, 2011 (expires April 30, 2011)

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PART 1 GENERAL CONDITIONS

1 Definitions

In this Licence:

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**generation facility**" means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system and includes any structures, equipment or other things used for that purpose;

"**Licensee**" means Ontario Power Generation Inc.;

"**regulation**" means a regulation made under the Act or the Electricity Act;

2 Interpretation

- 2.1 In this Licence words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of this Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this Licence where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens. Where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

- 3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this licence:
- a) to generate electricity or provide ancillary services for sale through the IMO-administered markets or directly to another person subject to the conditions set out in this Licence. This Licence authorizes the Licensee only in respect of those facilities set out in Schedule 1;
 - b) to purchase electricity or ancillary services in the IMO-administered markets or directly from a generator subject to the conditions set out in this Licence; and
 - c) to sell electricity or ancillary services through the IMO-administered markets or directly to another person, other than a consumer, subject to the conditions set out in this Licence.

4 Obligation to Comply with Legislation, Regulations and Market Rules

- 4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act, and regulations under these acts, except where the Licensee has been exempted from such compliance by regulation.
- 4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Maintain System Integrity

- 5.1 Where the IMO has identified, pursuant to the conditions of its licence and the Market Rules, that it is necessary for purposes of maintaining the reliability and security of the IMO-controlled grid, for the Licensee to provide energy or ancillary services, the IMO may require the Licensee to enter into an agreement for the supply of energy or such services.
- 5.2 Where an agreement is entered into in accordance with paragraph 5.1, it shall comply with the applicable provisions of the Market Rules or such other conditions as the Board may consider reasonable. The agreement shall be subject to approval by the Board prior to its implementation. Unresolved disputes relating to the terms of the Agreement, the interpretation of the Agreement, or amendment of the Agreement, may be determined by the Board.

6 Restrictions on Certain Business Activities

- 6.1 Neither the Licensee, nor an affiliate of the Licensee shall acquire an interest in a transmission or distribution system in Ontario, construct a transmission or distribution system in Ontario or purchase shares of a corporation that owns a transmission or distribution system in Ontario except in accordance with section 81 of the Act.

7 Provision of Information to the Board

- 7.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.
- 7.2 Without limiting the generality of paragraph 7.1 the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee, as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

8 Term of Licence

- 8.1 This Licence shall take effect on October 31, 2003 and expire on October 30, 2023. The term of this Licence may be extended by the Board.

9 Fees and Assessments

- 9.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

10 Communication

- 10.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.
- 10.2 All official communication relating to this Licence shall be in writing.
- 10.3 All written communication is to be regarded as having been given by the sender and received by the addressee:
- a) when delivered in person to the addressee by hand, by registered mail or by courier;
 - b) ten (10) business days after the date of posting if the communication is sent by regular mail; or
 - c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

11 Copies of the Licence

- 11.1 The Licensee shall:
- a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and
 - b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

PART 2 PRICE CAP AND REBATE

1 Definitions and Interpretation

In Parts 2 through 5 inclusive of these Licence Conditions:

"Average Price" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by summing the product of the Hourly Price multiplied by the Contract Weight for all hours of that Settlement Period;

"Changes in Law" means changes in law (including without limitation environmental laws, laws affecting OPGI's generation facilities, tax laws and the general laws affecting the regulation of electricity in Ontario), but excluding provincial tax laws and, for greater certainty, excluding changes in licence conditions and market rules;

"Contract Required Quantity" or "CRQ" means the quantity of energy upon which any Rebate is determined, in respect of a Settlement Period, as set forth in the Model Output Data and as may be modified pursuant hereto. Subject to such adjustments, the CRQ will equal the sum of all Hourly Quantities for all hours in a Settlement Period;

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“Contract Weight” or “ CW_h ” means the weighting for each hour in a Settlement Period, h , that is used to calculate the Average Price. For any particular hour, the Contract Weight equals the Hourly Quantity for that hour divided by the CRQ for that Settlement Period;

“Effective Control” in respect of output means control over the timing, quantity and bidding into the Ontario market of such output;

“Force Majeure Adjustment” or “FMA” means a reduction in the Rebate as a result of a *Force Majeure* Event;

“Force Majeure Event” means an event defined in clause 2(c)(ii) of Part 2 below;

“Force Majeure Replacement Cost” or “ $FMRC_h$ ” means, for any particular hour in a Settlement Period, h , the predetermined net incremental replacement cost for each OPGI generation unit, as set forth in the Model Output Data that is used in determining the Force Majeure Adjustment, and as may be modified pursuant hereto. $FMRC_h$ may be constant in the Model Output Data over the hours in a month or other period;

“Hourly Quantity” or “ Q_h ” means, for any particular hour in a Settlement Period, h , the quantity of energy upon which the Contract Weight is established, as set forth in the Model Output Data. The sum of the Hourly Quantities for all hours in a Settlement Period equals the CRQ for that Settlement Period;

“Hourly Price” or “ P_h ” means, for any particular hour in a Settlement Period, h , the unconstrained spot price for energy for that hour expressed in a price in \$ per MWh, as determined by the IESO pursuant to its market rules;

“Hourly Reserve Capacity Price” is the hourly market clearing price of reserve capacity;

“Hourly Unit Quantity,” or “ q_h^i ” means, for any particular hour in a Settlement Period, h , the hourly quantity of energy associated with a particular OPGI generation unit, i , upon which the Hourly Quantity is established, as set forth in the Model Output Data. The sum of all Hourly Unit Quantities for all OPGI generation units in respect of an hour equals the Hourly Quantity for that hour;

“Locational Spot Price” means, for any particular hour in a Settlement Period, h , and any particular OPGI generation unit, the spot price for energy at such generation unit’s interconnection, which will only apply if location-based marginal pricing is developed in Ontario;

“Model Output Data” means the data filed with the Board. The Model Output Data contains data, some of which is confidential, derived from a production cost model of the electricity market in Ontario and neighbouring regions under the assumption that OPGI is assumed to bid its generation units in a manner that achieves an average sales price of \$ 38/MWh. The resulting CRQ, Q_h , and q_h^i data reflects 90 per cent of OPGI’s predicted sales to Ontario customers;

“OPGI” means Ontario Power Generation Inc.

“Potential Force Majeure Event” means an event defined in clause 2(c)(i) of Part 2 below;

“Price Cap” or “CAP” means \$38/MWh, which is the threshold used in calculating the Rebate;

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"Price Spike Adjustment" or "PSA" means the reduction in the Rebate as a result of qualifying price spikes, as calculated pursuant hereto;

"Prime Rate" means the variable annual rate of interest, calculated on the basis of a calendar year, announced from time to time by the IESO's then principal Canadian banker as the reference rate of interest (commonly known as its prime rate) then in effect and used by such bank for determining interest rates on Canadian dollar denominated commercial loans made by it in Canada to customers of varying degrees of credit-worthiness;

"Rebate" or "R" means the amount OPGI must pay the IESO as a consequence of the Average Price in any Settlement Period exceeding the Price Cap, less any applicable adjustments;

"Rebate Carryforward Adjustment" or "RCA" means the adjustment in which negative Rebates from a Settlement Period are used to offset Rebates in subsequent Settlement Periods;

"Reserve Capacity Ratio" is a number greater than 1, such as 1.2, that is set by the IESO for the purposes of multiplying by the hourly demand to determine the reserve capacity target in such hour;

"Settlement Period" means each time period over which OPGI's compliance with the Price Cap shall be measured, which shall be over a 12 month period, except that (1) the first Settlement Period shall commence on the opening of the competitive electricity market and shall consist of the first full 12 calendar months plus the days, if any, in the first partial month; and (2) the last Settlement Period shall end on the termination of the provisions of Part 2, and therefore could be less than 12 full calendar months; and

"Tier 1" capacity means all nuclear and hydroelectric generation in Ontario and **"Tier 2"** capacity means that portion of Ontario's generation capacity, including inter-tie capacity and demand-side bidding, that is not part of Tier 1 capacity. For such purposes, generation capacity shall be based upon the maximum continuous rating of a unit, inter-tie capacity shall be based on the average of summer and winter season Ontario transfer capacity, and demand-side bidding shall be based on the sum of the dispatchable and interruptible loads, all expressed in MW.

All dollar amounts referred to are expressed in Canadian dollars.

2 **Determination of Rebate**

OPGI shall pay a Rebate to the IESO in respect of each Settlement Period in which the Average Price (AP) exceeds the Price Cap (CAP). The amount of the Rebate shall be determined in accordance with the following formula:

$$R = [(AP - CAP) * CRQ] - (RCA + PSA + FMA)$$

If the calculated Rebate in respect of any Settlement Period is a negative number, then there shall be no Rebate, and the Rebate Carryforward Adjustment shall be changed as described herein.

(a) *Rebate Carryforward Adjustment*

Initially, the Rebate Carryforward Adjustment ("RCA") shall be zero. In any Settlement Period in respect of which the calculated Rebate is negative, the absolute value of that amount shall be the Rebate Carryforward Adjustment for the purposes of the next Settlement Period.

(b) *Price Spike Adjustment*

A Price Spike Adjustment (PSA) shall be calculated for all hours in a Settlement Period in which both (1) the Hourly Price (P_h) exceeds \$125/MWh, and (2) OPGI's Generation for that hour is less than the Hourly Quantity (Q_h). The PSA for a Settlement Period shall equal the sum of the adjustments for each applicable hour, which shall be calculated pursuant to the following formula:

$$PSA = (P_h - \$125/MWh) * (Q_h - \text{OPGI's Generation for that hour})$$

where OPGI's Generation for that hour = OPGI's energy generated from all sources in Ontario (metered as per IESO market rules) the output of which is Effectively Controlled by OPGI and which was included as OPGI energy generated in the Model Output Data, and includes the current power purchase agreement with Manitoba Hydro.

(c) *Force Majeure Adjustment*

(i) *Potential Force Majeure Event*

A Potential *Force Majeure* Event is any event consisting of any of the following conditions or events that results in the loss or failure of, or the inability to operate, in whole or in part, one or more generation units in Ontario the output of which is Effectively Controlled by OPGI and that, in each case, is beyond the reasonable control of OPGI and which is not a result of OPGI's failure to comply with pre-existing laws or licence conditions or market rules or to reasonably maintain or to use its best efforts to promptly repair any generation unit or units:

- (A) acts of war, revolution, riot, sabotage, occupation or vandalism;
- (B) earthquakes, tornadoes or severe storms;
- (C) other acts of God;
- (D) local, regional or national states of emergency;
- (E) strikes or other labour disputes;
- (F) other failure or damage to an OPGI generating facility, including failure or damage caused by construction defects, fire, or damage to necessary equipment and which is not a result of negligence in the maintenance or repair thereof;
- (G) interruptions in the supply of fuel or other essential supplies (excluding variations in water supplies in the case of hydroelectric generation units);
- (H) failure of transmission or distribution facilities in Ontario;
- (I) other system emergencies in Ontario; and

(J) Changes in Law.

(ii) Definition of *Force Majeure* Event

A *Force Majeure* Event is either an Isolated *Force Majeure* Event or a Cumulative *Force Majeure* Event.

