CAPITAL STRUCTURE AND RETURN ON EQUITY

1.0 PURPOSE

This evidence describes the methodology that OPG has used to determine its capital structure and return on equity ("ROE") for the test period.

2.0 CAPITAL STRUCTURE

OPG is seeking approval of the test period cost of capital as presented in Ex. C1-1-1, Tables 1 through 5. In determining the cost of capital, OPG has applied the capital structure of 49 per cent equity and 51 per cent debt. The proposed capital structure is supported by the findings of the Common Equity Ratio Report carried out by Concentric Energy Advisors at Attachment 1 to this exhibit. The engagement letter executed with Concentric Energy Advisors is filed as Attachment 2 to this exhibit.

The proposed capital structure reflects the material increase in OPG's business and financial risks since EB-2013-0321, including the greater proportion of nuclear rate base within the total rate base as well as the increased risks resulting from Pickering Extended Operations (described at Ex. F2-2-3) and the Darlington Refurbishment Program (described at Ex. D2-2-1). As shown in Chart 1, nuclear business' proportion within the total rate base is expected to increase over the test period from close to 30 per cent to just over 50 per cent.

Chart 1

Rate Base	2017	2018	2019	2020	2021
Hydro ($B)[1]	7.5	7.5	7.5	7.6	7.7
Nuclear ($B)[2]	3.3	3.5	3.5	7.5	8.0
Total ($B)	10.8	11.0	10.9	15.1	15.6
Nuclear Proportion of Total Rate Base (%)	31%	32%	32%	50%	51%

[1] Reflects OPG's 2016-2018 Business Plan, which includes a projection for 2019-2021 (Ex. A2-2-1 Attachment 1).
[2] From Ex. I1-1-1, Table 1, sum of line 5, line 6 and line 7. Nuclear amounts do not include the lesser of unamortized asset retirement costs ("ARC") or unfunded nuclear liabilities ("UNL"). This is consistent with the OEB-approved methodology for determining rate base financed by capital structure, wherein the weighted average cost of capital is applied to OPG's rate base that does not include the lesser of ARC or UNL.

OPG proposes to establish the Hydroelectric Capital Structure Variance Account to record the revenue requirement impact of the difference between the capital structure approved by the OEB in this proceeding and the capital structure of 45 per cent equity and 55 per cent debt approved by the OEB in EB-2013-0321 that would underpin the proposed hydroelectric payment amounts in the test period. The proposed Hydroelectric Capital Structure Variance Account is described at Ex. H1-1-1 Section 6.4. This account is necessary to apply OPG's regulated operations-wide capital structure to the nuclear and regulated hydroelectric businesses consistently during the test period.

The debt component of OPG's capital structure is determined using the methodologies approved by the OEB in EB-2007-0905, EB-2010-0008 and EB-2013-0321. These are described in Ex. C1-1-2 and Ex. C1-1-3 for long-term and short-term debt, respectively. The capitalization and cost of capital for the 2013 to 2021 period is summarized in Ex. C1-1-1, Tables 1 - 9. OPG has applied this capitalization to the rate base, as adjusted to reflect the application of the "lesser of Asset Retirement Costs and Unfunded Nuclear Liabilities" provision applied by the OEB in EB-2007-0905, EB-2010-0008 and EB-2013-0321.

3.0 RETURN ON COMMON EQUITY FOR TEST PERIOD

OPG's Application incorporates an ROE of 9.19 per cent as this is the latest rate published by the OEB pursuant to the ROE formula as set out in *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 2009, EB-2009-0084* ("Cost of Capital Report").

OPG proposes to use the following methodology to establish the ROE for the nuclear business for the 2017 to 2021 period:

- For the first year of the test period (2017), the ROE will be set using the prevailing ROE specified by the OEB in accordance with the OEB's Cost of Capital Report as of the effective date of the Payments Amount Order;
- The 2017 ROE will be used to determine the revenue requirement approved by the OEB from 2018 to 2021;

- For the second through fifth year of the test period (2018 to 2021), the ROE will be set annually using the prevailing ROE specified by the OEB in accordance with the OEB's Cost of Capital Report;
- The revenue requirement impact of the variance between the forecast ROE approved for 2018 to 2021 in this Application and the actual ROE that the OEB will specify annually for 2018 to 2021 will be recorded in the proposed Nuclear ROE Variance Account, as described at Ex. H1-1-1 Section 6.3.

OPG does not propose to update the ROE for the regulated hydroelectric business for the 2017 to 2021 period. In those years, OPG's proposed hydroelectric payment amounts would be determined by the price-cap incentive regulation adjustments set out in Ex. A1-3-2.

ATTACHMENTS

Attachment 1: Common Equity Ratio: For OPG's Regulated Generation. Concentric Energy Advisors, May 2016.

Attachment 2: Executed engagement letter between Torys LLP and Concentric Energy Advisors to provide cost of capital-related advice

Note: Attachment 2 is marked "Confidential", however, OPG has determined it to be non-confidential with redactions as indicated.

COMMON EQUITY RATIO:
FOR OPG'S REGULATED GENERATION

PREPARED FOR
ONTARIO POWER GENERATION
MAY 2016

CONCENTRIC
ENERGY ADVISORS

WWW.CEADVISORS.COM

TABLE OF CONTENTS

Section 1: Executive Summary 1

Section 2: Scope of Analysis and Overview of Concentric 4

Section 3: Background 6

Section 4: Principles for a Fair Return 9

Section 5: Changes in Business and Financial Risk Since Previous Decision 12

Section 6: Comparative Analysis 28

Section 6: Conclusions and Recommendations 40

Appendix A: Precedent for Considering U.S. Data A-1

Appendix B: Résumé and Testimony Listing of James M. Coyne B-1

Appendix C: Résumé and Testimony Listing of Daniel S. Dane C-1

TABLE OF FIGURES

Figure 1: OPG's Prescribed Facilities 14

Figure 2: DRP as a Percentage of OPG's Net Assets, Compared to Two other North American Megaprojects 18

Figure 3: DBRS Ranking Criteria: Cost of Service vs. Incentive Regulation 23

Figure 4: Spread between Canadian BBB and A Utility Bond Yields 25

Figure 5: North American Electric Utility Proxy Group and OPG 32

Figure 6: Generation versus Transmission and Distribution Assets 34

Figure 7: Generation Mix (MW), Percentage Hydro and Nuclear Generation 35

Figure 8: Forecasted Capital Spending/ Net PP&E 36

Figure 9: Proxy Group Equity Ratios 37

Figure 10: Proxy Company Allowed Equity Ratios 38

SECTION 1:

EXECUTIVE SUMMARY

Concentric Energy Advisors, Inc. ("Concentric") was retained to prepare this independent report as to whether the application of the cost of capital approved by the Ontario Energy Board ("OEB" or the "Board") in EB-2013-0321 is an appropriate basis for setting Ontario Power Generation's ("OPG's" or the "Company's") nuclear and hydroelectric payment amounts in OPG's next rate application.[1] Concentric's analysis specifically focused on OPG's capital structure.

The Board previously found that the approach to establishing OPG's capital structure should be based on a detailed risk analysis of OPG, along with the changes to the Company's risk profile. That approach should also include an assessment of OPG's relative risk compared to other utilities. The Board has also applied the fair return standard in establishing the cost of capital for the utilities it regulates, which requires that three standards for the cost of capital be met: (1) the comparable investment standard; (2) the financial integrity standard; and (3) the capital attraction standard.

Concentric's analysis focused on: (a) changes to OPG's business and financial risks since EB-2013-0321; (b) expected changes to OPG's risk profile and financial integrity on a forward-looking basis, consistent with how an investor would analyze the Company; and (c) for comparative purposes, a review of capital structure data for similar North American electric utilities.

Specific to changes to OPG's business and financial risks since EB-2013-0321, Concentric reviewed both OPG's regulated hydroelectric and nuclear businesses, as well as the Company's anticipated rate proposals in the upcoming rate proceeding, and its overall regulatory environment.

As of December 31, 2015, OPG's regulated generation portfolio included two nuclear generating stations (*i.e.*, Pickering and Darlington), as well as 54 of the hydroelectric generating stations ("prescribed" facilities). OPG recently announced that it is to begin a $12.8 billion project to refurbish the Darlington facility starting in October 2016. That "megaproject" will more than double OPG's nuclear rate base.[2]

In terms of the hydroelectric business, the major risks generally faced by a regulated utility include: (1) the ability to license and gain permits and/or water power leases for new facilities; (2) availability of water to power the stations; (3) water management plans, including environmental and water level regulations that affect the way the stations operate or impede the license to operate; (4) the need for capital expenditures to address regulatory and sustaining requirements (*e.g.*, dam safety); and (5) the ability to recover costs, including a return, in a timely manner.

Concentric concludes that, based on the above, OPG's business risks related to its prescribed hydroelectric facilities have remained relatively the same since EB-2013-0321, with the exception of regulatory risk. The Company's regulatory risk is expected to increase during the period for which rates are expected to be set in the upcoming proceeding as a result of the movement to a five-year rate plan, as described further herein. Specifically, in Concentric's view, there is an anticipated

---

1 References to OPG or the Company throughout the report should be read as references to OPG's regulated operations.

2 Megaprojects are large, complex industrial construction projects. The construction industry handbook "Industrial Megaprojects: Concepts, Strategies, and Practices for Success" defines megaprojects as any project with a total capital cost of more than $1 billion (in 2003 U.S. dollars). *See*, Merrow, Edward W., "Industrial Megaprojects: Concepts, Strategies, and Practices for Success," John Wiley & Sons, Inc., 2011, at 15.

change in risk related to OPG's hydroelectric facilities that is attributable to the transition from a two-year cost of service rate-setting term to a five-year incentive regulation ("IR") regime.

In terms of the nuclear business, the major risks generally faced by a regulated utility include: (1) the ability to implement large and complex nuclear projects on time and on budget; (2) increases in costs and/or outage durations related to emerging safety regulations (*e.g.*, Fukushima-response costs); (3) age-related degradation of station components, discovery of unexpected conditions and/or extended outage durations that put nuclear plants at further risk of producing lower-than-forecasted power; (4) decommissioning of retired nuclear plants and long-term management of used nuclear fuel and other nuclear waste, including the cost and timing of decommissioning work and the ability to fund that work; and (5) the ability to recover costs, including a return, in a timely manner.

Specific to OPG, the $12.8 billion Darlington Refurbishment Project ("DRP") presents an incremental source of risk to the Company that will increase during the period for which rates in the upcoming proceeding are expected to be set. OPG's plans to pursue extended Pickering operations beyond 2020, the longest any Canadian Deuterium Uranium ("CANDU") plant will have ever operated, also poses risks. In addition, OPG continues to face risks related to the implementation of new safety and regulatory requirements. OPG's forecasts for costs and generation at its Darlington and Pickering nuclear facilities are being made in the face of these uncertainties, which are magnified by the longer, five-year term under the Company's ratemaking proposals, subject to the proposed mid-term review, discussed herein.

With the investment in OPG's regulated nuclear business due to the DRP, the nuclear operations are also projected to comprise a comparatively larger portion of OPG's overall regulated rate base than it did as of EB-2013-0321. The Board has recognized that nuclear assets are higher in risk than hydroelectric assets. The relative increase in nuclear assets as a percentage of rate base during the five-year rate period and beyond indicates that, all else being equal, OPG will become more risky over time.

Concentric concludes that OPG's risk profile will change materially over the 2017-2021 period as compared to its risk profile at the time of EB-2013-0321. Specifically, OPG's generation mix will change to reflect a significantly higher proportion of nuclear rate base than when the Board set the common equity ratio at 45% in EB-2013-0321. In fact, by the end of the test period in 2021, the nuclear rate base will exceed the relative level at which it stood when the Board set OPG's common equity ratio at 47% in EB-2007-0905 and EB-2010-0008. Given the Board's EB-2013-0321 finding that "[t]he business risk is reduced because of the addition of significant hydroelectric assets to rate base, which are less risky than nuclear assets,"[3] the opposite must hold equally true: business risk will have increased because of the addition of significant nuclear assets to rate base, which are more risky than hydroelectric assets. In addition, while operating risks of the hydroelectric business are expected to remain at current levels, these risks are expected to increase for the nuclear business in the 2017–2021 payment period supporting a higher common equity ratio.

The Company's risk profile is further affected by the increased forecasting and financial risks associated with the Company's proposed IR plans and longer rate setting periods, as well as recovery risks associated with both anticipated nuclear rate smoothing deferrals and pension and

3 EB-2013-0321, Decision with Reasons, at 114.

other post-employment benefit ("OPEB") costs. Based on the above, Concentric's opinion is that the appropriate equity ratio for the Company exceeds the currently deemed ratio of 45% previously set by the Board in the EB-2013-0321 rate proceeding.

In terms of the comparable return requirement of the fair return standard, the range of common equity ratios for comparable utilities is 40.27% to 54.29%, with an average equity ratio of 49.06% and a median of 49.95%. OPG's current equity ratio of 45% is on the low end of the comparable group despite its elevated level of risk relative to the proxy group. Specifically, with its significant nuclear concentration, as well as its status as the only company in the group that is a pure generating company, OPG falls toward the upper end of the risk spectrum. Thus, given OPG's elevated risk relative to the average level of risk faced by the proxy group, Concentric believes the proxy group average and median equity ratios of approximately 49% to 50% provide a floor for the consideration of an appropriate equity ratio for the Company for the 2017-2021 period.

Concentric also finds that an equity ratio of at least 49% will be: (1) more supportive of OPG's financial integrity and access to capital; (2) consistent with the requirements of the fair return standard, and (3) beneficial to customers. Specifically, an increase in OPG's equity ratio from its current 45% to 49% will increase cash flow to the Company, bettering its financial stability and strengthening the metrics that the ratings agencies evaluate when assigning credit ratings. Financial stability and strengthened cash flow benefit all stakeholders of the Company, both by maintaining the financial health of the utility, and by supporting its credit rating.

Lastly, while OPG's risk level is at the upper end of the risk spectrum, Concentric finds that an equity ratio at or above the proxy group average (rather than high end of the range) is appropriate.

In summary, given the material increase in risks since EB-2013-0321, Concentric recommends an equity ratio of no less than 49% be set in the upcoming proceeding, based on the following factors:

- The change in the nuclear to hydroelectric asset mix
- The increase in OPG's business risk driven by the DRP
- Plans to pursue extended Pickering operations beyond 2020 and the aging of the Pickering plant
- The move to IR for hydroelectric rate-setting and to long-term rate-setting periods for nuclear operations
- The recovery risks associated with pension and OPEB costs and revenue deferred under rate smoothing
- OPG's higher risk relative to comparable firms that have a median equity ratio of almost 50%

SECTION 2:

SCOPE OF ANALYSIS AND OVERVIEW OF CONCENTRIC

SCOPE

Concentric was retained to prepare this independent report as to whether the application of the cost of capital approved by the Board in EB-2013-0321 is an appropriate basis for setting OPG's nuclear and hydroelectric payment amounts in OPG's next rate application. Concentric's analysis specifically focused on OPG's capital structure. In preparing this report, Concentric performed the following assessment:

1. Examined the Board's decisions in EB-2007-0905, EB-2010-0008, and EB-2013-0321 to understand the Board's analysis and findings in past cases regarding OPG's cost of capital;
2. Analyzed OPG's business risks since EB-2013-0321 and on a forward-looking basis consistent with how an investor would analyze OPG's risk profile;
3. Examined the capital structures of a proxy group of comparable companies; and
4. Determined an appropriate capital structure for OPG.

OVERVIEW OF CONCENTRIC

Concentric is a management consulting and economic advisory firm, focused on the North American energy industry. Based in Marlborough, Massachusetts and Washington, D.C., Concentric specializes in regulatory and litigation support, transaction-related financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses. The firm provides financial, economic and regulatory advisory services to clients across North America, including utility companies, regulatory and public agencies, and utility sector investors. Concentric has advised energy industry participants on the purchase and sale of nuclear facilities, hydroelectric facilities, and other generation assets, and we have served in an independent monitoring or project advisory function on major capital projects at several nuclear generating units in North America. Concentric also has experience relating to major refurbishment work on life cycle management and extended power uprates in the U.S. and Canada. In addition, Concentric has provided expert testimony on the cost of capital in more than 65 regulatory proceedings in Canada and the U.S. over the past five years.

James Coyne, Senior Vice President at Concentric, and Daniel Dane, Assistant Vice President at Concentric, coauthored this report with assistance from other Concentric staff. Mr. Coyne is a senior expert who provides testimony before Canadian provincial and U.S. federal and state agencies on matters pertaining to economics, finance, and public policy in the energy industry. He regularly advises utilities, generating companies, public agencies and private equity investors on business issues pertaining to the utilities industry. This work includes determining the cost of capital for the purpose of ratemaking, and providing expert testimony and studies on matters pertaining to incentive regulation, rate policy, valuation, capital costs, demand side management, low-income programs, fuels and power markets. He has advised both buyers and sellers in numerous transactions involving hydroelectric, nuclear, fossil and renewable generation facilities, and worked with companies to develop strategies for acquiring these assets. He has testified or provided expert evidence before state, provincial and federal jurisdictions across Canada and the U.S. This work has been provided on behalf of utilities, regulatory commissions and staff.

Mr. Coyne is also a frequent speaker and author of articles and white papers on the energy industry. Recently, on behalf of the Canadian Gas Association and the Canadian Electric Association, he prepared a discussion paper for utility executives and provincial regulators that examined the roles that Canada's utilities and regulators can play to promote innovation. In addition, he facilitated workshops between Canadian regulators and utility executives on regulatory and utility responses to a low carbon world, and drafted follow-up white papers to facilitate further discussion on emerging industry issues. In collaboration with the Canadian Gas and Canadian Electric Associations, he publishes a newsletter summarizing allowed ROEs and capital structures for gas and electric utilities in Canada and the U.S. He has been an invited speaker for several CAMPUT events including the recent Energy Regulation Course at Queen's University where he spoke on "Innovations in Utility Business Models and Regulation," and will speak in May on North American cost of capital issues. Mr. Coyne also coauthored a report titled "A Comparative Analysis of Return on Equity of Natural Gas Utilities" with Mr. Dane that was prepared for the OEB in June 2007.

Prior to joining Concentric, Mr. Coyne was Senior Managing Director in the Corporate Economics Practice for FTI/Lexecon, and Managing Director for Arthur Andersen's Energy & Utilities Corporate Finance Practice. In those positions, he provided expert testimony and advisory services on mergers, acquisitions, divestitures and capital markets for clients in the energy industry. Previously, he was Managing Director for Navigant Consulting, with responsibility for the firm's Financial Services practice, Director in DRI/McGraw-Hills's Electric and Natural Gas practices, and Senior Economist for the Massachusetts Energy Facilities Siting Council, where he analyzed the supply plans and facilities proposals from the state's electric and gas utilities. He also served as State Energy Economist for the Maine Office of Energy Resources. He holds a B.S. in Business Administration from Georgetown University and a M.S. in Resource Economics from the University of New Hampshire.

Mr. Dane has advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of those assignments have included the determination of the cost of capital. Mr. Dane has also provided expert testimony on regulated ratemaking matters, including the cost of capital, for investor-owned utilities. Mr. Dane coauthored "A Comparative Analysis of Return on Equity of Natural Gas Utilities" with Mr. Coyne on behalf of the Board, as discussed above. Mr. Dane has provided sell-side support for approximately $2 billion in generating asset transactions in the U.S., including nuclear generating facilities, and has been a significant contributor to numerous assignments at Concentric involving independent evaluations of nuclear plant construction project commercial strategies, project controls and management oversight, and new power plant development. Mr. Dane has an MBA from Boston College in Chestnut Hill, Massachusetts and a BA in Economics from Colgate University in Hamilton, New York. Mr. Dane is a certified public accountant, and is a licensed securities professional (Series 7, 28, 63, 79, and 99). Mr. Dane also serves as the Financial and Operations Principal of CE Capital Advisors, a FINRA-Member firm and a subsidiary of Concentric.

Messrs. Coyne and Dane's qualifications are detailed more fully in Appendices B and C.

SECTION 3:
BACKGROUND

This is the fourth general rate setting proceeding before the Board for OPG. Below is a brief synopsis of the prior three proceedings, as well as the Board's findings in EB-2009-0084, the "Report of the Board on the Cost of Capital for Ontario's Regulated Utilities."

EB-2007-0905

EB-2007-0905 was OPG's first cost of service application before the Board, including cost of capital and capital structure. In its November 3, 2008 decision in EB-2007-0905, the Board laid out the legislative requirements regarding rate regulation of OPG and reached numerous conclusions regarding its approach to setting rates for OPG.

With regard to the capital structure, the Board stated: "The Board finds that the approach to setting the capital structure should be based on a thorough assessment of the risks OPG faces, the changes in OPG's risk over time and the level of OPG's risk in comparison to other utilities."[4] The Board further concluded that it would apply the stand-alone principle in establishing the capital structure for the Company, noting that "[t]he stand-alone principle is a long-established regulatory principle,"[5] and that "Provincial ownership will not be a factor to be considered by the Board in establishing capital structure."[6] The Board determined that a 47% equity ratio was appropriate for the Company, finding that OPG was of higher risk than any other Ontario energy utility but of lower risk than merchant generators.[7]

During EB-2007-0905, the Board set one overall capital structure for both regulated hydroelectric and nuclear businesses, but concluded that separate capital structures for the two businesses was an approach worth examining at the next proceeding.

At the time of EB-2007-0905, OPG owned and operated six prescribed hydroelectric generating stations (Sir Adam Beck I and II, Sir Adam Beck Pump Generating Station, DeCew Falls I and II, and R.H. Saunders), and three prescribed nuclear generating stations (Pickering A, Pickering B, and Darlington).

EB-2009-0084

In EB-2009-0084, the Board reviewed its cost of capital policies for Ontario's regulated utilities to determine whether the automatic adjustment formula was continuing to meet the fair return standard. As a result of its consultative process, the Board affirmed its view that the fair return standard frames the discretion of a regulator, by setting out three standards or requirements (comparable investment, financial integrity, and capital attraction) that must be satisfied by the cost of capital determinations.[8] The Board observed that meeting the fair return standard is not optional; it is a legal requirement.

4 EB-2007-0905, Decision with Reasons, November 3, 2008, at 136.
5 *Ibid*, at 140.
6 *Ibid*, at 142.
7 *Ibid*, at 149-150.
8 EB-2009-0084, Report of the Board, December 11, 2009, at i.

In discussing the application of the fair return standard, the Board made the following observations:[9]

1. The Board notes that the fair return standard expressly refers to an opportunity cost of capital concept, one that is prospective rather than retrospective;
2. The Board agrees with the National Energy Board which stated that "[i]t does not mean that in determining the cost of capital that investor and consumer interests are balanced;"
3. All three standards or requirements (comparable investment, financial integrity, and capital attraction) must be met and none ranks in priority to the others;
4. The Board reiterates that an allowed return on equity ("ROE") is a cost and is not the same concept as a profit, which is an accounting term for what is left from earnings after all expenses have been provided for;
5. The Board is of the view that utility bond metrics do not speak to the issue of whether a ROE determination meets the requirements of the fair return standard; and
6. The Board questions whether the fair return standard has been met, and in particular, the capital attraction standard, by the mere fact that a utility invests sufficient capital to meet service quality and reliability obligations. Rather, the Board is of the view that the capital attraction standard, indeed the fair return standard in totality, will be met if the cost of capital determined by the Board is sufficient to attract capital on a long-term sustainable basis given the opportunity costs of capital.

With respect to capital structure, the Board found that its current policy for all regulated utilities, which was developed in March 1997, continued to be appropriate. The decision in EB-2009-0084 states: "As noted in the Board's draft guidelines, capital structure should be reviewed only when there is a significant change in financial, business or corporate fundamentals."[10]

The Board also reiterated other policies, including that "the rate setting methodologies used by the Board apply uniformly to all rate-regulated utilities regardless of ownership. The determination of the rate-regulated utilities' cost of capital is no exception."[11]

EB-2010-0008

OPG's generation mix as of EB-2010-0008 was at approximately 38% nuclear and 62% hydroelectric, based on Board-approved rate base for the prescribed facilities (excluding the lesser of nuclear asset retirement costs and unfunded nuclear liability), which was approximately the same as it had been as of EB-2007-0905. In its March 11, 2011 decision in EB-2010-0008, the Board found that "there is no evidence of any material change in OPG's business risk and that the deemed capital structure of 47% equity and 53% debt, after adjusting for the lesser of Unfunded Nuclear Liabilities or Asset Retirement Costs, remains appropriate."[12]

9 *Ibid*, at 19-20.
10 *Ibid*, at 49.
11 *Ibid*, at 25.
12 EB-2010-0008, at 116.

In EB-2010-0008, there was a discussion of technology-specific costs of capital and capital structures. Pollution Probe's experts Drs. Lawrence Kryzanowski and Gordon Roberts recommended an equity ratio of 43% for the hydroelectric operations and an equity ratio of 53% for the nuclear operations, premised on OPG retaining its aggregate equity ratio of 47%. The Board found that there was not enough evidence to support technology-specific capital structures, and reaffirmed its findings in EB-2007-0905 that the risks related to nuclear generation are higher than those related to hydroelectric generation.

In addition, while the issue was identified by the Board in the context of technology-specific capital structures, the OEB recognized an emerging issue, noting that "[a]s the relative size of the hydroelectric and nuclear businesses changes (through major additions to rate base, for example) the issue will arise as to whether the overall ratio of 47% is to remain unchanged."[13]

EB-2013-0321

In EB-2013-0321, the Board found that OPG's business risks had changed, pointing to the addition of 48 hydroelectric assets to OPG's regulated assets and the then recently completed Niagara Tunnel Project, as well as a pension and OPEB variance account that was established after OPG's equity thickness was first set in EB-2007-0905. Specifically, the Board found that the addition of hydroelectric assets and the Niagara Tunnel Project, "increase the proportionate share of rate base related to hydroelectric facilities from about half in 2010 to approximately two-thirds now [*i.e.*, as of EB-2013-0321]."[14]

As a result of these findings, the Board lowered the equity ratio for OPG from 47% to 45%. Specifically, the Board stated, "…[t]he Board has determined that business risk has changed for this payment setting period, and that the business risk is reduced. The business risk is reduced because of the addition of significant hydroelectric assets to rate base, which are less risky than nuclear assets."[15]

In addition, the Board found that, at the time of EB-2013-0321, moving to incentive regulation did not significantly increase risks to OPG such that the capital structure should be reset, noting that the capital structure for the Province's electricity and gas distributors had not been reset when they moved to incentive regulation. The Board did note, however, that part of its decision was based on the fact that OPG was not moving to incentive regulation in EB-2013-0321, and that "any potential changes to business risk this may entail could be considered in the incentive regulation proceeding."[16]

13 *Ibid.*, at 117.
14 EB-2013-0321, Decision with Reasons, at 113. Clarification added.
15 *Ibid.*, at 114.
16 *Ibid.*

SECTION 4:
PRINCIPLES FOR A FAIR RETURN

The Supreme Court of Canada established the principles surrounding the concept of a "fair return" for a regulated company in the *Northwestern Utilities v. City of Edmonton* (1929) ("Northwestern") case, where the Supreme Court found:

> *By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.*[17]

As stated by Major and Priddle in 2008, this definition remains in full legal effect today.[18]

United States law regarding fair return for utility cost of capital has evolved similarly. The U.S. Supreme Court set out guidance in the bellwether cases of *Bluefield Water Works* and *Hope Natural Gas Co.* as to the legal criteria for setting a fair return. In *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia* (262 U.S. 679, 693 (1923)), the Court found:

> *The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.*

The U.S. Court further elaborated on this requirement in its decision in *Federal Power Commission v. Hope Natural Gas Company* (320 U.S. 591, 603 (1944)). There the Court described the relevant criteria as follows:

> *From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock [....] By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.*

With the passage of time, the fair return standard has been interpreted many times in both Canada and the U.S. In Canada, the National Energy Board ("NEB") summarized its interpretation of the

---

17 Northwestern at 193.

18 The Fair Return Standard for Return on Investment by Canadian Gas Utilities: Meaning, Application, Results, Implications, by The Honourable John C. Major, Former Justice, Supreme Court of Canada, and Roland Priddle, President, Roland Priddle Energy Consulting Inc., Former Chair of the National Energy Board, March 2008, at 4.

"fair return standard" in its RH-2-2004 Phase II Decision and more recently reiterated that interpretation in its Trans Québec & Maritimes Pipelines Inc. RH-1-2008 Decision, at pp. 6-7.

> *The [NEB] is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:*
>
> - *be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);*
> - *enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and*
> - *permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).*
>
> *In the [NEB]'s view, the determination of a fair return in accordance with these enunciated standards will, when combined with other aspects for the Mainline's revenue requirement, result in tolls that are just and reasonable.*[19]

Similarly, in its EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, the OEB discussed the necessity of adhering to the fair return standard as follows:

> *The Board affirms its view that the Fair Return Standard frames the discretion of a regulator, by setting out the three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. Notwithstanding this obligation, the Board notes that the Fair Return Standard is sufficiently broad that the regulator that applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity's cost of capital.*
>
> ***
>
> *… all three standards or requirements (comparable investment, financial integrity, and capital attraction) must be met and none ranks in priority to the others. The Board agrees with the comments made to the effect that the cost of capital must satisfy all three requirements which can be measured through specific tests and that focusing on meeting the financial integrity and capital attraction tests without giving adequate comparability to the comparable investment test is not sufficient to meet the [Fair Return Standard].*[20]

Canadian regulatory authorities, including the Board, have also determined that another key principle in establishing a fair return on equity for a regulated utility is the "stand-alone" principle.

[19] National Energy Board RH-2-2004 Reasons for Decision, TransCanada PipeLines Ltd, Phase II, April 2005, at 17.

[20] Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at i and 19.

The Board's specific findings with regard to the stand-alone principle for OPG are included above in the summary of EB-2007-0905.

Furthermore, the Board has recognized that the cost of capital is a forward-looking concept. For example, in its decision in EB-2009-0084, the Board referenced a presentation by Dr. Bill Cannon at CAMPUT's 2009 Energy Regulation Conference during which Dr. Cannon explained the forward-looking nature of the cost of capital as follows: "First, it [the cost of capital] is forward looking. Investment returns are inherently uncertain and the ex post, actual returns experienced by investors may differ from those that were expected ahead of time. The cost of capital is therefore an *expected* rate of return."[21] Elsewhere in that same decision, the Board stated: "First, the Board notes that the [Fair Return Standard] expressly refers to an opportunity cost of capital concept; one that is prospective rather than retrospective."[22] In other words, investors establish their return requirements based on expectations regarding economic growth, inflation, interest rates, the market risk premium and other factors affecting future risks and opportunity costs.

Investors also consider the business and financial risks of a particular company relative to other similarly situated companies in the same industry. For example, as mentioned previously, the Board has expressed its view that "the capital attraction standard, indeed the [Fair Return Standard] in totality, will be met if the cost of capital determined by the Board is sufficient to attract capital on a long-term sustainable basis given the opportunity costs of capital."[23] Further, the Board has determined that "[t]he comparable investment standard requires empirical analysis to determine the similarities and differences between rate-regulated utilities." However, the assessment of comparability "does not require that those entities be 'the same'."[24]

21 *Ibid*, at 25.
22 *Ibid*, at 19.
23 *Ibid*, at 20.
24 *Ibid*, at 21.