An Isolated *Force Majeure* Event is that portion of any Potential *Force Majeure* Event that occurs after the Potential *Force Majeure* Event has caused a reduction in the energy actually generated by the applicable units greater than 250,000 MWh from the sum of such units' Hourly Unit Quantities during the effectiveness of such Potential *Force Majeure* Event.

A Cumulative *Force Majeure* Event occurs in a Settlement Period when the cumulative reduction in that Settlement Period of energy actually generated by affected generation units in Ontario the output of which is Effectively Controlled by OPGI caused by Potential *Force Majeure* Events exceeds 500,000 MWh when compared to the sum of such affected units' Hourly Unit Quantities during the effectiveness of such Potential *Force Majeure* Events. OPGI will, where applicable, designate within 15 days following the end of the applicable Settlement Period that portion of Potential *Force Majeure* Events that is in excess of 500,000 MWh and that qualifies as a Cumulative *Force Majeure* Event.

A Potential *Force Majeure* Event, or a portion of a Potential *Force Majeure* Event, that qualifies as both an Isolated *Force Majeure* Event or a Cumulative *Force Majeure* Event may at the discretion of OPGI within 15 days following the end of the applicable Settlement Period be designated as either type of *Force Majeure* Event, but not as both, and, for greater certainty, a Potential *Force Majeure* Event designated as one type of *Force Majeure* Event by OPGI shall not be treated for purposes of determining whether the other type of *Force Majeure* Event has occurred.

(iii) *Force Majeure* Adjustment

A *Force Majeure* Adjustment (FMA) in respect of any Settlement Period shall be equal to the sum, for all generation units the output of which is Effectively Controlled by OPGI subject to *Force Majeure* Events, of the *Force Majeure* Replacement Cost (FMRC_h) in respect of each applicable unit for each hour during the effectiveness of each *Force Majeure* Event in respect of such unit during the Settlement Period, less any insurance or other recovery in respect of such loss or deemed loss.

The *Force Majeure* Adjustment in respect of any Settlement Period for each generation unit the output of which is Effectively Controlled by OPGI whose generation is reduced as a consequence of a *Force Majeure* Event shall be calculated pursuant to the following formula, prior to any recovery adjustment:

$$\sum_n [q_h^i * FMRCh * ((Capacity - Reduced Capacity_h)/Capacity)]$$

where:

Capacity = the maximum continuous rating of the unit at the time of the *Force Majeure* Event (at normal head for hydroelectric generation units);

and
Reduced Capacity_h = the reduced capacity in an hour of the unit as a consequence of and during the effectiveness of the *Force Majeure* Event.

(iv) Adjustment to *Force Majeure* Replacement Cost

In the event that over 2,000 MW of OPGI generating capacity the output of which is Effectively Controlled by OPGI qualifies for a particular *Force Majeure* Event, OPGI shall have the right to petition the Board to increase the amount of the *Force Majeure* Replacement Cost in respect of one or more affected unit(s) in the applicable hours, which petition shall be granted if OPGI can demonstrate to the Board's satisfaction higher incremental replacement costs (net of any variable costs avoided as a consequence of the *Force Majeure* Event) than those set forth in the Model Output Data.

(v) Notice

OPGI shall promptly notify the IESO of any *Force Majeure* Event claimed by OPGI and shall provide the IESO with all information reasonably required to verify the *Force Majeure* Event and to calculate the *Force Majeure* Adjustment.

3 Conduct of OPGI

- 3.1 OPGI may engage in unilateral actions to attempt to maintain Hourly prices at levels that will result in the Average Price for a Settlement Period equaling the Price Cap, plus all adjustments provided for in Part 2, Section 2 above. In the event that unilateral actions taken by OPGI cause the Average Price to exceed such a level, the sole remedy shall be for OPGI to pay the Rebate as provided for in paragraph 2 of Part 2 above.

4 Reduction to CRQ and Q_h Upon Decontrol

(a) *Unadjusted Reductions*

Except as may be provided in (b) below, in the event that OPGI completes the transfer of Effective Control over the output of a generation unit, as determined by the Board under Part 3, then Q_h for each hour in respect of the current and any subsequent Settlement Period shall be reduced by 110 percent of the q_h¹ of the transferred unit for each hour subsequent to the completion of the transfer. As a result, the CRQ in respect of each applicable Settlement Period shall be reduced by these reductions in Q_h.

(b) *Adjustment Necessitated by Environmental Laws*

In the event that OPGI transfers Effective Control over the output of a generation unit and the transferee, at the date of completion of the transfer, does not have and cannot reasonably obtain sufficient environmental emission permits or other environmental authorizations ("emission permits"), in respect of the applicable hours in the period commencing following the completion of the transfer of Effective Control (the "applicable hours"), to enable the unit's potential output during the applicable hours (the "transferred permitted output") to meet or exceed 110 percent times the sum for the applicable hours of the q_h¹ of such unit (the "transferred output"), whether as the result of a change in environmental laws or otherwise, then:

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- (i) any adjustment to Q_h and CRQ otherwise provided for in (a) above will be reduced by the proportion that the transferred permitted output is of the transferred output, subject to (ii) below;
- (ii) in circumstances where OPGI's remaining emission permits following the transfer of Effective Control are not sufficient to enable its remaining output during the applicable hours (the "remaining permitted output") to meet or exceed 110 percent times the sum for the applicable hours of the q_h^i 's of its remaining units, (the "remaining output"), then, in lieu of the adjustment provided for in (i) above, any adjustment to Q_h and CRQ otherwise provided for in (a) above will be multiplied by the result of the following formula, which if greater than 1.0 shall be deemed to be equal to 1.0:

$$\frac{(\text{transferred permitted output}/\text{transferred output})}{(\text{remaining permitted output}/\text{remaining output}); \text{ and}}$$

- (iii) where the transferee's emission permits are affected by more than one substance, then the resulting adjustment to Q_h and CRQ otherwise provided for in (i) or (ii) above will be that which operates to constrain the transferee's output.

5 Administration of Rebate

- 5.1 OPGI shall enter into and comply with a settlement agreement with the IESO consistent with the document attached as Schedule A and B to this licence.

6 Capacity Reserve Market

- 6.1 In the event that a capacity reserve market is developed in Ontario at any time while the provisions of Part 2 are in effect, then:

- (a) the following definition of "Average Price" or "AP" shall be used in lieu of the definition provided for in paragraph 1 of Part 2 above:

"Average Price" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by using the following formula:

AP=

$$\sum_h [CW_h * [P_h + (\text{Hourly Reserve Capacity Price} * \text{Reserve Capacity Ratio})]]$$

- (b) the Price Spike Adjustment shall be calculated according to the following formula in lieu of the formula provided for in paragraph 2(b) of Part 2 above:

$$PSA = [(P_h + \text{Hourly Reserve Capacity Price} * \text{Reserve Capacity Ratio}) - \$125/\text{MWh}] * (Q_h - \text{OPGI's Generation for that hour});$$

- (c) OPGI may apply to the Board for adjustments to (a) or (b) above if necessary or desirable depending upon the precise nature of the capacity reserve market introduced.

7 Location-Based Marginal Pricing

In the event that location-based marginal pricing is developed in Ontario at any time while the provisions of Part 2 are in effect, then:

- (a) the following definition of "Average Price" or "AP" shall be used in lieu of the definition provided for in paragraph 1 of Part 2 above:

"Average Price" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by using the following formula:

$$AP = \frac{\sum_{h,j} (\text{Locational Spot Price} * q^i_h)}{CRQ}$$

- (b) the Hourly Price, or P_h, for purposes of determining if a price spike has occurred and in order to calculate the Price Spike Adjustment in each applicable hour, shall be the average price of energy OPGI sells into the IESO spot market in that hour, which average price shall be determined by dividing OPGI's hourly spot market revenue in \$ by the quantity (calculated in MWh) of OPGI's spot market sales; and
- (c) OPGI may apply to the Board for adjustments to (a) or (b) above if necessary or desirable depending upon the precise nature of the location-based marginal pricing introduced.

8 Capacity Reserve Market and Location-Based Marginal Pricing

In the event that both a capacity reserve market and location-based marginal pricing are developed in Ontario at any time while the provisions of Part 2 are in effect, then:

- (a) the following definition of "Average Price" or "AP" shall be used in lieu of the definitions provided for in paragraphs 1, 6 or 7 of Part 2 above:

"Average Price" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by using the following formula:

$$AP = \sum_h [CW_h * (\text{Hourly Reserve Capacity Price} * \text{Reserve Capacity Ratio})] + \sum_{h,j} (\text{Locational Spot Price} * q^i_h) / CRQ$$

- (b) the Price Spike Adjustment shall be calculated according to the following formula in lieu of the formula provided for in paragraphs 2(b) or 6 of Part 2 above:

$$PSA = [(\text{Hourly Reserve Capacity Price} * \text{Reserve Capacity Ratio}) + \sum_i ((\text{Locational Spot Price} * q^i_h) / Q_h) - \$125/MWh] * (Q^h - \text{OPGI's Generation for that hour});$$

- (c) OPGI may apply to the Board for adjustments to (a) or (b) above if necessary or desirable depending upon the precise nature of the capacity reserve market or location-based marginal pricing introduced.

9 Additional Adjustment for Changes in Law

If one or more Changes in Law cause or are reasonably expected to cause a decrease in OPGI's net annual income equal to or greater than \$60,000,000, then, rather than treating such Changes in Law as a Force Majeure Event for purposes of paragraph 2 above, OPGI may apply to the Board for a variation in the CRQ, Rebate, and/or the Price Cap methodology in respect of the Settlement Period in which the Change in Law occurs and all subsequent Settlement Periods the Change in Law is reasonably expected to affect in order to ensure that OPGI is not materially adversely affected as a result, taking into account all Changes in Law and whether the net effect of these Changes in Law have benefited or are reasonably likely to benefit OPGI during the same time period or any prior or subsequent time period.

10 Termination of Part 2

Beginning April 1, 2005 the OPG rebate calculation will be determined by the formula set out in Schedule B - Additional Terms and Conditions of Settlement Agreement Between IESO & OPG as amended from time to time.

PART 3 TRANSFER OF EFFECTIVE CONTROL

[Part 3 is revoked, effective December 7, 2005]

PART 4 INBOUND TRANSMISSION RIGHTS AND IMPORT LIMITS

1 Definitions and Interpretation

In this Part 4, "season" means the winter period (the "winter season") from and including November 1 until and including April 30 of the following year or the summer period (the "summer season") from and including May 1 until and including October 31 of the same year, as applicable.

2 Inter-tie and Import Limits

- (a) OPGI shall not import energy into Ontario in excess of the energy import limits set forth in (b) below. In no event shall a purchase from the IESO spot market in Ontario be construed as an import of energy into Ontario for such purposes.
- (b) The energy import limits referred to in (a) above are:
- (i) 7.24 TWh during the winter season (increased to 7.28 TWh in a leap year);
and
 - (ii) 6.58 TWh during the summer season;

all of which figures shall be increased, at the in service date of new or upgraded inter-tie facilities, by 35 percent times the number of hours in a season multiplied by any applicable net increase in inter-tie capacity in Ontario as determined by the IESO from that in effect on the date of the opening of the competitive electricity market. For such

purposes, inter-tie capacity shall be based on the Ontario transfer capacity in the applicable season.