SECTION 5:

CHANGES IN BUSINESS AND FINANCIAL RISK SINCE THE EB-2013-0321 DECISION

INTRODUCTION

Business risk for a regulated utility results from variability in cash flows and earnings that impact the ability of the utility to recover its costs including a fair return on, and of, its capital in a timely manner. Concentric includes operating risk and regulatory risk under this broad definition of business risk. Financial risk relates to a utility's ability to access capital and the effect of management's and economic regulators' decision-making on a utility's credit profile. Financial risk also affects the financial integrity of a utility. Both business and financial risk have a direct bearing on a utility's cost of capital.

The cost of capital is also a forward-looking concept, and utility investors tend to be long-term providers of capital. For those reasons, it is important to not only review OPG's current business and financial risk profile and its consistency or inconsistency with the Company's deemed capital structure, but also to assess how that risk profile has changed and will change going forward. This approach is consistent with the OEB's findings in its EB-2013-0321 decision regarding OPG's capital structure. The Board determined that because the business risk for the Company's regulated operations had changed in the specific payment-setting period in that proceeding, the capital structure should reflect that change.

This section contains an overview and analysis of OPG's business and financial risks, with a focus on how those risks have changed since EB-2013-0321 and how they are forecast to change over the period from 2017 to 2021, which is the specific payment-setting period under review in OPG's upcoming rate case.

To evaluate OPG's business risks, Concentric performed an independent review of the Company and its regulatory environment. That review included: (1) gaining an understanding of OPG's current and forecasted operating plans for its prescribed facilities; (2) evaluating the risks related to the prescribed hydroelectric facilities; (3) evaluating the risks related to the prescribed nuclear facilities, including the Darlington refurbishment project and plans to pursue extended Pickering operations beyond 2020; (4) analyzing OPG's projected rate bases for its nuclear and hydroelectric businesses, and how those rate bases are expected to change relative to one another over the rate-setting period; and (5) gaining an understanding of the Company's planned rate-setting proposals for the upcoming proceeding and how those proposals would affect OPG's business and financial risks over the period to 2021.

Our experience in assessing business and financial risks and the effect on the cost of capital in other regulatory jurisdictions, as well as our prior roles as an independent monitor and advisor to the power industry, informed our review. Our additional experience advising buyers and sellers of generation facilities, including hydroelectric and nuclear facilities, further informs our views on the investor perspective regarding the business risk of these assets. Our evaluation process included a review of investment analyst reports regarding OPG (such as those from credit rating agencies Standard & Poor's Ratings Service ("S&P") and DBRS), relevant industry data such as that provided by the World Nuclear Association, other publicly-available materials such as Ontario's December

2013 Long-Term Energy Plan ("LTEP"), regulatory filings made by the Company, the OPG 2016 to 2018 business plan with financial projections through 2021, the Company's financial reports, and interviews with OPG subject matter experts.

Concentric concludes in this section that OPG's overall risk level will increase materially over the period 2017-2021 from its level as of EB-2013-0321, driven primarily by business risks related to the significant project being undertaken to refurbish the Darlington facility, planned extended Pickering operations beyond 2020, the implementation of incentive regulation for the prescribed hydroelectric assets and rate smoothing for the prescribed nuclear assets, longer rate setting periods, and changes in the Company's regulatory environment. OPG's financial risks are also expected to increase over the upcoming rate-setting period, as the Company's debt levels are forecast to increase during the Darlington refurbishment period. Credit metrics are expected to be further pressured by deferral of some revenues to the post refurbishment period.

COMPANY OVERVIEW

OPG is an electricity generation company established under the *Business Corporations Act* and is wholly owned by the Province of Ontario. As of December 31, 2015, OPG's regulated generation portfolio included two nuclear generating stations (*i.e.*, Pickering and Darlington) as well as 54 of the hydroelectric generating stations. OPG's regulated facilities are referred to as the "prescribed" facilities.

Figure 1 provides the relative rate base from the start of OPG rate regulation by the OEB through to the upcoming test period, and includes, for illustrative purposes, estimated rate base in 2026, after the end of the Darlington refurbishment period.[25] Specifically, the figure provides the rate base, in dollars, for both the prescribed nuclear and hydroelectric facilities, and a "hydroelectric-to-nuclear" ratio.

OPG's common equity ratio, both the historical ratio as well as the ratio proposed in this proceeding, is also provided. As can be seen in the figure, the hydroelectric-to-nuclear ratio peaked during the period for which rates in EB-2013-0321 were set, which was also the period for which the Board lowered OPG's common equity ratio to 45%. However, starting in 2017, the hydroelectric-to-nuclear ratio is expected to begin to decline significantly. By 2021, *i.e.*, the end of the proposed five-year rate period, the hydroelectric-to-nuclear ratio is expected to be at its lowest point historically, and is expected to continue to decline over the following five years. The average test-period hydroelectric-to-nuclear ratio for 2017-2021 is nearly one-half the ratio for the period for which EB-2013-0321 rates were set.

25 Nuclear amounts do not include the lesser of unfunded nuclear liabilities or unamortized asset retirement costs, which is consistent with the OEB-approved methodology for calculating OPG's rate base subject to the weighted average cost of capital for purposes of setting payment amounts.

Figure 1: OPG's Prescribed Facilities Rate Base ($ billions)

	EB-2007-0905 Payment Order		**EB-2010-0008 Payment Order**		**EB-2013-0321 Payment Order**		**Test Period[26]**					**End of DRP (Illustrative)**
	2008	**2009**	**2011**	**2012**	**2014**	**2015**	**2017**	**2018**	**2019**	**2020**	**2021**	**2026**
Hydro	$3.9	$3.9	$3.8	$3.8	$7.5	$7.5	$7.5	$7.5	$7.5	$7.6	$7.7	$7.5B
Nuclear[27]	$2.4	$2.5	$2.4	$2.4	$2.3	$2.4	$3.3	$3.5	$3.5	$7.5	$8.0	$13.5B
Test Period Hydro/ Nuclear ratio	158%	157%	159%	161%	325%	319%	227%	214%	214%	101%	96%	56%
Test Period Ratio Avg	159%				322%		171%					56%
Common Equity Ratio	47%	47%	47%	47%	45%	45%	**Recommended Minimum** 49%	49%	49%	49%	49%	

26 Estimated rate base values pending finalization of OPG's rate application.

27 Nuclear amounts do not include the lesser of unfunded nuclear liabilities or unamortized asset retirement costs, which is consistent with the OEB-approved methodology for calculating OPG's rate base subject to the weighted average cost of capital for purposes of setting payment amounts.

OPG, as a corporation, has a split "A (low)" issuer and unsecured debt rating (as of April 25, 2016) from DBRS, and a "BBB+" corporate credit rating (as of July 7, 2015) from S&P. Both ratings agencies point to support provided by the Province, a strong market position, and a supportive regulatory framework as credit positive factors, while considering the Company's capital expenditure plan coupled with already weak credit metrics to be a credit risk.

DBRS further specifically cites nuclear generation risk as being a "challenge" for OPG. In addition, S&P notes that it rates OPG as "BBB-" (*i.e.*, two notches below its "BBB+" corporate credit rating) on a stand-alone basis, before consideration of support by the Province. This is an important point with regard to OPG, as its evaluated operations are regulated by the OEB on a stand-alone basis.

HYDROELECTRIC FACILITIES

As noted earlier, OPG has 54 hydroelectric stations that are subject to OEB regulation, which supply approximately 6,425 MW of generating capacity. OPG's hydroelectric stations vary in size, location, age, operating and hydrological characteristics (*i.e.*, base load, intermediate, peaking). The hydroelectric system thus represents a diverse set of assets. Because of the geographic diversity of the system, the hydroelectric assets are subject to numerous Federal, interprovincial, and provincial regulations, treaties, agreements, and waterpower leases.

Generally, the major risks to a regulated utility related to hydropower include: (1) the ability to license and gain permits and/or water power leases for new facilities; (2) availability of water to power the stations; (3) water management plans, including environmental and water level regulations that affect the way the stations operate or impede the license to operate; (4) the need for capital expenditures to address regulatory and sustaining requirements (*e.g.*, dam safety); and (5) the ability to recover costs, including a return, in a timely manner.

OPG's hydroelectric business is expected to be relatively stable from an operating risk perspective relative to recent experience and conditions as they existed at the time of EB-2013-0321, as discussed further below. As discussed in the section following, business risks related to the hydroelectric rate setting mechanism are expected to increase relative to EB-2013-0321.

OPG's hydroelectric system is a mature system (the average age of OPG's hydroelectric system is 78 years). This means that, while the risk of equipment failure is higher, the risk of discovering new operational issues or the intervention of new stakeholders is lower than it would be for a newer system. In addition, Concentric understands that, while OPG has planned capital project expenditures totaling approximately $1 billion over the 2017-2021 period, OPG is not planning to add any significant amount of new hydroelectric capacity during that period. Because of this, OPG's need to obtain new water power leases or rights would not materially deviate from recent experience, leaving associated risks at similar levels as those faced at the time of EB-2013-0321.

OPG is subject to variances in water flow and surplus baseload generation curtailments.[28] However, while the availability of water to power the stations can vary significantly from year to year (for instance, hydroelectric production by OPG was approximately five terawatt-hours less in 2010 than

[28] Surplus baseload generation occurs when production from baseload generation facilities exceeds demand as determined by the Independent Electricity System Operator ("IESO"). In recognition of the significance of surplus baseload generation to OPG's financial results, the Board approved a Surplus Baseload Generation Variance Account in EB-2010-0008.

it had been in 2009), Concentric is not aware of any reason why variances in water flow over the rate period are more or less at risk of being higher or lower than at the time of EB-2013-0321. In addition, Concentric is not aware of factors that would materially change the risks related to surplus baseload generation in the test period. Further, OPG has a Hydroelectric Water Conditions Variance Account that records and mitigates the financial impact of differences between forecast and actual water conditions, and a Surplus Baseload Generation Variance Account that records and mitigates the financial impact of surplus baseload generation curtailments (and is applying to continue those accounts in this proceeding). The Hydroelectric Water Conditions and Surplus Baseload Generation variance accounts apply to OPG's six hydroelectric facilities that were regulated prior to EB-2013-0321, as well as 21 of the hydroelectric facilities that were newly regulated as of EB-2013-0321. As such, Concentric is of the view that the risks related to the availability of water to power the stations and surplus generation curtailment have not changed since EB-2013-0321.

Similar to the risks related to the availability of water flows, Concentric is not aware of changes in risks related to environmental regulations affecting hydroelectric power relative to the risk level that has existed in the recent past.

In terms of the need for capital expenditures to address regulatory requirements, while OPG is expecting enhancements to the existing dam safety technical guidelines in the near future, the risk related to these enhancements is not materially different from recent years. In other words, Concentric is not aware of any event or change in regulatory regimes that would lead to a significant departure from past trends in the risks related to implementation of hydroelectric-related regulations.

Regarding OPG's ability to recover hydroelectric costs, including a return in a timely manner, there is a substantial change in risk related to OPG's hydroelectric facilities attributable to the planned transition in the rate setting term from a two-year cost of service to a five-year incentive regulation regime. Risks related to incentive regulation are described below.

OPG is proposing that all currently-approved deferral and variance accounts related to its prescribed hydroelectric facilities remain in place so there is no change in risk in that regard. These include the Hydroelectric Water Conditions Variance Account and the Hydroelectric Surplus Baseload Generation Variance Account (as discussed above).

Concentric concludes that, based on the above, OPG's operational risks related to its prescribed hydroelectric facilities have remained relatively the same since EB-2013-0321, but OPG's regulatory risk related to the hydroelectric facilities is expected to change as a result of the movement to a five-year incentive rate plan, as discussed in a later section.

NUCLEAR FACILITIES

OPG has two prescribed nuclear facilities: Darlington and Pickering. Darlington is a CANDU, four-unit station with a generating capacity of about 3,500 MW. Pickering is a CANDU, six-unit station with a generating capacity of about 3,100 MW. Both facilities feature prominently in Ontario's 2013 LTEP over the 2017-2021 period.[29]

[29] Ontario's Long-Term Energy Plan, December 2013, at 28-30.

Generally, the major risks to a regulated utility related to nuclear power generation include: (1) the ability to implement large and complex projects on time and on budget; (2) increases in costs and/or outage durations related to emerging safety regulations (*e.g.*, Fukushima-response costs); (3) age-related degradation of station components, discovery of unexpected conditions and/or extended outage durations that put nuclear plants at further risk of producing lower-than-forecasted power; (4) decommissioning of retired nuclear plants and long-term management of used nuclear fuel and other nuclear waste, including the cost and timing of decommissioning work and the ability to fund that work; and (5) the ability to recover costs, including a return, in a timely manner.

Specific to OPG, the Darlington Refurbishment Project presents an incremental source of risk to the Company that will become increasingly significant during the upcoming rate-setting period. That incremental risk is not only related to the execution of the project, but is also due to inherent uncertainty related to its timing and completion, as outlined in the LTEP. While the Province has granted OPG approval to proceed with the first unit refurbishment, OPG is required to seek the Province's approval to proceed with each subsequent unit refurbishment. OPG's plans to pursue extended Pickering operations beyond 2020 also poses considerable risks. In addition, OPG continues to face risks related to the implementation of new safety and regulatory requirements.

OPG's forecasts for nuclear costs and generation levels are being made in the face of this uncertainty, while also covering a longer, five-year term under the Company's ratemaking proposals, subject to a proposed mid-term review, discussed below.

A. Darlington

OPG is planning to refurbish Darlington for 30 additional years of operations. In terms of the DRP, the four-unit refurbishment project is a megaproject with a budget of $12.8 billion including interest and escalation,[30] lasting approximately a decade. For OPG, the DRP is a significant undertaking, as the $12.8 billion cost of the project represents over 100% of OPG's total regulated rate base as of EB-2013-0321 (*i.e.*, the rate base most recently approved by the Board), and approximately 70% of OPG's overall net in-service property, plant and equipment ("PP&E") balance (both prescribed and non-regulated). Relative to the size of the Company, the DRP is one of the most significant undertakings in the North American nuclear industry in the recent past. For context, Figure 2 below provides a comparison of the size of the DRP relative to OPG's size to the size of two other nuclear megaprojects that are currently ongoing in North America relative to their owners' sizes.

---

[30] OPG, "Refurbishment of the Darlington Nuclear Generating Station. An Impact Analysis on Ontario's Economy," November 2015.

Figure 2: DRP as a Percentage of OPG's Net Assets, Compared to Two other North American Nuclear Megaprojects

	Darlington Refurbishment Project (OPG)	V.C. Summer New Nuclear Plant (SCANA Corporation)[31]	Vogtle New Nuclear Plant (Southern Company)[32]
Estimated Cost	$12.8b	$6.85b (US)	$7.5b (US)
Sponsor Net In-service PP&E	$20.6b[33]	$12.7b (US)	$58.2b (US)
Estimated Cost / Net PP&E	62%	54%	13%

A project of the DRP's size and schedule length, regardless of the technology, that will more than double the Company's rate base, inherently presents a significant source of risk for any utility. As noted in the Scope of Analysis and Overview of Concentric section of this report, Concentric has been an advisor to several North American utilities undertaking megaprojects such as the DRP. We have witnessed firsthand the issues even the most well planned large construction projects can face, including scope, budget, and schedule increases, as well as increased regulatory scrutiny. The performance of large construction projects in a nuclear setting compounds those issues.

Specifically, the DRP will include multiple complex work packages, including the removal and replacement of the reactor calandria tubes and pressure tubes from each reactor, replacement of all feeders, refurbishment of the existing fuel handling equipment, refurbishment of the existing turbine generators, refurbishment of the existing steam generators, and a set of supporting refurbishment projects aligned with existing station systems. The project will involve numerous third-party vendors and the coordination of multiple scopes of work, all within the highly regulated and safety-conscious environment of a nuclear facility. In addition, the Canadian marketplace for nuclear construction firms is limited, increasing the risks related to vendor management and performance.

The inherent risks related to an undertaking of the DRP's magnitude are significant. As noted in the construction industry handbook "Industrial Megaprojects: Concepts, Strategies, and Practices for Success:"

> *As the projects have increased in size and complexity, they have become much more difficult to manage. Cost overruns, serious slips in completion schedules, and operability problems have all become more common.*[34]

The Company does employ robust risk mitigation strategies related to the DRP. For instance, the LTEP requires adherence to risk-mitigating principles that include off-ramps[35] and all major

31 Amounts shown are for SCANA Corporation's 55% share in the V.C. Summer plant only. Sources: "Costs and Deadlines Continue to Challenge V.C. Summer Nuclear Plant Project," Power, August 19, 2015. SCANA Corporation SEC Form 10-Q for the period ended September 30, 2015.

32 Amounts shown are for Southern Company's 45.7% share in the Vogtle plant only. Sources: "No new cost overruns at Vogtle nuclear plant," Times Free Press, September 3, 2015. Southern Company SEC Form 10-Q for the period ended September 30, 2015.

33 OPG, 2015 Consolidated Financial Statements, at 7.

34 Merrow, Edward W., "Industrial Megaprojects: Concepts, Strategies, and Practices for Success," John Wiley & Sons, Inc., 2011, at 12.

35 Ontario's Long-Term Energy Plan, December 2013, at 29.

contracts executed by OPG for the DRP contain suspension and termination provisions.[36] In general, OPG has approached the project strategically and methodically, including performing numerous front-end loading activities to plan and prepare for the DRP, such as completion of detailed designs and construction of a full-scale model training reactor. In addition, the recent changes to O. Reg. 53/05 provide some reduction to future recovery risk by establishing the overall need for the DRP in the regulatory context.[37] However, notwithstanding the above, in Concentric's opinion, significant inherent risks associated with the DRP remain. These risks cannot be fully offset by mitigation strategies.

Importantly, there is no model of a successfully implemented commercial strategy for OPG to follow with regard to the DRP, as prior CANDU refurbishments have encountered significant challenges. As demonstrated by those prior projects, project schedules can slip, outage durations can be different than expected, and there are risks related to the performance and output of the nuclear facilities post-refurbishment. In addition, while OPG has carefully planned its commercial and contracting strategies for the DRP, the Company does remain at risk related to the performance of project contractors and suppliers. Lastly, the size and schedule length of the DRP are subject to changes in economic, regulatory, and political assumptions underlying the project, putting the Company at risk of not recovering its full investment.

In addition, as discussed in further detail below, OPG also faces an increase in risk related to its rate-setting proposal for prescribed nuclear facilities. That proposal, and in particular its revenue deferral elements, is driven in part by the overall anticipated size and cost of the DRP.

Apart from the DRP, OPG also faces increased risks due to degradation of Darlington's primary heat transport pump motors. Failure of the motors could lead to unexpected downtime and loss of generation from Darlington. While the Company has started to replace and/or refurbish the motors, the risks related to their degradation will persist until the replacement program is completed.

---

[36] OPG, 2015 Consolidated Financial Statements, at 21.
[37] Ontario Regulation 53/05, Payments under Section 78.1 of the Act, as amended on January 1, 2016.

B. Pickering

OPG has announced its intention to pursue extension of Pickering operations beyond 2020 to 2024, and has received the Government of Ontario's approval to do so.[38] Specifically, OPG plans to operate all six operating Pickering units until 2022, at which point two units would be shut down, and the remaining four units would operate through 2024. Approval from the Canadian Nuclear Safety Commission ("CNSC") is also required, expected through a relicensing process in 2017/2018, as is approval by the OEB for cost recovery of the cost and production impacts. Incremental OM&A expenses of approximately $300 million and additional outage days reducing production will be required during the upcoming rate period, through 2020, to enable extended Pickering operation. OPG's current operating license for the Pickering station expires on August 31, 2018, and OPG is required to notify the CNSC by June 30, 2017 of the end date of commercial operation for all operating Pickering units. There are risks associated with the re-licensing of the units to the end of the planned extended operation period.

Risks associated with OPG's plans for Pickering extended operations principally include the risk that there is a future determination that extended operation of the plant is not feasible, if, for instance, it is determined that the fuel channels (the life limiting components of a CANDU reactor) or another major component or system cannot support operations through 2024. If Pickering were to cease operation before 2024, OPG may be at risk for recovery of the expenditures incurred to enable extended operation and for foregone production. The main risk reducing factors include the fact that, through extended operation, OPG has more time to plan for the eventual retirement of the plant, and the additional cash flow to the Company from continued Pickering generation during the DRP period.

Life extension at Pickering puts OPG much in the same situation that it faced as of EB-2013-0321 in terms of the planned remaining operational life of the facility. Namely, as of EB-2013-0321, OPG was planning to retire Pickering in 2020 (*i.e.*, approximately seven years hence), a timeframe similar to what the Company is planning for now. However, Pickering is now older than it was as of EB-2013-0321, which increases reliability concerns including potential discovery of unexpected conditions and increases risks related to production loss and revenue recovery. In fact, no other CANDU plant has operated as long as the planned life of Pickering. These factors indicate that, on balance, risks related to Pickering operations have increased since EB-2013-0321.

C. Nuclear Regulation and Safety Requirements

The nuclear industry is in an unprecedented era related to the introduction and required implementation of new safety requirements. This era was launched by the earthquake and tsunami that affected Japan on March 11, 2011, causing significant damage to the Fukushima Daiichi nuclear complex. The safety requirements are likely to continue to impact the nuclear industry, both internationally and in Canada. In addition, such regulations and safety requirements are not limited to earthquake protection at nuclear plants, but also include such factors as security enhancements, storage of spent fuel, fire protection, and cybersecurity. As the Chief Nuclear Officer at U.S. utility Xcel Energy recently stated in testimony before the Minnesota Public Utilities Commission:

---

[38] OPG Press Release, "OPG Ready to Deliver Refurbishment of Darlington Nuclear Station; OPG also Planning Continued Operation of Pickering Station," January 11, 2016.

> *It is important to recognize that the nuclear industry (including Xcel Energy) is in the heart of the biggest regulatory implementation of NRC rules ever witnessed… These rules translate into mandated compliance work for us resulting from the incident at Fukushima (including flooding and seismic analysis), fire protection, used fuel storage, plant security, and "hardening" the grid for protecting both the regional system and our plants.*[39]

Specific to the nuclear industry's response to the accident at Fukushima, SNL Financial noted in a recent article that the "work is hardly done" with regard to the implementation of Fukushima-related measures.[40] The article further cited a representative from the U.S. Nuclear Energy Institute, an industry policy organization, as stating that cost estimates to respond to new NRC rules are "hard to predict [or make] an educated guess at this point."[41]

In Canada, there is similar uncertainty with regard to the final size, scope, and timing of plant modifications, design changes, and licensing/regulatory requirements to maintain compliance with the industry's reaction to Fukushima and other safety and regulatory requirements. While the CNSC has made its recommendations for changes in the industry and closed out its Fukushima-related action items for OPG specifically, the risk remains for additional requirements as the CNSC evaluates nuclear plant owners' implementation of their Fukushima-related projects and adopts any additional safety standards being developed in the industry, both in Canada and internationally. Examples of recent evolving requirements of the CNSC include new hold points on pressure tubes, a requirement for multi-unit probabilistic safety assessments, and a requirement to distribute potassium iodide pills to residents in proximity of nuclear facilities.

D. Conclusion Regarding Nuclear Facilities

Concentric's opinion is that the operational business risks related to OPG's prescribed nuclear facilities have increased since EB-2013-0321, and will continue to increase over the 2017-2021 period. In particular, the risks posed by the DRP, plans for extended Pickering operation, increasing risks associated with degradation of aging station components, and the nuclear industry's evolving response to increasing safety and regulatory requirements subject the Company to both heightened cost and generation related risk. The risks related to the Company's anticipated rate proposals in the upcoming rate proceeding, which further contribute to higher overall business risk, are discussed in a later section.

---

39 Direct Testimony and Schedules of Timothy J. O'Connor before the Minnesota Public Utilities Commission, In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota, November 2, 2015.

40 SNL Financial, "NRC prepares to vote on 'centerpiece' of post-Fukushima nuke plant regulations," August 17, 2015.

41 *Ibid.*

GENERATION MIX

With the expansion of OPG's regulated nuclear business due to the DRP, nuclear generation is projected to comprise a comparatively larger portion of OPG's overall regulated rate base. As previously noted, the Board has recognized that nuclear assets are higher in risk than hydroelectric assets. The relative increase in nuclear assets as a percentage of rate base by the end of the upcoming rate period to 2021 indicates that, all else being equal, OPG will become more risky over time.

Specifically, the Company's prescribed generation mix is projected to change over the 2017-2021 period, with a significant increase in nuclear rate base since EB-2013-0321 due in large part to the DRP, as shown in Figure 1. OPG's hydroelectric business risk level will remain relatively the same over the upcoming rate period, other than the transition to a five-year IR plan, while nuclear risks are expected to increase on a number of fronts.

In support of its findings in EB-2013-0321 that OPG's business risk had changed between EB-2010-0008 and EB-2013-0321, the Board cited the "increase [in the] proportionate share of rate base related to hydroelectric facilities from about half to approximately two-thirds now [*i.e.,* as of EB-2013-0321],"[42] while noting that the "relative business risk of hydroelectric generation versus nuclear has been accepted by the Board as being lower in previous proceedings."[43] By the end of the upcoming rate period, nuclear rate base is projected to be 51% of OPG's total prescribed generation rate base, as compared to 24% at the end of the current rate period (for reference, nuclear rate base comprised less than 40% of total prescribed rate base during the period in which OPG's deemed equity ratio was 47%). By the end of 2026, OPG estimates its nuclear rate base to be approximately 64% of total generation rate base, significantly higher than any time following the inception of OEB's regulation of OPG in 2008. This, coupled with the increase in nuclear-specific risks discussed above, indicates an increase in OPG's overall business risk level for its regulated operations, which Concentric concludes supports an increase in OPG's deemed equity thickness.

OPG'S RATE PROPOSALS[44]

Since April 1, 2008, OPG has operated under cost-of-service regulation, which is the traditional framework under which regulated utilities' rates are set. Under cost of service regulation, rates are set on the basis of a defined forward-looking test period, typically one or two years. Rates are not set again until the next rate case, in which the cost of service is re-established based on current conditions and forecasts. If costs begin to or are forecast to materially change from levels established in the last rate case, a new rate proceeding provides the opportunity to reflect those changes. There will, however, be regulatory lag until costs are adjusted, thereby affecting the utility's cash flows and earnings (positively or negatively) during this interim period, subject to any authorized deferral and variance accounts.

42 EB-2013-0321, Decision with Reasons, at 113.

43 *Ibid*.

44 Concentric's analysis of regulatory risk assumes continuation of all applicable existing Deferral and Variance accounts for both OPG's prescribed hydroelectric and nuclear facilities during the 2017-2021 period, as planned as part of OPG's rate proposal. Business risk for OPG would be higher than currently assumed by Concentric if some of these accounts are not approved.

Some regulators have approved incentive regulation mechanisms or performance-based regulation ("PBR") plans, which, to various degrees, decouple the setting of rates/revenue from utilities' costs. Concentric is of the view that IR and PBR frameworks can create additional risk for utilities. In its "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach," the Board expressed a view that "[PBR] provides the utilities with incentive for behaviour which more closely resembles that of competitive, cost-minimizing, profit-maximizing companies."[45] Competitive companies are subject to a greater amount of risk than traditionally rate-regulated companies, in that competitive companies bear the incremental risk of profits significantly declining from expected levels, while having a greater opportunity to accrue profits that are over and above expectations. Those companies generally have lower credit ratings than OPG and higher costs of capital.

In assessing regulatory risk for the utilities sector, DBRS has indicated that it views incentive regulation as higher risk than cost-of-service regulation. This is consistent with Concentric's opinion regarding OPG's planned rate proposals. In addition, DBRS considers the length of an incentive regulation period, and assigns higher risk to longer incentive regulation mechanism periods.[46] Figure 3 shows how DBRS assigns rankings based on the method of rate regulation (*i.e.*, cost of service vs. incentive regulation).

Figure 3: DBRS Ranking Criteria: Cost of Service vs. Incentive Regulation[47]

Score	Item	Definition
Excellent	Cost of Service	• COS regime allowing utilities to recover prudently and reasonably incurred operating costs
Good	IRM (3 years or shorter)	• IRM regime with maximum three years between the COS years • For an IRM period of more than three years, there are reasonable mechanisms in place to mitigate unexpected capital investment and operating costs. In addition, key IRM assumptions, including CPI and productivity factors, are reasonable
Satisfactory	IRM (4-5 year framework)	• The IRM period is four to five years
Below Average	IRM (6-10 year framework)	• The IRM period is six to ten years
Poor	IRM (10+ years)	• The IRM period is over ten years

In this proceeding, based on the Board's expectation, OPG plans on making key ratemaking proposals that, if accepted by the Board, will have material effects on the Company's risk profile. Specifically, for the prescribed hydroelectric facilities, OPG expects to propose an incentive

45 Report of the Board, "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach," October 18, 2012, at 10, citing RP-1999-0034, Decision with Reasons, January 18, 2000.
46 DBRS, "Methodology: Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry," October 2015, at 13.
47 *Ibid*.

regulation plan based on a price cap index with coverage of both capital and OM&A. The incentive regulation plan will be proposed for a term of five years (2017-2021) and does not include a proposal to rebase costs in 2017. As a result, costs last approved by the OEB in 2014 will provide the basis for OPG's payment amounts through 2021. Under the proposed hydroelectric IR plan, OPG will be exposed to the risk that costs deviate from the price cap over the five-year rate period. In addition to the decoupling of revenues from costs, the hydroelectric IR plan will differ from OPG's traditional regulatory framework in that rates will be established for a five-year period, whereas, OPG's cost of service rates have traditionally been set for significantly shorter periods of time (two years or less).

For the prescribed nuclear facilities, the Company plans to propose a five-year Custom Incentive Regulation plan. OPG is aligning its proposal with the principles of the Renewed Regulatory Framework as required by the OEB in its letter of February 17, 2015.[48] The proposal is expected to include all of OPG's nuclear costs and forecast production, with an additional stretch factor reduction in certain elements of OPG's forecast revenue requirement to provide additional incentives for cost performance improvements.

OPG is also planning a rate smoothing proposal that involves deferring recovery of a substantial portion of the OEB-approved revenue requirement until after the end of the DRP in a Rate Smoothing Deferral Account established by O.Reg. 53/05, which will track the difference between the Board determined smoothed payment amount and OPG's Board-approved revenue requirement. OPG's rate-setting proposal is expected to be for a five-year (2017-2021) period. OPG also plans on requesting a mid-term review to identify any forecast changes in production and related fuel costs for the period July 1, 2019 to December 31, 2021. Differences between the applicable forecast approved by the OEB in the upcoming proceeding and such forecasts for the period July 1, 2019 to December 31, 2021 approved by the OEB during the mid-term review would be recorded in a proposed variance account. Like the proposed hydroelectric IR plan, OPG's proposed rate-setting plan for the prescribed nuclear facilities will expose the Company to incremental risks related to costs deviating from expectations for longer periods than its historical two-year cost of service-based rate plans as well as risks in achieving the additional stretch factor reduction in the revenue requirement.

Consistent with DBRS' findings regarding the increased level of risk a utility faces with relatively longer incentive rate plans, discussed above, OPG's planned five-year rate-setting proposals expose the Company to material incremental risk relative to the two-year cost-of-service rate periods established in EB-2007-0905, EB-2010-0008 and EB-2013-0321.