- (c) The foregoing provisions of paragraph 2 shall not be required to be complied with by OPGI with the IESO's consent in an emergency situation.

3 Export Limits

Unless otherwise provided herein, none of the provisions of Parts 2 through 5 shall limit OPGI's ability to export energy from Ontario.

PART 5 MARKET BASED ANCILLARY SERVICES

(Note: Market based ancillary services are currently comprised of Operating Reserves only, but the principles outlined herein suggest a framework that could be used for other market based ancillary services.)

Unless the IESO has determined, based on the number of independently controlled competing alternatives and other circumstances in its discretion, that a competitive market for any category of operating reserves (i.e. 10-minute and 30-minute) exists, OPGI shall be required to comply with the following requirements:

- (a) subject to (a.1), the price to be offered by OPGI associated with each category of OPGI operating reserve services will not exceed a cap to be contained in an agreement to be negotiated between OPGI and the IESO, which cap will be designed, taking into account the relevant IESO market rules, to compensate OPGI for its actual cost of providing such operating reserve services, including additional operating and maintenance costs, additional fuel costs, additional opportunity costs associated with providing such operating reserve services from OPGI hydroelectric generation units, and a reasonable rate of return on incremental capital needed to provide such operating reserve services, and which agreement shall require OPGI to offer the maximum available amount of each category of operating reserve services, consistent with good utility practices, for each OPGI generation unit capable of providing such services;
- (a.1) notwithstanding (a) above, save and except where the IESO has advised OPGI that specific units are required to offer in for reliability, OPGI may offer less than the maximum available amount of any category of operating reserve where this is necessary in order for OPGI to satisfy its obligations under, or to give effect to, any shareholder declaration or resolution of the Minister of Energy in effect at the relevant time relating to, or any Regulation made under the *Environmental Protection Act* (Ontario) relating to, carbon dioxide (CO₂) emissions arising from the use of coal at OPGI's coal-fired generation stations;
- (b) subject to (a.1), in the event that the agreement referred to in (a) above cannot be reached, the terms of such agreement shall be determined through binding commercial arbitration by a mutually agreed independent arbitrator on agreed terms of arbitration;
- (c) subject to (a.1), in the event that either OPGI or the IESO subsequently determines that the operation of the market is such that the intent of the agreement referred to in (a) or (b) above is materially frustrated, then OPGI and the IESO shall negotiate amendments (which may be retroactive) to the terms of such agreement with a view to correcting such situation and, in the event that they cannot agree on such amendments, the amendments, if any, shall be determined

through binding commercial arbitration by a mutually agreed independent arbitrator on agreed terms of arbitration;

- (d) subject to (a.1), OPGI shall comply with the terms of the agreement referred to in (a) or (b) above, as it may be amended under (c) above;
- (e) subject to (a.1), pending reaching an agreement, or pending the resolution of any dispute, the IESO may at any time set the price cap and terms on which OPGI must provide any category of operating reserve services, subject to later adjustment upon final agreement or final resolution of the dispute with interest at the Prime Rate, calculated and accrued daily; and
- (f) subject to (a.1), if the IESO's market rules at any time are such that the market clearing price for a category of operating reserve services does not include both the offer price and the opportunity cost of the marginal unit providing the service, and the agreement referred to in (a) or (b) above has not taken such factors into account, then the agreement referred to in (a) or (b) above shall be considered to have been materially frustrated for purposes of (c) above.

PART 6 BRUCE DECONTROL RELATED CONDITIONS

1. The Licensee shall implement a Ring-Fence plan in accordance with the plans referred to in Section 8A of OPG's pre-filed evidence, and as detailed more fully in Interrogatory Responses I 6.5, and I 15.13 of RP-2002-0142, with the following exception:
 - a) Only commercially sensitive information will be captured by the Ring-Fence plan. For clarity, this consists of Bruce Power outage information not already in the public domain and unit condition information only.
2. The Licensee shall conduct internal audits of the Ring-Fence plan every two calendar years. For clarity, the next internal audit will take place in 2007.
3. The Licensee must provide to the Board every year a self-certification statement signed by both the Chief Executive Officer and the Senior Regulatory Officer or other Senior Officer of OPG that the Ring-Fence plan methodology is operational for the activities that remain ring-fenced.
4. OPG shall make Status Reports to the Board within 30 days of:
 - a. Any additional agreements entered into with BP LP;
 - b. Any amendments, replacements or extensions of existing agreements with BP LP; and
 - c. Expired agreements under the Bruce Transaction.
5. Prior to May 1st of every other year of this licence (coincident with the years in which an internal audit is conducted), OPG shall submit an annual Confidential Audit Report to the Board. For clarity, the next report will be filed on or before May 1, 2007. The report shall include:
 - a. A review of the design, implementation, completeness and security of the Ring-Fence plan by OPG's internal audit group;

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- b. A list of all the violations of the Ring-Fence plan with an explanation as to the type of violation, the employee's position and department or group, and whether the incident represents a repeat violation by a given employee;
 - c. Recommendations regarding corrective action where the Ring-Fence plan has been violated;
 - d. A list of the number of employees that have moved outside the Ring-Fence to a new position in OPG (whether the position is permanent or temporary) The Report shall identify the old position and department or group that was in the Ring-Fence plan, and the new position and department or group in which the employee now works.
6. Prior to December 31st of every other year of this licence (coincident with the years in which an internal audit is conducted), OPG shall submit an annual Public Audit Report to the Board for the public record. The report shall include the above findings from the Confidential Audit Report, however, the report shall be redacted to remove personal information and any other information that the Board agrees may be redacted under its confidential filing guidelines. For clarity, the next report will be filed on or before December 31, 2007.
 7. The Contract for Differences for Forced Outages agreement between OPG and BP LP shall not be renewed at its expiry on the second anniversary of Market Opening.

SCHEDULE A

TERMS AND CONDITIONS OF SETTLEMENT AGREEMENT BETWEEN IESO AND OPGI

For these purposes, terms with initial capitals not otherwise defined herein shall have the meanings ascribed thereto in paragraph 1 of Part 3 of the licence conditions of OPGI or the IESO's Market Rules, as applicable.

OPGI will be required to rebate annually to the IESO. As soon as practicable and preferably within 15 days following the final settlement of transactions which occurred during each Settlement Period, the IESO shall calculate the Rebate and notify OPGI of such calculated Rebate.

If OPGI agrees with the IESO's calculation then, within 30 days of being notified, OPGI will be required to pay such Rebate, if any, to the IESO. If OPGI does not agree with the IESO's calculation and the parties can agree within a further 30 days on a revised Rebate, then, within 30 days of so agreeing, OPGI will be required to pay the agreed revised Rebate, if any, to the IESO. If OPGI does not agree with the IESO's calculation and the parties cannot agree on a revised Rebate within such further 30 day period, then the matter shall be finally determined by arbitration by the Dispute Resolution Panel of the IESO, and, within 30 days of such final determination, OPGI will be required to pay the finally determined Rebate, if any, to the IESO. The initially calculated, agreed revised, or finally determined Rebate, as applicable, shall be the Rebate in respect of such Settlement Period for all purposes hereof. Unless the Rebate is paid within 30 days of the IESO notifying OPGI, interest at the Prime Rate, calculated and accrued daily, from such 30th day until the date of payment to the IESO will in all cases be added to (and based upon) the final Rebate owing.

Following payment of the Rebate by OPGI to the IESO, the IESO shall pay or apply the Rebate as follows:

- (a) Where the Rebate is \$10 million or more, exclusive of any amounts representing interest or GST, the IESO shall pay the Rebate, including GST and interest, to all persons who were Market Participants in Ontario during the Settlement Period and who pursuant to the Market Rules had attributed to them during the Settlement Period an allocated quantity of energy withdrawn at a Delivery Point (the "Ontario Payees"). The IESO shall pay the Rebate to Ontario Payees by the next IESO Payment Date for the real-time market following the end of the month in which the payment from OPGI is received and the IESO shall distribute payment of the Rebate to Ontario Payees in proportion to the allocated quantities of energy withdrawn at a Delivery Point which were attributed to each Ontario Payee during the Settlement Period. The IESO may, to the extent practicable, pay the Rebate to all or some Ontario Payees by applying a Rebate settlement credit to the Ontario Payees' applicable Settlement Statements; and
- (b) Where the Rebate is less than \$10 million, exclusive of any amounts representing interest or GST, the IESO shall retain and apply the Rebate, inclusive of any amounts representing interest or GST, to offset the IESO Administration Charge imposed on Market Participants in accordance with section 4.5, Chapter 9 of the Market Rules, during the period in which the first order of the OEB approving the IESO Administration Charge made,
 - (i) pursuant to subsection 19(2) of the Electricity Act, 1998, and
 - (ii) subsequent to the date on which payment of the Rebate is received by the IESO, is in effect.

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Where paragraph (a) applies, if by the date upon which the IESO is required to pay the Rebate to Ontario Payees, the IESO cannot locate an Ontario Payee, or a successor or other representative of the said Ontario Payee to whom the IESO is permitted or required by law to pay the said Ontario Payee's share of the Rebate, the IESO shall retain the said Ontario Payee's share of the Rebate for a period of 90 days from the date upon which the Rebate is otherwise payable to all other Ontario Payees, and during this period the IESO will make commercially reasonable efforts to locate and payout the applicable share of the Rebate to the said Ontario Payee or his successor or other legal representative. If the IESO is unable to locate the said Ontario Payee or his successor or other legal representative within this 90 day period, the IESO shall retain the said Ontario Payee's share of the Rebate and apply it to the IESO Administration Charge in accordance with paragraph (b), as set out herein.

Nothing shall preclude agreements that require the purchaser to return the rebate or any portion thereof to OPGI or any other party.