FINANCIAL RISK

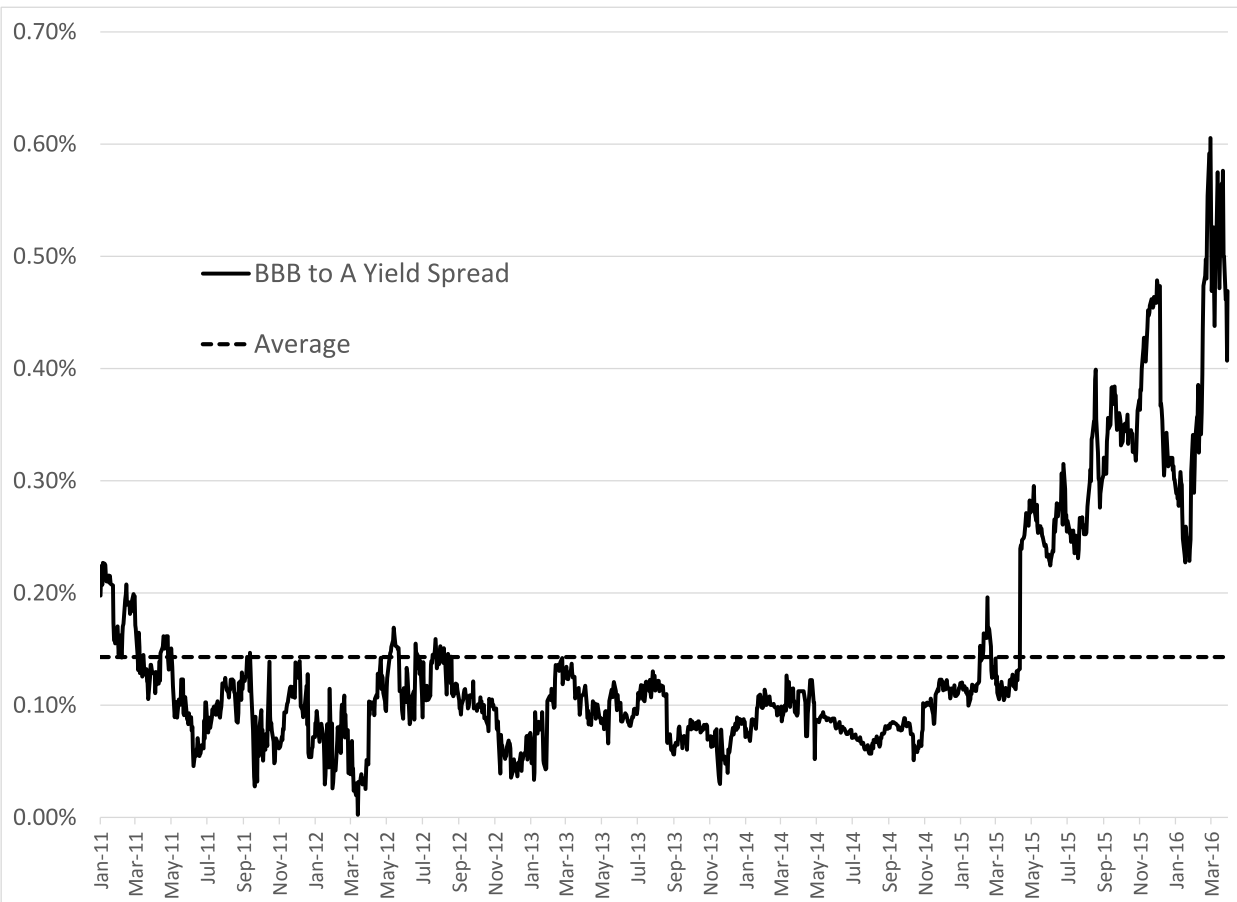
Financial risk refers to the amount of debt in the utility's capital structure and the extent to which fixed debt obligations must be met before utility shareholders receive their returns. Financial risk also relates to a utility's ability to access capital and the effect of management and regulatory decision-making on a utility's credit profile. In developing an assessment of a regulated utilities' financial risk profile, credit rating agencies view financial risk as an important consideration. Specifically, S&P states:

48 The Board expects OPG to develop an IR framework for its hydroelectric assets, and a custom IR framework for its nuclear assets based on the principles outlined in the RRFE.

> *The financial risk profile is the outcome of decisions that management makes in the context of its business risk profile and its financial risk tolerances. This includes decisions about the manner in which management seeks funding for the company and how it constructs its balance sheet. It also reflects the relationship of the cash flows the organization can achieve, given its business risk profile, to the company's financial obligations. The criteria use cash flow/leverage analysis to determine a corporate issuer's financial risk profile assessment.*[49]

Having adequate cash flows to support or improve a utility's credit rating benefits all utility stakeholders. There is a direct link between a utility's credit rating and its cost of borrowing, as well as its ability to access capital in difficult financial settings. Figure 4, below, provides the historical spread between A-rated and BBB-rated Canadian utility bonds, which on a 30-day average basis is currently above 50 basis points (*i.e.*, 0.50%), well in excess of the five-year average.

Figure 4: Spread between Canadian BBB and A Utility Bond Yields



The magnitude of the DRP, with $12.8 billion in capital expenditures, will pose significant risks to OPG's ability to earn its authorized return and maintain credit metrics that support the Company's credit rating over the short to medium term. In particular, OPG's credit metrics are expected to be

49 Standard & Poor's Ratings Services, "Corporate Methodology," November 19, 2013, at 3.

under pressure during the execution of the DRP as a result of reduced nuclear generation, elevated capital expenditures for the refurbishment, deferral of collection of a portion of the approved revenue requirements under nuclear rate smoothing, and resulting higher debt levels and the potential need for additional external financing. For example, in its July 2015 report downgrading OPG from A- to BBB+, S&P stated:

> *We expect the Company to continue with a number of projects that require significant capital spending, about C$1.6 billion per year, over the next two years including the Darlington nuclear facility refurbishment plus the additional maintenance capital expenditures, which pressures the credit metrics. We forecast adjusted funds from operations (AFFO)-to-debt of 14%-16% for each of 2015 and 2016 before dropping to about 13% in 2017, when the Darlington refurbishment project execution starts.*[50]

With respect to nuclear rate smoothing, the incremental increase in financial risk arises, in part, due to inherent uncertainty related to the collection of amounts deferred for a decade into the future. The other major risk with nuclear rate smoothing is the uncertainty associated with the smoothed payment amount level established during the DRP (both in the upcoming and future proceedings), which Concentric understands is at the OEB's discretion under O.Reg. 53/05. As such, the Company is exposed to a risk of lower than expected cash flow levels that could impact the Company's credit metrics, as well as its ability to meet long-term obligations, undertake capital expenditures and otherwise manage cash needs. Concentric notes that, according to OPG's 2016-2018 Business Plan, which also includes financial projections for the 2019-2021 period, the Company's credit metrics are under some pressure during the period to 2021 even assuming an 11% per year nuclear rate smoothing increase. According to the business plan, one of the two key credit metrics monitored by S&P (*i.e.*, the debt-to-EBITDA ratio) is projected to breach threshold levels in at least two years of the upcoming five-year rate period.

Another area of incremental financial risk for OPG relates to the recovery of its pension and OPEB costs, even assuming the continuation of the Company's Pension and OPEB Cost Variance account.[51] Specifically, in EB-2013-0321, the Board authorized OPG to recover its cash requirements for pensions and OPEBs, approving a pension and OPEB revenue requirement of $836.9 million compared to OPG's $1.3 billion proposed accrual-basis pension and OPEB costs. In doing so, the OEB also approved a deferral account to track the difference between cash and accrual based costs for pensions and OPEBs, but left the eventual disposition of the account uncertain.[52] The OEB noted the disposition of that account would be informed by the outcome of a future generic proceeding.[53] In EB-2031-0321, the OEB also left open the issue of whether to transition away from the accrual basis of recovery in the future, based on the outcome of the generic proceeding. On May 14, 2015,

---

[50] Standard & Poor's Ratings Services, "Ontario Power Generation Inc. Rating Lowered to 'BBB+' from 'A-' on Province of Ontario Downgrade; Outlook Stable," July 7, 2015, at 3.

[51] In EB-2013-0321, the OEB found that OPG's Pension and OPEB Cost Variance Account reduced the Company's forecast risk associated with pension and OPEB costs. As such, the risk mitigating properties of that account are already factored into OPG's current equity ratio (*i.e.*, 45%). Therefore, from the perspective of changes in OPG's risks since EB-2013-0321, continuation of that account or an equivalent account if the OEB includes Pension/OPEB costs in OPG's revenue requirement on a basis other than accrual in the upcoming proceeding would be risk neutral.

[52] EB-2013-0321, Decision with Reasons, at 88-89.

[53] The deferral account has enabled OPG to continue to record income for the period on an accrual rate recovery basis for pension and OPEB.

the OEB issued a letter opening a consultation on rate-regulated pensions and OPEBs, the objectives of which are to:

> *[D]evelop standard principles to guide the OEB's review of pension and OPEB costs in the future, to establish specific information requirements for applications that will be incremental to current filing requirements, and to establish appropriate regulatory mechanisms for cost recovery which can be applied consistently across the gas and electricity sectors for rate-regulated entities.*[54]

At the time of writing, the consultation is currently ongoing.

Based on the above, the Company is at risk of non-recovery for close to $450 million (*i.e.*, the cumulative forecast difference between the cash and accrual basis of accounting for pensions and OPEBs by the end of 2016).

In addition, as identified in the Company's initial written submission in the above consultation, OPG would face the potential of charging significant amounts to other comprehensive income related to the write-off of pension and OPEB-related regulatory assets if it is required to maintain the rate recovery of pension and OPEB expenses on a cash basis with no cash-to-accrual variance account. Moreover, if the Company is impeded in the future in its ability to recognize regulatory assets related to the timing differences between cash and accrual accounting for pension and OPEB costs, it would result in lower net income for a number of years, compared to the existing recovery methodology that includes a cash-to-accrual variance account. If that were to happen, it would weaken the Company's credit metrics and increase the financial risk of OPG.

Based on those two factors (*i.e.*, pressure on cash flows due to nuclear rate smoothing and the potential permanent switch to recovery of pension and OPEB costs on a cash basis), Concentric finds that OPG's financial risk level has increased since EB-2013-0321.

CONCLUSION REGARDING CHANGES IN BUSINESS AND FINANCIAL RISK SINCE EB-2013-0321

Concentric concludes that OPG's overall risk level will increase over the period 2017-2021 from its level as of EB-2013-0321, driven by business risks related to the DRP, pursuit of extended Pickering operation, increasing risks associated with degradation of aging nuclear station components, the implementation of incentive regulation, and changes in the Company's regulatory treatment, among other factors. Increased financial risks, including those arising from OPG's rate-setting proposal for its prescribed nuclear facilities and risks related to future recovery of Pension and OPEB accrual costs will negatively affect the Company's credit metrics, leading to additional financial risks relative to prior risk levels. Concentric's opinion is that an appropriate equity ratio for the Company exceeds the currently deemed ratio of 45% previously set by the Board prior to the EB-2013-0321 rate proceeding.

[54] May 14, 2015 letter from the Ontario Energy Board to Ontario's regulated utilities regarding "Consultation on the Regulatory Treatment of Pensions and Other Post-Employment Benefit Costs Board File Number EB-2015-0040."

SECTION 6:

COMPARATIVE ANALYSIS

In addition to assessing changes to OPG's business and financial risk profile since EB-2013-0321, Concentric has also analyzed the equity ratios of other utilities screened for risk characteristics similar to OPG's risk characteristics. A review of equity ratios authorized at similarly situated regulated utilities provides context for where, within a reasonable range, OPG's equity ratio should be set by the Board. Our analysis of comparable regulated utilities with significant regulated generation assets indicates that OPG's current equity thickness is low relative to comparable companies, despite OPG falling towards the upper end of the spectrum of risk profiles established by the proxy companies. The authorized equity ratios of the proxy companies range from 40.27% to 54.29%, with an average of 49.06% and a median of 49.95%.

USE OF PROXY COMPANY ANALYSIS IN MAKING COST OF CAPITAL DETERMINATIONS AND IN BENCHMARKING RISK

Analyses of comparable, or "proxy," companies is a common and well-accepted approach used in the determination of the cost of capital for regulated utilities and for benchmarking business and financial risks. Proxy groups are used for the following main reasons in cost of capital determinations: (1) adherence to the comparable investment standard; (2) since the cost of capital is a market-based concept, and given that OPG is not a publicly-traded entity, it is necessary to establish a group of companies that is both publicly traded and comparable to the Company in certain fundamental business and financial respects to serve as its "proxy" for purposes of the cost of capital evaluation process; and (3) even if OPG's regulated operations were held by a stand-alone publicly traded entity, it is possible that transitory events could bias its market-determined cost of capital in one way or another over a given period of time. A significant benefit of using a proxy group is its ability to mitigate the effects of anomalous events that may be associated with any one company.

Regulatory commissions and cost of capital analysts generally apply a set of screening criteria in order to define a risk-appropriate group of comparable companies. For instance, the Federal Energy Regulatory Commission ("FERC") provides the following summary of its practice for selection of a proxy group for electric transmission companies:

> ***Composition of the Proxy Group**: In this section we address the following issues concerning the proper methodology for developing a proxy group and calculating the zone of reasonableness: (1) the use of a national group of companies considered electric utilities by Value Line; (2) the inclusion of companies with credit ratings no more than one notch above or below the utility or utilities whose rate is at issue; (3) the inclusion of companies that pay dividends and have neither made nor announced a dividend cut during the six-month study period; (4) the inclusion of companies with no*

> *major merger activity during the six-month study period; and (5) companies whose DCF results pass threshold tests of economic logic.*[55]

While the individual screens require modification based on the subject company to which proxy companies are being compared,[56] the goal of screening companies based on their risk characteristics increases both the comparability of the group and the confidence the analyst can have in drawing conclusions based on analyses of the proxy group. Therefore, for consistency with the above considerations, Concentric relied on a screening process similar to that we typically apply in cost of capital analyses to narrow the list of potential companies in order to establish a proxy group of electric utility companies that are risk appropriate for comparison to OPG.

Given the unique characteristics of OPG, and, in particular, the fact that its regulated operations consist of 100% generating assets, it is not possible to find proxy companies that are perfectly comparable from a risk perspective. Therefore, even within a group of similarly situated companies, it is common for analytical results to reflect a seemingly wide range.

At issue, then, is how to determine an appropriate equity ratio in the context of that range. That determination must be based on an assessment of the company-specific risks relative to the proxy group and the informed judgment and experience of the analyst. As such, it is incumbent on the analyst to apply judgment to determine where, within a range of equity ratios determined by use of a proxy group, the subject company (in this case, OPG), falls. For example, the NEB, in discussing the cost of capital for the TransCanada Mainline, stated, "[t]o the greatest extent possible, comparable companies have to face similar business risk as the Mainline. If they do not, judgment needs to be applied to the cost of capital estimates to reflect business risk differences."[57] In other words, whereas a subject company of average risk relative to the proxy group could warrant an equity ratio equal to the average or median result of the proxy group, a company of greater risk could warrant an equity ratio above the mean or median result, and a company of lower risk could warrant an equity ratio below the mean or median result.

In summary, the use of comparable companies to benchmark business and financial risks in the context of cost of capital determinations is a common practice among North American regulatory jurisdictions, and it is a method Concentric has applied to our evaluation of OPG's capital structure. In the discussion that follows, we present Concentric's analysis of OPG's level of business and financial risk relative to a proxy group of electric utilities, as well as our review of equity ratios authorized for the proxy group to provide context for where, within a reasonable range, OPG's equity ratio should be set by the Board.

---

55 Opinion No. 531, *Order on Initial Decision*, 147 FERC ¶ 61,234 (June 19, 2014), at 44-45.

56 For instance, the FERC applies a screen for the inclusion of master limited partnerships ("MLPs") in natural gas pipeline proxy groups that the MLPs derive at least 50% of operating income from, or have 50% of their assets devoted to, interstate operations (*see*, Opinion No. 510, *Portland Natural Gas Transmission System*, 134 FERC ¶ 61,129 (February 17, 2011), at 62.

57 National Energy Board RH-003-2011 Reasons for Decision, TransCanada PipeLines Ltd, NOVA Gas Transmission Ltd., and Foothills Pipe Lines Ltd., March 2013, at 165.

SELECTION OF PROXY COMPANIES

As a starting point for our screening process, Concentric reviewed data related to both Canadian and U.S. utilities, including the following Canadian utilities: Canadian Utilities Limited, Emera Inc. ("Emera"), Enbridge Inc., Fortis Inc. ("Fortis"), and TransCanada Corporation, and the 46 U.S. companies that Value Line classifies as "Electric Utilities".[58]

From that group, Concentric screened for companies that:

1. **Own regulated generation assets that are included in rate base**. As it relates to the rate setting process, OPG's assets represent 100% rate-regulated generation. As such, it is important to exclude companies from the proxy group that bear no risks related to regulated generation. The reason for this is the generation function is generally regarded by investors as being higher risk than electric transmission or distribution. As stated by Moody's Investors Services in its 2013 ratings methodology for regulated electric and gas utilities, "[w]e view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays;"[59]
2. **Own regulated nuclear and/or hydroelectric generation**.[60] As noted earlier, OPG's rate regulated facilities consist of the Pickering and Darlington nuclear stations, as well as 54 hydroelectric generating stations. In addition, as previously noted, the Board has recognized that nuclear assets are higher in risk than hydroelectric assets. Therefore, it is important to compare OPG against a group of companies that also own regulated nuclear and/or hydroelectric generation facilities.
3. **Have regulated revenue and regulated net income that make up greater than 60% of total revenue and total income for the consolidated company**. This screen, in combination with the screen below regarding electric revenue and net income, serves to exclude companies that do not derive a significant portion of their financial results from regulated, electric operations. While rates in this proceeding are being set for OPG's 100% rate-regulated operations, these two screens are set at levels below 100% so that the resulting proxy group is not unduly small. Including only those companies that derive more than 60% of their revenues and net income from regulated operations ensures that the proxy companies are protected by regulation rather than being subject to substantial merchant or market-related risks. While 60% is not a "bright line" percentage for separating regulated from non-regulated companies, in Concentric's experience, using a screening criteria of around 60% increases the comparability of the proxy group to the regulated utility without unduly limiting the size of the group;

---

58 Precedent for the consideration of U.S. proxy companies in Canadian cost of equity analyses is discussed in Appendix A.
59 Moody's Investors Services, Rating Methodology: Regulated Electric and Gas Utilities," December 23, 2013, at 23.
60 Excludes utilities with only a minimal (*i.e.*, less than 5% of their total generation portfolio) amount of nuclear or hydroelectric generation.

4. **<u>Have regulated electricity revenue and net income that make up greater than 80% of revenue and income for the consolidated company's regulated operations</u>**. Including only those companies that derive more than 80% of their regulated revenue and net income from regulated electric operations ensures that the proxy companies, like OPG, derive the predominant share of their revenues and operating income from their regulated electricity segments. Similar to the regulated revenue and net income screen, the 80% regulated electric revenue and net income screen is not a "bright line," but rather balances the comparability of the proxy group with its overall size; and

5. **<u>Have an investment grade credit rating similar to that of OPG</u>**. As noted earlier, OPG has an "A (low)" issuer and unsecured debt rating from DBRS, and a "BBB+" corporate credit rating from S&P. In addition, as noted earlier, S&P rates OPG as "BBB-" (*i.e.*, two notches below its "BBB+" corporate credit rating) on a stand-alone basis, before consideration of support by the Province. Credit ratings are based on the utility's business risk profile (which includes an assessment of the regulatory environment in which the utility operates) and its financial risk profile. Companies with similar credit ratings have been determined by the rating agency to have similar levels of business and financial risk. This concept has been adopted by regulatory agencies, including the FERC, which has found that "it is reasonable to use the proxy companies' corporate credit rating as a good measure of investment risk, since this rating considers both financial and business risk."[61] Concentric's credit rating screen selects electric utility companies with investment-grade credit ratings. Selecting a proxy group of similar risk electric utility companies with investment-grade credit ratings minimizes the need to adjust the results to account for perceived differences in business or financial risk between those companies and OPG. Further, selecting proxy companies that, like OPG, have an investment grade credit rating (an S&P credit rating of BBB- or above or a Moody's credit rating of Baa3 and above) ensures that the proxy companies are generally in sound financial condition. Because credit ratings take into account business and financial risks, the ratings provide a broad measure of investment risk that is widely referenced by investors.

None of the publicly traded Canadian companies that Concentric reviewed met all of our screening criteria. Emera, however, only failed the screen that each utility should have more than a minimal amount of regulated hydroelectric and/or nuclear generation. Fortis, Inc. ("Fortis") only failed the screens that each utility should have regulated electricity revenue and net income that make up greater than 80% of the consolidated company's regulated operations and that each utility should have more than a minimal amount of regulated hydroelectric and/or nuclear generation. Specifically, Emera currently owns no regulated hydroelectric or nuclear generation, and Fortis has 63% regulated electricity revenue and 62% regulated net income, while only owning a minimal amount of regulated hydroelectric generation (and no nuclear generation). In order to broaden the proxy group to include at least a minimal number of Canadian utilities, Concentric included Emera and Fortis in the proxy group, as they otherwise meet our screening criteria. Figure 5 presents the eighteen U.S. companies that met our screening criteria, along with OPG and the two Canadian companies noted above. In addition to the company name, Concentric also provides the S&P rating,

61 See, for example, Potomac-Appalachian Transmission Highline, LLC, 122 FERC ¶ 61,188 (2008), at 97.

as well as S&P's business risk and financial risk rating summary for each company. Exhibit 1 details how each proxy company meets the screening criteria above.

Figure 5: North American Electric Utility Proxy Group and OPG

Company	Ticker	S&P Ratings Summary – Credit Rating/ Outlook	S&P Ratings Summary – Business Risk	S&P Ratings Summary – Financial Risk
OPG	--	**BBB+/Stable**	**Strong**	**Aggressive**
ALLETE, Inc.	ALE	BBB+/Stable	Strong	Significant
Ameren Corporation	AEE	BBB+/Stable	Excellent	Significant
American Electric Power Company, Inc.	AEP	BBB/Positive	Strong	Significant
Duke Energy Corporation	DUK	A-/Negative	Excellent	Significant
Edison International	EIX	BBB+/Stable	Excellent	Significant
El Paso Electric Company	EE	BBB/Stable	Strong	Significant
Emera Inc.	EMA	BBB+/Negative	Excellent	Aggressive
Entergy Corporation	ETR	BBB/Positive	Strong	Significant
FirstEnergy Corporation	FE	BBB-/Stable	Strong	Significant
Fortis Inc.	FTS	A-/Stable	Excellent	Significant
Great Plains Energy Inc.	GXP	BBB+/Stable	Excellent	Significant
IDACORP, Inc.	IDA	BBB/Stable	Strong	Significant
NextEra Energy, Inc.	NEE	A-/Stable	Strong	Intermediate
PG&E Corporation	PCG	BBB/Positive	Strong	Significant
Pinnacle West Capital Corporation	PNW	A-/Stable	Excellent	Intermediate
PNM Resources, Inc.	PNM	BBB+/Stable	Strong	Significant
Portland General Electric Company	POR	BBB/Stable	Strong	Significant
Southern Company	SO	A-/Negative	Excellent	Significant
Westar Energy, Inc.	WR	BBB+/Stable	Excellent	Significant
Xcel Energy Inc.	XEL	A-/Stable	Excellent	Significant

RISK ANALYSIS

In order to evaluate the comparability of the proxy group companies, Concentric has examined the business risks of each operating company relative to those of OPG. The purpose of this evaluation was to determine the extent to which the companies in the proxy group have similar risk profiles to OPG (indicating that OPG is of average risk, compared to the proxy group), or are more or less risky than OPG (indicating a need to potentially establish a proxy-based capital structure for OPG that is above or below the mean and median of the group).

A. Business Risk

As noted previously, business risk for a regulated utility results from variability in cash flows and earnings that impact the ability of the utility to recover its costs including a fair return on, and of, its capital in a timely manner. Concentric includes operating risk and regulatory risk under this broad definition of business risk. For purposes of this report, Concentric has focused on four primary business risks:

i. Operational profile;

ii. Generation percentage and mix;

iii. Capital expenditures; and

iv. Cost recovery risk.

i. Operational Profile

Concentric examined the operations and financing of each of the companies in the proxy group. Exhibit 2 provides a summary of several relevant indicators for the proxy group companies, including: (1) the province or state in which the utility provides service; (2) the S&P credit rating for the parent company; (3) the most recent deemed equity ratio for the operating company; and (4) regulated electricity revenues for the most recent year available. Exhibit 3 provides a summary of the various cost recovery mechanisms in place at the operating subsidiaries of the proxy group companies, including automatic adjustment clauses, cost trackers and variance accounts.

ii. Generation Percentage and Mix

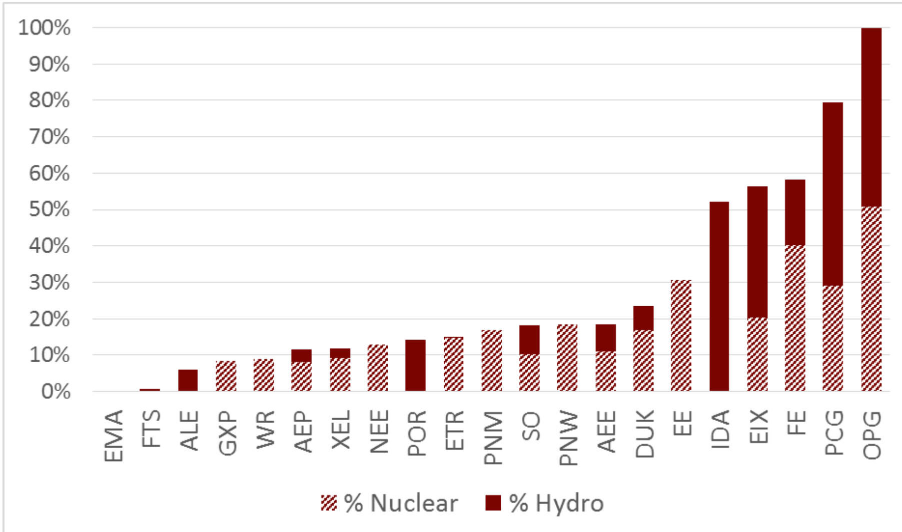
Concentric analyzed the generation percentage and mix of each proxy company to assess the percentage of each company's assets that is generation, and further, the percentage of generation capacity that is comprised of nuclear generation. As shown in Figure 6, OPG is the only company in the proxy group that is a pure-play regulated generation company. As discussed above, the investment community generally considers the generation function to be higher risk than other regulated electric operations.

Figure 6: Generation versus Transmission and Distribution Assets

In addition, Figure 7 demonstrates that OPG has the greatest percentage of nuclear generation plant in relation to total generating assets of any company in the proxy group. Only one company (*i.e.,* FirstEnergy Corporation ("FE")) comes close, but this is effectively offset, from a risk perspective, by ownership of transmission and distribution ("T&D") assets (*see*, Figure 6). In EB-2013-0321, the Board stated, "the business risk is reduced because of the addition of significant hydroelectric assets to rate base, which are less risky than nuclear assets."[62] Based on this assessment that nuclear assets are more risky than hydroelectric assets (and the investment community's view that generation, in general, is the riskiest business segment for a regulated utility), Concentric concludes that OPG is more risky than the proxy companies because of its nuclear generation concentration, as well as its overall concentration in generation in relation to lower risk T&D assets. In addition, while OPG has a high relative concentration of hydroelectric assets, other companies in the proxy group also have significant proportions of the generation mix in hydroelectric assets, with certain proxy companies such as IDACORP, Inc. ("IDA"), and to a lesser extent Portland General Electric Company ("POR"), and ALLETE, Inc. ("ALE"), being concentrated in that area.

62 EB-2013-0321, Decision with Reasons, at 114.

Figure 7: Generation Mix (MW), Percentage Hydro and Nuclear Generation[63]

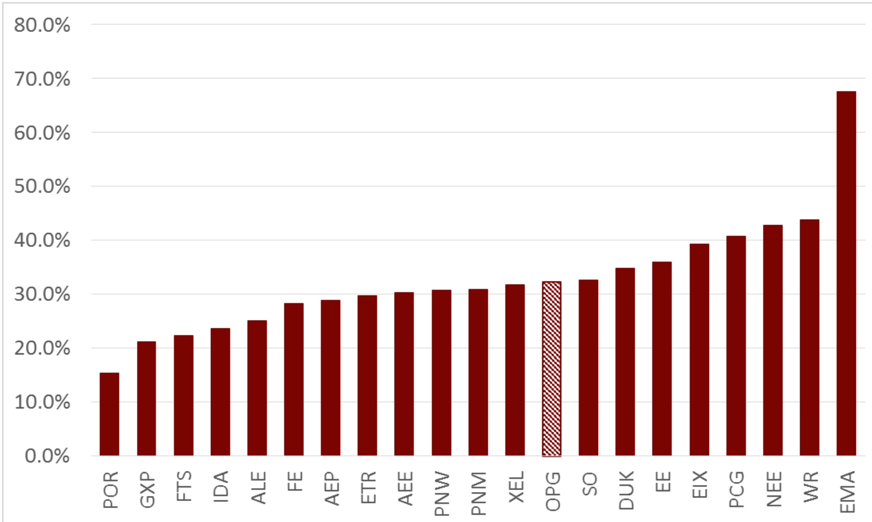


iii. Capital Expenditures

OPG is projecting a substantial investment in the future generation capacity of the province and will require continued access to capital on reasonable terms in order to finance this investment and maintain the Company's current investment grade credit rating. Figure 8 displays forecast capital spending for the period from 2018-2020 as a percentage of net in-service utility PP&E as of December 31, 2014 (*i.e.*, the most recent consistently-available date for the proxy group) for each of the proxy companies and OPG. Before consideration of the entire scope of the DRP, OPG's forecast capital expenditure ratio of 32.3% is above the median forecasted capital expenditure ratio of 30.9% for the proxy group companies. However, consideration of the full scope of the DRP (which, as discussed in Figure 2, is estimated at 62% of the Company's net PP&E) would place OPG at the high end of the chart. Therefore, OPG has, at a minimum, somewhat more risk than these other companies on this factor. Once the DRP is accounted for, OPG's forecast capital expenditure plan puts it at even greater than average risk compared to the proxy group.

63 Based on regulated capacity owned.

Figure 8: Forecasted Capital Spending/ Net PP&E[64]



iv. Cost Recovery Risk

Exhibit 3 shows many of the deferral and variance accounts and riders used by each of the proxy companies as well as OPG. Some of OPG's main deferral and variance accounts include accounts related to certain changes in nuclear decommissioning and nuclear waste management liability, capacity refurbishment costs, variability in water flows, foregone hydroelectric production due to surplus baseload conditions, and certain changes in income taxes. As can be seen in the exhibit, the proxy group companies likewise have many accounts with similar risk-mitigating properties, and therefore, Concentric concludes that in this respect OPG is generally risk comparable to the proxy companies, assuming these accounts are authorized to continue in the upcoming proceeding. Should some of these accounts not continue, OPG's risk level may increase.

B. Financial Risk

In order to assess the financial risk of OPG relative to the proxy group, Concentric analyzed the allowed equity ratios for these companies. The proxy group average and median results are measures of central tendency for the proxy group from which inferences about a reasonable equity ratio can be made for OPG, after consideration of differences in risk profile between the Company and the proxy group. Specifically, the mean is "generally the best measure of central location for purposes of statistical inference,"[65] while also being at risk of being "unduly influenced by extreme observations."[66] The median, or middle point of a set of observations at which half of the set of observations are above it and half are below it, is not subject to the same distortion due to extreme

64 The U.S. capital expenditure and net plant data are calculated using Value Line data: capital spending per share and common shares outstanding. All U.S. forecasts are for the period 2018-2020. Canadian data were gathered from publicly available sources.

65 Keller and Warrack, Statistics for Management and Economics, 5e ed., Duxbury Thompson Learning, 2000, at 92.

66 *Ibid.*

observations.[67] Figure 9 summarizes the proxy group results in tabular format, and Figure 10 presents the results graphically.

Figure 9: Proxy Group Equity Ratios[68]

Company	Equity Ratio %
ALE	54.29
AEE	50.87
AEP	45.77
DUK	50.14
EIX	48.00
EE	NA
EMA	40.27
ETR[69]	46.27
FE	49.22
FTS	43.31
GXP	51.04
IDA	49.90
NEE	NA
PCG	52.00
PNW	53.94
PNM	45.00
POR	50.00
SO	49.09
WR	50.13
XEL	53.89
Proxy Average	49.06
Proxy Median	49.95
OPG[70]	45.00

67 *Ibid.*, at 93.

68 Represents a composite equity ratio for each holding company based on a weighting of each holding company's jurisdictional utility equity ratios. Equity ratios were weighted by total retail electric customers for each jurisdictional utility. Companies with an "NA" for an equity ratio are those for which the most recent rate case parameters were not provided and/or public information was not available via SNL.

69 Entergy Arkansas equity ratio adjusted to exclude zero cost capital items.

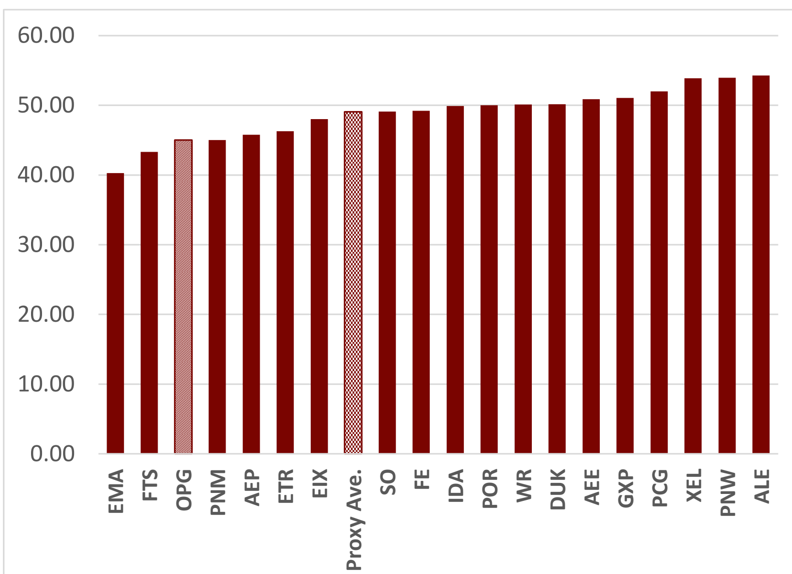
70 Nuclear amounts do not include the lesser of unfunded nuclear liabilities or unamortized asset retirement costs, which is consistent with the OEB-approved methodology for calculating OPG's rate base subject to the weighted average cost of capital for purposes of setting payment amounts.

As shown in Figures 9 and 10, OPG's deemed equity ratio is 45% as compared to the proxy average of 49.06% and median of 49.95%. OPG's deemed equity ratio is 4.06 percentage points below the proxy group average, 4.95 percentage points below the proxy group median, and the third lowest overall.

The two Canadian companies, Emera and Fortis, as well as two U.S. companies, AEP and PNM, have equity ratios close to OPG's, but these companies have substantial T&D assets to mitigate their generation risk. As discussed previously, generation assets are generally considered riskier from an investment perspective than T&D assets because generation assets typically have longer construction lead times, are subject to production risk and to risk from changes in environmental regulations and requirements, and are more subject to technological obsolescence. For example, in EB-2007-0905, the Board concluded: "OPG's nuclear business is riskier than regulated transmission and distribution utilities in terms of operational and production risk, but is less risky than merchant generation."[71] In that same decision, the Board also commented on the relative risk of generation as follows: "The Board has concluded that OPG is of higher risk than electricity LDCs, gas utilities and electric transmission utilities and of lower risk than merchant generation."[72]

Figure 6, presented earlier, provides the percentage of generation assets and T&D assets for OPG and the proxy group companies. As shown in that Figure, 100% of OPG's assets are dedicated to generation, while the proxy group companies have a mixture of generation assets and T&D assets. As discussed above, the Board has recognized that generation assets are typically considered riskier than T&D assets. On that basis, OPG has higher business risk than the proxy group companies, which suggests a higher deemed equity ratio is appropriate for OPG.

Figure 10: Proxy Company Allowed Equity Ratios[73]



With the lower deemed equity ratio of OPG compared to the proxy group companies, Concentric

71 EB-2007-0905, Decision with Reasons, November 3, 2008, at 149.
72 *Ibid.*
73 Represents composite equity ratio for each holding company based on weighting of jurisdictional equity ratios. Equity ratios weighted by total retail electric customers. Excluded companies for which most recent rate case parameters were not provided and/or public information was not available via SNL.

concludes that OPG has greater financial risk than the proxy group. Concentric also considers that OPG would be rated two notches lower than its corporate rating on a stand alone basis according to S&P. This point is underscored by the S&P rating of OPG's financial risk as "Aggressive". Only one other proxy group company, Emera, is rated Aggressive on financial risk. All others are rated better at "Significant" or "Intermediate" on financial risk, and one half of the companies also have better business risk ratings at "Excellent" by S&P, as illustrated in Figure 5. As a result, the risk profile of OPG suggests OPG's equity ratio should fall at the upper end of the proxy group.

COMPARATIVE ANALYSIS CONCLUSIONS

Based on the comparative analyses of business and financial risk, Concentric draws the following conclusions:

- OPG's generation mix is comprised of more nuclear generation than the proxy group, indicating that OPG is riskier than the group on this factor.
- OPG has an asset mix that is 100% generation in contrast to the proxy group companies with an average of 47%, making OPG a riskier business.
- OPG's capital expenditure forecasts are higher than average for the proxy group over the near-term, indicating that OPG is riskier than the group. In addition, when the full scope of the DRP is considered, OPG's ratio of capital expenditures to net PP&E will increase substantially, indicating even higher relative risk for the Company.
- OPG has several deferral and variance accounts for its operations, as do other proxy companies; therefore, the Company is considered to be risk comparable to the proxy group in this area.
- OPG's deemed equity ratio is lower than all but two other proxy companies, exposing OPG to more financial risk than the proxy companies.

On a relative risk basis, Concentric finds OPG, with its significant nuclear concentration, a pure generating company business profile, and the magnitude of its capital spending program, to fall towards the upper end of the spectrum of risk profiles established by the proxy companies, which have mean and median equity ratios between 49% and 50%. Therefore, Concentric believes the proxy group average equity ratio of approximately 49% provides a floor for the consideration of an appropriate equity ratio for the Company in the upcoming rate proceeding.

SECTION 6:

CONCLUSIONS AND RECOMMENDATIONS

The fair return standard requires that three standards for the cost of capital be met: (1) the comparable investment standard; (2) the financial integrity standard; and (3) the capital attraction standard. In addition, the Board has established that it will reassess a utility's capital structure when there have been significant changes in the company's business and/or financial risk. Concentric's analysis of changes to OPG's risk profile, as well as the relatively greater risk of OPG in relation to the proxy companies, indicates that OPG's current equity ratio of 45% no longer meets the fair return standard and is thus no longer adequate for the Company.

Concentric concludes that OPG's risk profile will change materially, and will specifically increase, over the 2017-2021 period as compared to its risk profile at the time of EB-2013-0321. Specifically, OPG's generation mix will change to reflect a significantly higher proportion of nuclear generation than when the Board set the common equity ratio at 45% in EB-2013-0321. By the end of the test period in 2021, nuclear rate base will exceed the relative level at which it stood when the Board set OPG's common equity ratio at 47% in EB-2007-0905 and EB-2010-0008. Given the Board's EB-2013-0321 finding that "[t]he business risk is reduced because of the addition of significant hydroelectric assets to rate base, which are less risky than nuclear assets,"[74] the opposite must hold equally true: business risk will have increased because of the addition of significant nuclear assets to rate base, which are more risky than hydroelectric assets.

In addition, while the operating risks of the hydroelectric business are generally expected to remain at current levels, they are expected to increase for the nuclear business in the 2017–2021 payment amount period. Finally, the increased forecasting risk and uncertainty related to the Company's planned five-year ratemaking proposal further increases the Company's business and financial risks. That finding is consistent with DBRS' assessment of the change in risk scores for utilities moving from cost-of-service regulation to incentive regulation. Furthermore, OPG's nuclear rate smoothing proposal, in conjunction with the significant cash flow requirements of the DRP, will put pressure on the Company's credit metrics and increase its financial risk. Thus, Concentric's opinion is that an appropriate equity ratio for the Company exceeds the deemed ratio of 45% set by the Board in the EB-2013-0321 rate proceeding.

The range of common equity ratios for comparable utilities is 40.27% to 54.29%, with the average equity ratio being 49.06% and the median being 49.95%. OPG's current equity ratio of 45% is on the low end of the comparable group, having the third lowest equity ratio despite its elevated level of risk relative to the proxy group. Specifically, with its significant nuclear concentration, as well as its status as the only company in the group that is a pure generating company, and its significant capital expenditure program, OPG falls toward the upper end of the risk spectrum. Thus, given OPG's elevated risk relative to the average level of risk faced by the proxy group, Concentric believes the proxy group average equity ratio of approximately 49% provides a floor for the consideration of an appropriate equity ratio for the Company in the upcoming rate proceeding.

In summary, given the Company's projected increase in risks since EB-2013-0321, the change in the nuclear to hydroelectric asset mix, the increase in OPG's risk level driven by uncertainty

[74] EB-2013-0321, Decision with Reasons, at 114.

surrounding the Darlington refurbishment project in particular, plans to pursue extended Pickering operations and the move to incentive regulation, as well as OPG's higher risk relative to comparable firms whose equity ratios average over 49%, Concentric recommends an equity ratio of no less than 49% be set in this proceeding.

APPENDIX A:

PRECEDENT FOR CONSIDERING U.S. DATA

There is precedent among Canadian regulators for considering U.S. data and a U.S. proxy group for cost of capital evaluations. In recent orders, other Canadian regulators have determined that it is appropriate to consider the use of U.S. data and U.S. proxy groups to estimate the allowed ROE for a Canadian regulated utility. Regulators in Canada have noted several reasons that support consideration of U.S. data. First, the development of a proxy group comprised entirely of Canadian electric utilities is difficult due to the small number of publicly-traded utilities in Canada and the fact that many of those Canadian companies derive a significant percentage of their revenues and net income from operations other than the provision of regulated electric utility service. Second, this problem has been exacerbated by the continuing trend toward mergers and acquisitions in the utility industry, both within Canada and across the border with U.S. utility companies. The question for Canadian regulators has become: How do we account for any differences in risk between U.S. and Canadian utilities? Concentric's research and analysis demonstrate that it is possible to select a group of U.S. electric utilities that is comparable to Canadian utilities in terms of business and operating risk. In that regard, Concentric agrees with the conclusion of the Board that it is not necessary to find that utilities are the same, only that they are comparable,[75] and with the NEB's conclusion that it is possible to account for differences in risk that would influence an investor's required rate of return.[76]

A growing number of Canadian utility regulators have accepted the use of U.S. data or U.S. proxy groups in recent years. For example, in its TQM Decision, the NEB found that U.S. market returns are relevant to the cost of capital for Canadian firms, and that the regulatory regimes in Canada and the U.S. are sufficiently similar as to justify comparison. The NEB appears to view U.S. market returns as valuable information in establishing the cost of capital for Canadian utilities. Moreover, the NEB found that Canadian utilities are competing for capital in global financial markets that are increasingly integrated. The NEB recognized that it is no longer possible to view Canada as insulated from the remainder of the investing world, and that doing so would be detrimental to the ability of Canadian utilities to compete for capital.[77] Importantly, the NEB also found that the regulatory regimes in the U.S. and Canada were sufficiently similar as to justify comparison between utilities in the two countries, stating:

> *The Board is not persuaded that the U.S. regulatory system exposes utilities to notable risks of major losses due either to unusual events or cost disallowances. The Board views the losses and disallowances experienced by U.S. regulated entities as a result of the restructuring that took place to terminate the merchant gas function of pipelines, as well as some other circumstances such as the Duquesne nuclear build, to be, to a large extent, unique events. The Board also finds that such instances are not likely to*

75 Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at 21.
76 National Energy Board, Reasons for Decision, TQM RH-1-2008 (March 2009), at 71.
77 *Ibid,* at 66-72.

> *weigh significantly in investors' perceptions today, and would thus have little or no impact on cost of capital.*[78]

Likewise, the OEB concluded that the U.S. is a relevant source of comparable data and that it often looks to the U.S. to inform its decisions:

> *The Board is of the view that the U.S. is a relevant source for comparable data. The Board often looks to the regulatory policies of State and Federal agencies in the United States for guidance on regulatory issues in the province of Ontario. For example, in recent consultations, the Board has been informed by U.S. regulatory policies relating to low income customer concerns, transmission cost connection responsibility for renewable generation, and productivity factors for 3rd generation incentive ratemaking.*
>
> *Finally, the Board agrees with Enbridge that, while it is possible to conduct DCF and CAPM analyses on publicly-traded Canadian utility holding companies of comparable risk, there are relatively few of these companies. As a result, the Board concludes that North American gas and electric utilities provide a relevant and objective source of data for comparison.*[79]

Finally, the British Columbia Utilities Commission ("BCUC") accepted the use of U.S. data, stating:

> *In addition, the Commission Panel continues to be prepared to accept the use of historical and forecast data of U.S. utilities when applied: as a check to Canadian data, as a substitute for Canadian data when Canadian data do not exist in significant quantity or quality, or as a supplement to Canadian data when Canadian data gives unreliable results. Given the paucity of relevant Canadian data, the Commission Panel considers that natural gas distribution companies operating in the US have the potential to act as a useful proxy in determining TGI's capital structure, ROE, and credit metrics.*[80]

The BCUC affirmed this position in its 2013 Generic Cost of Capital Decision:

> *The Commission Panel reaffirms the 2009 Decision determination on when to use historical and forecast data for US utilities. Canadian utilities need to be able to compete in a global marketplace and be allowed a return for them to do so. In addition, the Panel accepts that there continues to be limited Canadian data upon which to rely and considers that there may be times when natural gas companies operating within the US may prove to be a useful proxy in determining the cost of capital. Accordingly, we have determined that it is appropriate to continue to accept*

78 *Ibid.*
79 Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at 23.
80 British Columbia Utilities Commission, In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc., Return on Equity and Capital Structure, Decision G-158-09, December 16, 2009, at 16.

> *the use of historical and forecast data for US utilities and securities as outlined in the 2006 Decision and again in the 2009 Decision.*

And,

> *[I]n the view of the Commission Panel, the use of US data must be considered on a case by case basis and weighed with consideration to the sample being relied upon and any jurisdictional differences which may exist.*[81]

In summary, regulatory authorities in Canada have recognized that Canadian utility companies are competing for capital in global financial markets and that Canadian data are often limited by the small number of publicly-traded utilities. They have also recognized the integrated nature of Canadian and U.S. financial markets, and the similarity of the utility regulatory regimes. Therefore, they have determined that it is reasonable and appropriate to consider the results of a risk comparable U.S. proxy group for purposes of cost of capital analyses for a Canadian natural gas or electric utility. These findings suggest that it is reasonable and appropriate to consider a proxy group of U.S. utility companies as sufficiently comparable to Canadian regulated utilities in terms of their risk profile.

81 British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage I), Decision, May 10, 2013, at 20.

APPENDIX B:

Résumé and Testimony Listing of James M. Coyne

James M. Coyne
Senior Vice President

Mr. Coyne provides financial, regulatory, strategic, and litigation support services to clients in the natural gas, power, and utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, and matters pertaining to rate and regulatory policy. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. He has authored numerous articles on the energy industry and provided testimony and expert reports before the Federal Energy Regulatory Commission and numerous jurisdictions in the U.S. and Canada. Mr. Coyne holds a B.S. in Business from Georgetown University with honors and an M.S. in Resource Economics from the University of New Hampshire.

REPRESENTATIVE PROJECT EXPERIENCE

Expert Testimony Experience

- Vermont Gas Systems, Inc.: Before the Vermont Public Service Board, provided expert testimony on the cost of capital and business risk for the Company's gas distribution operations. (Docket No. ___)
- Northern States Power Co.: Before the Minnesota Public Utilities Commission, provided expert testimony on the cost of capital for the Company's electric distribution operations. (Docket No. E002/GR-15-826)
- Maritime Electric: Before the Island Regulatory and Appeals Commission, provided expert testimony on the cost of capital for the Company's electric distribution operations. (Docket No. UE20942)
- Newfoundland Power Inc.: Before the Newfoundland and Labrador Board of Commissioners of Public Utilities, provided expert testimony on the cost of capital and business risk for the Company's electric distribution operations. (2016/2017 General Rate Application)
- FortisBC Energy Inc.: Before the British Columbia Utilities Commission, provided expert testimony on the cost of capital and business risk for the Company's BC gas distribution operations. (Docket No. 3698852)
- Hydro-Québec: Before the Régie de l'énergie, filed expert testimony on performance based regulation recommendations for the Company's Québec electric transmission and distribution businesses, with Robert Yardley. (R-3897-2014)
- Green Mountain Power Company: Before the Vermont Public Service Board, provided expert testimony on the cost of capital for the Company's Vermont Electric Utility Business. (Docket No. 8191)
- Northern States Power Company: Before the Public Service Commission of Wisconsin, provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-119)

- Hydro-Québec: Before the Régie de l'énergie, filed expert testimony on the cost of capital and business risk for the Company's Québec electric transmission and distribution businesses, with John Trogonoski. (R-3842-2013)
- Enbridge: Before the Ontario Energy Board, filed expert testimony with Jim Simpson and Melissa Bartos in support of the Company's proposed 2nd Generation Incentive Regulation plan. Our work focused on development of a proposed plan consistent with the OEB's objectives for such plans, while recognizing the Company's operating environment and business objectives, and capitalizing on the experience with other IR programs. Concentric conducted a series of analyses, including industry benchmarking, and productivity analyses for the industry and Enbridge using both total factor productivity "TFP" analysis and partial factor productivity ("PFP") analysis. These analyses produced productivity measures ("X factors") for both Enbridge and the industry peer group that were utilized to test parameters for the proposed IR plan. Concentric also evaluated alternative measures of inflation ("I factors") for utility inputs. Lastly, we examined Enbridge's anticipated 2014 to 2016 costs, and evaluated the ability of a traditional I-X framework to accommodate the Company's cost profile. (EB-2012-0459)
- Gaz Métro: Before the Régie de l'énergie, filed expert testimony on the cost of capital, business risk, and capital structure for the Company's Québec gas distribution operations. (R-3809-2012)
- Startrans IO, LLC: Before the Federal Energy Regulatory Commission, filed expert testimony on the appropriate cost of equity for the Startrans transmission facilities in Nevada and California, and the economic and business environment for transmission investments. (FERC Dockets Nos. ER13-272-000, and EL13-26-000)
- Nova Scotia Power: Before the Nova Scotia Utility and Review Board, provided direct and rebuttal evidence on the business risk of Nova Scotia Power in relation to its North American peers for purposes of determining the appropriate cost of capital. (Docket No. 2013 GRA)
- FortisBC Utilities: Before the British Columbia Utilities Commission, provided direct evidence and a supporting study on formulaic approaches to the determination of the cost of capital. (BCUC 2012 Generic Cost of Capital Proceeding)
- Northern States Power Company: Before the South Dakota Public Utilities Commission provided expert testimony on the appropriate cost of capital for the company's South Dakota electric utility operations. (Docket No. EL12 -)
- Vermont Gas Systems, Inc: Before the Vermont Public Service Board, filed expert testimony on the appropriate cost of equity and capital structure. (Docket No. 7803A)
- Northern States Power Company: Before the South Dakota Public Utilities Commission, provided expert testimony on the appropriate cost of capital for the company's South Dakota electric utility operations. (Docket No. EL11-019)
- Public Service Commission of Wisconsin: Provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-117)
- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, filed expert testimony on the appropriate rate of return for the Path 15 transmission facilities in California, and the economic and business environment for transmission investments. (FERC Dockets Nos. ER11-2909 and EL11-29)
- Enbridge: Cost of capital witness for the company's 2013 rate filing, providing testimony on recommended ROE and capital structure for the company's Ontario gas distribution

business, and a separate benchmarking analysis designed to illustrate the efficiency of the company's operations in relation to its' North American peers. (EB-2011-0354)

- Northern States Power Company: Before the Public Service Commission of Wisconsin, provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-117)
- FortisBC Energy, Inc: Provided a detailed study of alternative automatic adjustment mechanisms for setting the cost of equity, filed with the British Columbia Public Utilities Commission, December 2010. (In response to BCUC Order No. G-158-09)
- Commonwealth of Massachusetts, Superior Court, Central Water District vs. Burncoat Pond Watershed District: Provided expert testimony on the appropriate method for computing interest in an eminent domain taking. (Civil Action No. WDCV2001-01051, May 2010)
- Retained by the Ontario Energy Board to evaluate the existing DSM regulatory framework and guidelines for gas distributors, and based on research on best practices in other jurisdictions, make recommendations and lead a stakeholder conference on proposed changes. (2009-2010)
- ATCO Utilities: Primary cost of capital witness on behalf of ATCO Utilities in the 2009 Alberta Generic Cost of Capital proceeding, for the establishment of the return on equity and capital structure for each of Alberta's gas and electric utilities. (AUC Proceeding ID. 85)
- Enbridge: Primary cost of capital witness before the Ontario Energy Board in its Consultative Process on the Board's policy for determination of the cost of capital. (EB-2009-0084)
- Provided written comments to the Ontario Energy Board on behalf of Enbridge Gas Distribution, and separately for Hydro One Networks and the Coalition of Large Distributors in response to the Board's invitation to interested stakeholders to provide comments to help the Board better understand whether current economic and financial market conditions have an impact on the reasonableness of the Cost of Capital parameter values calculated in accordance with the Board's established Cost of Capital methodology; and to help the Board determine if, when, and how to make any appropriate adjustments to those parameter values. (2009)
- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, provided expert testimony on the appropriate rate of return, capital structure, and rate incentives for the development and operation of the Path 15 transmission facilities in California. (FERC Docket ER08-374-000)
- Wisconsin Power and Light Company: Before the Public Service Commission of Wisconsin, on establishing ratemaking principles for the company's proposed wind and coal electric generation facility additions, providing expert testimony on the appropriate return on equity. (PSCW Docket Nos. 6680-CE-170 and 6680-CE-171, 2007)
- Aquarion Water Company: Before the Connecticut Department of Public Utility Control, providing expert testimony on establishing the appropriate return on equity for the Company's Connecticut operations. (DPUC Docket No. 07-05-19, 2007)
- Central Maine Power Company: Before the Maine Public Utilities Commission, provided expert testimony on the theoretical and analytical soundness of the Company's sales forecast for ratemaking purposes. (MPUC Docket No. 2007-215, 2007)
- Vermont Gas Systems, Inc.: Before the State of Vermont Public Board, on the company's petition for approval of an alternative regulation plan, provided expert testimony on models of incentive regulation and their relative benefits for VGS and its ratepayers. (VPSB Docket No. 7109, 2006)

- Texas New Mexico Power Company: Before the Public Utility Commission of Texas, on the approval of the company's stranded cost recovery associated with the auction of the company's generating assets. (PUC Docket No. 29206, 2004)
- TransCanada Corporation: Provided an independent expert valuation of a natural gas pipeline, filed with the American Arbitration Association. (AAA Case No. 50T 1810018804, 2004)
- Advised the Board of Directors of El Paso Corporation on settlement matters pertaining to western power and gas markets before FERC. (2003)
- Conectiv: Before the New Jersey Board of Public Utilities, on the approval of the proposed sale of Atlantic City Electric Company's fossil and nuclear generating assets. (NJBPU Docket No. EM00020106, 2000-2001)
- Bangor Hydro Electric Company: Before the Maine Public Utilities Commission, on the approval of the proposed sale of the company's hydroelectric and fossil generation assets. (MPUC Docket No. 98-820, 1998)
- Maine Office of Energy Resources: Before the Maine Public Utilities Commission on behalf of the Maine Office of Energy on the establishment of avoided costs rates for generators under PURPA. (1981-1982)

Regulatory Support Experience

- Provided consulting services to Hydro One Networks for the Company's 2015 – 2019 Custom Distribution Rate Application to the OEB. Assisted the Company in developing its proposal for specific performance metrics for the Plan; reviewed the comments of stakeholders on performance metrics; reviewed the Company's existing performance metrics; reviewed the fastest growing areas of budgeted expenditures for their performance metric potential; developed a set of recommended metrics for review with the Company; and assisted the Company with drafting its submission to the OEB. (2014)
- Advised the Ontario Power Authority (OPA) on appropriate efficiency metrics to utilize in measuring the effectiveness of the organization in response to a directive by the Ontario Energy Board. Conducted research and analysis to examine efficiency metrics used in the industry to measure the effectiveness of organizations with similar responsibilities to those of the OPA. This analysis was designed to help facilitate the OPA's recommended metrics to the OEB. (2013)
- Retained by Gaz Métro to provide an independent assessment of the comprehensive incentive rate mechanism designed to improve the performance of Gaz Métro, and evaluate the proposed mechanism resulting from the Company's collaboration with a stakeholder working group. (R-3693-2009, 2011)
- For the Canadian Gas Association, facilitated workshops between Canadian regulators and utility executives on regulatory and utility responses to a low carbon world, and drafted follow-up white paper to facilitate further discussion on emerging industry issues. (2010-2013)
- Retained by Ontario's Coalition of Large Distributors (Enersource Hydro, Horizon Utilities, Hydro Ottawa, PowerStream, Toronto Hydro, and Veridian Connections) to examine the cost of capital for Ontario's electric utilities in relation to those in other provinces and in the U.S. (2008)
- Retained by the Ontario Energy Board to analyze ROE awards for the past two years in Ontario, and compare against other jurisdictions in Canada, the U.S., the U.K., and select other European jurisdictions. Differences in awarded ROEs were examined for underlying factors, including ROE methodology, company size, business risks, tax issues, subsidiary vs.

parent, and sources of capital. The analysis also addressed the question of whether Canadian utilities compete for capital on the same basis as U.S. utilities. (2007)

- Retained by the Nantucket Planning and Economic Development Commission to educate government officials and island residents on the wind industry, and provide analysis leading to constructive input to the Army Corps of Engineers and the Minerals Management Service on the siting of proposed wind projects. (2004-2007)
- Interim manager of Government and Regulatory affairs for Boston Generating, LLC. Coordinate activities and interventions before FERC, NE-ISO, state regulatory agencies, and local communities hosting Boston Generating power plants. (2004)
- Facilitated the development of an Alternative Regulation Plan with the Department of Public Service and Vermont Gas Systems providing research and advice leading to a rate proposal for the Vermont Public Service Board. Conducted several workshops including the major stakeholders and regulatory agencies to develop solutions satisfying both public policy and utility objectives. (2004-2005)
- For an independent power company, perform market analysis and annual audits of its utility power contract. Services provided include verification of the contract price as a function of its index components, surveys of regional competitive energy suppliers, and analysis of regional spot prices for an independent benchmark. Meet with PUC staff to discuss and represent the company in its annual adjustment process, and report results to the company and its creditors. (2003-2004)

Areas of Expertise

- **Energy Regulation**
  - Rate policy
  - Cost of capital
  - Incentive regulation
  - Fuels and power markets
- **Management and Business Strategy**
  - Fuels and power market assessments
  - Investment feasibility
  - Corporate and business unit planning
  - Benchmarking and productivity analysis
- **Financial and Economic Advisory**
  - Valuation analysis
  - Due diligence
  - Buy and sell-side advisory

PUBLICATIONS AND RESEARCH

- "Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers" (with Robert Yardley), prepared for the Canadian Gas Association and Canadian Electricity Association, May 2015.
- "Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with John Trogonoski), Public Utilities Fortnightly, May 2010
- "A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Dan Dane and Julie Lieberman), prepared for the Ontario Energy Board, June 2007
- "Do Utilities Mergers Deliver?" (with Prescott Hartshorne), Public Utilities Fortnightly, June 2006

- "Winners and Losers: Utility Strategy and Shareholder Return" (with Prescott Hartshorne), Public Utilities Fortnightly, October 2004
- "Winners and Losers in Restructuring: Assessing Electric and Gas Company Financial Performance" (with Prescott Hartshorne), white paper distributed to clients and press, August 2003
- "The New Generation Business," commissioned by the Electric Power Research Institute (EPRI) and distributed to EPRI members to contribute to a series on the changes in the Power Industry, December 2001
- Potential for Natural Gas in the United States, Volume V, Regulatory and Policy Issues (co-author), National Petroleum Council, December 1992
- "Natural Gas Outlook," articles on U.S. natural gas markets, published quarterly in the Data Resources Energy Review and Natural Gas Review, 1984-1989

SELECTED SPEAKING ENGAGEMENTS

- "Innovations in Utility Business Models and Regulation", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2015 Energy Regulation Course, Queens University, Kingston, Ontario, June 2015
- "M&A and Valuations," Panelist at Infocast Utility Scale Solar Summit, September 2010
- "The Use of Expert Evidence," The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2010 Energy Regulation Course, Queens University, Kingston, Ontario, June 2010
- "A Comparative Analysis of Return on Equity for Utilities in Canada and the U.S.", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) Annual Conference, Banff, Alberta, April 22, 2008
- "Nuclear Power on the Verge of a New Era," moderator for a client event co-hosted by Sutherland Asbill & Brennan and Lexecon, Washington D.C., October 2005
- "The Investment Implications of the Repeal of PUCHA," Skadden Arps Client Conference, New York, NY, October 2005
- "Anatomy of the Deal," First Annual Energy Transactions Conference, Newport, RI, May 2005
- "The Outlook for Wind Power," Skadden Arps Annual Energy and Project Finance Seminar, Naples, FL, March 2005
- "Direction of U.S. M&A Activity for Utilities," Energy and Mineral Law Foundation Conference, Sanibel Island, FL, February 2002
- "Outlook for U.S. Merger & Acquisition Activity," Utility Mergers & Acquisitions Conference, San Antonio, TX, October 2001
- "Investor Perspectives on Emerging Energy Companies," Panel Moderator at Energy Venture Conference, Boston, MA, June 2001
- "Electric Generation Asset Transactions: A Practical Guide," workshop conducted at the 1999 Thai Electricity and Gas Investment Briefing, Bangkok, Thailand, July 1999
- "New Strategic Options for the Power Sector," Electric Utility Business Environment Conference, Denver, CO, May 1999
- "Electric and Gas Industries: Moving Forward Together," New England Gas Association Annual Meeting, November 1998
- "Opportunities and Challenges in the Electric Marketplace," Electric Power Research Institute, July 1998

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2006 – Present)
Senior Vice President
Vice President

FTI Consulting (Lexecon) (2002 – 2006)
Senior Managing Director – Energy Practice