The Settlement Agreement may also include the following terms:

- Definitions and Interpretation
- Notice by OPGI to IESO of Payment and Non-Payment
- Appropriate limitations of liability
- IESO shall recover its reasonable rebate administration expenses through its fees
- Appropriate indemnification provisions
- IESO to act on its own behalf and as agent for Ontario Metered Market Participants entitled to rebates to the extent of their interests, and such Metered Market Participants are entitled, provided that they give a satisfactory funded indemnity to the IESO, to enforce, by arbitration, the Settlement Agreement directly against OPGI if desired, with reasonable assistance to be provided by IESO at their expense
- IESO may assign agreement to a qualified replacement upon approval of OEB. No other assignments without consent of other party and OEB
- IESO may subcontract any duties required of it
- Fund transfer instructions, which may be changed on notice to OPGI by IESO
- Arbitration clause with Dispute Resolution Panel as arbitrator
- Recipient registrants responsible for all taxes, if any
- Any interest earned on funds by IESO shall be paid to recipient registrants similarly to other funds
- IESO not to be viewed as in conflict in any respect as a result of its participation in the Settlement Agreement
- IESO may hold funds on deposit with a Canadian financial institution or in short-term obligations of the federal or Ontario government or any Canadian financial institution
- IESO may, but shall not be obliged to, retain and refrain from distributing any funds in the event of any dispute, and may seek advice from the Dispute Resolution Panel
- Termination of agreement when OPGI Rebate obligations terminate and all funds distributed or applied. OPGI/IESO indemnification obligations and third party enforcement rights to survive termination, former indefinitely and latter for 2 years only
- IESO may rely on any document which it believes to be genuine and on the advice of counsel, if it acts in good faith
- IESO not responsible for any non-payment by OPGI
- Binding on successors and permitted assigns
- Notice clause

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- Only may be amended in writing
- Governed by the laws of Ontario
- Counterparts clause
- Further assurances clause

SCHEDULE B

ADDITIONAL TERMS AND CONDITIONS OF SETTLEMENT AGREEMENT BETWEEN IESO & OPG

The following sets out the procedure for calculating, allocating and passing through the Market Power Mitigation Agreement (MPMA) Rebate. Where there is a conflict between Schedule A in the Minister's Directive dated March 24, 1999, as amended or replaced by a subsequent Ministerial Directive dated February 25, 2003 which relates to Order-in-Council 654/2003 (dated March 19, 2003), and subsequent Orders-in-Council including Order-in-Council No. 843/2003 (dated April 2, 2003), Order-In-Council No. 207/2005 (dated February 16, 2005), Order-in-Council No. 1909/2005 (dated December 7, 2005), Order-in-Council No. 141/2006 (dated February 3rd, 2006), Order-in-Council No. 1062/2006 (dated May 17, 2006) and this Schedule B, then this Schedule B prevails.

For the First Settlement Period (May 1, 2002 to April 30, 2003)

- 1) The first MPMA Rebate is to be paid out for the 9-month period ending January 31, 2003. This is the amount, as calculated by the IESO and agreed to by OPG, that OPG is required to rebate for the nine month period, based on OPG's MPMA license conditions, less the interim payment already made by OPG of approximately \$335 million and amounts relating to decontrol applications pending before the Ontario Energy Board. OPG is to pay this net amount to the IESO by May 9, 2003.
- 2) The second MPMA Rebate will cover the three-month period February 1, 2003 to April 30, 2003 inclusive. This is the amount, as calculated by the IESO and agreed to by OPG, that OPG is required to rebate for the three month period, based on OPG's license conditions, adjusted for any true-up required to ensure that the sum of the two rebates for the first settlement period, including the interim payment, is equal to OPG's full rebate requirements for the first Settlement Period under the OPG's MPMA license conditions. OPG is to pay this amount to the IESO by August 12, 2003.
- 3) The IESO will pay the pro rata share of the first MPMA Rebate and the second MPMA Rebate based on the allocated quantity of energy withdrawn during the applicable period by market participants who are receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* to the Ontario Electricity Financial Corporation.
- 4) The IESO will pay the pro rata share of the first MPMA Rebate and the second MPMA Rebate based on the allocated quantity of energy withdrawn during the applicable period by market participants who are not distributors and are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their MPMA rebate.
- 5) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the first MPMA Rebate and the second MPMA Rebate based on the share of energy withdrawn during the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* and by customers of retailers who have assigned all or a portion of their entitlement to an MPMA Rebate to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the first MPMA Rebate or

the second MPMA Rebate in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

- 6) After making the payments set out in 3), 4), and 5), the IESO is to pay any remaining Rebate to the Ontario Electricity Financial Corporation to offset in whole or in part the cost of providing the fixed price of 4.3 cents per kilowatt hour to consumers who are eligible to receive, are receiving or have received the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*. Any amounts returned to the IESO by distributors in accordance with their license conditions shall be paid over to the Ontario Electricity Financial Corporation.

For the Settlement Periods (May 1, 2003 to January 31, 2005)

- 7) For each Settlement Period or partial Settlement Period from May 1, 2003 to January 31, 2005, OPG is to make quarterly MPMA Rebate payments to the IESO, consistent with OPG's MPMA license conditions, as calculated by the IESO and agreed to by OPG. The IESO and OPG may agree to appropriate true-up and carry forward mechanisms provided that these are consistent with forwarding the Rebate as soon as practicable.
- 8) For each Settlement Period or partial Settlement Period from May 1, 2003 to January 31, 2005 the MPMA rebate payments to market participants will be calculated and determined by the IESO as follows:

$$\text{BPPR} = [(\text{WAP} - \text{CAP}) \times 0.5 \times \text{TAQEW}]$$

Where:

"Business Protection Plan Rebate" or **"BPPR"** is the MPMA Rebate paid out to consumers who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*. The BPPR is to rebate half of the amount by which the weighted average commodity price of electricity exceeds 3.8 cents per kilowatt- hour.

"Weighted Average Price" or **"WAP"** is the average Hourly Ontario Electricity Price weighted by load over the Settlement Period as determined by the IESO.

"Total Allocated Quantity of Energy Withdrawn" or **"TAQEW"** is the total electricity withdrawn from the IESO-controlled grid for use in Ontario during the Settlement Period.

- 9) The IESO will make quarterly MPMA payments to market participants based on the applicable Settlement Period to the end of the previous quarter, and taking into account all prior quarterly MPMA payments made with respect to the applicable Settlement Period. The IESO will adjust the payment for the final quarter of each Settlement Period to ensure that the sum of the quarterly MPMA payments for the applicable Settlement Period does not exceed the BPPR entitlement for the Settlement Period. If there is an overpayment of quarterly payments over a Settlement Period based on the BPPR entitlement for that Settlement Period, any such overpayment can be carried over to successive Settlement Periods to be offset against future payments.
- 10) The IESO will pay the pro rata share of the BPPR based on the allocated quantity of energy withdrawn for the applicable period by market participants who are receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* to the Ontario Electricity Financial Corporation.

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- 11) The IESO will pay the pro rata share of the BPPR based on the allocated quantity of energy withdrawn for the applicable period by market participants who are not distributors and are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their MPMA Rebate.
- 12) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the BPPR based on the share of energy withdrawn for the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* for the MPMA Rebate and by customers of retailers who have assigned all or a portion of their entitlement to an MPMA Rebate to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the BPPR for that quarter in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.
- 13) For the quarterly periods from May 1, 2003 to January 31, 2005, after making the payments set out in 10), 11), and 12), the IESO is to pay any remaining Rebate to the Ontario Electricity Financial Corporation to offset in whole or in part the cost of providing the prices established under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* to consumers who are eligible to receive the prices established under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*. Any amounts returned to the IESO by distributors in accordance with their license conditions shall be paid over to the Ontario Electricity Financial Corporation.

For the Payment for the Period (February 1, 2005 to March 31, 2005)

- 14) For the Payment for the Period from February 1, 2005 to March 31, 2005, OPG is to make an MPMA Rebate payment to the IESO, consistent with OPG's MPMA license conditions, as calculated by the IESO and agreed to by OPG. The IESO and OPG may agree to appropriate true-up and carry forward mechanisms provided that these are consistent with forwarding the Rebate as soon as practicable.
- 15) For the Payment for the Period from February 1, 2005 to March 31, 2005 the MPMA rebate payments to market participants will be calculated and determined by the IESO as follows:

$$\text{BPPR} = [(\text{WAP} - \text{CAP}) \times 0.5 \times \text{TAQEW}]$$

Where:

"**Business Protection Plan Rebate**" or "**BPPR**" is the MPMA Rebate paid out to consumers who are not receiving the fixed price under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998*. The BPPR is to rebate half of the amount by which the weighted average commodity price of electricity exceeds 3.8 cents per kilowatt hour.

"**Weighted Average Price**" or "**WAP**" is the average Hourly Ontario Electricity Price weighted by load over the Settlement Period as determined by the IESO.

"**Total Allocated Quantity of Energy Withdrawn**" or "**TAQEW**" is the total electricity withdrawn from the IESO-controlled grid for use in Ontario during the Settlement Period.

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- 16) The IESO will make the MPMA payment to market participants for the two month period ending March 31, 2005 taking into account all prior MPMA payments made in that Settlement Period.
- 17) The IESO will pay the pro rata share of the BPPR based on the allocated quantity of energy withdrawn for the applicable period by market participants who are receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* to the Ontario Electricity Financial Corporation.
- 18) The IESO will pay the pro rata share of the BPPR based on the allocated quantity of energy withdrawn for the applicable period by market participants who are not distributors and are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their MPMA Rebate.
- 19) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the BPPR based on the share of energy withdrawn for the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* for the MPMA Rebate and by customers of retailers who have assigned all or a portion of their entitlement to an MPMA Rebate to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the BPPR for that quarter in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.
- 20) After making the payments set out in 17), 18), and 19), the IESO is to pay any remaining Rebate to the Ontario Electricity Financial Corporation to offset in whole or in part the cost of providing the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* to consumers who are eligible to receive the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998*. Any amounts returned to the IESO by distributors in accordance with their license conditions shall be paid over to the Ontario Electricity Financial Corporation.

Replacement of the MPMA Rebate With A New Payment for the Period (April 1, 2005 to December 31, 2005)

- 21) For the Payment for the Period from April 1, 2005 to December 31, 2005, OPG is to make a single payment to the IESO, calculated as follows:

$$\text{Payment} = \text{Sum over all hours } [(\text{HOEP} - \$47) \times (\text{ONPA (output)} \times 0.85)]$$

Where:

ONPA or OPG's Non-Prescribed Assets are those generation assets operated and controlled by Ontario Power Generation, excluding Lennox Generating Station, that are not prescribed assets under section 78.1 of the *Ontario Energy Board Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

HOEP is the Hourly Ontario Energy Price as determined by the IESO.

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ONPA (output) is the generation output from OPG's Non-Prescribed Assets generation assets over each hour of the period adjusted to take account of volumes sold through Transitional Rate Option contracts and forward contracts in effect as of January 1, 2005.

- 22) For the Payment for the Period from April 1, 2005 to December 31, 2005 the single payment to market participants will be equal to the payment calculated in 21) above.
- 23) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable period by market participants who are receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.
- 24) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable period by market participants who are not distributors and are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their Payment.
- 25) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the Payment based on the share of energy withdrawn for the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* for the Payment and by customers of retailers who have assigned all or a portion of their entitlement to a Payment to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the Payment for the period in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.
- 26) After making the payments set out in 23), 24), and 25), the IESO is to pay any remaining amount of the Payment to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.
- 27) With respect to its non-prescribed generating facilities, OPG shall maximize their value to the people of Ontario by operating those facilities in response to the price signals of the IESO-administered markets. OPG's conduct in the IESO-administered markets under this direction is subject to review by the Market Surveillance Panel of the Ontario Energy Board.

Replacement of the MPMA Rebate With A New Payment for the Period (January 1, 2006 to April 30, 2006)

- 28) For the Payment for the Period from January 1, 2006 to April 30, 2006, OPG is to make a single payment to the IESO, calculated as follows:

$$\text{Payment} = \text{Sum over all hours } [((\text{HOEP} - \$47) \times (\text{ONPA (output)} \times 0.85)) + \{(\text{PA (price)} - \$52) \times (\text{PA (amount)})\}]$$

Where:

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ONPA or OPG's Non-Prescribed Assets are those generation assets operated and controlled by Ontario Power Generation, excluding Lennox Generating Station, that are not prescribed assets under section 78.1 of the *Ontario Energy Board Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

HOEP is the Hourly Ontario Energy Price as determined by the IESO.