Arthur Andersen LLP (2000 – 2002)
Managing Director, Andersen Corporate Finance – Energy and Utilities

Navigant Consulting, Inc. (1996 – 2000)
Managing Director, Financial Services Practice
Senior Vice President, Strategy Practice

TotalFinaElf (1990 – 1996)
Manager, Corporate Planning and Development
Manager, Investor Relations
Manager of Strategic Planning and Vice President, Natural Gas Division

Arthur D. Little, Inc. (1989 – 1990)
Senior Consultant – International Energy Practice

DRI/McGraw-Hill (1984 – 1989)
Director, North American Natural Gas Consulting
Senior Economist, U.S. Electricity Service

Massachusetts Energy Facilities Siting Council (1982 – 1984)
Senior Economist – Gas and Electric Utilities

Maine Office of Energy Resources (1981 – 1982)
State Energy Economist

EDUCATION

M.S., Resource Economics, University of New Hampshire, with Honors, 1981
B.S., Business Administration and Economics, Georgetown University, Cum Laude, 1975

DESIGNATIONS AND AFFILIATIONS

NASD General Securities Representative and Managing Principal (Series 7, 63 and 24 Certifications), 2001
NARUC, Advanced Regulatory Studies Program, Michigan State University, 1984
American Petroleum Institute, CEO's Liaison to Management and Policy Committees, 1994-1996
National Petroleum Council, Regulatory and Policy Task Forces, 1992

President, International Association for Energy Economics, Dallas Chapter, 1995
Gas Research Institute, Economics Advisory Committee, 1990-1993
Georgetown University, Alumni Admissions Interviewer, 1988 – current

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Alberta Utilities Commission				
ATCO Utilities Group	2008	ATCO Gas; ATCO Pipelines Ltd.; ATCO Electric Ltd.	Application No. 1578571 / Proceeding ID. 85	2009 Generic Cost of Capital Proceeding (Gas & Electric)
American Arbitration Association				
TransCanada Corporation	2004	TransCanada Corporation	AAA Case No. 50T 1810018804	Valuation of Natural Gas Pipeline
British Columbia Utilities Commission				
FortisBC	2012	FortisBC Utilities	G-20-12	Cost of Capital Adjustment Mechanisms
FortisBC	2015	FortisBC Utilities	Project 3698852	Cost of Capital (Gas Distribution)
Connecticut Department of Public Utility Control				
Aquarion Water Company of CT/ Macquarie Securities	2007	Aquarion Water Company of CT	DPUC Docket No. 07-05-19	Return on Equity (Water)
Federal Energy Regulatory Commission				
Atlantic Power Corporation	2007	Atlantic Path 15, LLC	ER08-374-000	Return on Equity (Electric)
Atlantic Power Corporation	2010	Atlantic Path 15, LLC	Docket No. ER11-2909-000	Return on Equity (Electric)
Atlantic Power Corporation	2011	Atlantic Path 15, LLC	Docket Nos. ER11-2909 and EL11-29	Rate of Return (Electric Transmission)
Startrans IO, LLC	2012	Startrans IO, LLC	ER-13-272-000	Cost of Capital (Electric Transmission)
Maine Public Utility Commission				
Bangor Hydro Electric Company	1998	Bangor Hydro Electric Company	MPUC Docket No. 98-820	Transaction-Related Financial Advisory Services, Valuation

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Central Maine Power Company	2007	Central Maine Power Company	MPUC Docket No. 2007-215	Sales Forecast
Massachusetts Superior Court				
Burncoat Pond Watershed District	2010	Central Water District v. Burncoat Pond Watershed District	WDCV 2001-0105	Valuation/Eminent Domain
Minnesota Public Utilities Commission				
Northern States Power Company	2015	Northern States Power Company	E-002-GR-15-826	Cost of Capital (Electric)
Newfoundland and Labrador Board of Commissioners of Public Utilities				
Newfoundland Power	2015 2016	Newfoundland Power	2016/2017 GRA	Cost of Capital (Electric)
New Jersey Board of Public Utilities				
Conectiv	2000-2001	Atlantic City Electric Company	NJBPU Docket No. EM00020106	Transaction-Related Financial Advisory Services
Nova Scotia Utility and Review Board				
Nova Scotia Power Inc.	2012	Nova Scotia Power Inc.	2013 GRA	Return on Equity/Business Risk (Electric)
Ontario Energy Board				
Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	2009	Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	EB-2009-0084	Ontario Energy Board's 2009 Consultative Process on Cost of Capital Review (Gas & Electric)
Enbridge Gas Distribution	2012	Enbridge Gas Distribution	EB-2011-0354	Industry Benchmarking Study and Cost of Capital (Gas Distribution)
Enbridge Gas Distribution	2014	Enbridge Gas Distribution	EB-2012-0459	Incentive Regulation Plan and Industry Productivity Study

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Prince Edward Island Regulatory and Appeals Commission				
Maritime Electric Company	2015	Maritime Electric Company	UE20942	Return on Capital (Electric)
Régie de l'énergie du Québec				
Gaz Métro	2012	Gaz Métro	R-3809-2012	Return on Equity/Business Risk/ Capital Structure (Gas Distribution)
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2013	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3842-2013	Return on Equity/Business Risk (Electric)
Hydro-Québec Distribution	2014	Hydro-Québec Distribution	R-3905-2014	Remuneration of Deferral Accounts
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2015	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3897-2014	Performance-Based Ratemaking
South Dakota Public Service Commission				
Northern States Power Company-MN	2012	Northern States Power Company-MN	EL 11-019	Return on Equity
Texas Public Utility Commission				
Texas New Mexico Power Company	2004	Texas New Mexico Power Company	PUC Docket No. 29206	Auction Process and Stranded Cost Recovery
Vermont Public Service Board				
Vermont Gas Systems, Inc.	2006	Vermont Gas Systems, Inc.	VPSB Docket No. 7109	Models of Incentive Regulation
Vermont Gas Systems, Inc.	2012	Vermont Gas Systems, Inc.	Docket No. 7803A	Cost of Capital (Gas Distribution)
Green Mountain Power Corporation	2013	Green Mountain Power Corporation	Docket No. 8191	Return on Equity (Electric)
Vermont Gas Systems, Inc.	2016	Vermont Gas Systems, Inc.		Return on Equity (Gas Distribution)
Wisconsin Public Service Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-170	Return on Equity (Electric)
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-171	Return on Equity (Electric)
Northern States Power Company	2011	Northern States Power Company	PSCW Docket No. 4220-UR-117	Return on Equity (Electric)
Northern States Power Company	2013	Northern States Power Company	PSCW Docket No. 4220-UR-119	Return on Equity (Gas & Electric)
Northern States Power Company	2015	Northern States Power Company	PSCW Docket No. 4220-UR-121	Return on Equity (Gas & Electric)

APPENDIX C:

Résumé and Testimony Listing of Daniel S. Dane

Daniel S. Dane, CPA
Assistant Vice President

Daniel S. Dane has extensive experience in the energy and financial services industries providing advisory services to power companies, natural gas pipelines, and local gas distribution companies in the areas of regulation and ratemaking, litigation support, generating asset divestitures, valuation, financial statement audits and analysis, and the examination of financial reporting systems and controls. Mr. Dane has also provided expert testimony on regulated ratemaking matters for investor-owned utilities. Mr. Dane has an MBA from Boston College in Chestnut Hill, Massachusetts and a BA in Economics from Colgate University in Hamilton, New York. Mr. Dane is a certified public accountant, and is a licensed securities professional (Series 7, 28, 63, 79, and 99). Mr. Dane also serves as the Financial and Operations Principal of CE Capital Advisors, a FINRA-Member firm and a subsidiary of Concentric.

REPRESENTATIVE PROJECT EXPERIENCE

Ratemaking and Utility Regulation Assignments

Expert Testimony

- Submitted expert direct testimony on behalf of Northern States Power, a wholly-owned subsidiary of Xcel Energy Inc., to present evidence and provide an opinion regarding the company's proposed ROE in South Dakota Public Utilities Commission Docket No. EL11-019.
- Submitted expert direct and rebuttal testimony on behalf of Ameren's Illinois utilities regarding ratemaking policy issues specifically related to regulated rate base (Illinois Commerce Commission Docket No. 09-0306 through 09-0311 (Cons.)).

Regulatory Support

- Provided financial modeling, development of expert reports, and preparation of multiple rounds of testimony on behalf of U.S. and Canadian investor-owned electric and natural gas utilities related to multiple aspects of the ratemaking process, including: cost of capital; ring fencing; revenue requirements; decoupling; prudence and cost recovery; capital tracker tariff mechanisms; cost allocation and shared services; merger approval; and ratemaking policy.
- Developed marketing materials, regulatory filings, and cost of service/rate design financial models for natural gas pipeline facilities for U.S. and state regulatory filings and open seasons.
- For natural gas pipeline filings, advised applicants on Federal Energy Regulatory Commission (FERC) policies and precedent regarding tariff rates and other filing requirements.

- Developed market power studies, along with supporting testimony, for developers and owners of U.S. natural gas storage facilities.
- Assignments include utilities in Ontario, Alaska, Arizona, California, Colorado, Connecticut, Delaware, Florida, Hawaii, Illinois, Iowa, Kansas, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Hampshire, New Jersey, New York, North Dakota, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota, North Dakota, Texas, Wisconsin, Vermont, and the District of Columbia.

Financial Advisory Assignments

Competitive Solicitations & Asset Divestitures

- Sell-side support provide for approximately $2 billion in generating asset transactions, including nuclear, natural gas, and coal generating facilities.
- Buy-side due diligence support for U.S. and international investors in wind generation and natural gas pipeline facilities.

Valuation Services

- Developed Fairness Opinions issued by CE Capital Advisors, Inc. to Boards of Directors of companies entering into asset purchases and sales. Led valuation modeling on multiple energy-related valuation assignments using the Income Approach, Cost Approach, and Sales Comparison Approach.

Litigation Advisory Assignments

Prepared economic and financial analyses and expert reports in proceedings related to contract disputes, takings claims, and bankruptcy proceedings. Clients include international diversified energy companies, regulated utilities, and bondholders.

Management and Operations Consulting Assignments

Prudence reviews, including contracting strategy reviews and assessments of project controls and oversight for developers of nuclear generating capacity uprates and new nuclear facilities.

PRESENTATIONS

"Increasing Shareholder Value through the Capital Markets." University of Idaho Utility Executive Course, June 2015.

"A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Jim Coyne and Julie Lieberman), presented to the Ontario Energy Association, June 2007.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2004 – Present)
CE Capital Advisors, Inc.
Assistant Vice President (Concentric)
Financial and Operations Principal (CE Capital)

Ernst & Young (2000 – 2001, 2003 – 2004)
Staff Auditor and Database Management Associate

ZIA Information Analysis Group (1997 – 2000)

EDUCATION AND CERTIFICATIONS

M.B.A., Boston College, 2003
B.A., Economics, Colgate University, 1996
Licensed Securities Professional: NASD Series 7, 28, 63, 79 and 99 Licenses

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Public Accountant, 2004
Massachusetts Society of Certified Public Accountants, 2004
American Institute of Certified Public Accountants, 2011

Exhibit 1: Proxy Group Criteria

	Company [1]	Ticker	Credit Rating (Criteria: Investment Grade)	Generation Assets Included in Rate Base	Regulated Revenue / Total Revenue (Criteria: >60%)	Regulated Income / Total Income (Criteria: >60%)	Regulated Electric Revenue / Total Reg. Revenue (Criteria: >80%)	Regulated Electric Income / Total Reg. Income (Criteria: >80%)	Fuel Mix: Percent Nuclear [2]	Fuel Mix: Percent Hydro [2]
1	ALLETE, Inc.	ALE	BBB+	Yes	90%	101%	97%	97%	0%	6%
2	Ameren Corporation	AEE	BBB+	Yes	100%	102%	83%	89%	11%	7%
3	American Electric Power Company, Inc.	AEP	BBB	Yes	92%	85%	100%	100%	8%	3%
4	Duke Energy Corporation	DUK	A-	Yes	92%	102%	98%	97%	17%	7%
5	Edison International	EIX	BBB+	Yes	100%	101%	100%	100%	20%	36%
6	El Paso Electric Company	EE	BBB	Yes	100%	100%	100%	100%	31%	0%
7	Emera Inc. [3]	EMA	BBB+	Yes	87%	86%	98%	86%	0%	0%
8	Entergy Corporation	ETR	BBB	Yes	79%	96%	98%	99%	15%	0%
9	FirstEnergy Corporation	FE	BBB-	Yes	64%	113%	100%	100%	40%	18%
10	Fortis Inc. [3]	FTS	A-	Yes	94%	94%	63%	62%	0%	1%
11	Great Plains Energy Inc.	GXP	BBB+	Yes	100%	101%	100%	100%	8%	0%
12	IDACORP, Inc.	IDA	BBB	Yes	100%	100%	100%	100%	0%	52%
13	NextEra Energy, Inc.	NEE	A-	Yes	69%	72%	100%	100%	13%	0%
14	PG&E Corporation	PCG	BBB	Yes	100%	100%	80%	96%	29%	50%
15	Pinnacle West Capital Corporation	PNW	A-	Yes	100%	100%	100%	100%	18%	0%
16	PNM Resources, Inc.	PNM	BBB+	Yes	100%	99%	100%	100%	17%	0%
17	Portland General Electric Company	POR	BBB	Yes	100%	100%	100%	100%	0%	14%
18	Southern Company	SO	A-	Yes	95%	93%	100%	100%	10%	8%

	Company [1]	Ticker	Credit Rating (Criteria: Investment Grade)	Generation Assets Included in Rate Base	Regulated Revenue / Total Revenue (Criteria: >60%)	Regulated Income / Total Income (Criteria: >60%)	Regulated Electric Revenue / Total Reg. Revenue (Criteria: >80%)	Regulated Electric Income / Total Reg. Income (Criteria: >80%)	Fuel Mix: Percent Nuclear [2]	Fuel Mix: Percent Hydro [2]
19	Westar Energy, Inc.	WR	BBB+	Yes	100%	100%	100%	100%	9%	0%
20	Xcel Energy Inc.	XEL	A-	Yes	99%	99%	83%	89%	9%	3%

Notes:

[1] Eversource Energy, while otherwise meeting Concentric's screening criteria, is in the process of selling its remaining regulated generation. As such, Eversource may not be comparable to the proxy companies going forward, and was thus excluded from the comparison group.

[2] Nuclear and hydroelectric generation criteria: Companies for which nuclear and/or hydroelectric generation make up less than 5% of their generation mix were excluded from the proxy group.

[3] None of the publicly traded Canadian companies that Concentric reviewed met all of our screening criteria. Emera, Inc. ("Emera"), however, only failed the screen that each utility should have more than a minimal amount of regulated hydroelectric and/or nuclear generation. Fortis, Inc. ("Fortis"), only failed the screens that each utility should have regulated electric revenue and net income that make up greater than 80 percent of the consolidated company's regulated operations and that each utility should have a more than an minimal amount of hydroelectric and/or nuclear regulated generation. In order to broaden the proxy group to include at least a minimal number of Canadian utilities, Concentric included Emera and Fortis in the proxy group, as they otherwise meet our screening criteria.

Exhibit 2: Proxy Group Company Relevant Indicators

Parent Company Ticker	Operating Company	State or Province	Weighted Common Equity/Total Cap (%)	S&P Credit Rating	Operating Revenue: Electric
ALE	ALLETE (Minnesota Power)	MN	54.29		
ALE [1]			54.29	BBB+	$1,013,221
AEE	Union Electric Company	MO	51.76		
AEE	Ameren Illinois Company	IL	50.00		
AEE [1]			50.87	BBB+	$4,953,315
AEP	Columbus Southern Power Company	OH	50.64		
AEP	Ohio Power Company	OH	53.79		
AEP	Appalachian Power Company	WV	47.16		
AEP	Indiana Michigan Power Company	IN	42.67		
AEP	Appalachian Power Company	VA	42.89		
AEP	Indiana Michigan Power Company	MI	42.07		
AEP	Southwestern Electric Power Company	AR	33.99		
AEP	AEP Texas Central Company	TX	40.00		
AEP	AEP Texas North Company	TX	40.00		
AEP	Southwestern Electric Power Company	TX	49.10		
AEP [1]			45.77	BBB	$14,490,000
DUK	Duke Energy Ohio, Inc.	OH	53.30		

Parent Company Ticker	Operating Company	State or Province	Weighted Common Equity/Total Cap (%)	S&P Credit Rating	Operating Revenue: Electric
DUK	Duke Energy Indiana, LLC	IN	44.44		
DUK	Duke Energy Florida, LLC	FL	45.74		
DUK	Duke Energy Carolinas, LLC	SC	53.00		
DUK	Duke Energy Progress, LLC	SC	44.72		
DUK	Duke Energy Progress, LLC	NC	53.00		
DUK	Duke Energy Carolinas, LLC	NC	53.00		
DUK [1]			50.14	A-	$22,581,161
EIX	Southern California Edison Company	CA	48.00		
EIX [1]			48.00	BBB+	$14,195,273
EE [2]	El Paso Electric Company		NA	BBB	$917,525
EMA	Maine Public Service Company	ME	50.00		
EMA	Emera Maine	ME	49.00		
EMA	Nova Scotia Power Inc.	Nova Scotia	37.50		
EMA [1]			40.27	BBB+	$2,067,200
ETR	Entergy Arkansas, Inc. [3]	AR	46.27		
ETR [1]			46.27	BBB	$10,904,103
FE	Cleveland Electric Illuminating Company	OH	49.00		
FE	Ohio Edison Company	OH	49.00		

Parent Company Ticker	Operating Company	State or Province	Weighted Common Equity/Total Cap (%)	S&P Credit Rating	Operating Revenue: Electric
FE	Toledo Edison Company	OH	49.00		
FE	Potomac Edison Company	WV	46.42		
FE	Jersey Central Power & Light Company	NJ	50.00		
FE [1]			49.22	BBB-	$9,871,000
FTS	Central Hudson Gas & Electric Corporation	NY	48.00		
FTS	Tucson Electric Power Company	AZ	43.50		
FTS	UNS Electric, Inc.	AZ	52.60		
FTS	Fortis BC Electric	British Columbia	40.00		
FTS	Fortis Alberta	Alberta	40.00		
FTS	Newfoundland Power	Newfoundland & Labrador	45.00		
FTS	Maritime Electric	Prince Edward Island	40.00		
FTS	Fortis Ontario	Ontario	40.00		
FTS [1]			43.31	A-	$3,554,612
GXP	KCP&L Greater Missouri Operations Company	MO	52.30		
GXP	Kansas City Power & Light Company	MO	50.09		
GXP	Kansas City Power & Light Company	KS	50.48		
GXP Weighted Average [1]			51.04	BBB+	$2,568,200
IDA	Idaho Power Co.	OR	49.90		

Parent Company Ticker	Operating Company	State or Province	Weighted Common Equity/Total Cap (%)	S&P Credit Rating	Operating Revenue: Electric
IDA [1]			49.90	BBB	$1,278,651
NEE [2]	NextEra Energy Inc.		NA	A-	$11,421,000
PCG	Pacific Gas and Electric Company	CA	52.00		
PCG [1]			52.00	BBB	$13,658,000
PNW	Arizona Public Service Company	AZ	53.94		
PNW [1]			53.94	A-	$3,491,632
PNM	Texas-New Mexico Power Company	TX	45.00		
PNM [1]			45.00	BBB+	$1,435,853
POR	Portland General Electric Company	OR	50.00		
POR [1]			50.00	BBB	$1,900,000
SO	Mississippi Power Company	MS	53.68		
SO	Alabama Power Company	AL	45.60		
SO	Georgia Power Company	GA	50.84		
SO [1]			49.09	A-	$17,354,000
WR	Kansas Gas and Electric Company	KS	50.13		
WR [1]			50.13	BBB+	$2,601,703
XEL	Northern States Power Company - MN	ND	52.56		
XEL	Public Service Company of Colorado	CO	56.00		

Parent Company Ticker	Operating Company	State or Province	Weighted Common Equity/Total Cap (%)	S&P Credit Rating	Operating Revenue: Electric
XEL	Northern States Power Company - WI	WI	52.49		
XEL	Southwestern Public Service Company	TX	51.00		
XEL	Northern States Power Company - MN	MN	52.50		
XEL [1]			53.89	A-	$9,467,664
OPG		**Ontario**	**45.00**	BBB+	$4,963,000

Notes:
[1] Equity Ratio Weighted by Total Retail Electric Customers. Excludes companies for which most recent rate case parameters were not provided and/or public information was not available via SNL.
[2] Recent authorized equity ratios for the operating companies of El Paso Electric Company and NextEra Energy Inc. were not available via SNL. Therefore, the equity ratios for those companies are listed as NA.
[3] Equity ratio adjusted to exclude zero cost capital items.

Exhibit 3: Proxy Company Cost Recovery Mechanisms

Company	Inter-Rate Case Cost Recovery and other Adjustment Mechanisms
OPG	Nuclear liability Nuclear development Capacity refurbishment Ancillary services net revenue – hydro & nuclear Hydroelectric water conditions Income and other taxes Nuclear and hydro deferral and variance over/under recovery Bruce lease net revenues Pension and OPEB cost Pension & OPEB cash payment and Pension & OPEB cash versus accrual differential Niagara Tunnel Project pre-December 2008 Disallowance Gross revenue charge Hydro incentive mechanism Hydro surplus base load generation Impact resulting from changes in station end-of-life dates
AEE	Purchased Power Cost Adjustment – Fuel Adjustment Clause (incl. Off-System Sales) Conservation Program Expense – DSM Program Recovery Partial Decoupling Renewables Expense – Renewable Energy Standards rate adjustment Environmental Compliance – Hazardous Materials Adjustment Clause Rider RTO-Related Transmission Expense Other – Bad Debt Cost Recovery Other – Certain Taxes and Franchise Fee Recovery
ALE	Purchased Power Cost Adjustment Conservation Program Expense Renewables Expense Environmental Compliance RTO-Related Transmission Expense
AEP	Purchased Power Cost Adjustment Conservation Program Expense – Energy Efficiency Rider Partial Decoupling Renewables Expense Environmental Compliance – Environmental Adjustment Clause Environmental Compliance – Energy Efficiency Rider Generation Capacity Generation Capacity – Big Sandy Plant Recovery Generic Infrastructure – T&D and storage system improvement charge rider Generic Infrastructure – CWIP Recovery Generic Infrastructure – Distribution Cost Recovery Factor Generic Infrastructure – Electric Security Plans RTO-Related Transmission Expense Other – Certain Taxes and Franchise Fee Recovery Other – OSS Sharing Mechanism Other – Compliance and Cyber-security Requirements

Company	Inter-Rate Case Cost Recovery and other Adjustment Mechanisms
DUK	Purchased Power Cost Adjustment Conservation Program Expense Conservation Program Expense – Energy Efficiency Recovery Rider Partial Decoupling Renewables Expense Renewables Expense – EPS Rider Environmental Compliance Generation Capacity – Capacity Cost Recovery Clause Generic Infrastructure – Electric Security Plans Recovery RTO-Related Transmission Expense Other – Certain Taxes and Franchise Fee Recovery Other – OSS Margin Sharing Mechanism
EE	Purchased Power Cost Adjustment Conservation Program Expense Generic Infrastructure – Distribution Cost Recovery Factor Other – Certain Taxes and Franchise Fee Recovery
EIX	Purchased Power Cost Adjustment Full Decoupling
ETR	Purchased Power Cost Adjustment Conservation Program Expense Conservation Program Expense – Energy Efficiency Programs Partial Decoupling Environmental Compliance – Environmental Adjustment Clause Generation Capacity – Capacity Acquisition Rider Generation Capacity –New generation and Capacity Additions Generic Infrastructure – Distribution Cost Recovery Generic Infrastructure – Government-related Expenses RTO-Related Transmission Expense Other – Storm Cost Securitization
FE	Purchased Power Cost Adjustment – Electric Fuel Rate Conservation Program Expense Partial Decoupling Renewables Expense Generic Infrastructure – Electric Security Plans Recovery RTO-Related Transmission Expense Other – Certain Taxes and Franchise Fee Recovery
GXP	Purchased Power Cost Adjustment Conservation Program Expense Partial Decoupling Renewables Expense Environmental Compliance RTO-Related Transmission Expense Other – Certain Taxes and Franchise Fee Recovery Other – Energy Cost Adjustment Mechanism
IDA	Purchased Power Cost Adjustment Renewables Expense Conservation Program Expense Partial Decoupling

Company	Inter-Rate Case Cost Recovery and other Adjustment Mechanisms
NEE	Purchased Power Cost Adjustment Conservation Program Expense Environmental Compliance Generation Capacity – Capacity Cost Recovery Clause Generic Infrastructure – Transmission Cost of Service Mechanism Other – Certain Taxes and Franchise Fee Recovery
PCG	Purchased Power Cost Adjustment Full Decoupling
PNM	Purchased Power Cost Adjustment Conservation Program Expense Renewables Expense Environmental Compliance Generic Infrastructure – Distribution Cost Recovery Factor Other – Certain Taxes and Franchise Fee Recovery
PNW	Purchased Power Cost Adjustment Conservation Program Expense Partial Decoupling Renewables Expense Generation Capacity RTO-Related Transmission Expense Other – Certain Taxes and Franchise Fee Recovery
POR	Purchased Power Cost Adjustment Partial Decoupling Renewables Expense
SO	Purchased Power Cost Adjustment Conservation Program Expense Environmental Compliance Generation Capacity Other – Certain Taxes and Franchise Fee Recovery Other – Storm Cost Securitization
WR	Purchased Power Cost Adjustment Conservation Program Expense Partial Decoupling – Energy Efficiency Program Recovery Renewables Expense Environmental Compliance RTO-Related Transmission Expense Other – Certain Taxes and Franchise Fee Recovery
XEL	Purchased Power Cost Adjustment Conservation Program Expense Conservation Program Expense – Demand-Side Management Rider Conservation Program Expense – Energy Efficiency Rider Renewables Expense Environmental Compliance Generic Infrastructure – Distribution Cost Recovery Factor Generic Infrastructure – Transmission Cost Recovery Rider Generic Infrastructure – Infrastructure Rider RTO-Related Transmission Expense Other – Certain Taxes and Franchise Fee Recovery Other – OSS Sharing Mechanism Other – Limited Issue Reopener Other – Lost Revenue Rider Associated with University Discounts Other – "Non-asset-based" Wholesale Power Margin Sharing Other – Renewable Energy Credit Sales

Company	Inter-Rate Case Cost Recovery and other Adjustment Mechanisms
FTS	Deferred income taxes Employee future benefits Manufactured gas plant ("MGP") site remediation deferral Rate stabilization accounts Deferred energy management costs Deferred lease costs Derivative instruments Deferred operating overhead costs Deferred net losses on disposal of utility capital assets and intangible assets Final mine reclamation and retiree health care costs Property tax deferrals Natural gas for transportation incentives Income taxes recoverable on OPEB plans Carrying charges – employee future benefits Customer Care Enhancement Project cost deferral Non-ARO removal cost provision Rate stabilization accounts Deferred income taxes Employee future benefits Customer and community benefits obligation AESO charges deferral Renewable energy surcharge Carrying charges – employee future benefits Derivative instruments Full Decoupling Renewables Expense Purchased Power Cost Adjustment Conservation Program Expense Partial Decoupling – Lost Fixed Cost Recovery Mechanism Environmental Compliance Other – Certain Taxes and Franchise Fee Recovery RTO-Related Transmission Expense

Company	Inter-Rate Case Cost Recovery and other Adjustment Mechanisms
EMA	Deferred income tax regulatory asset Unamortized defeasance costs Fuel adjustment mechanism Deferrals related to derivative instruments Large industrial customers fixed cost deferral Stranded cost recovery Pension and post-retirement medical plan Stranded cost revenue & purchase power reconciliation deferrals Purchase power contracts Hydro-Québec Obligation November 2014 Maine storm 2013 Maine ice storm Earnings Share Mechanism Asset impairment recovery Seabrook nuclear project Deferral of income and capital taxes not included in Q1 2005 rates Smart Grid Rate stabilization fixed cost deferral Self-Insurance Fund Deferrals related to derivative instruments Deferred income tax regulatory liabilities Maine FERC ROE

Sources:
U.S. Companies: SNL RRA Adjustment Mechanism Report as of October 2, 2015.
EMA & FTS: 2014 Consolidated Financial Statements and 2014 Annual Report and above SNL report, respectively
OPG: EB-2014-0370 and Company Data.

TORYS LLP

79 Wellington St. W., 30th Floor
Box 270, TD South Tower
Toronto, Ontario M5K 1N2 Canada
P. 416.865.0040 | F. 416.865.7380
www.torys.com

Crawford Smith
csmith@torys.com
P. 416.865.8209

May 4, 2015

EMAIL
PRIVILEGED AND CONFIDENTIAL

James M. Coyne
Senior Vice-President
Concentric Energy Advisors
293 Boston Post Road West, Suite 500
Marlborough, Massachusetts
01752

Dear Mr. Coyne:

Re: Ontario Power Generation Payment Amounts Application

We represent Ontario Power Generation Inc. ("OPG") in connection with an application to be brought by OPG to the Ontario Energy Board (the "Board") to determine payment amounts (i.e. rates).

I confirm that Torys LLP ("Torys") has agreed to retain Concentric Energy Advisors and you (collectively "you") as an expert in this matter, to provide us with cost of capital related advice in order to assist us in providing legal advice to our client and in contemplation for litigation, as further detailed in the Scope of Work attached as Schedule A.

You are to be compensated at rates for all services as detailed on the attached Schedule B and will bill for actual expenses as incurred without mark-up. You will bill for travel expenses only in accordance with OPG's Standard Form Business Expense Schedule provided by Torys to you as the same may be amended, supplemented or replaced from time to time. Please direct your accounts to my attention at the address above.

Our agreement with you is subject to the terms in Attachment C.

In the event that we request that you prepare an expert report for filing with the Board, Rule 13A of the OEB's Rules of Practice applies, a copy of which is attached. You agree to accept the responsibilities that are or may be imposed on you as an expert pursuant to the provisions of Rule 13A.06.

Please indicate your agreement to the terms of your retainer as set out above, by signing a copy of this letter and returning it to me.

Thank you for your assistance.

Yours truly,

Crawford G. Smith

Tel 416.865.8209
csmith@torys.com

CS/tm
Enclosure

Agreed, this 5th day of May, 2015

Concentric Energy Advisors

per: James M. Coyne

Enclosures:
Attachment A - Scope of Services
Attachment B - OPG's Standard Form Business Expense Schedule
Attachment C - Terms and Conditions
Attachment D – OEB Rules of Practice and Procedure

cc: Carlton Mathias

1

Privileged and Confidential

Schedule "A" - Scope of Work

Objective:

Provide information and support in order to assist Torys LLP to advise OPG with respect to cost of capital in OPG's next Payment Amounts Application.

Requirements:

Requirement is to prepare for and participate in activities to support Torys LLP in respect of obtaining the OEB's approval of rates established pursuant to the new rate-making methodologies approved by the OEB for hydroelectric and nuclear operations including:

a) Prepare an independent report as to whether the application of the cost of capital approved by the OEB in EB-2013-0321 is an appropriate basis for setting OPG's nuclear and regulated hydroelectric payment amounts in OPG's next application.

   In preparing the report, select the appropriate peer group against which OPG should be compared, including establishing appropriate selection criteria for inclusion in the peer group. The report should include a review of the cost of capital awarded to approximately 15-20 relevant North American utilities.

   The report shall build upon the OEB's findings in EB-2007-0905, EB-2010-0008 and EB-2013-0321 in respect of OPG's cost of capital. Specifically:

   i. OPG's cost of capital shall be established based on the stand-alone principle.
   ii. OPG's ROE shall be set in accordance with a formula based approach provided in the OEB's Cost of Capital Report issued December 11, 2009, which adopts the Fair Return Standard.
   iii. The 45% common equity ratio awarded in EB-2013-0321 reflects the OEB's view that the business risks associated with the nuclear business are higher than those of the regulated hydroelectric business.
   iv. The report will address whether the 45% common equity ratio is reasonable, given Pickering End of Commercial Operations and the Darlington Refurbishment Project.

   Initial draft of the report must be submitted by March 31, 2015 for review. Final report to be delivered by April 30, 2015.

For requirement (a), Concentric will provide a quote with a cost range for completion of the work. Once Concentric and Torys agree on the costs range, the work shall be completed at a cost within that range and per other terms of the Torys LLP retainer agreement.

b) Prepare other studies, if required, to assess whether the application of the cost of capital approved by the OEB in EB-2013-0321 is an appropriate basis for setting OPG's nuclear and regulated hydroelectric payment amounts in OPG's next application.

   The decision to proceed with Requirement (b) will be determined by Torys LLP. If Requirement (b) is carried out, it will be completed on a time and materials basis and per other terms of the Torys LLP retainer agreement. All activities will be performed on an as required basis at the request of TorysLLP. For each study, Torys will be provide specific instructions and shall then recieve a forecast level of effort to complete the work at agreed upon hourly rates as set out in Schedule B.

c) Preparation for and participation in OPG's hydro and nuclear applications pursuant to OEB approved ratemaking methodology including: preparing evidence, responding to interrogatories, providing oral testimony, responding to undertakings and supporting the preparation of argument, all as directed by Torys.

Schedule "B" – Rates

Name and Title	Hourly Rate	Annual Rate
Robert Yardley Responsible Officer	[redacted]	[redacted]
Danielle Powers Project Manager	[redacted]	[redacted]
Timothy Wang SME	[redacted]	[redacted]
Andrew MacBride Research & Analysis Report	[redacted]	[redacted]
TBD Chairman and Chief Executive Officer	[redacted]	[redacted]
TBD Sr. Vice-President	[redacted]	[redacted]
TBD Vice-President	[redacted]	[redacted]
TBD Assistant Vice-President	[redacted]	[redacted]
TBD Sr. Project Manager	[redacted]	[redacted]
TBD Project Manager	[redacted]	[redacted]
TBD Sr. Consultant	[redacted]	[redacted]
TBD Consultant	[redacted]	[redacted]
TBD Assistant Consultant	[redacted]	[redacted]
TBD Analyst	[redacted]	[redacted]
TBD Associate	[redacted]	[redacted]
TBD Project Assistant	[redacted]	[redacted]

STANDARD FORM

BUSINESS EXPENSE SCHEDULE

Effective June 17, 2009

For

ONTARIO POWER GENERATION INC.

Updated July 27th, 2010

TABLE OF CONTENTS

SECTION 1 – INTERPRETATION 1

- 1.1 Three Types of Reimbursement 1
- 1.2 Definitions 1
- 1.3 Headings 2
- 1.4 Expanded Definitions 2
- 1.5 Business Day 2
- 1.6 Payment Currency 2
- 1.7 Conflict 2
- 1.8 Notice 2

SECTION 2 - REIMBURSEMENT OF ALLOWABLE EXPENSES 3

- 2.1 Allowable Expenses 3
- 2.2 Expenses Minimised 3
- 2.3 Excluded Items 3
- 2.4 Method of Reimbursement 4
- 2.5 Travel Agency 5
- 2.6 Confirming Rates 5
- 2.7 Home Base and Work Site 5

SECTION 3 – AIR, RAIL OR BUS TRAVEL 6

- 3.1 Air, Rail or Bus Travel 6
- 3.2 Economy Class 6
- 3.3 Vehicle Instead of Air, Rail or Bus Travel 6
- 3.4 Visits Home 6
- 3.5 Minimising Expenses 6

SECTION 4 - VEHICLES 7

- 4.1 Reimbursable Vehicle Expenses 7
- 4.2 Terms of Rental 7
- 4.3 Personal Vehicle 7
- 4.4 Reducing Expenses 8
- 4.5 Multiple Users 8

SECTION 5 - LODGING 8

- 5.1 Overnight Accommodation 8

SECTION 6 - DAILY RATES 8

- 6.1 Daily Rates Instead of Allowable Expenses 8
- 6.2 Daily Rates 9
- 6.3 All Inclusive 9
- 6.4 Rates 9
- 6.5 Application of Rate 9
- 6.6 Method of Reimbursement 9
- 6.7 Absences 10

SECTION 7 – MONTHLY RATES 10

BUSINESS EXPENSE SCHEDULE

RECITALS

A. Ontario Power Generation Inc. ("**OPG**") entered into an agreement (the "**Agreement**") with the other party to the Agreement (the "**Contractor**"). This schedule (this "**Schedule**") forms part of the Agreement. Under the Agreement, OPG agreed to reimburse the Contractor for certain business expenses incurred by employees of the Contractor ("**Eligible Employees**") in performing work for OPG under the Agreement.

B. This Schedule sets out the terms on which OPG will reimburse the Contractor for business expenses incurred by Eligible Employees in performing work for OPG.

SECTION 1 – INTERPRETATION

1.1 Three Types of Reimbursement

OPG will reimburse the Contractor for expenses that are eligible for reimbursement in accordance with this Schedule. OPG will make the reimbursements in one of three ways respecting each Eligible Employee in respect of whom reimbursements are payable. The three ways of reimbursement are:

(a) reimbursement of individually incurred Allowable Expenses as set out in section 2 through section 5;

(b) payment on a flat rate daily basis as set out in section 6; or

(c) payment on a flat rate monthly basis as set out in section 7.

Except as expressly set out in section 6 or section 7, if OPG pays the Contractor the daily or monthly rate in respect of an Eligible Employee, OPG will reimburse the Contractor no Allowable Expenses in respect of that Eligible Employee.

1.2 Definitions

In this Schedule, the following terms have the respective meanings set out below.

(a) **Agreement** is defined in Recital A.

(b) **Allowable Expenses** is defined in section 2.1.

(c) **Business Day** means any day other than a Saturday, Sunday, New Year's Day, Family Day, Good Friday, Easter Monday, Victoria Day, Canada Day, Civic Holiday, Labour Day, Remembrance Day, Thanksgiving Day, Christmas Day and Boxing Day.

(d) **Contractor** is defined in Recital A.

(e) **Eligible Employees** is defined in Recital A.

(f) **Home Base** means the permanent residence of the Eligible Employee.

(g) **OPG Representative** is defined in section 2.1(d).

(h) **Schedule** is defined in Recital A.

(i) **Work Site** means a location at which the Eligible Employee is ordinarily required to provide services to OPG under the Agreement.

1.3 Headings

The division of this Schedule into sections, the insertion of headings and the provision of a table of contents are for convenience of reference only and are not to affect the construction or interpretation of this Schedule.

1.4 Expanded Definitions

Unless otherwise specified, words importing the singular include the plural and vice versa and words importing gender include all genders. The term "**including**" means "including without limitation", and the terms "**include**", "**includes**" and "**included**" have similar meanings. The term "**will**" means "shall".

1.5 Business Day

If under this Schedule any payment or calculation is to be made on or as of a day which is not a Business Day, that payment or calculation is to be made on or as of the next day that is a Business Day.

1.6 Payment Currency

Except as expressly set out in the Agreement, amounts to be paid or calculated under this Schedule will be paid or calculated in Canadian dollars. Any amounts to be paid or calculated which are denominated in a foreign currency will be converted into Canadian dollars, within three Business Days of the invoice date, using the Bank of Canada nominal noon exchange rate, as posted on the Bank of Canada website (currently located at www.bankofcanada.ca).

1.7 Conflict

If there is conflict between any term of this Schedule and any term in another part of the Agreement, the relevant term in the other part of the Agreement will prevail.

1.8 Notice

Any notices to be given under this Schedule will be given in accordance with the notice terms set out elsewhere in the Agreement.

SECTION 2 - REIMBURSEMENT OF ALLOWABLE EXPENSES

2.1 Allowable Expenses

OPG will only reimburse the Contractor for the following eligible expenses ("**Allowable Expenses**") to the extent they otherwise meet the requirements of this Schedule and the rest of the Agreement:

(a) air, rail and bus travel expenses permitted under section 3;

(b) vehicle expenses permitted under section 4;

(c) lodging expenses permitted under section 5; and

(d) any other expenses which have been approved in writing by the OPG individual managing the Agreement (the "**OPG Representative**").

2.2 Expenses Minimised

Notwithstanding any term in this Schedule, the Contractor will use all reasonable efforts to ensure that Eligible Employees minimise Allowable Expenses and the Contractor will ensure that all Allowable Expenses are reasonable and properly incurred in a manner consistent with effective and efficient business practice. OPG is not obliged to reimburse any expenses which are not so incurred. Eligible Employees who normally live together are expected to share accommodations and vehicle expenses, where reasonable.

2.3 Excluded Items

Notwithstanding any term in this Schedule, OPG will not reimburse any amounts to the Contractor or any Eligible Employee for any hospitality, food or incidental expenses, including, but not limited to, in respect of the following:

(a) meals, snacks, alcoholic and non-alcoholic beverages

(b) any expense whatsoever if the one way distance between the Eligible Employee's Home Base and the Work Site is less than 100 kilometres;

(c) gratuities;

(d) airline or railway club dues, fees or other charges;

(e) personal service expenses, including hair care, shoe shine, toiletry and spa treatment expenses;

(f) laundry, dry cleaning or valet expenses;

(g) hotel telephone charges or internet access

(h) personal telephone calls;

(i) cellular telephones, data devices (for example, Blackberries) or other communication devices;

(j) entertainment or recreation expenses, including pay-per-view, video, compact disk or DVD rental, in-room entertainment, games, gaming, reading, sports or exercise expenses;

(k) headsets or other in-flight expenses;

(l) dependant care expenses

(m) pet care expenses;

(n) mini bar charges or sundry items (including gum and snacks);

(o) credit card interest or other credit card expenses;

(p) automobile washes;

(q) fines or other expenses assessed or otherwise incurred in respect of traffic or parking violations; or

(r) fees or other expenses for toll highways or vehicle rental agency administration charges for use of toll highways.

2.4 Method of Reimbursement

OPG will reimburse the Contractor for Allowable Expenses which otherwise meet the requirements of this Schedule and the rest of the Agreement in accordance with the following terms.

(a) **Monthly Invoice.** The Contractor will deliver to OPG, to the address indicated in the purchase order or Agreement, on a monthly basis, an invoice for Allowable Expenses in a form and manner acceptable to the OPG Representative, acting reasonably. The Contractor will deliver to the OPG Representative, a copy of the invoice and will ensure that the invoice legibly itemises and, if necessary, briefly describes all Allowable Expenses. The Contractor will not invoice or otherwise charge OPG for any expenses other than Allowable Expenses. The Contractor will ensure that all expenses claimed on each such invoice meet the requirements of this Schedule and the rest of the Agreement and are first approved by the Contractor. If the Contractor fails to deliver an invoice to OPG for an expense within six months of the expense being incurred, OPG will not be obliged to reimburse the Contractor for such expense.

(b) **Receipts.** The Contractor will deliver to the OPG Representative, together with a copy of the invoice, original official itemised receipts for each Allowable Expense claimed (including airline, railway or bus ticket passenger coupons or electronic tickets, boarding passes, vehicle rental contracts, itemised hotel bills and travel itineraries). The Contractor will separate expenses for each Eligible Employee. Debit card and credit card receipts are not acceptable without the itemised receipt. OPG will not accept electronic, photocopied or fax copies of receipts.

(c) **GST/HST Deducted.** The Contractor will deduct all Canadian goods and services tax/harmonized sales tax levied under the *Excise Tax Act* (Canada) recovered or recoverable by the Contractor on the payment of expenses before submitting any invoice to OPG covering any Allowable Expenses. The Contractor will ensure that each such invoice will separately set out all Canadian goods and services tax /harmonized sales tax levied under the *Excise Tax Act* (Canada) and reimbursable by OPG under this Schedule.

(d) **Reimbursement.** OPG will reimburse the Contractor for Allowable Expenses which meet all of the requirements of this Schedule, received and approved by OPG before the 25th of each month on the 25th of the following month.

The Contractor will ensure that all Eligible Employees initially pay for expenses using their own payment methods. OPG will not provide any advances respecting Allowable Expenses. The Contractor is exclusively responsible for the reimbursement of expenses to all Eligible Employees. Failure by the Contractor to comply with the requirements of this Schedule and the rest of the Agreement may result in delay of reimbursement of expenses or rejection of any invoice in whole or in part.

2.5 Travel Agency

OPG has and may in the future negotiate rates with a travel service to reduce travel and lodging expenses. Unless OPG provides the Contractor with written notice stating otherwise, or the Contractor can demonstrate it can obtain lower rates from providers other than American Express Business Travel, the Contractor will ensure that all Eligible Employees process travel requirements through American Express Business Travel. OPG also encourages the Contractor to have all vehicle rental and hotel arrangements made through American Express Business Travel. American Express Business Travel may be reached in Canada and the United States at 1-866-868-4441. The Contractor will ensure that all Eligible Employees travelling for the purpose of providing services under the Agreement identify themselves to American Express Business Travel as such.

2.6 Confirming Rates

The Contractor will ensure that the rates booked by it or an Eligible Employee are the same or lower than that listed on the travel itinerary.

2.7 Home Base and Work Site

Where applicable, the Contractor will specify in each invoice the Home Base and the Work Site for each Eligible Employee. At OPG's request, the Contractor will provide written confirmation from each Eligible Employees as to the employee's permanent residence and street address. A post office box is not an acceptable street address.

SECTION 3 – AIR, RAIL OR BUS TRAVEL

3.1 Air, Rail or Bus Travel

The expense of air, rail and bus travel is an Allowable Expense to the extent the actual amount of airfare or, rail or bus fare was incurred by an Eligible Employee in providing services to OPG under the Agreement and to the extent of compliance with the other requirements of this Schedule and the rest of the Agreement. The Contractor will cause Eligible Employees, to the extent possible, to take advantage of hotel and airport shuttles where available. OPG will reimburse the Contractor for the expenses actually incurred by an Eligible Employee for travel between the Eligible Employee's Home Base, Work Site or hotel and the airport, railway station or bus terminal where the Eligible Employee arrives or departs. In addition, the amount of any such reimbursement may not exceed the lesser of:

(a) the expense of the taxi fare or other similar out of pocket charge to travel to or from the airport, railway station or bus terminal; and

(b) if applicable, parking charges at the airport, railway station or bus terminal.

3.2 Economy Class

Air expenses are not Allowable Expenses unless the Eligible Employee travels on economy class or equivalent. Rail expenses will be permitted for travel by VIA 1 or equivalent.

3.3 Vehicle Instead of Air, Rail or Bus Travel

OPG will only reimburse the Contractor for use of a personal vehicle or rental car for trips which would customarily be travelled by air, rail or bus, for the amount which is equal to the lesser of:

(a) the expense of the airfare, rail fare or bus fare that would have been reimbursed by OPG to the Contractor under section 3; and

(b) the amount that would otherwise be reimbursable by OPG to the Contractor for vehicle travel pursuant to section 4.

OPG will not reimburse the Contractor for any lodging that would not have been incurred had the trip been made by air, rail or bus.

3.4 Visits Home

OPG will reimburse air, rail or bus travel expenses for a maximum of one round trip home per month for each Eligible Employees on assignment at a Work Site where the duration is more than 45 days and the Home Base of that employee is greater than 400 kilometres from the Work Site.

3.5 Minimising Expenses

The Contractor will, to the extent possible, cause all air travel, to be by "lowest logical airfare", to take advantage of weekend specials and other discount fares and to reduce overall expenses and plan ahead (booking at least two weeks before the departure date is expected).

SECTION 4 - VEHICLES

4.1 Reimbursable Vehicle Expenses

The expense of rental vehicles or personal vehicles used by Eligible Employees will be an Allowable Expense to the extent that:

(a) the use of the vehicle was for official OPG business;

(b) the one way distance between the Eligible Employee's Home Base and the Work Site is greater than 100 kilometres or the Eligible Employee is required to provide services at a location other than the Eligible Employee's Work Site;

(c) the use of the rental vehicle was pre-approved in writing by the OPG Representative; and

(d) the expense otherwise meets the requirements of this Schedule and the rest of the Agreement.

4.2 Terms of Rental

The Contractor will make all bookings of rental vehicles through American Express Business Travel or directly with one of the OPG approved rental car agencies. The Contractor will book only mid size or smaller vehicles unless otherwise approved in writing by the OPG Representative where circumstances require it (for example, a van to carry equipment or a large group). When the Contractor books a rental vehicle, the Contractor will make the following selections when asked to select insurance coverage:

(a) where collision damage waiver is provided through the credit card company, the Contractor will decline collision damage waiver insurance; and

(b) where collision damage waiver is not provided through the credit card company, the Contractor will accept collision damage wavier insurance.

Where the Contractor fails to comply with sections 4.2(a) or 4.2(b), any additional expense that is incurred by failing to comply with either of those sections will not constitute an Allowable Expense.

4.3 Personal Vehicle

OPG will not reimburse the Contractor for use of a personal vehicle by an Eligible Employee for the first 200 kilometres of any trip (round trip), except if the Eligible Employee is required to provide services at a location other than the Eligible Employee's Work Site. If otherwise in accordance with the terms of this Schedule, OPG will reimburse the Contractor as an Allowable Expense for all personal vehicle travel by an Eligible Employee in excess of 200 kilometres (round trip), at the published rates per kilometre on the date of invoice, for vehicle expenses for Ontario set out on the Canada Revenue Agency website (http://www.cra-arc.gc.ca/tx/llrts/menu-eng.html). This Canada Revenue Agency amount covers all vehicle related expenses, except parking.

4.4 Reducing Expenses

The Contractor will use all reasonable attempts to reduce the expenses of vehicle travel by:

(a) arranging for employees to share vehicles to minimise travel expense;

(b) requiring Eligible Employees to use a rental vehicle and refuel it before returning it;

(c) considering a long-term lease for lengthy work assignments (that is, more than 30 consecutive days) when the Eligible Employee requires a rental vehicle; and

(d) requiring Eligible Employees to use public transit when travelling to locations within or around urban centres.

4.5 Multiple Users

OPG will only reimburse the Eligible Employee whose vehicle is used when two or more Eligible Employees travel in one vehicle. If two or more Eligible Employees share a rental vehicle, OPG will only reimburse the Eligible Employee who incurred the expense.

SECTION 5 - LODGING

5.1 Overnight Accommodation

The expense of overnight accommodation for Eligible Employees will be an Allowable Expense to the extent that the overnight stay was pre-approved in writing by the OPG Representative and to the extent that the expense otherwise meets the requirements of this Schedule and the rest of the Agreement. The OPG Representative will not approve any overnight accommodation unless:

(a) the presence of the Eligible Employee is required at a Work Site which is more than 200 kilometres (one way) from that Eligible Employee's Home Base; or

(b) poor weather creates hazardous driving conditions and the Eligible Employee cannot safely return to the Eligible Employee's Home Base.

The Contractor will include a written explanation for all overnight accommodation with the invoice.

SECTION 6 - DAILY RATES

6.1 Daily Rates Instead of Allowable Expenses

To the extent this section 6 applies to any Eligible Employee, none of the terms of section 2 to section 5 apply, except for any Allowable Expenses for air, rail or bus travel between an Eligible Employee's Work Site and Home Base that is reimbursable in accordance with section 3.

Notwithstanding the previous sentence, the temporary residence (where the Eligible Employee resides while working on the OPG project) will be considered the Home Base for the purposes of calculating Allowable Expenses in the event the Eligible Employee is required to travel to a location other than the Work Site.

6.2 Daily Rates

Before the commencement of, or at any time during, a work assignment for any Eligible Employee, OPG may elect based on the remaining duration of the work assignment, the distance between the Eligible Employee's Home Base and the Work Site or for other reasons to pay the Contractor a daily rate in respect of that Eligible Employee rather than to reimburse the Contractor for Allowable Expenses.

6.3 All Inclusive

Except as expressly set out in this section 6, the daily rate set out in section 6.4 is inclusive of all expenses whatsoever that will be reimbursed by OPG, including expenses respecting accommodation, local transportation, work permits and fees, utilities, communication charges, furnishings, insurance and any Allowable Expenses that would otherwise be reimbursable to the Contractor under section 2 to section 5.

6.4 Rates

Subject to adjustment under section 6.5, the following are the daily rates that OPG will pay the Contractor in respect of Work Sites:

(a) City of Toronto, $150; and

(b) all other locations, $120 (including Mississauga, Pickering, Whitby and Darlington).

6.5 Application of Rate

Where OPG has elected to pay the daily rate for an Eligible Employee, OPG will pay the daily rate to the Contractor on a monthly basis for that Eligible Employee for each full day that the Eligible Employee provided services under the Agreement and for each weekend day unless the Eligible Employee surrendered his or her accommodations. The daily rate will not be paid for any period of an unexcused absence or when the Eligible Employee has surrendered the Eligible Employee's accommodation during a home visit or absence (includes unavailability to work on weekends if trip home was taken on the weekend). The daily rate will be reduced by $35 for each day of approved trips home and on the last day of providing services under the Agreement. Where OPG has elected to pay the daily rate for Eligible Employees who normally live together, the Eligible Employees are expected to share accommodations. Adjustments may be made to the daily rate set out in section 6.4 if Eligible Employees share accommodations and other expenses.

6.6 Method of Reimbursement

OPG will pay the Contractor the applicable daily rate in accordance with the following terms.

(a) **Monthly Invoice.** The Contractor will provide OPG, on a monthly basis, with an invoice listing the number of Eligible Employees for whom the Contractor is claiming the daily rate and the number of days being claimed for each Eligible Employee. The Contractor will ensure that the invoice includes a description of the work package or project name and project number (and work breakdown structure element if applicable).

(b) **Evidence of Expenses.** The Contractor will provide OPG with original itemised receipts and time sheets evidencing that the Eligible Employee attended the Work Site and made use of temporary accommodation on each day for which the daily rate is being requested. Debit card and credit card receipts are not acceptable without the itemised receipt.

Failure by the Contractor to comply with the requirements of this Schedule and the rest of the Agreement may result in delay of reimbursement of expenses or rejection of any invoice in whole or in part.

6.7 Absences

Unless authorised in writing by the OPG Representative, OPG will not be required to pay the daily rate for an Eligible Employee where that Eligible Employee was absent from the Work Site without having been excused by the OPG Representative or where that Eligible Employee did not make use of the Eligible Employee's accommodation during an absence from the Work Site (other than an absence required to perform services to OPG under the Agreement). The OPG Representative may consider authorising payment of the daily rate for absences such as an infrequent sick day or medical appointments requiring exams or tests.

SECTION 7 – MONTHLY RATES

To the extent this section 7 applies to any Eligible Employee, none of the terms of section 2 to section 6 apply, except for any Allowable Expenses for air, rail or bus travel between an Eligible Employee's Work Site and Home Base that is reimbursable in accordance with section 3. Where OPG elects to pay on a monthly basis in respect of any Eligible Employee, OPG will pay the Contractor $1800 per month (or pro-rated portion of a month). All the terms of section 6 apply to the calculation of this monthly rate, with such modifications as the circumstances require.

Attachment C - Terms and Conditions

TERMS AND CONDITIONS

1. *Scope* – Concentric Energy Advisors, Inc. ("Concentric") will perform the services set forth in the Letter or Proposal of which these Terms and Conditions (Terms) are a part. The provisions of these Terms shall control in the case of conflict with any provisions of the Letter or Proposal.

2. *Fees and Expenses* – Unless otherwise stated, fees for services by Concentric shall be based upon the rates, at the time the work is performed, of the personnel actually involved in the assignment, on the basis of the rates most recently communicated to, and accepted by, Torys. Report production and printing, reproduction, and telephone charges will be billed to you at Concentric's standard charges for such materials for services. Expenses of consultants while on assignment or any other charge incurred or expenditure made on your behalf will be charged at our cost.

3. *Payment* – Concentric will submit monthly invoices reflecting actual work performed and expenses incurred. Payment shall be due in U.S. funds 30 days after the date of an invoice. Amounts past due more than 30 days shall bear interest at an annual rate of 12% from the due date until payment is received.

4. *Sales Tax* – You are responsible for paying any local, state, or federal sales, use, or ad valorem tax that might be assessed on our services.

5. *Independent Contractor* – It is understood and agreed that Concentric shall for all purposes be an independent contractor, shall not hold itself out as representing or acting in any manner for you, and shall have no authority to bind you to any contract or in any other manner.

6. *Termination* – These terms shall be subject to the right of either party to terminate at any time upon not less than ten (10) days prior written notice to the other party. Upon termination, you shall pay the full amount due for services rendered and costs and expenses incurred and not paid for up to that time, and the costs of returning consultant personnel to home base and other reasonable costs and expenses incurred in effecting termination and returning documents.

7. *Responsibility Statement* – Concentric agrees that the services provided for herein will be performed in accordance with recognized professional consulting standards for similar services and that adequate personnel will be assigned for that purpose. If, during the performance of these services or within six months following completion of the assignment, such services shall prove to be faulty or defective by reason of a failure to meet such standards, Concentric agrees that upon prompt written notification from you prior to the expiration of the six month period following the completion of the assignment containing any such fault or defect, such faulty portion of the services shall

be redone at no cost to you up to a maximum amount equivalent to the cost of the services rendered under this assignment. The foregoing shall constitute Concentric's sole liability with respect to the accuracy or completeness of the work and the activities involved in its preparation. In no event shall Concentric, its agents, employees, or others providing materials or performing services in connection with work on this assignment be liable for any direct, consequential or special loss or damage, whether attributable to breach of contract, tort, including negligence, or otherwise; and except as herein provided, you release, indemnify, and hold Concentric, its agents, employees, or others providing materials or performing services in connection with work on this assignment harmless from any and all liability including costs of defense, settlement and reasonable attorney's fees.

8. *Work Product* – Any report or other document prepared pursuant to these Terms shall be for your use, or OPG's. Concentric's prior written consent is required for the use of (or reference to) its report or any other document prepared pursuant to these Terms in connection with a public offering of securities or in connection with any other financing. Concentric hereby agrees, however, to the Client's reference to the work product in connection with any proxy relating to a combination between two parties. It is understood and agreed that Concentric's use of its proprietary computer software, methodology, procedures, or other proprietary information in connection with an assignment shall not give you any rights with respect to such proprietary computer software, methodology, procedures or other proprietary information. Concentric may retain and further use the technical content of its work hereunder.

9. *Excused Performance* – Concentric shall not be deemed in default of any provision hereof or be liable for any delay, failure in performance, or interruption of service resulting directly or indirectly from acts of God, civil or military authority, civil disturbance, war, strikes or other labor disputes, fires, other catastrophes, or other forces beyond its reasonable control, whether or not such event may be deemed foreseeable.

10. *Related Litigation* – In the event that Concentric employees (current or former), subcontractors or agents are compelled to provide testimony, produce documents, or otherwise incur costs or expend time in any legal proceeding related to Concentric's work for you, you agree to reimburse Concentric at its regular billing rate per hour for its time expended, and for any expenses incurred in accordance with sections 17 and 18 herein.

11. *Notices* – All notices given under or pursuant to the Terms shall be sent by Certified or Registered Mail, Return Receipt Requested, and shall be deemed to have been delivered when physically delivered if to Concentric Energy Advisors, Inc., 293 Boston Post Road West, Suite 500, Marlborough, MA 01752, Attention Mr. John J. Reed, Chairman and Chief Executive Officer, and if to you at the address shown on the Letter or Proposal of which these Terms are a part or such other address as you may designate by written notice to us.

12. *Complete Agreement* – It is understood and agreed that these Terms and the Letter or Proposal of which they are a part embody the complete understanding of the parties and that any and all provisions, negotiations and representations not included herein are hereby abrogated and that these terms cannot be changed, modified or varied except by written instrument signed by both parties. In the event you issue a purchase order or memorandum or other instrument covering the services herein provided, it is hereby specifically agreed and understood that such purchase order, memorandum, or instrument is for your internal purposes only, and any and all terms and conditions contained therein, whether printed or written, shall be of no force or effect unless agreed to in writing by Concentric. No waiver by either parties of a breach hereof or default hereunder shall be deemed a waiver by such party of a subsequent breach or default of like or similar nature.

13. *Conflicts of Interest* – Concentric confirms it is and will remain free of any actual or potential conflicts of interest, respecting this assignment relating to OPG.

14. *Staffing of Assignments* – Concentric's initial staffing for this assignment will include: James Coyne, Daniel Dane, and Sarah Crimmins. Concentric will be permitted to assign up to two other consulting staff members without Torys' prior approval. Concentric will obtain the prior approval from Torys before assigning any material work to any person beyond those permitted by this paragraph.

    Concentric will strive to avoid duplication of effort in handling the assignment.

15. *Privilege and Confidential Information* - Concentric confirms that correspondence and other communications, memorandums, documents, opinion letters and records exchanged between Torys, OPG business personnel or other OPG representatives and any OPG Counsel are not to be released to other persons without the prior written approval of Torys. It is recognised, however, that the rules of privilege governing the release of such correspondence and other communications, memorandums, documents, opinion letters and records vary from jurisdiction to jurisdiction. Concentric and Torys will agree on a protocol in an effort to minimise the risk of required disclosure and shall agree as to when Concentric must make any required disclosure. In addition to any requirements imposed on Concentric by law or regulation, Concentric will maintain all information provided to Concentric by Torys and OPG in strict confidence, including the fact of this retainer.

16. *Public Disclosure* - Concentric will not publicly disclose or reference work activities performed for Torys and OPG in any manner, including promotional brochures, advertisements, websites or similar representations, without the prior written approval of Torys and OPG.

17. *Accounts* - Notwithstanding the provisions of section 2 above respecting Fees and Expenses, Concentric agrees to the following provisions respecting this assignment. Due to the confidential nature of this assignment, Concentric agrees to submit:

    (1) a summary sheet only of each account, showing: (a) the fee, (b) expenses, (c) Canadian goods and services tax or any other applicable taxes, (d) a subtotal, excluding taxes, and (e) the grand total;

(2) a detailed account which will include at least the following information:

(a) identification of the billing period to which the account relates;

(b) an itemised summary of the work that has been undertaken, including a brief description of each service, the date on which each service was rendered, the time spent on each service, the individual who performed the service and the billing rate of such individual;

(c) an itemisation and brief description of all expenses incurred during the billing period, with copies of supporting invoices for any expenses in excess of $100, unless Torys indicates that such invoices are not required;

18. *Other Rules on Fees and Expenses*

(a) Concentric will bill for travel expenses only in accordance with OPG's Standard Form Business Expense Schedule provided by Torys to Concentric as the same may be amended, supplemented or replaced from time to time. Concentric may not bill for any time away from the office which is not spent on this assignment.

(b) Concentric will bill for photocopying and printing at a rate of no more than $0.075 per page for all pages on the assignment. If it is anticipated that the photocopying expenses for a particular matter will exceed $500 in any month, Concentric will advise Torys accordingly so that it may be considered whether the copying services should be performed by a third party service provider.