ONPA (output) is the generation output from OPG's Non-Prescribed Assets generation assets over each hour of the period adjusted to take account of volumes sold through Transitional Rate Option contracts and forward contracts in effect as of January 1, 2005 and volumes sold through the Pilot Auction administered by the Ontario Power Authority in the first half of 2006 with sales volumes commencing on April 1, 2006.

PA is the Pilot Auction administered by the Ontario Power Authority in the first half of 2006, which includes a limited amount of output from OPG's non-prescribed assets, with sales to commence on April 1, 2006.

PA (amount) is the hourly volume in MWh of OPG non-prescribed assets output sold through the Pilot Auction administered by the Ontario Power Authority in the first half of 2006 with sales commencing on April 1, 2006.

PA (price) is the weighted average auction price in \$/ MWh realized in each hour of the Period for the output of the limited amount of OPG non-prescribed assets output volume sold through the Pilot Auction administered by the Ontario Power Authority in the first half of 2006 with sales volumes commencing on April 1, 2006.

- 29) For the Payment for the Period from January 1, 2006 to April 30, 2006 the single Payment to market participants will be equal to the Payment calculated in 28) above.
- 30) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable period by market participants who are receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.
- 31) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable period by market participants who are not distributors and are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their Payment.
- 32) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the Payment based on the share of energy withdrawn for the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* for the Payment and by customers of retailers who have assigned all or a portion of their entitlement to a Payment to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the Payment for the period in accordance with this Schedule B, there

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shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

- 33) After making the payments set out in 30), 31), and 32), the IESO is to pay any remaining amount of the Payment to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.
- 34) With respect to its non-prescribed generating facilities, OPG shall maximize their value to the people of Ontario by operating those facilities in response to the price signals of the IESO-administered markets. OPG's conduct in the IESO-administered markets under this direction is subject to review by the Market Surveillance Panel of the Ontario Energy Board.

OPG Rebate for the Period (May 1, 2006 to April 30, 2009)

- 35) For the Period from May 1, 2006 to April 30, 2009, OPG is to make quarterly Payments to the IESO, as calculated by the IESO and agreed to by OPG as follows:

$$\text{Payment} = \text{Sum over all hours } [(HOEP - ORL) \times (ONPAO \times 0.85 - PAA) + (PAP - PAORL) \times PAA]$$

Ontario Power Generation's quarterly payments will be based on a cumulative calculation commencing May 1, 2006 to the end of each quarter less the same cumulative calculation to the end of the previous quarter. This will continue until the final quarter ending April 30, 2009. For greater certainty, where the payment formula results in an amount owing to OPG for any quarter, no such payment will be made to OPG by the IESO and any such amount will be carried forward into subsequent quarters.

Where:

ONPA or OPG's Non-Prescribed Assets are those generation assets operated and controlled by Ontario Power Generation assets in service as of January 1, 2006, excluding Lennox Generating Station and excluding stations whose generation output is subject to a contract with the Ontario Power Authority (OPA) in the form of a hydroelectric energy supply agreement [entered into by the OPA and OPG pursuant to a ministerial direction made under section 25.32 of the *Electricity Act, 1998*], that are not prescribed assets under section 78.1 of the *Ontario Energy Board Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

HOEP is the Hourly Ontario Energy Price as determined by the IESO.

ONPAO is the generation output from OPG's Non-Prescribed Assets, over each hour of the quarter adjusted to take account of volumes sold through forward contracts in effect as of January 1, 2005. For greater certainty, any output from ONPA resulting from fuel conversion by Ontario Power Generation in ONPA, or incremental output from ONPA resulting from refurbishment or expansion, or is subject to a contract with the OPA in the form of a hydroelectric energy supply agreement, [entered into by the OPA and OPG pursuant to a ministerial direction made under section 25.32 of the *Electricity Act, 1998*] is to be excluded from ONPAO.

Incremental Output is defined as:

generation output x (new total installed capacity – installed capacity as of January 1, 2006) / new total installed capacity.

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ORL is the Ontario Power Generation Revenue limit.

For the period May 1, 2006 to April 30, 2007 ORL is equal to \$46/ MWh.

For the period May 1, 2007 to April 30, 2008 ORL is equal to \$47/ MWh.

For the period May 1, 2008 to April 30, 2009 ORL is equal to \$48/ MWh.

PA is the Pilot Auction administered by the Ontario Power Authority in the first half of 2006.

PAA is the volume in MWh over each hour in the quarter that is sold by Ontario Power Generation through the PA.

PAORL is the Pilot Auction Ontario Power Generation Revenue limit.

For the period May 1, 2006 to April 30, 2007 PAORL is equal to \$51/ MWh.

For the period May 1, 2007 to April 30, 2008 PAORL is equal to \$52/ MWh.

For the period May 1, 2008 to April 30, 2009 PAORL is equal to \$53/ MWh.

PAP is the weighted average auction price in \$/ MWh over each hour of the quarter realized for the PAA by Ontario Power Generation.

- 36) For the Payment for the Period from May 1, 2006 to April 30, 2009 quarterly payments made by the IESO to market participants will be equal to the quarterly Payment calculated in 35) above. In the event of any quarterly Payment calculated in 35) above being negative, no quarterly payment will be made by the IESO to market participants.
- 37) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable quarter by market participants who are receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.
- 38) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable quarter by market participants who are not distributors and are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* directly to those market participants.
- 39) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the Payment based on the share of energy withdrawn for the applicable quarter by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* for the Payment. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the Payment for the quarter in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.
- 40) After making the payments set out in 37), 38), and 39), the IESO is to pay any remaining amount of the Payment to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

- 41) With respect to its non-prescribed generating facilities, OPG shall maximize their value to the people of Ontario by operating those facilities in response to the price signals of the IESO-administered markets. OPG's conduct in the IESO-administered markets under this direction is subject to review by the Market Surveillance Panel of the Ontario Energy Board.

SCHEDULE 1 LIST OF LICENSED GENERATION FACILITIES

The Licence authorizes the Licensee only in respect to the following:

Hydraulic Generation Facilities by River System - Owned and Operated

<u>Niagara River System</u> Sir Adam Beck - No. 1 Sir Adam Beck - No. 2 Pumping Gen. Stn. DeCew Falls No. 1 DeCew Falls No. 2	<u>Montreal River System</u> Indian Chute	<u>Aguasabon River System</u> Aguasabon
<u>St. Lawrence River System</u> Robert H. Saunders Ottawa River Otto Holden Des Joachims Chenaux Chats Falls (Units 2,3,4,5)	<u>Matabitchuan River System</u> Matabitchuan South River Elliott Chute Bingham Chute Nipissing	<u>Mississippi River System</u> High Falls
<u>Madawaska River System</u> Mountain Chute Barrett Chute Amprior Stewartville Calabogie	<u>Sturgeon River System</u> Crystal Falls	<u>Rideau River System</u> Merrickville
<u>Trent River System</u> Healey Falls Ranney Falls Meyersburg Sidney Hagues Reach Seymour Franford Sills Island	<u>Wanapitej River System</u> Stinson Coniston McVittie	<u>Otonabee River System</u> Auburn Lakefield
<u>Montreal River System</u> Lower Notch	<u>Nipigon River System</u> Pine Portage Cameron Falls Alexander	<u>Muskoka River System</u> Ragged Rapids Big Eddy South Muskoka South Falls Trethewey Falls Hanna Chute
	<u>English River System</u> Ear Falls Manitou Falls Caribou Falls Lac Seul	<u>Beaver River System</u> Eugenia Falls
	<u>Winnipeg River System</u> Whitedog Falls	<u>Severn River System</u> Big Chute
	<u>Kaministikwia River System</u> Silver Falls Kakabeka Falls	<u>Abitibi River System</u> Abitibi Canyon Otter Rapids
		<u>Mattagami River System</u> (Amendment February 11, 2011 Authorization to own expires April 30, 2011) Little Long Harmon Kipling Smokey Falls

Hydraulic Generation Facilities by River System – Operated Only

St. Lawrence River System

Chats Falls (Units 6,7,8,9)

Fossil Generation - Owned and Operated

Lambton
Nanticoke
Thunder Bay - Unit 1
Thunder Bay - Units 2, 3
Atikokan
Lennox

Nuclear Generation - Owned and Operated

Pickering A
Pickering B
Darlington

Wind Generation - Owned and Operated

BIC Wind Turbine
Pickering Wind Turbine

Nuclear Generation - Owned Only

Bruce A
Bruce B

STAKEHOLDER CONSULTATION

1.0 PURPOSE

This evidence provides a description of the stakeholder consultation process that OPG held while it was developing this 2017-2021 payment amounts application.

Given the novel elements of this application (in particular, the transition to incentive regulation), OPG found it beneficial to share its plans for the application with stakeholders while the filing was still under development.

2.0 BACKGROUND

OPG first held stakeholder consultation sessions in late 2014 and early 2015 regarding the company's potential 2016-2020 payment amounts application (the "initial consultation"). The consultation process consisted of three information sessions. While OPG did not ultimately file an application for 2016 payment amounts, the stakeholder feedback from that process was helpful in developing this application. OPG has included the agendas from the initial consultation as attachments to this schedule.

Following the initial consultation, OPG held a series of consultation sessions regarding the current application for 2017-2021 payment amounts.

This schedule provides an outline of the entire consultation process, including the initial consultation and the subsequent sessions. It includes a summary of material changes that OPG made to this application based on feedback from stakeholders.

3.0 OBJECTIVE

The objective of the consultation process was to inform stakeholders about the application and to seek input on OPG's transition to incentive regulation.

1 **4.0 PROCESS**

2 **4.1 Initial Consultation**

3 In the initial consultation, OPG held three stakeholder information sessions regarding its
4 potential 2016-2020 application. These sessions were held on December 17, 2014, January
5 22, 2015, and February 18, 2015. Copies of the presentations that were made at the session
6 and facilitator notes are posted on OPG's website at:

7 [http://www.opg.com/about/regulatory-affairs/stakeholder-information/Pages/payment-](http://www.opg.com/about/regulatory-affairs/stakeholder-information/Pages/payment-amounts.aspx)
8 [amounts.aspx.](http://www.opg.com/about/regulatory-affairs/stakeholder-information/Pages/payment-amounts.aspx)

9

10 OPG invited stakeholders who participated in the last OEB proceeding regarding OPG's
11 payment amounts, and other stakeholders who, in OPG's view, may have a material interest
12 in the application. Funding was offered to participants who qualified under the funding
13 guidelines.

14

15 The information sessions were held on a non-confidential, without-prejudice basis. Steve
16 Klein, VP and Practice Manager at OPTIMUS | SBR was retained as a neutral, third-party
17 facilitator and to document and report on the sessions.