(c) Concentric will not bill for telephone expenses or the transmission or receipt of faxes. Whenever possible, e-mail is preferred.

(d) Concentric will not bill for routine (non project specific) secretarial work or office administration, and will not bill for charges for "opening a file", software licenses, system application charges, legal research search fees or office supplies.

(e) Concentric will not bill for overtime of administrative staff, unless Torys has consented to such billings in advance.

(f) Concentric will not bill for time spent preparing or reviewing proposals, accounts or budgets.

19. *General* - These Terms are governed by, and are to be construed and interpreted in accordance with, the laws of Ontario and the laws of Canada applicable in Ontario. These Terms will not be amended by any invoice or other document, even where such document purports to be paramount to any term of these Terms, unless such document is signed by Concentric and Torys.

ONTARIO ENERGY BOARD

Rules of Practice and Procedure
(Revised November 16, 2006, July 14, 2008, October 13, 2011 and January 9, 2012)

13A. Expert Evidence

13A.01 A party may engage, and two or more parties may jointly engage, one or more experts to give evidence in a proceeding on issues that are relevant to the expert's area of expertise.

13A.02 An expert shall assist the Board impartially by giving evidence that is fair and objective.

13A.03 An expert's evidence shall, at a minimum, include the following:

(a) the expert's name, business name and address, and general area of expertise;

(b) the expert's qualifications, including the expert's relevant educational and professional experience in respect of each issue in the proceeding to which the expert's evidence relates;

(c) the instructions provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert's evidence relates;

(d) the specific information upon which the expert's evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence; and

(e) in the case of evidence that is provided in response to another expert's evidence, a summary of the points of agreement and disagreement with the other expert's evidence.

13A.04 In a proceeding where two or more parties have engaged experts, the Board may require two or more of the experts to:

(a) in advance of the hearing, confer with each other for the purposes of, among others, narrowing issues, identifying the points on which their views differ and are in agreement, and preparing a joint written statement to be admissible as evidence at the hearing; and

(b) at the hearing, appear together as a concurrent expert panel for the purposes of, among others, answering questions from the Board and others as permitted by the Board, and providing comments on the views of another expert on the same panel.

13A.05 The activities referred to in **Rule 13A.04** shall be conducted in accordance with such directions as may be given by the Board, including as to:

(a) scope and timing;

(b) the involvement of any expert engaged by the Board;

(c) the costs associated with the conduct of the activities;

(d) the attendance or non-attendance of counsel for the parties, or of other persons, in respect of the activities referred to in paragraph (a) of **Rule 13A.04**; and

(e) any issues in relation to confidentiality.

13A.06 A party that engages an expert shall ensure that the expert is made aware of, and has agreed to accept, the responsibilities that are or may be imposed on the expert as set out in this **Rule 13A**.

Table 1
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital
Calendar Year Ending December 31, 2021

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	37.1	0.2%	3.65%	3.8
2	**Existing/Planned Long-Term Debt**	2	3,406.0	21.8%	4.48%	152.6
3	**Other Long-Term Debt Provision**	3	4,534.6	29.0%	4.48%	203.1
4	**Total Debt**	4	7,977.7	51.0%	4.51%	359.5
5	**Common Equity**	4	7,664.9	49.0%	9.19%	704.4
6	**Rate Base Financed by Capital Structure**	5, 7	15,642.6	96.4%	6.80%	1,063.9
7	**Adjustment for Lesser of UNL or ARC**	5, 6	590.1	3.6%	5.11%	30.2
8	**Rate Base**		16,232.7	100%	6.74%	1,094.0

Notes:

1. Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.
2. Ex. C1-1-2 Table 10, line 29.
3. Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.
4. Capital Structure proposed in Ex. C1-1-1, Attch 1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (October 15, 2015).
5. The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.
6. Principal from C2-1-1 Table 2, line 27. Cost rate from Ex. C2-1-1, section 3.2.
7. As shown in Ex. C1-1-1 Chart 1.

Table 2
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital
Calendar Year Ending December 31, 2020

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	37.1	0.2%	3.80%	3.8
2	**Existing/Planned Long-Term Debt**	2	3,527.6	23.4%	4.49%	158.5
3	**Other Long-Term Debt Provision**	3	4,125.8	27.4%	4.49%	185.4
4	**Total Debt**	4	7,690.6	51.0%	4.52%	347.7
5	**Common Equity**	4	7,389.0	49.0%	9.19%	679.0
6	**Rate Base Financed by Capital Structure**	5, 7	15,079.5	96.0%	6.81%	1,026.7
7	**Adjustment for Lesser of UNL or ARC**	5, 6	624.6	4.0%	5.11%	31.9
8	**Rate Base**		15,704.1	100%	6.74%	1,058.6

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. C1-1-2 Table 9, line 33.

3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.

4 Capital Structure proposed in Ex. C1-1-1, Attch 1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (October 15, 2015).

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from C2-1-1 Table 2, line 27. Cost rate from Ex. C2-1-1, section 3.2.

7 As shown in Ex. C1-1-1 Chart 1.

Table 3
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital
Calendar Year Ending December 31, 2019

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	37.1	0.3%	3.75%	3.8
2	**Existing/Planned Long-Term Debt**	2	3,489.7	31.9%	4.52%	157.8
3	**Other Long-Term Debt Provision**	3	2,044.2	18.7%	4.52%	92.4
4	**Total Debt**	4	5,571.0	51.0%	4.56%	254.0
5	**Common Equity**	4	5,352.5	49.0%	9.19%	491.9
6	**Rate Base Financed by Capital Structure**	5, 7	10,923.5	94.2%	6.83%	745.9
7	**Adjustment for Lesser of UNL or ARC**	5, 6	674.9	5.8%	5.11%	34.5
8	**Rate Base**		11,598.4	100%	6.73%	780.4

Notes:
1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.
2 Ex. C1-1-2 Table 8, line 36.
3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.
4 Capital Structure proposed in Ex. C1-1-1, Attch 1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (October 15, 2015).
5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.
6 Principal from C2-1-1 Table 2, line 27. Cost rate from Ex. C2-1-1, section 3.2.
7 As shown in Ex. C1-1-1 Chart 1.

Table 4
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital
Calendar Year Ending December 31, 2018

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	37.1	0.3%	2.73%	3.4
2	**Existing/Planned Long-Term Debt**	2	3,168.1	28.8%	4.60%	145.7
3	**Other Long-Term Debt Provision**	3	2,401.8	21.8%	4.60%	110.4
4	**Total Debt**	4	5,606.9	51.0%	4.63%	259.6
5	**Common Equity**	4	5,387.0	49.0%	9.19%	495.1
6	**Rate Base Financed by Capital Structure**	5, 7	10,993.9	93.8%	6.86%	754.6
7	**Adjustment for Lesser of UNL or ARC**	5, 6	725.1	6.2%	5.11%	37.1
8	**Rate Base**		11,719.0	100%	6.76%	791.7

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. C1-1-2 Table 7, line 38.

3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.

4 Capital Structure proposed in Ex. C1-1-1, Attch 1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (October 15, 2015).

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from C2-1-1 Table 2, line 27. Cost rate from Ex. C2-1-1, section 3.2.

7 As shown in Ex. C1-1-1 Chart 1.

Table 5
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital
Calendar Year Ending December 31, 2017

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	37.1	0.3%	1.41%	2.9
2	**Existing/Planned Long-Term Debt**	2	2,878.4	26.6%	4.89%	140.6
3	**Other Long-Term Debt Provision**	3	2,603.7	24.1%	4.89%	127.2
4	**Total Debt**	4	5,519.1	51.0%	4.91%	270.8
5	**Common Equity**	4	5,302.7	49.0%	9.19%	487.3
6	**Rate Base Financed by Capital Structure**	5, 7	10,821.8	93.3%	7.01%	758.1
7	**Adjustment for Lesser of UNL or ARC**	5, 6	775.4	6.7%	5.11%	39.6
8	**Rate Base**		11,597.2	100%	6.88%	797.7

Notes:
1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.
2 Ex. C1-1-2 Table 6, line 41.
3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.
4 Capital Structure proposed in Ex. C1-1-1, Attch 1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (October 15, 2015).
5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.
6 Principal from C2-1-1 Table 2, line 27. Cost rate from Ex. C2-1-1, section 3.2.
7 As shown in Ex. C1-1-1 Chart 1.

Table 6
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital
Calendar Year Ending December 31, 2016

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	37.1	0.4%	0.79%	2.7
2	**Existing/Planned Long-Term Debt**	2	2,558.8	25.1%	5.19%	132.9
3	**Other Long-Term Debt Provision**	3	3,010.9	29.5%	5.19%	156.4
4	**Total Debt**	4	5,606.7	55.0%	5.21%	292.0
5	**Common Equity**	4	4,587.3	45.0%	3.00%	137.8
6	**Rate Base Financed by Capital Structure**	5	10,194.1	92.5%	4.22%	429.8
7	**Adjustment for Lesser of UNL or ARC**	5, 6	825.7	7.5%	5.11%	42.2
8	**Rate Base**		11,019.8	100%	4.28%	472.0

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. C1-1-2 Table 5, line 40.

3 Debt required to balance capital structure with forecast rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2) per EB-2013-0321 Decision with Reasons.

4 Capital Structure approved by the OEB in EB-2013-0321. Return on Equity as calculated in Ex. I1-1-1 Table 4.

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from C2-1-1 Table 2, line 27. Cost rate from Ex. C2-1-1, section 3.2.

Table 7
Capitalization and Cost of Capital
Summary of Capitalization and Actual Cost of Capital
Calendar Year Ending December 31, 2015

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Actual Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Achieved Capitalization and Return on Capital:					
1	**Short-term Debt**	1	45.5	0.5%	1.01%	2.8
2	**Existing/Planned Long-Term Debt**	2	2,590.0	26.4%	5.18%	134.0
3	**Other Long-Term Debt Provision**	3	2,765.3	28.2%	5.18%	143.1
4	**Total Debt**	4	5,400.8	55.0%	5.18%	279.9
5	**Common Equity**	4, 5	4,418.9	45.0%	2.67%	118.0
6	**Rate Base Financed by Capital Structure**	6	9,819.7	88.2%	4.05%	398.0
7	**Adjustment for Lesser of UNL or ARC**	6, 7	1,308.7	11.8%	5.37%	70.3
8	**Rate Base**		11,128.4	100%	4.21%	468.3

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. C1-1-2 Table 4, line 40.

3 Debt required to balance capital structure with actual rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2) per EB-2013-0321 Decision with Reasons.

4 Capital Structure as approved by the OEB in EB-2013-0321.

5 Return on Equity in col. (d) determined using the reconciliation approach discussed in EB-2013-0321 Ex. C1-1-1 Section 4.2, starting with the financial results for OPG's prescribed assets calculated in accordance with US GAAP.

6 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

7 Principal from C2-1-1 Table 2, line 27.

Table 8
Capitalization and Cost of Capital
Summary of Capitalization and Actual Cost of Capital
Calendar Year Ending December 31, 2014

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Actual Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Achieved Capitalization and Return on Capital:					
1	**Short-term Debt**	1	72.7	0.7%	1.20%	3.6
2	**Existing Long-Term Debt**	2	3,181.7	32.2%	5.01%	159.5
3	**Other Long-Term Debt Provision**	3	2,007.6	20.3%	5.01%	100.6
4	**Total Debt**	4	5,262.0	53.3%	5.01%	263.7
5	**Common Equity**	4, 5	4,610.4	46.7%	6.32%	291.5
6	**Rate Base Financed by Capital Structure**	6	9,872.4	87.7%	5.62%	555.2
7	**Adjustment for Lesser of UNL or ARC**	6, 7	1,389.4	12.3%	5.37%	74.6
8	**Rate Base**	8	11,261.8	100.0%	5.59%	629.8

Notes:
1. Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.
2. Ex. C1-1-2 Table 3, line 41.
3. Debt required to balance capital structure with actual rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2) per EB-2013-0321 and EB-2010-0008 Decisions with Reasons.
4. For January to October 2014, the capital structure reflects 53% debt and 47% equity approved in EB-2010-0008. Effective November 1, 2014, the capital structure reflects 55% debt and 45% equity approved in EB-2013-0321.
5. Return on Equity in col. (d) determined using the reconciliation approach discussed in EB-2013-0321 Ex. C1-1-1 Section 4.2, starting with the financial results for OPG's prescribed assets calculated in accordance with US GAAP.
6. The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.
7. Principal from C2-1-1 Table 2, line 27.
8. Newly regulated hydroelectric facilities are included for the full year beginning on January 1, 2014, as presented in the EB-2013-0321 Payment Amounts Order. For January 1, 2014 to October 31, 2014, revenues for production from these facilities were based on electricity market prices.

Table 9
Capitalization and Cost of Capital
Summary of Capitalization and Actual Cost of Capital
Calendar Year Ending December 31, 2013

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Actual Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Achieved Capitalization and Return on Capital:					
1	**Short-term Debt**	1	10.7	0.1%	1.17%	2.2
2	**Existing Long-Term Debt**	2	2,514.2	35.2%	5.09%	128.0
3	**Other Long-Term Debt Provision**	3	1,258.3	17.6%	5.09%	64.0
4	**Total Debt**	4	3,783.2	53.0%	5.13%	194.2
5	**Common Equity**	4, 5	3,354.9	47.0%	0.46%	15.3
6	**Rate Base Financed by Capital Structure**	6	7,138.2	82.9%	2.93%	209.5
7	**Adjustment for Lesser of UNL or ARC**	6, 7	1,470.2	17.1%	5.37%	78.9
8	**Rate Base**	8	8,608.3	100%	3.35%	288.4

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. C1-1-2 Table 2, line 40.

3 Debt required to balance capital structure with actual rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2) per EB-2010-0008 Decision with Reasons.

4 Capital Structure as approved by the OEB in EB-2010-0008.

5 Return on Equity in col. (d) determined using the reconciliation approach discussed in EB-2013-0321 Ex. C1-1-1 Section 4.2, starting with the financial results for OPG's prescribed assets calculated in accordance with US GAAP.

6 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

7 Principal from C2-1-1 Table 2, line 27.

8 Amount in col. (a) as shown in EB-2013-0321, L-1.0-1, Staff-002, Att. 1, Table 5, col. (a).
Newly regulated hydroelectric assets are not included as they were not prescribed until 2014.

COST OF LONG-TERM DEBT

1.0 PURPOSE

This evidence describes the methodology used to determine the long-term debt and associated cost for OPG's regulated operations for the test period. It also provides details of OPG's existing and planned long-term borrowing and associated costs for 2013 to 2021.[1]

2.0 OVERVIEW

The long-term debt supporting OPG's regulated operations is comprised of existing and planned long-term debt issues plus a long-term debt provision required to reconcile OPG's regulated debt to its OEB-approved capital structure. The summary of capitalization for the test period is provided in Ex. C1-1-1 Tables 1 through 5.

OPG has used the same methodology to determine the regulated portion of existing and planned long-term debt as was approved by the OEB in EB-2007-0905, EB-2010-0008, and EB-2013-0321.

3.0 METHODOLOGY

3.1 Project-Related Long-Term Debt Issues

OPG assigns all existing and planned project-related financing to regulated or unregulated operations based on whether the project is related to its regulated assets. All project-related financing that is not associated with OPG's regulated assets is assigned to unregulated operations. OPG may also forecast financing requirements for projects that are still in the design/assessment phase; however these financing requirements are not assigned to OPG's regulated operations unless, and until, they are specifically identified as a project in OPG's capital budget for its regulated operations.

3.2 Corporate Long-Term Debt Issues

The portfolio of long-term debt remaining after project-related financing has been directly assigned is allocated to regulated and unregulated operations. For the test period, OPG has

[1] This evidence is substantially unchanged from that filed in EB-2013-0321; it has been updated as appropriate.

applied the allocation methodology approved by the OEB in EB-2007-0905, EB-2010-0008 and EB-2013-0321.

Under this methodology, the book value of OPG's net fixed assets (gross fixed assets less accumulated depreciation plus construction work in progress) is used to allocate the remaining portfolio of long-term debt. The net fixed asset values are adjusted to remove asset values that were financed pursuant to project-specific arrangements, and nuclear liabilities (the lesser of OPG's asset retirement cost and unfunded nuclear liabilities). The adjusted relative net fixed asset ratio is then applied to OPG's portfolio of long-term debt (excluding project-related financing) to determine the amount of existing/planned debt to be included in the long-term debt component of OPG's capital structure for its regulated assets. The allocation ratios are used to allocate company-wide borrowing in Ex. C1-1-2 Table 2 (2013) through Ex. C1-1-2 Table 10 (2021).

The above allocation ratios are calculated in Ex. C1-1-2 Table 1. Consistent with the approach in EB-2007-0905, EB-2010-0008, and EB-2013-0321, OPG has used information from its most recent audited financial statements (2015) to develop the allocation factor for 2016 to 2021.

For 2013 to 2015, the allocation ratio is based on actual year-end values for net fixed assets in the corresponding year.

4.0 COST OF EXISTING AND PLANNED NEW DEBT ISSUES

4.1 Existing Debt Issues

OPG's debt continuity schedules (Ex. C1-1-2 Tables 2 through 4) provide the actual cost of debt issued and outstanding between January 1, 2013 and December 31, 2015.[2] The average remaining term of these long-term debt issues is approximately 7 years as at December 31, 2015.

[2] Long-term debt outstanding prior to January 1, 2013 is detailed in EB-2013-0321 Ex. C1-1-2 Tables 2 (2010), Table 3 (2011) and Table 4 (2012)

Existing Ontario Electricity Financial Corporation ("OEFC") corporate debt will be retired or refinanced at maturity depending on OPG's liquidity at that time. OPG does not plan to redeem the debt prior to its maturity since its agreements with the OEFC contain call provisions that make it more expensive to redeem the debt compared to the potential benefit of refinancing in a lower interest rate environment.

OPG's long-term debt outstanding at December 31, 2015, as reflected in OPG's 2015 financial results, is $5,472M. This balance consisted of corporate debt held by the OEFC of $1,960M and project-related debt held by the OEFC related to regulated operations of $1,065M. The remaining $2,447M of OPG's long term debt obligation outstanding as of December 31, 2015 is OEFC and non OEFC project related financing associated directly with OPG's unregulated operations.

At December 31, 2015 most of OPG's long-term debt outstanding is of approximately 10 year duration (Ex. C1-1-2, Table 4 Issues 17 to 21, 23 and 25 and Niagara 1 to 24) except for 30 year corporate debt issued in 2011 and 2012, 9.8 year corporate debt issued in 2007, and 5 year corporate debt issued in 2010. OPG did not issue any new debt in 2014 or 2015.

Project-related debt for OPG's regulated operations is limited to borrowing for the Niagara Tunnel under an agreement with the OEFC.

4.2 Interest Rate on Planned New Debt Issues

The rate of interest on OPG's debt is determined using the same methodology as described in EB-2007-0905, EB-2010-0008, and EB-2013-0321. It is based on the prevailing benchmark Government of Canada bond for the corresponding term of the debt, as published by a verifiable market monitoring service on the day prior to the date funds are advanced, plus a credit margin determined five business days before the date funds are advanced. The credit margin is determined based on a sample of quotes for OPG's credit margin as provided by a selected group of Canadian banks. The credit margin will be the same for corporate and project-related debt as the credit margin evaluates OPG as a borrowing entity rather than a particular project. The interest rate for project-related debt will be the same as the interest rate for corporate debt issued on the same date for the same terms and conditions.

The cost of planned new and refinanced corporate debt and project-related debt for 2016 to 2021 is based on a forecast of the 10-year Long Canada Bond published in January 2016 by Global Insight, a third party independent market source, as shown in Chart 1.

Chart 1:
Forecast 10-year Long Canada Bond Rates (%)

Year	Q1	Q2	Q3	Q4
2016	1.98	2.13	2.20	2.26
2017	2.32	2.36	2.39	2.48
2018	2.62	2.79	3.07	3.28
2019	3.32	3.32	3.32	3.32
2020	3.32	3.32	3.32	3.32
2021	3.32	3.32	3.32	3.32

OPG’s credit spread at the end of 2015 was 161 basis points. This spread has been added to the Global Insight rates noted in Chart 1 to determine the forecast rate for OPG’s OEFC planned debt in 2016 to 2021, as shown in Chart 2.

Chart 2:
Forecast 10-year Long Canada Bond Rates Plus Credit Risk Spread (%)

Year	Q1	Q2	Q3	Q4
2016	3.59	3.74	3.81	3.87
2017	3.93	3.97	4.00	4.09
2018	4.23	4.40	4.68	4.89
2019	4.93	4.93	4.93	4.93
2020	4.93	4.93	4.93	4.93
2021	4.93	4.93	4.93	4.93

4.3 Planned Long-Term Debt Issues

The total amounts of planned debt issues are listed in Ex. C1-1-2 Table 5a (2016), Table 6a (2017), Table 7a (2018), Table 8a (2019), Table 9a (2020), and Table 10a (2021). Maturing and new debt issues (total corporate and Niagara Tunnel) are summarized in Chart 3 below.

Chart 3:
Long-Term Debt Retirements and Planned Issues ($M)

	2016	2017	2018	2019	2020	2021	Total
Debt Issues Maturing	$160	$780	$300	$250	$660	$185	$2,335
Planned New Debt Issues	$400	$1,500	$850	$600	$550	$100	$4,000

OPG does not plan to issue any additional project-related financing for the regulated assets during the bridge and test periods.

5.0 OTHER LONG-TERM DEBT

As discussed above, OPG finances long-term assets with long-term financing. Consistent with the methodology approved in EB-2007-0905, EB-2010-0008 and EB-2013-0321, OPG has used a provision for long-term debt to reconcile the debt component of its regulated capital structure with the proposed rate base that financing supports. OPG's other long-term debt provision is determined based on the following approach:

- The total debt for regulated operations is determined by applying OPG's proposed capital structure to its proposed regulated rate base.
- The actual and projected project-related and corporate long-term debt assigned or allocated to OPG's regulated operations is deducted.
- The actual and projected portion of short-term debt allocated to regulated operations is deducted. This calculation is described in Ex. C1-1-3.
- The result is the residual long-term debt.

Consistent with the OEB's findings in EB-2007-0905, EB-2010-0008 and EB-2013-0321, OPG has applied the rate for its existing and planned long-term debt to the other long term debt provision.

Table 1
Capitalization and Cost of Capital
Allocation of Existing Long-term Debt ($M)

Line No.	Asset	Note	Amount 2013 [1]	2014	2015
			(a)	(b)	(c)
	Company-Wide:				
1	**Net Fixed Assets**		13,635.6	15,796.8	18,098.2
2	**Adjusted Construction Work in Progress**		3,161.9	1,872.4	2,594.9
3	**Asset Values Using Project Financing**		(4,148.0)	(4,417.8)	(4,549.9)
4	**Adjusted Net Fixed Assets**		12,649.6	13,251.5	16,143.2
5	**Adjustment for Lesser of UNL or ARC**	2,3	2,416.5	2,331.1	2,291.5
6	**Adjusted Net Fixed Funded Assets** (line 4 - line 5)		10,233.1	10,920.4	13,851.8
	Regulated Operations				
7	**Net Fixed Assets**	4	8,118.6	10,400.0	9,983.6
8	**Adjusted Construction Work in Progress**		854.5	1,740.7	2,391.7
9	**Asset Values Using Project Financing**	5	(1,443.9)	(1,354.9)	(1,340.1)
10	**Adjusted Net Fixed Assets**		7,529.2	10,785.7	11,035.2
11	**Adjustment for Lesser of UNL or ARC**	2, 6	1,470.2	1,389.4	1,308.7
12	**Adjusted Net Fixed Funded Assets** (line 10 - line 11)		6,059.1	9,396.3	9,726.5
13	**Total Regulated/Company-Wide Adjusted Net Fixed Assets**		59.2%	86.0%	70.2%
	(line 12 / line 6)				

Notes:

1 Newly regulated hydroelectric assets are not included in 2013 as they were not prescribed until 2014, and are included starting in 2014.

2 Reflects OEB direction to adjust the allocation of existing long-term debt to regulated operations to reflect the OEB's decision with respect to the unfunded nuclear liabilities (EB-2007-0905 Decision with Reasons, p. 165).

3 Methodology is as reflected in the EB-2013-0321 and EB-2010-0008 Payment Amounts Orders. Company-wide adjustment is derived as follows:

Table to Note 3

Line No.	Company-Wide Lesser of UNL and ARC	2013	2014	2015
		(a)	(b)	(c)
	Company-Wide UNL:			
1a	C2-T1-S1 Table 2, line 20	1,719.6	1,659.2	1,562.7
2a	+ C2-T1-S1 Table 3, line 11	7,293.3	7,637.8	8,005.2
3a	- C2-T1-S1 Table 3, line 17	6,596.4	6,965.9	7,276.5
4a	= Company Wide UNL	2,416.5	2,331.1	2,291.5
	Company-Wide ARC:			
5a	C2-T1-S1 Table 2, line 26	1,470.2	1,389.4	1,308.7
6a	+ C2-T1-S1 Table 3, line 24	1,894.2	1,793.7	1,693.6
7a	= Company Wide ARC	3,364.3	3,183.1	3,002.3
8a	Lesser of Company Wide UNL and ARC	2,416.5	2,331.1	2,291.5

4 Represents closing net book value of Property, Plant & Equipment assets of the regulated business reflected in the calculation of actual rate base.

5 Represents the closing net book value of the Niagara Tunnel Project.

6 Ex. C2-1-1 Table 2, line 27.

Table 2
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2013

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 and 2 Matured During 2007							
	Issues 3 and 4 Matrued During 2008							
	Issues 5 and 6 Matured During 2009							
	Issues 7, 8, 11, 12, 13, 14, 15 Matured During 2010							
	Issues 9 and 10 Matured During 2011							
	Issue 16 Matrured During 2012						**(Note 4)**	
1	**Issue 17**		100.0	6/22/2007	10.0	6/22/2017	5.44%	5.4
2	**Issue 18**		200.0	9/24/2007	10.0	9/22/2017	5.53%	11.1
3	**Issue 19**		400.0	12/21/2007	9.8	9/22/2017	5.31%	21.2
4	**Issue 20**		200.0	3/22/2008	10.0	3/22/2018	5.35%	10.7
5	**Issue 21**		100.0	3/22/2009	10.0	3/22/2019	5.65%	5.7
6	**Issue 22**		300.0	3/22/2010	5.0	3/22/2015	3.56%	10.7
7	**Issue 23**		230.0	3/22/2010	10.0	3/22/2020	4.68%	10.8
8	**Issue 24**		200.0	9/22/2010	5.0	9/22/2015	3.24%	6.5
9	**Issue 25**		230.0	9/22/2010	10.0	9/22/2020	4.39%	10.1
10	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
11	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
12	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
13	**Total**		**2,460.0**				**4.72%**	**116.0**
	Regulated Portion of Company-Wide Borrowing							
14	**Allocation**	3	**1,456.6**				**4.72%**	**68.7**
	Project Financing - Regulated Projects							
15	**Niagara 1**		160.0	10/22/2006	10.0	10/22/2016	5.23%	8.4
16	**Niagara 2**		50.0	1/22/2007	10.0	1/22/2017	5.10%	2.5
17	**Niagara 3**		30.0	4/23/2007	10.0	4/22/2017	5.09%	1.5
18	**Niagara 4**		40.0	1/22/2008	10.0	1/22/2018	5.53%	2.2
19	**Niagara 5**		30.0	4/22/2008	10.0	4/22/2018	5.90%	1.8
20	**Niagara 6**		30.0	7/22/2008	10.0	7/22/2018	5.87%	1.8
21	**Niagara 7**		30.0	1/22/2009	10.0	1/22/2019	8.41%	2.5
22	**Niagara 8**		35.0	4/22/2009	10.0	4/22/2019	7.71%	2.7
23	**Niagara 9**		35.0	7/22/2009	10.0	7/22/2019	6.41%	2.2
24	**Niagara 10**		50.0	10/22/2009	10.0	10/22/2019	5.63%	2.8
25	**Niagara 11**		50.0	1/22/2010	10.0	1/22/2020	5.44%	2.7
26	**Niagara 12**		65.0	4/22/2010	10.0	4/22/2020	5.73%	3.7
27	**Niagara 13**		35.0	7/22/2010	10.0	7/22/2020	5.57%	1.9
28	**Niagara 14**		50.0	10/22/2010	10.0	10/22/2020	4.87%	2.4
29	**Niagara 15**		40.0	1/24/2011	10.0	1/22/2021	5.18%	2.1
30	**Niagara 16**		35.0	4/26/2011	10.0	4/22/2021	5.34%	1.9
31	**Niagara 17**		50.0	7/22/2011	10.0	7/22/2021	5.24%	2.6
32	**Niagara 18**		60.0	10/24/2011	10.0	10/22/2021	5.74%	3.4
33	**Niagara 19**		40.0	1/22/2012	10.0	1/22/2022	5.50%	2.2
34	**Niagara 20**		35.0	4/22/2012	10.0	4/22/2022	5.36%	1.9
35	**Niagara 21**		45.0	7/22/2012	10.0	7/22/2022	5.51%	2.5
36	**Niagara 22**		30.0	10/22/2012	10.0	10/22/2022	5.52%	1.7
37	**Niagara 23**	1,5	18.8	1/22/2013	10.0	1/22/2023	5.35%	1.0
38	**Niagara 24**	2,5	13.9	4/22/2013	10.0	4/22/2023	5.37%	0.7
39	**Total**		1,057.7				5.60%	59.3
	Total Regulated Funded Long-Term Debt							
40	Line 14+39		2,514.2				5.09%	128.0

See Ex. C1-1-2 Table 2a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 2a
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2013
Notes to Ex. C1-1-2, Table 2

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Niagara 23	1/22/2013	20.0	343.0	18.8
Note 2	Niagara 24	4/22/2013	20.0	253.0	13.9

Note 3 Allocation ratio for 2013 as per Ex. C1-1-2 Table 1, line 13, col (a) (excludes Newly Regulated Hydroelectric net fixed assets).

Note 4 Includes related costs of issuance/maturity and the amortization of debt discount or premium.