18

19 The December 17, 2014 session highlighted the challenges and uncertainties inherent in
20 OPG's operating environment for the five year period commencing in 2016. In addition, the
21 session provided information on the Inflation Factor Analysis and Total Factor Productivity
22 Study for OPG's hydroelectric operations prepared by London Economics International LLC.
23 A copy of the session agenda is provided in Attachment 1.

24

25 At the January 22, 2015 session, OPG outlined proposed regulatory approaches for both
26 hydroelectric and nuclear facilities. A copy of the session agenda is provided in Attachment 2.

27

28 At the February 18, 2015 session, OPG gave stakeholders another opportunity to request
29 clarification or ask other questions about the materials presented at the second information
30 session. OPG also presented updated plans on various aspects of the application, as they
31 were developing. A copy of the session agenda is provided in Attachment 3.

1 **4.2 2016 Consultation**

2 Since OPG ultimately did not apply for new payment amounts in 2016, it held a further round
3 of consultations on the current application in 2016. These sessions were held on February 8,
4 2016, March 21, 2016, and May 19, 2016. As it did in the initial consultation, OPG invited
5 parties that participated in the previous application and retained OPTIMUS | SBR to facilitate
6 and provide notes. Copies of the presentations that were made at the session and facilitator
7 notes are posted on OPG’s website at:

8 [http://www.opg.com/about/regulatory-affairs/stakeholder-information/Pages/payment-](http://www.opg.com/about/regulatory-affairs/stakeholder-information/Pages/payment-amounts.aspx)
9 [amounts.aspx](http://www.opg.com/about/regulatory-affairs/stakeholder-information/Pages/payment-amounts.aspx).

10

11 At the February 8, 2016 session, OPG presented the company’s plan to file an application
12 covering payment amounts for 2017-2021. A copy of the session agenda is provided in
13 Attachment 4. OPG presented the structure and major elements of the company’s planned
14 application. The session included a keynote presentation by OPG President and CEO Jeffrey
15 Lyash, as well as detailed updates on the Darlington Refurbishment Program (“DRP”) and on
16 the Pickering Life Extension program.

17

18 The March 21, 2016 session was held at the Darlington Energy Complex. Participants toured
19 the reactor mock-up used to prepare for the DRP. While touring the Darlington site,
20 stakeholders were given an overview of the Facility and Infrastructure Projects and Safety
21 Improvement Opportunities. OPG briefed the participants on the scope of the DRP, the
22 company’s DRP contracting strategy, and provided an overview of the DRP-related evidence
23 planned for the company’s payment amounts application. A copy of the session agenda is
24 provided in Attachment 5.

25

26 Following the consultations, OPG made a number of changes to the planned application,
27 including:

28

29

30

- i. Eliminating the proposal to establish hydro base rates using a 2017 forecast test year cost of service review – instead, the filed application escalates existing hydro payment amounts by the proposed price-cap index;

- 1 ii. Eliminating the proposed symmetrical earnings sharing mechanism for nuclear and
- 2 hydro;
- 3 iii. Eliminating the situational off-ramp proposed for nuclear;
- 4 iv. Eliminating the New Cost of Capital Variance Account proposed to record differences
- 5 in hydro return on equity during the incentive regulation (“IR”) term;
- 6 v. Modifying the hydro x-factor, increasing the annual productivity adjustment from -1 per
- 7 cent (as identified by the independent Total Factor Productivity study) to 0 per cent,
- 8 reflecting OEB policy in the electric distribution sector;
- 9 vi. Expanding the application of nuclear stretch factor applied to include corporate support
- 10 costs; and
- 11 vii. Expanding the proposed performance reporting metrics to include all of the key
- 12 hydroelectric performance areas filed in OPG’s prior payment amounts application
- 13 (EB-2013-0321, Ex. F1-1-1, Appendix B) and all measures used in annual nuclear
- 14 benchmarking.

15

16 OPG also held a briefing for stakeholders on the final application on May 19, 2016. A copy of
17 the session agenda is provided in Attachment 6. Materials from this presentation are
18 available at <http://www.opg.com>.

19

ATTACHMENTS

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- Attachment 1: December 17, 2014 Information Session Agenda
- Attachment 2: January 22, 2015 Information Session Agenda
- Attachment 3: February 18, 2015 Information Session Agenda
- Attachment 4: February 8, 2016 Information Session Agenda
- Attachment 5: March 21, 2016 Information Session Agenda
- Attachment 6: May 19, 2016 Information Session Agenda

AGENDA

Information Session December 17, 2014

Mini Auditorium – 700 University Avenue, Toronto, ON

8:45 a.m. – 9:00 a.m.	- Registration
9:00 a.m. – 9:15 a.m.	- Welcome - Introductions - Safety Rules - Agenda
9:15 a.m. – 10:00 a.m.	- Hydroelectric Overview
10:00 a.m. – 10:30 a.m.	- Discussion
10:30 a.m. – 10:45 a.m.	- Break
10:45 a.m. – 12:00 a.m.	- Hydroelectric TFP Study and Inflation Factor Assessment
12:00 a.m. – 12:30 p.m.	- Discussion
12:30 p.m. – 1:15 p.m.	- Lunch
1:15 p.m. – 2:00 p.m.	- Nuclear Overview
2:00 p.m. – 2:30 p.m.	- Discussion
2:30 p.m. – 2:45 p.m.	- Break
2:45 p.m. – 3:30 p.m.	- Status of the Deferral and Variance Accounts Application



Agenda

January 22, 2015

8:30 a.m. – 9:00 a.m.	<ul style="list-style-type: none"> Registration 	
9:00 a.m. – 9:15 a.m.	<ul style="list-style-type: none"> Welcome / Opening Remarks Agenda Participant Introductions Safety Rules Session Approach 	<p>Randy Pugh, Director, Regulatory Affairs</p> <p>Steve Klein, VP and Practice Manager, Optimus SBR</p>
9:15 a.m. – 10:30 a.m.	<ul style="list-style-type: none"> OPG’s Initial Incentive Rate-making Proposal for Hydroelectric Operations 	<p>Mario Mazza, VP, Strategic Operations, Hydro-Thermal Operations</p> <p>Randy Pugh, Director, Regulatory Affairs</p>
10:30 a.m. – 10:45 a.m.	<ul style="list-style-type: none"> Break 	
10:45 a.m. – 11:15 a.m.	<ul style="list-style-type: none"> Hydroelectric Inflation Factor Assessment / Questions and Discussion 	<p>Julia Frayer, Managing Director, London Economics International LLC</p>
11:15 a.m. – 12:00 p.m.	<ul style="list-style-type: none"> Hydroelectric TFP Study Report / Questions and Discussion 	<p>Julia Frayer, Managing Director, London Economics International LLC</p>
12:00 p.m. – 12:45 p.m.	<ul style="list-style-type: none"> Lunch 	
12:45 p.m. – 2:00 p.m.	<ul style="list-style-type: none"> OPG’s Initial Multi-year Cost of Service Proposal for Nuclear Operations 	<p>Carla Carmichael, VP Nuclear Finance</p> <p>Randy Pugh, Director, Regulatory Affairs</p>
2:00 p.m. – 2:15 p.m.	<ul style="list-style-type: none"> Closing Remarks 	<p>Randy Pugh, Director, Regulatory Affairs</p>

AGENDA

Information Session February 18, 2015

Main Auditorium – 700 University Avenue, Toronto, ON

8:30 a.m. – 9:00 a.m.	- Registration
9:00 a.m. – 9:10 a.m.	- Welcome - Introductions - Safety Rules - Agenda
9:10 a.m. – 10:30 a.m.	- OPG's Initial Incentive Rate-making Proposal for Hydroelectric Operations - Initial Proposal for Service Quality Metric Reporting for Hydroelectric and Nuclear Operations
10:30 a.m. – 10:45 a.m.	- Break
10:45 a.m. – 11:50 a.m.	- OPG's Initial Multi-year Cost of Service Proposal for Nuclear Operations
11:50 a.m. – 12:00 p.m.	- Closing Remarks

OPG Regulated Facilities Payment Amounts Stakeholder Meeting - February 8, 2016

Feb. 8	Topic	Presenter
8:30-9:00	Arrival and Continental Breakfast	
9:00-9:10	Welcome and Introductions	Andrew Barrett VP, Regulatory Affairs Chris Ginther SVP Legal, Ethics and Compliance
9:10-9:20	Keynote Speaker	Jeffrey Lyash President and CEO
9:20-9:25	Agenda and Facilitation	Steve Klein OPTIMUS SBR
9:25-9:40	Application Overview	Colin Anderson Director, Ontario Regulatory Affairs
9:40-10:20	Regulatory Methodology Overview - Nuclear	Colin Anderson Director, Ontario Regulatory Affairs
10:20-10:45	Break	
10:45-11:15	Regulatory Methodology Overview - Hydroelectric	Randy Pugh Director, Ontario Regulatory Affairs
11:15-12:00	Additional Discussion	Steve Klein OPTIMUS SBR
12:00-1:00	Lunch	
1:00-1:30	Key Topic #1 – Darlington Refurbishment	Gary Rose VP, Planning and Project Controls, Nuclear Projects
1:30-2:00	Key Topic #2 – Pickering Life Extension	John Blazanin VP, Strategy and Support
2:00-2:30	Stakeholder Issues / Discussion / Wrap Up	Steve Klein OPTIMUS SBR
2:30	Adjourn	

**OPG Regulated Facilities Payment Amounts
 Stakeholder Meeting at the DEC - March 21, 2016**

March 21	Topic	Presenter
8:15 - 8:30am	Bus Pick up at Queen's Park	
8:30 – 9:45	Travel to Darlington Energy Complex (DEC)	
9:45 - 10:00	Arrival and Continental Breakfast	
10:00 – 10:05	Welcome and Introductions	Colin Anderson Director, Regulatory Affairs
10:05 – 10:10	Agenda and Facilitation	Steve Klein OPTIMUS SBR
10:10 – 10:20	Keynote Speaker	Jeff Lyash President & CEO
10:20 – 10:40	Darlington Refurbishment - Session #1 Overview of Scope	Gary Rose VP, Planning and Project Controls, Nuclear Projects
10:40 – 10:55	DEC Safety Briefing on Mock Up	
10:55 – 11:20	Mock Up Tour Overview of the Re-tube and Feeder Replacement Mock Ups	Mike Allen SVP, Nuclear Refurbishment
11:20 – 11:30	Board Bus	
11:30 – 12:15	Bus Tour of the Darlington Site Overview of Facility and Infrastructure and Safety Improvement Projects	Dragan Popovic Project Director
12:15 – 1:15	Lunch	
1:15 – 2:00	Darlington Refurbishment - Session #2 Overview of OPG's Contract Strategy	Meg Timberg VP, Project Assurance
2:00 – 2:30	Darlington Refurbishment - Session #3 Overview of OEB Filing	Gary Rose VP, Planning and Project Controls, Nuclear Projects
2:30 – 2:45	Questions and Discussion	Steve Klein OPTIMUS SBR
2:45	Bus Departs for Toronto	
4:00 (approx)	Bus Arrives in Toronto (Queen's Park)	

**Payment Amounts for OPG's Prescribed Facilities
 Stakeholder Information Session – May 19, 2016**

	Topic	Presenter
8:00 – 8:30	Arrival and Continental Breakfast	
8:30 - 8:40	Welcome and Introductions	Chris Fralick VP, Regulatory Affairs
8:40 - 8:50	Facilitator's Opening Remarks and Session Protocol	Steve Klein OPTIMUS SBR
8:50 - 9:40	Application Overview and Regulatory Framework	Barb Reuber EB-2016-0152 Case Manager
9:40 - 10:10	Nuclear Operations OM&A, Capital Projects and Production Forecast	Carla Carmichael VP, Nuclear
10:10 - 10:25	Break	
10:25 - 10:55	Support Services and Compensation Costs	Donna Rees Director, Total Rewards
10:55 - 11:30	Rate Base, Depreciation, Nuclear Liabilities, Pension/OPEB, Deferral and Variance Accounts	Alex Kogan VP, Business Planning and Reporting
11:30 - 11:50	Cost of Capital	Randy Pugh Director, Ontario Regulatory Affairs
11:50 - 12:15	Closing Remarks	Chris Fralick VP, Regulatory Affairs
12:15 - 12:30	Questions / Wrap Up/Adjourn	Steve Klein OPTIMUS SBR
12:30 - 2:00	Lunch	

1 **PROCEDURAL ORDERS / CORRESPONDENCE / NOTICES**

2

3 To be filed behind this tab when procedural orders, correspondence, and notices are filed.

LIST OF WITNESSES

1

2

3 To be filed behind this tab when list of witnesses is filed.

1

CURRICULA VITAE OF WITNESSES

2

3 To be filed behind this tab when curricula vitae of witnesses are filed.

DRAFT ISSUES LIST¹

1. GENERAL

- 1.1. Secondary - Has OPG responded appropriately to all relevant Board directions from previous proceedings?
- 1.2. Primary - Are OPG's economic and business planning assumptions appropriate for the nuclear assets?
- 1.3. Primary - Is the overall increase in nuclear payment amounts reasonable given the overall bill impact on customers?

2. RATE BASE

- 2.1. Primary - Are the amounts proposed for nuclear rate base appropriate?

3. CAPITAL STRUCTURE AND COST OF CAPITAL

- 3.1. Primary - Are OPG's proposed capital structure and rate of return on equity appropriate?
- 3.2. Secondary – Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

4. CAPITAL PROJECTS

Nuclear

- 4.1. Primary - Do the costs associated with the nuclear projects that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery meet the requirements of that section?
- 4.2. Primary - Are the proposed nuclear capital expenditures and/or financial commitments reasonable?
- 4.3. Primary - Are the proposed test period in-service additions for nuclear projects (excluding those for the Darlington Refurbishment Program) appropriate?

¹ The draft Issues List includes prioritization of issues into primary and secondary issues as specified in EB-2011-0286, *Filing Guidelines for Ontario Power Generation*, November 11, 2011.

1 4.4. Primary - Are the proposed test period in-service additions for the Darlington
2 Refurbishment Program appropriate?
3

4 **5. PRODUCTION FORECASTS**

5 **Nuclear**

6 5.1. Primary - Is the proposed nuclear production forecast appropriate?
7

8 **6. OPERATING COSTS**

9 **Nuclear**

10 6.1. Primary - Is the test period Operations, Maintenance and Administration budget for
11 the nuclear facilities appropriate?

12 6.2. Primary - Are the benchmarking results and targets flowing from OPG's nuclear
13 benchmarking reasonable?

14 6.3. Secondary - Is the forecast of nuclear fuel costs appropriate?

15 6.4. Primary - Is the test period Operations, Maintenance and Administration budget for
16 the Darlington Refurbishment Program appropriate?

17 6.5. Primary - Are the test period expenditures related to extended operations for
18 Pickering appropriate?
19

20 **Corporate Costs**

21 6.6. Primary - Are the test period human resource related costs for the nuclear facilities
22 (wages, salaries, benefits, incentive payments, FTEs and pension costs)
23 appropriate?

24 6.7. Primary - Are the corporate support services costs allocated to the nuclear
25 business appropriate?

26 6.8. Primary - Are the centrally held costs allocated to the nuclear business
27 appropriate?
28
29
30

1 **Depreciation**

2 6.9. Secondary - Is the proposed test period nuclear depreciation expense
3 appropriate?
4

5 **Income and Property Taxes**

6 6.10. Secondary - Are the amounts proposed to be included in the test period nuclear
7 revenue requirement for income and property taxes appropriate?
8

9 **Other Costs**

10 6.11. Secondary - Are the asset service fee amounts charged to the nuclear business
11 appropriate?
12

13 **7. OTHER REVENUES**

14 **Nuclear**

15 7.1. Secondary - Are the forecasts of nuclear business non-energy revenues
16 appropriate?
17

18 **Bruce Generating Station**

19 7.2. Secondary - Are the test period costs related to the Bruce Generating Station, and
20 costs and revenues related to the Bruce lease appropriate?
21

22 **8. NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES**

23 8.1. Primary - Is the revenue requirement impact of the nuclear liabilities appropriately
24 determined?
25

26 **9. DEFERRAL AND VARIANCE ACCOUNTS**

27 9.1. Secondary - Is the nature or type of costs recorded in the deferral and variance
28 accounts appropriate?

29 9.2. Secondary - Are the balances for recovery in each of the deferral and variance
30 accounts appropriate?

31 9.3. Secondary - Are the proposed disposition amounts appropriate?

- 1 9.4. Secondary - Is the disposition methodology appropriate?
2 9.5. Secondary - Is the proposed continuation of deferral and variance accounts
3 appropriate?
4 9.6. Primary - Are the deferral and variance accounts that OPG proposes to establish
5 appropriate?
6

6

7 **10. REPORTING AND RECORD KEEPING REQUIREMENTS**

- 8 10.1. Secondary – Are the proposed reporting and record keeping requirements
9 appropriate?
10

10

11 **11. METHODOLOGIES FOR SETTING PAYMENT AMOUNTS AND RATE SMOOTHING**

- 12 11.1. Primary - Has OPG responded appropriately to Board direction on establishing
13 incentive regulation?
14 11.2. Secondary - Is the design of the regulated hydroelectric and nuclear payment
15 amounts appropriate?
16 11.3. Primary - Is OPG's proposal for smoothing nuclear payment amounts consistent
17 with O. Reg. 53/05?
18

18

19 **12. IMPLEMENTATION**

- 20 12.1. Primary - Are the effective dates for new payment amounts and riders appropriate?

1 **SUMMARY OF OEB DIRECTIVES AND UNDERTAKINGS**
2 **FROM PREVIOUS PROCEEDINGS**

3
4 This exhibit discusses OPG's responses to OEB directives to OPG from previous
5 proceedings. In this case, the only applicable directives arise from the OEB's Decision and
6 Order on OPG's application for payment amounts for prescribed facilities for 2014 and 2015
7 (EB-2013-0321).

8
9 Chart 1 below identifies the OEB directives from the above noted proceeding and the
10 schedules in this application where OPG's evidence responds to the OEB directives.

11

Chart 1

Actions from the Decision and Order on OPG's application for payment amounts for prescribed facilities for 2014 and 2015 (EB-2013-0321)

1
2
3
4
5

Decision Chapter/Section	Pg. No.	Issue	OEB Decision / Directive	Reference Exhibit In OPG Evidence
2	REGULATED HYDROELECTRIC FACILITIES			
2.2	18	6.1 and 6.2	The Board orders OPG to undertake a fully independent hydroelectric benchmarking study using an approach comparable to the ScottMadden methodology used for nuclear benchmarking. Data used in the study should be as recent as possible (i.e. not older than 2013), without creating delays in the completion and dissemination of the study.	A1-3-2, Att. 2
3	NUCLEAR FACILITIES			
3.2	45	6.3 and 6.4	It is the Board's expectation that OPG will continue to produce annual nuclear benchmarking reports based on the ScottMadden methodology and that OPG will file these reports in future cost of service applications.	F2-1-1, Att. 1
3.6.1	55	6.7	In relation to the Darlington Refurbishment Project, the Board will require OPG to file at its next cost of service proceeding updates of actual costs of environmental assessment follow-up studies, costs of environmental monitoring studies and costs of any adaptive management projects.	D2-2-1, Att. 5

6

4	CORPORATE COSTS			
4.1.2	76	6.8	The Board directs OPG to file an independent, comprehensive compensation study, similar to the AON Report, that compares OPG compensation with broadly comparable organizations in the next cost of service application.	F4-3-1 Att. 2
4.3	95	6.9	The Board directs that an independent benchmarking study be undertaken of corporate support functions and costs given the significant changes resulting from the Business Transformation initiative. The results of this study will need to be shown in a manner that facilitates transparent comparison before and after Business Transformation.	F3-1-1, Att. 1
10	METHODOLOGIES FOR SETTING PAYMENT AMOUNTS			
10.1	129	11.1	OPG shall file the London Economics International hydroelectric productivity study immediately upon completion.	A1-3-2, Att. 1

ACRONYMS

1
2

AA	Adjuster Absorber
AACE	Association for the Advancement of Cost Engineering
Aecon/SNC JV	A joint venture of SNC-Lavalin Nuclear Inc. and Aecon Industrial, a division of Aecon Construction Group Inc.
ACM	Advance Capital Module
AFI	Area For Improvement
AGC	Automatic Generation Control
AHPS	Advanced Hydrologic Prediction System
AHS	Auxiliary Heating System
AIC	Argument-in-Chief
AIP	Annual Incentive Plan
AIR	All Injury Rate
AISC	Asset Investment Screening Committees
ALARA	As Low As Reasonably Achievable
Alstom	Alstom Power Canada Inc.
AL/TC	Air Lock and Transfer Chamber
AOCI	Accumulated Other Comprehensive Income
AON	AON Hewitt
AOV	Air Operated Valve
ARBPRIA	Amended and Restated Bruce Power Refurbishment Implementation Agreement
APM	Adaptive Phase Management
AR	Adjuster Rods
ARC	Asset Retirement Costs
ARO	Asset Retirement Obligation
AS	Ancillary Services
ASR	Accident Severity Rate
AWE	Average Weekly Earnings
Babcock & Wilcox	Babcock & Wilcox Canada Ltd., with GE-Hitachi Canada and Black & MacDonald as sub-contractors
BAS	Business and Administration Services
BATEA	Best Available Technology Economically Achievable
BCS	Business Case Summary
Blue Ribbon Task Force	Darlington Nuclear Refurbishment Scope Review Panel
BMcD/Modus	Burns & McDonnell Canada Ltd. and Modus Strategic Solutions Canada Company
BOP	Balance of Plant
BPRIA	Bruce Power Refurbishment Implementation Agreement
Bruce	Bruce Power L.P.
BS&IT	Business Services & Information Technology
BT	Business Transformation initiative
BWR	Boiling Water Reactors

BWXT/CANDU JV	BWXT Canada Ltd. (formerly Babcock & Wilcox Canada Ltd) and CANDU Energy Inc.
C&C	Coordination & Control
CANDU	Canadian Deuterium Uranium
CBD	Corporate Business Development
CBH	Construction Boilerhouse
CCA	Capital Cost Allowance
CCB	Change Control Board
CCD	Construction Completion Declaration
CCF	Change Control Form
CCGT	Combined Cycle Gas Turbines
CDA	Canadian Dam Association
CEA	Canadian Electrical Association
CEO	Chief Executive Officer
CFEP	Collaborative Front End Planning
CFSI	Counterfeit, Fraudulent, and Sub-standard Items
CGAAP	Canadian Generally Accepted Accounting Principles
CIA	Canadian Institute of Actuaries
CIGAR	Channel Inspection and Gauging Apparatus for Reactors
CM	Cyclical Maintenance
CMSC	Congestion Management Settlement Credits
CNO	Chief Nuclear Officer
CNSC	Canadian Nuclear Safety Commission
CO	Central Operations
Concentric	Concentric Energy Advisors
CPI	Consumer Price Index
CPI	Cost Performance Index
CRA	Canada Revenue Agency
CRVA	Capacity Refurbishment Variance Account
CWIP	Construction Work in Progress
CWP	Comprehensive Work Package
Darlington	Darlington Generating Station
DC	Direct Current
DC Intertie	Direct Current Transmission
DEC	Darlington Energy Complex
DESA	Design Engineering Services Agreement
DFL	Direct Field Labour
DNNJP	Darlington New Nuclear Project
DNRP	Darlington Nuclear Refurbishment Program
DOR	Division of Responsibility
DRB	Dispute Review Board
DRC	Depreciation Review Committee
DRP	Darlington Refurbishment Program
DSL	Direct Site Labour
DSO	Dispatch Scheduling Optimizer

DSR	Darlington Scope Request
DTRF	Darlington Tritium Removal Facility
EA	Environmental Assessment
EBIT	Earnings Before Interest and Taxes
EBITDA	Earnings Before Interest Taxes Depreciation and Amortization
ECS	Executive and Corporate Services
EFOR	Equivalent Forced Outage Rate
EFPH	Equivalent Full Power Hours
EIS	Environmental Impact Statement
EO	Eastern Operations
EOL	End-of-Life
EPC	Engineering, Procurement, and Construction
EPG	Emergency Power Generator
EPI	Environmental Performance Index
EPSCA	Electrical Power Systems Construction Association
ERI	Equipment Reliability Index
ERO	Emergency Response Organization
ERT	Emergency Response Team
ESESA	Engineering Services and Equipment Supply Agreement
ESM	Earnings Sharing Mechanism
ESMSA	Extended Services Master Services Agreement
ESW	Emergency Service Water
ETRM	Energy Trading and Risk Management
EUCG	Electric Utility Cost Group
EVM	Earned Value Management
F&IP	Facility and Infrastructure Projects
FA	Foundation Architecture
FAI	Fukushima Action Items
FCLE	Fuel Channel Life Extension
FD	Flux Detectors
FDR	Franklin D. Roosevelt
FEPO	Forced Extension to a Planned Outage
FFO	Funds from Operations
FHERI	Fuel Handling Equipment Reliability Index
FIN	Fix It Now
FLR	Forced Loss Rate
F/M	Fuelling Maching
FO	Forced Outages
Fosters	Foster Associates, Inc.
4GIRM	Fourth Generation Incentive Rate-setting Mechanism
FSCO	Financial Services Commission of Ontario
FTE	Full-Time Equivalents
Functions	OPG functional support groups
GAAP	Generally Accepted Accounting Principles

GAR	Global Assessment Report
GDP-IPI FDD	Canadian Gross Domestic Product Implicit Price Index – Final Domestic Demand
GHNEC	GE-Hitachi Nuclear Energy Canada Inc.
GLERL	Great Lakes Environmental Research Laboratory
GRC	Gross Revenue Charges
GS	Generating Station
GST	Goods and Services Tax
Hackett	Hackett Group
Heavy Water Facility	Heavy Water Storage and Drum Handling Facility
HIM	Hydroelectric Incentive Mechanism
HOEP	Hourly Ontario Energy Price
HONI	Hydro One Networks Inc.
HPER	Human Performance Error Rate
HSG	HSG Group Inc.
HST	Harmonized Sales Tax
HTO	Hydro Thermal Operations
HVAC	Heating, Ventilation and Air Conditioning System
ICM	Incremental Capital Module
IER	Independent Estimating Review
IESO	Independent Electricity System Operator
IFRS	International Financial Reporting Standards
IIP	Integrated Implementation Plan
IJC	International Joint Commission
IMS	Inspection and Maintenance Services
INC	International Niagara Committee
INCW	International Niagara Control Works
IO	Infrastructure Ontario
IR	Incentive Rate-setting
IRP	International Recommended Practice
ISAR	Industrial Safety Accident Rate
ISLRBC	International St. Lawrence River Board of Control
ISO	International Organization of Standardization
ISR	Integrated Safety Review
IT	Information Technology
ITC	Investment Tax Credits
IVA	Interim Variance Account
KPI	Key Performance Indicators
L&ILW	Low and Intermediate Level Waste
LEAP	Leveraging Enterprise Application Project
LEI	London Economics International LLC
LOE	Level of Effort
LRIA	<i>Lakes and Rivers Improvement Act</i>
LTD	Long-term Disability
LTEP	Long Term Energy Plan

LUEC	Levelized Unit Energy Cost
MCF	Master Consolidated File
MDS	Machine Delivered Scrape
MD&A	Management's Discussion and Analysis
MNRF	Ministry of Natural Resources and Forestry
MOA	Memorandum of Agreement
MOE	Ontario Ministry of Environment
MOU	Memorandum of Understanding
MPA	Major Project Advisory
MUE	Major Unforeseen Event
MTL	Mod Team Leader
MW	Megawatt
MWh	Megawatt hour
NDVA	Nuclear Development Variance Account
NEC	Nuclear Executive Committee
NEO	Northeast Operations
NERC	North American Electric Reliability Corporation
NFWA	Nuclear Fuel Waste Act
NHSS	New Horizon System Solutions
NNP	New Nuclear Project
NO	Niagara Operations
NOAA	National Oceanic and Atmospheric Administration
NOSS	Nuclear Operations Support and Services
NPA	Niagara Parks Act
NPI	Nuclear Performance Index
NSCA	Nuclear Safety and Control Act
NTP	Niagara Tunnel Project
NWMO	Nuclear Waste Management Organization
NWO	Northwest Operations
NYPA	New York Power Authority
O. Reg.	Ontario Regulation
OAR	Organizational Authority Register
OCC	Ontario Control Centre
OCT	Ontario Capital Tax
OEB	Ontario Energy Board
OEM	Original Equipment Manufacturer
OEFC	Ontario Electricity Financial Corporation
OM&A	Operations, Maintenance and Administration Costs
ONFA	Ontario Nuclear Funds Agreement
OPA	Ontario Power Authority
OPEB	Other Post-Employment Benefits
OPG	Ontario Power Generation Inc.
OPG Board	The Board of Directors of Ontario Power Generation Inc.
OR	Operating Reserve
OSM	Owner Specified Materials

OSPG	Ottawa - St. Lawrence Plant Group
P&C	People and Culture
P&M	Projects and Modifications
PARTS	Pickering A Return To Service
PBA	Pension Benefits Act (Ontario)
PCA	Plant Condition Assessment
PCC	Project Control Categories
PCCB	Program Change Control Board
PCE	Project Control Elements
PCI	Plant Condition Index
PDPS	Project Detailed Production Schedules
PEP	Project Execution Plan
PGS	Pump Generating Station
PHT	Primary Heat Transport
PHWR	Pressurized Heavy Water Reactor
PILs	Payments in Lieu of Corporate, Income, and Capital Taxes
PIMS	Program Integrated Master Schedule
PINO	Performance Improvement and Oversight
PIR	Post Implementation Review
PMBOK	Project Management Body of Knowledge
PMI	Project Management Institutes
PMP	Project Management Plan
PMS	Program Milestone Schedule
PMT	Project Management Team
Program	Darlington Refurbishment Program
Program Charter	Darlington Refurbishment Program Charter
PSRB	Project Scope Review Board
PST	Provincial Sales Tax
PSVS	Powerhouse Steam Venting System
PUEC	Nuclear Production Unit Energy Cost
PWR	Pressurized Water Reactors
PWU	Power Workers' Union
QAR	Quality Assessment Report
RACI	Responsible, Accountable, Consult, Inform
RCRB	Refurbishment Construction Review Board
RFP	Request for Proposals
RFQ	Request for Quotes
RFR	Retube and Feeder Replacement
FRISA	Retube and Feeder Replacement Island Support Annex
RM	Risk Management
RMD	Reactivity Mechanism Deck
RMO	Risk Management and Oversight
RMP	Risk Management Plan
ROC	Risk Oversight Committee

ROE	Return on Equity
RPC	Radiation Protection Coordinators
RPO	Refurbishment Project Office
RPP	Registered Pension Plan
RQE	Release Quality Estimate
RRFE	Renewed Regulatory Framework for Electricity Distributors
RRWF	Revenue Requirement Work Form
RSDA	Rate Smoothing Deferral Account
RSF	Refurbishment Support Facilities
RTE	Ready to Execute
RTWB	Re Tube Waste processing Building
RWPB	Retube Waste Processing Building
SAB	Sir Adam Beck
SAVH	Sickness, Accident, Vacation and Holiday
SBG	Surplus Baseload Generation
SCO	Station Containment Outage
Scope Requests	Darlington Scope Requests
SDLU	Shut Down Lay Up
SG	Steam Generators
SIO	Safety Improvement Opportunities
SLAR	Spacer Location and Relocation Program
SMO	Segregated Mode of Operation
SNC/AECON JV	SNC-Lavalin Nuclear Inc. and Aecon Industrial, a division of Aecon Construction Group Inc.
Society	Society of Energy Professionals
SPI	Schedule Performance Index
SR&ED	Scientific Research and Experimental Development
SR&ED ITC	Scientific Research and Experimental Development Investment Tax Credit
TBM	Tunnel Boring Machine
TFP	Total Factor Productivity
TG or Turbine Generator	Turbines, Generators and Auxiliaries
TGC	Total Generating Cost
TGC/MWh	Total Generating Cost per MWh
TLG	TLG Services
TPG	Tool Performance Guarantee
TRF	Tritium Removal Facility
TSW	Trent Severn Waterway
UCC	Undepreciated Capital Cost
UCF	Unit Capability Factor
UDM	Universal Delivery Machine
UEC	Unit Energy Cost
UNL	Unfunded Nuclear Liabilities
US GAAP	Generally Accepted Accounting Principles of the United States of America

VBO	Vacuum Building Outage
VERT	Voluntary Emergency Response Team
VFD	Vertical Flux Detector
VVRS	Vault Vapour Recovery System
WACC	Weighted Average Cost of Capital
WANO	World Association Of Nuclear Operators
WBS	Work Breakdown Structure
WCA	Work Control Area
WDP	Workforce Development Plan
WFFAA	West Fuelling Facility Auxiliary Area
Willis Towers Watson	Towers
WT	Water Transfer
YMPE	Year's Maximum Pensionable Earnings