Note 5 Realized effective rate on 2013 debt issuances:

New Issues	Effective Rate
Niagara 23	5.35%
Niagara 24	5.37%
Average Rate	5.36%

Table 3
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2014

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 and 2 Matrured During 2007							
	Issues 3 and 4 Matrured During 2008							
	Issues 5 and 6 Matrured During 2009							
	Issues 7, 8, 11, 12, 13, 14, 15 Matrured During 2010							
	Issues 9 and 10 Matrured During 2011							
	Issue 16 Matrured During 2012						**(Note 2)**	
1	**Issue 17**		100.0	6/22/2007	10.0	6/22/2017	5.44%	5.4
2	**Issue 18**		200.0	9/24/2007	10.0	9/22/2017	5.53%	11.1
3	**Issue 19**		400.0	12/21/2007	9.8	9/22/2017	5.31%	21.2
4	**Issue 20**		200.0	3/22/2008	10.0	3/22/2018	5.35%	10.7
5	**Issue 21**		100.0	3/22/2009	10.0	3/22/2019	5.65%	5.7
6	**Issue 22**		300.0	3/22/2010	5.0	3/22/2015	3.56%	10.7
7	**Issue 23**		230.0	3/22/2010	10.0	3/22/2020	4.68%	10.8
8	**Issue 24**		200.0	9/22/2010	5.0	9/22/2015	3.24%	6.5
9	**Issue 25**		230.0	9/22/2010	10.0	9/22/2020	4.39%	10.1
10	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
11	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
12	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
13	**Total**		**2,460.0**				**4.72%**	**116.0**
	Regulated Portion of Company-Wide Borrowing							
14	**Allocation**	1	2,116.7				4.72%	99.8
	Project Financing - Regulated Projects							
15	**Niagara 1**		160.0	10/22/2006	10.0	10/22/2016	5.23%	8.4
16	**Niagara 2**		50.0	1/22/2007	10.0	1/22/2017	5.10%	2.5
17	**Niagara 3**		30.0	4/23/2007	10.0	4/22/2017	5.09%	1.5
18	**Niagara 4**		40.0	1/22/2008	10.0	1/22/2018	5.53%	2.2
19	**Niagara 5**		30.0	4/22/2008	10.0	4/22/2018	5.90%	1.8
20	**Niagara 6**		30.0	7/22/2008	10.0	7/22/2018	5.87%	1.8
21	**Niagara 7**		30.0	1/22/2009	10.0	1/22/2019	8.41%	2.5
22	**Niagara 8**		35.0	4/22/2009	10.0	4/22/2019	7.71%	2.7
23	**Niagara 9**		35.0	7/22/2009	10.0	7/22/2019	6.41%	2.2
24	**Niagara 10**		50.0	10/22/2009	10.0	10/22/2019	5.63%	2.8
25	**Niagara 11**		50.0	1/22/2010	10.0	1/22/2020	5.44%	2.7
26	**Niagara 12**		65.0	4/22/2010	10.0	4/22/2020	5.73%	3.7
27	**Niagara 13**		35.0	7/22/2010	10.0	7/22/2020	5.57%	1.9
28	**Niagara 14**		50.0	10/22/2010	10.0	10/22/2020	4.87%	2.4
29	**Niagara 15**		40.0	1/24/2011	10.0	1/22/2021	5.18%	2.1
30	**Niagara 16**		35.0	4/26/2011	10.0	4/22/2021	5.34%	1.9
31	**Niagara 17**		50.0	7/22/2011	10.0	7/22/2021	5.24%	2.6
32	**Niagara 18**		60.0	10/24/2011	10.0	10/22/2021	5.74%	3.4
33	**Niagara 19**		40.0	1/22/2012	10.0	1/22/2022	5.50%	2.2
34	**Niagara 20**		35.0	4/22/2012	10.0	4/22/2022	5.36%	1.9
35	**Niagara 21**		45.0	7/22/2012	10.0	7/22/2022	5.51%	2.5
36	**Niagara 22**		30.0	10/22/2012	10.0	10/22/2022	5.52%	1.7
37	**Niagara 23**		20.0	1/22/2013	10.0	1/22/2023	5.35%	1.1
38	**Niagara 24**		20.0	4/22/2013	10.0	4/22/2023	5.37%	1.1
39	**Total**		1,065.0				5.60%	59.7
40								
	Total Regulated Funded Long-Term Debt							
41	Line 14 + 39		3,181.7				5.01%	159.5

See Ex. C1-1-2 Table 3a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 3a
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2014
Notes to Ex. C1-1-2, Table 3

Note 1 Allocation ratio for 2014 as per Ex. C1-1-2 Table 1, line 13, col (b) (includes Newly Regulated Hydroelectric net fixed assets).

Note 2 See Ex. C1-1-2 Table 2a, Note 4

Table 4
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2015

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 and 2 Matrured During 2007							
	Issues 3 and 4 Matrured During 2008							
	Issues 5 and 6 Matrured During 2009							
	Issues 7, 8, 11, 12, 13, 14, 15 Matrured During 2010							
	Issues 9 and 10 Matrured During 2011							
	Issue 16 Matrured During 2012						**(Note 4)**	
1	**Issue 17**		100.0	6/22/2007	10.0	6/22/2017	5.44%	5.4
2	**Issue 18**		200.0	9/24/2007	10.0	9/22/2017	5.53%	11.1
3	**Issue 19**		400.0	12/21/2007	9.8	9/22/2017	5.31%	21.2
4	**Issue 20**		200.0	3/22/2008	10.0	3/22/2018	5.35%	10.7
5	**Issue 21**		100.0	3/22/2009	10.0	3/22/2019	5.65%	5.7
6	**Issue 22**	1	66.6	3/22/2010	5.0	3/22/2015	3.56%	2.4
7	**Issue 23**		230.0	3/22/2010	10.0	3/22/2020	4.68%	10.8
8	**Issue 24**	2	145.2	9/22/2010	5.0	9/22/2015	3.24%	4.7
9	**Issue 25**		230.0	9/22/2010	10.0	9/22/2020	4.39%	10.1
10	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
11	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
12	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
13	**Total**		2,171.8				4.88%	105.9
	Regulated Portion of Company-Wide Borrowing							
14	**Allocation**	3	1,525.0				4.88%	74.4
	Project Financing - Regulated Projects							
15	**Niagara 1**		160.0	10/22/2006	10.0	10/22/2016	5.23%	8.4
16	**Niagara 2**		50.0	1/22/2007	10.0	1/22/2017	5.10%	2.5
17	**Niagara 3**		30.0	4/23/2007	10.0	4/22/2017	5.09%	1.5
18	**Niagara 4**		40.0	1/22/2008	10.0	1/22/2018	5.53%	2.2
19	**Niagara 5**		30.0	4/22/2008	10.0	4/22/2018	5.90%	1.8
20	**Niagara 6**		30.0	7/22/2008	10.0	7/22/2018	5.87%	1.8
21	**Niagara 7**		30.0	1/22/2009	10.0	1/22/2019	8.41%	2.5
22	**Niagara 8**		35.0	4/22/2009	10.0	4/22/2019	7.71%	2.7
23	**Niagara 9**		35.0	7/22/2009	10.0	7/22/2019	6.41%	2.2
24	**Niagara 10**		50.0	10/22/2009	10.0	10/22/2019	5.63%	2.8
25	**Niagara 11**		50.0	1/22/2010	10.0	1/22/2020	5.44%	2.7
26	**Niagara 12**		65.0	4/22/2010	10.0	4/22/2020	5.73%	3.7
27	**Niagara 13**		35.0	7/22/2010	10.0	7/22/2020	5.57%	1.9
28	**Niagara 14**		50.0	10/22/2010	10.0	10/22/2020	4.87%	2.4
29	**Niagara 15**		40.0	1/24/2011	10.0	1/22/2021	5.18%	2.1
30	**Niagara 16**		35.0	4/26/2011	10.0	4/22/2021	5.34%	1.9
31	**Niagara 17**		50.0	7/22/2011	10.0	7/22/2021	5.24%	2.6
32	**Niagara 18**		60.0	10/24/2011	10.0	10/22/2021	5.74%	3.4
33	**Niagara 19**		40.0	1/22/2012	10.0	1/22/2022	5.50%	2.2
34	**Niagara 20**		35.0	4/22/2012	10.0	4/22/2022	5.36%	1.9
35	**Niagara 21**		45.0	7/22/2012	10.0	7/22/2022	5.51%	2.5
36	**Niagara 22**		30.0	10/22/2012	10.0	10/22/2022	5.52%	1.7
37	**Niagara 23**		20.0	1/22/2013	10.0	1/22/2023	5.35%	1.1
38	**Niagara 24**		20.0	4/22/2013	10.0	4/22/2023	5.37%	1.1
39	**Total**		1,065.0				5.60%	59.7
	Total Regulated Funded Long-Term Debt							
40	Line 14+39		2,590.0				5.18%	134.0

See Ex. C1-1-2 Table 4a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 4a
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2015
Notes to Ex. C1-1-2, Table 4

	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Issue 22	3/22/2015	300.0	81.0	66.6
Note 2	Issue 24	9/22/2015	200.0	265.0	145.2

Note 3 Allocation ratio for 2015 as per Ex. C1-1-2 Table 1, line 13, col (c).

Note 4 See Ex. C1-1-2 Table 2a, Note 4

Numbers may not add due to rounding.

Filed: 2016-05-27
EB-2016-0152
Exhibit C1
Tab 1
Schedule 2
Table 5

Table 5
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2016

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 and 2 Matured During 2007							
	Issues 3 and 4 Matured During 2008							
	Issues 5 and 6 Matured During 2009							
	Issues 7, 8, 11, 12, 13, 14, 15 Matured During 2010							
	Issues 9 and 10 Matured During 2011							
	Issue 16 Matured During 2012							
	Issues 22 and 24 Matured During 2015						**(Note 5)**	
1	**Issue 17**		100.0	6/22/2007	10.0	6/22/2017	5.44%	5.4
2	**Issue 18**		200.0	9/24/2007	10.0	9/22/2017	5.53%	11.1
3	**Issue 19**		400.0	12/21/2007	9.8	9/22/2017	5.31%	21.2
4	**Issue 20**		200.0	3/22/2008	10.0	3/22/2018	5.35%	10.7
5	**Issue 21**		100.0	3/22/2009	10.0	3/22/2019	5.65%	5.7
6	**Issue 23**		230.0	3/22/2010	10.0	3/22/2020	4.68%	10.8
7	**Issue 25**		230.0	9/22/2010	10.0	9/22/2020	4.39%	10.1
8	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
9	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
10	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
11	**Issue 29**	1,6	155.6	3/22/2016	10.0	3/22/2026	3.59%	5.6
12	**Issue 30**	2,6	54.8	9/22/2016	10.0	9/22/2026	3.81%	2.1
13	**Total**		2,170.4				4.91%	106.6
	Regulated Portion of Company-Wide Borrowing							
14	**Allocation**	4	1,524.0				4.91%	74.8
	Project Financing - Regulated Projects							
15	**Niagara 1**	3	129.8	10/22/2006	10.0	10/22/2016	5.23%	6.8
16	**Niagara 2**		50.0	1/22/2007	10.0	1/22/2017	5.10%	2.5
17	**Niagara 3**		30.0	4/23/2007	10.0	4/22/2017	5.09%	1.5
18	**Niagara 4**		40.0	1/22/2008	10.0	1/22/2018	5.53%	2.2
19	**Niagara 5**		30.0	4/22/2008	10.0	4/22/2018	5.90%	1.8
20	**Niagara 6**		30.0	7/22/2008	10.0	7/22/2018	5.87%	1.8
21	**Niagara 7**		30.0	1/22/2009	10.0	1/22/2019	8.41%	2.5
22	**Niagara 8**		35.0	4/22/2009	10.0	4/22/2019	7.71%	2.7
23	**Niagara 9**		35.0	7/22/2009	10.0	7/22/2019	6.41%	2.2
24	**Niagara 10**		50.0	10/22/2009	10.0	10/22/2019	5.63%	2.8
25	**Niagara 11**		50.0	1/22/2010	10.0	1/22/2020	5.44%	2.7
26	**Niagara 12**		65.0	4/22/2010	10.0	4/22/2020	5.73%	3.7
27	**Niagara 13**		35.0	7/22/2010	10.0	7/22/2020	5.57%	1.9
28	**Niagara 14**		50.0	10/22/2010	10.0	10/22/2020	4.87%	2.4
29	**Niagara 15**		40.0	1/24/2011	10.0	1/22/2021	5.18%	2.1
30	**Niagara 16**		35.0	4/26/2011	10.0	4/22/2021	5.34%	1.9
31	**Niagara 17**		50.0	7/22/2011	10.0	7/22/2021	5.24%	2.6
32	**Niagara 18**		60.0	10/24/2011	10.0	10/22/2021	5.74%	3.4
33	**Niagara 19**		40.0	1/22/2012	10.0	1/22/2022	5.50%	2.2
34	**Niagara 20**		35.0	4/22/2012	10.0	4/22/2022	5.36%	1.9
35	**Niagara 21**		45.0	7/22/2012	10.0	7/22/2022	5.51%	2.5
36	**Niagara 22**		30.0	10/22/2012	10.0	10/22/2022	5.52%	1.7
37	**Niagara 23**		20.0	1/22/2013	10.0	1/22/2023	5.35%	1.1
38	**Niagara 24**		20.0	4/22/2013	10.0	4/22/2023	5.37%	1.1
39	**Total**		1,034.8				5.61%	58.1
	Total Regulated Funded Long-Term Debt							
40	Line 14+39		2,558.8				5.19%	132.9

See Ex. C1-1-2 Table 5a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 5a
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2016
Notes to Ex. C1-1-2, Table 5

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Issue 29	3/22/2016	200.0	284.0	155.6
Note 2	Issue 30	9/22/2016	200.0	100.0	54.8
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 3	Niagara 1	10/22/2016	160.0	296.0	129.8

Note 4 Allocation ratio as per Ex. C1-1-2 Table 1, line 13, col (c). The 2015 allocation ratio is used as it reflects OPG's most recent financial results.

Note 5 See Ex. C1-1-2 Table 2a, Note 4

Note 6 Future issue rate reference Global Insight (January 2016).

Issue 29

GOC & OPG Spread	
GOC Q1-16	1.98%
OPG Spread	1.61%
Effective Rate	3.59%

Issue 30

GOC & OPG Spread	
GOC Q3-16	2.20%
OPG Spread	1.61%
Effective Rate	3.81%

Numbers may not add due to rounding.

Table 6
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2017

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 and 2 Matured During 2007							
	Issues 3 and 4 Matured During 2008							
	Issues 5 and 6 Matured During 2009							
	Issues 7, 8, 11, 12, 13, 14, 15 Matured During 2010							
	Issues 9 and 10 Matured During 2011							
	Issue 16 Matured During 2012							
	Issues 22 and 24 Matured During 2015						**(Note 9)**	
1	**Issue 17**	3	47.4	6/22/2007	10.0	6/22/2017	5.44%	2.6
2	**Issue 18**	4	145.2	9/24/2007	10.0	9/22/2017	5.53%	8.0
3	**Issue 19**	5	290.4	12/21/2007	9.8	9/22/2017	5.31%	15.4
4	**Issue 20**		200.0	3/22/2008	10.0	3/22/2018	5.35%	10.7
5	**Issue 21**		100.0	3/22/2009	10.0	3/22/2019	5.65%	5.7
6	**Issue 23**		230.0	3/22/2010	10.0	3/22/2020	4.68%	10.8
7	**Issue 25**		230.0	9/22/2010	10.0	9/22/2020	4.39%	10.1
8	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
9	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
10	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
11	**Issue 29**		200.0	3/22/2016	10.0	3/22/2026	3.59%	7.2
12	**Issue 30**		200.0	9/22/2016	10.0	9/22/2026	3.81%	7.6
13	**Issue 31**	1,10	544.7	3/22/2017	10.0	3/22/2027	3.93%	21.4
14	**Issue 32**	2,10	219.2	9/22/2017	10.0	9/22/2027	4.00%	8.8
15	**Total**		2,906.8				4.55%	132.1
	Regulated Portion of Company-Wide Borrowing							
16	**Allocation**	8	2,041.1				4.55%	92.8
	Project Financing - Regulated Projects							
	Niagara 1 Matured during 2016							
17	**Niagara 2**	6	3.0	1/22/2007	10.0	1/22/2017	5.10%	0.2
18	**Niagara 3**	7	9.2	4/23/2007	10.0	4/22/2017	5.09%	0.5
19	**Niagara 4**		40.0	1/22/2008	10.0	1/22/2018	5.53%	2.2
20	**Niagara 5**		30.0	4/22/2008	10.0	4/22/2018	5.90%	1.8
21	**Niagara 6**		30.0	7/22/2008	10.0	7/22/2018	5.87%	1.8
22	**Niagara 7**		30.0	1/22/2009	10.0	1/22/2019	8.41%	2.5
23	**Niagara 8**		35.0	4/22/2009	10.0	4/22/2019	7.71%	2.7
24	**Niagara 9**		35.0	7/22/2009	10.0	7/22/2019	6.41%	2.2
25	**Niagara 10**		50.0	10/22/2009	10.0	10/22/2019	5.63%	2.8
26	**Niagara 11**		50.0	1/22/2010	10.0	1/22/2020	5.44%	2.7
27	**Niagara 12**		65.0	4/22/2010	10.0	4/22/2020	5.73%	3.7
28	**Niagara 13**		35.0	7/22/2010	10.0	7/22/2020	5.57%	1.9
29	**Niagara 14**		50.0	10/22/2010	10.0	10/22/2020	4.87%	2.4
30	**Niagara 15**		40.0	1/24/2011	10.0	1/22/2021	5.18%	2.1
31	**Niagara 16**		35.0	4/26/2011	10.0	4/22/2021	5.34%	1.9
32	**Niagara 17**		50.0	7/22/2011	10.0	7/22/2021	5.24%	2.6
33	**Niagara 18**		60.0	10/24/2011	10.0	10/22/2021	5.74%	3.4
34	**Niagara 19**		40.0	1/22/2012	10.0	1/22/2022	5.50%	2.2
35	**Niagara 20**		35.0	4/22/2012	10.0	4/22/2022	5.36%	1.9
36	**Niagara 21**		45.0	7/22/2012	10.0	7/22/2022	5.51%	2.5
37	**Niagara 22**		30.0	10/22/2012	10.0	10/22/2022	5.52%	1.7
38	**Niagara 23**		20.0	1/22/2013	10.0	1/22/2023	5.35%	1.1
39	**Niagara 24**		20.0	4/22/2013	10.0	4/22/2023	5.37%	1.1
40	**Total**		837.2				5.71%	47.8
	Total Regulated Funded Long-Term Debt							
41	Line 16+40		2,878.4				4.89%	140.6

See Ex. C1-1-2 Table 6a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 6a
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2017
Notes to Ex. C1-1-2, Table 6

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Issue 31	3/22/2017	700.0	284.0	544.7
Note 2	Issue 32	9/22/2017	800.0	100.0	219.2
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 3	Issue 17	6/22/2017	100.0	173.0	47.4
Note 4	Issue 18	9/22/2017	200.0	265.0	145.2
Note 5	Issue 19	9/22/2017	400.0	265.0	290.4
Note 6	Niagara 2	1/22/2017	50.0	22.0	3.0
Note 7	Niagara 3	4/22/2017	30.0	112.0	9.2

Note 8 See Ex. C1-1-2 Table 5a, Note 4
Note 9 See Ex. C1-1-2 Table 2a, Note 4
Note 10 Future issue rate reference Global Insight (January 2016).

Issue 31

GOC & OPG Spread	
GOC Q1-17	2.32%
OPG Spread	1.61%
Effective Rate	3.93%

Issue 32

GOC & OPG Spread	
GOC Q3-17	2.39%
OPG Spread	1.61%
Effective Rate	4.00%

Table 7
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2018

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 and 2 Matured During 2007							
	Issues 3 and 4 Matured During 2008							
	Issues 5 and 6 Matured During 2009							
	Issues 7, 8, 11, 12, 13, 14, 15 Matured During 2010							
	Issues 9 and 10 Matured During 2011							
	Issue 16 Matured During 2012							
	Issues 22 and 24 Matured During 2015							
	Issues 17, 18 and 19 Matured During 2017						**(Note 8)**	
1	**Issue 20**	3	44.4	3/22/2008	10.0	3/22/2018	5.35%	2.4
2	**Issue 21**		100.0	3/22/2009	10.0	3/22/2019	5.65%	5.7
3	**Issue 23**		230.0	3/22/2010	10.0	3/22/2020	4.68%	10.8
4	**Issue 25**		230.0	9/22/2010	10.0	9/22/2020	4.39%	10.1
5	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
6	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
7	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
8	**Issue 29**		200.0	3/22/2016	10.0	3/22/2026	3.59%	7.2
9	**Issue 30**		200.0	9/22/2016	10.0	9/22/2026	3.81%	7.6
10	**Issue 31**		700.0	3/22/2017	10.0	3/22/2027	3.93%	27.5
11	**Issue 32**		800.0	9/22/2017	10.0	9/22/2027	4.00%	32.0
12	**Issue 33**	1,9	311.2	3/22/2018	10.0	3/22/2028	4.23%	13.2
13	**Issue 34**	2,9	123.3	9/22/2018	10.0	9/22/2028	4.68%	5.8
14	**Total**		3,438.9				4.25%	146.0
	Regulated Portion of Company-Wide Borrowing							
15	**Allocation**	7	2,414.8				4.25%	102.6
	Project Financing - Regulated Projects							
	Niagara 1 Matured during 2016							
	Niagara 2 and 3 - Matured during 2017							
16	**Niagara 4**	4	2.4	1/22/2008	10.0	1/22/2018	5.53%	0.1
17	**Niagara 5**	5	9.2	4/22/2008	10.0	4/22/2018	5.90%	0.5
18	**Niagara 6**	6	16.7	7/22/2008	10.0	7/22/2018	5.87%	1.0
19	**Niagara 7**		30.0	1/22/2009	10.0	1/22/2019	8.41%	2.5
20	**Niagara 8**		35.0	4/22/2009	10.0	4/22/2019	7.71%	2.7
21	**Niagara 9**		35.0	7/22/2009	10.0	7/22/2019	6.41%	2.2
22	**Niagara 10**		50.0	10/22/2009	10.0	10/22/2019	5.63%	2.8
23	**Niagara 11**		50.0	1/22/2010	10.0	1/22/2020	5.44%	2.7
24	**Niagara 12**		65.0	4/22/2010	10.0	4/22/2020	5.73%	3.7
25	**Niagara 13**		35.0	7/22/2010	10.0	7/22/2020	5.57%	1.9
26	**Niagara 14**		50.0	10/22/2010	10.0	10/22/2020	4.87%	2.4
27	**Niagara 15**		40.0	1/24/2011	10.0	1/22/2021	5.18%	2.1
28	**Niagara 16**		35.0	4/26/2011	10.0	4/22/2021	5.34%	1.9
29	**Niagara 17**		50.0	7/22/2011	10.0	7/22/2021	5.24%	2.6
30	**Niagara 18**		60.0	10/24/2011	10.0	10/22/2021	5.74%	3.4
31	**Niagara 19**		40.0	1/22/2012	10.0	1/22/2022	5.50%	2.2
32	**Niagara 20**		35.0	4/22/2012	10.0	4/22/2022	5.36%	1.9
33	**Niagara 21**		45.0	7/22/2012	10.0	7/22/2022	5.51%	2.5
34	**Niagara 22**		30.0	10/22/2012	10.0	10/22/2022	5.52%	1.7
35	**Niagara 23**		20.0	1/22/2013	10.0	1/22/2023	5.35%	1.1
36	**Niagara 24**		20.0	4/22/2013	10.0	4/22/2023	5.37%	1.1
37	**Total**		753.3				5.73%	43.1
	Total Regulated Funded Long-Term Debt							
38	Line 15+37		3,168.1				4.60%	145.7

See Ex. C1-1-2 Table 7a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 7a
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2018
Notes to Ex. C1-1-2, Table 7

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Issue 33	3/22/2018	400.0	284.0	311.2
Note 2	Issue 34	9/22/2018	450.0	100.0	123.3
	Issue	Matrurity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 3	Issue 20	3/22/2018	200.0	81.0	44.4
Note 4	Niagara 4	1/22/2018	40.0	22.0	2.4
Note 5	Niagara 5	4/22/2018	30.0	112.0	9.2
Note 6	Niagara 6	7/22/2018	30.0	203.0	16.7

Note 7 See Ex. C1-1-2 Table 5a, Note 4
Note 8 See Ex. C1-1-2 Table 2a, Note 4
Note 9 Future issue rate reference Global Insight (January 2016).

Issue 33

GOC & OPG Spread	
GOC Q1-18	2.62%
OPG Spread	1.61%
Effective Rate	4.23%

Issue 34

GOC & OPG Spread	
GOC Q3-18	3.07%
OPG Spread	1.61%
Effective Rate	4.68%

Table 8
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2019

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 and 2 Matured During 2007							
	Issues 3 and 4 Matured During 2008							
	Issues 5 and 6 Matured During 2009							
	Issues 7, 8, 11, 12, 13, 14, 15 Matured During 2010							
	Issues 9 and 10 Matured During 2011							
	Issue 16 Matured During 2012							
	Issues 22 and 24 Matured During 2015							
	Issues 17, 18 and 19 Matured During 2017							
	Issues 20 Matured During 2018						**(Note 9)**	
1	**Issue 21**	3	22.2	3/22/2009	10.0	3/22/2019	5.65%	1.3
2	**Issue 23**		230.0	3/22/2010	10.0	3/22/2020	4.68%	10.8
3	**Issue 25**		230.0	9/22/2010	10.0	9/22/2020	4.39%	10.1
4	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
5	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
6	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
7	**Issue 29**		200.0	3/22/2016	10.0	3/22/2026	3.59%	7.2
8	**Issue 30**		200.0	9/22/2016	10.0	9/22/2026	3.81%	7.6
9	**Issue 31**		700.0	3/22/2017	10.0	3/22/2027	3.93%	27.5
10	**Issue 32**		800.0	9/22/2017	10.0	9/22/2027	4.00%	32.0
11	**Issue 33**		400.0	3/22/2018	10.0	3/22/2028	4.23%	16.9
12	**Issue 34**		450.0	9/22/2018	10.0	9/22/2028	4.68%	21.1
13	**Issue 35**	1,10	233.4	3/22/2019	10.0	3/22/2029	4.93%	11.5
14	**Issue 36**	2,10	82.2	9/22/2019	10.0	9/22/2029	4.93%	4.1
15	**Total**		4,047.8				4.30%	173.9
	Regulated Portion of Company-Wide Borrowing							
16	**Allocation**	8	2,842.3				4.30%	122.1
	Project Financing - Regulated Projects							
	Niagara 1 Matured during 2016							
	Niagara 2 and 3 - Matured during 2017							
	Niagara 4, 5 and 6 - Matured during 2018							
17	**Niagara 7**	4	1.8	1/22/2009	10.0	1/22/2019	8.41%	0.2
18	**Niagara 8**	5	10.7	4/22/2009	10.0	4/22/2019	7.71%	0.8
19	**Niagara 9**	6	19.5	7/22/2009	10.0	7/22/2019	6.41%	1.2
20	**Niagara 10**	7	40.4	10/22/2009	10.0	10/22/2019	5.63%	2.3
21	**Niagara 11**		50.0	1/22/2010	10.0	1/22/2020	5.44%	2.7
22	**Niagara 12**		65.0	4/22/2010	10.0	4/22/2020	5.73%	3.7
23	**Niagara 13**		35.0	7/22/2010	10.0	7/22/2020	5.57%	1.9
24	**Niagara 14**		50.0	10/22/2010	10.0	10/22/2020	4.87%	2.4
25	**Niagara 15**		40.0	1/24/2011	10.0	1/22/2021	5.18%	2.1
26	**Niagara 16**		35.0	4/26/2011	10.0	4/22/2021	5.34%	1.9
27	**Niagara 17**		50.0	7/22/2011	10.0	7/22/2021	5.24%	2.6
28	**Niagara 18**		60.0	10/24/2011	10.0	10/22/2021	5.74%	3.4
29	**Niagara 19**		40.0	1/22/2012	10.0	1/22/2022	5.50%	2.2
30	**Niagara 20**		35.0	4/22/2012	10.0	4/22/2022	5.36%	1.9
31	**Niagara 21**		45.0	7/22/2012	10.0	7/22/2022	5.51%	2.5
32	**Niagara 22**		30.0	10/22/2012	10.0	10/22/2022	5.52%	1.7
33	**Niagara 23**		20.0	1/22/2013	10.0	1/22/2023	5.35%	1.1
34	**Niagara 24**		20.0	4/22/2013	10.0	4/22/2023	5.37%	1.1
35	**Total**		647.4				5.51%	35.7
	Total Regulated Funded Long-Term Debt							
36	Line 16+35		3,489.7				4.52%	157.8

See Ex. C1-1-2 Table 8a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 8a
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2019
Notes to Ex. C1-1-2, Table 8

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Issue 35	3/22/2019	300.0	284.0	233.4
Note 2	Issue 36	9/22/2019	300.0	100.0	82.2
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 3	Issue 21	3/22/2019	100.0	81.0	22.2
Note 4	Niagara 7	1/22/2019	30.0	22.0	1.8
Note 5	Niagara 8	4/22/2019	35.0	112.0	10.7
Note 6	Niagara 9	7/22/2019	35.0	203.0	19.5
Note 7	Niagara 10	10/22/2019	50.0	295.0	40.4

Note 8 See Ex. C1-1-2 Table 5a, Note 4
Note 9 See Ex. C1-1-2 Table 2a, Note 4
Note 10 Future issue rate reference Global Insight (January 2016).

Issue 35 & 36

GOC & OPG Spread	
GOC Q1-19	3.32%
OPG Spread	1.61%
Effective Rate	4.93%

Numbers may not add due to rounding.

Table 9
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2020

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 and 2 Matured During 2007							
	Issues 3 and 4 Matured During 2008							
	Issues 5 and 6 Matured During 2009							
	Issues 7, 8, 11, 12, 13, 14, 15 Matured During 2010							
	Issues 9 and 10 Matured During 2011							
	Issue 16 Matured During 2012							
	Issues 22 and 24 Matured During 2015							
	Issues 17, 18 and 19 Matured During 2017							
	Issues 20 Matured During 2018							
	Issues 21 Matured During 2019						**(Note 10)**	
1	**Issue 23**	3	51.7	3/22/2010	10.0	3/22/2020	4.68%	2.4
2	**Issue 25**	4	167.6	9/22/2010	10.0	9/22/2020	4.39%	7.4
3	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
4	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
5	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
6	**Issue 29**		200.0	3/22/2016	10.0	3/22/2026	3.59%	7.2
7	**Issue 30**		200.0	9/22/2016	10.0	9/22/2026	3.81%	7.6
8	**Issue 31**		700.0	3/22/2017	10.0	3/22/2027	3.93%	27.5
9	**Issue 32**		800.0	9/22/2017	10.0	9/22/2027	4.00%	32.0
10	**Issue 33**		400.0	3/22/2018	10.0	3/22/2028	4.23%	16.9
11	**Issue 34**		450.0	9/22/2018	10.0	9/22/2028	4.68%	21.1
12	**Issue 35**		300.0	3/22/2019	10.0	3/22/2029	4.93%	14.8
13	**Issue 36**		300.0	9/22/2019	10.0	9/22/2029	4.93%	14.8
14	**Issue 37**	1,11	233.4	3/22/2020	10.0	3/22/2030	4.93%	11.5
15	**Issue 38**	2,11	68.5	9/22/2020	10.0	9/22/2030	4.93%	3.4
16	**Total**		4,371.2				4.36%	190.4
	Regulated Portion of Company-Wide Borrowing							
17	**Allocation**	9	3,069.4				4.36%	133.7
	Project Financing - Regulated Projects							
	Niagara 1 Matured during 2016							
	Niagara 2 and 3 - Matured during 2017							
	Niagara 4, 5 and 6 - Matured during 2018							
	Niagara 7, 8, 9 and 10 - Matured during 2019							
18	**Niagara 11**	5	3.0	1/22/2010	10.0	1/22/2020	5.44%	0.2
19	**Niagara 12**	6	20.1	4/22/2010	10.0	4/22/2020	5.73%	1.2
20	**Niagara 13**	7	19.6	7/22/2010	10.0	7/22/2020	5.57%	1.1
21	**Niagara 14**	8	40.5	10/22/2010	10.0	10/22/2020	4.87%	2.0
22	**Niagara 15**		40.0	1/24/2011	10.0	1/22/2021	5.18%	2.1
23	**Niagara 16**		35.0	4/26/2011	10.0	4/22/2021	5.34%	1.9
24	**Niagara 17**		50.0	7/22/2011	10.0	7/22/2021	5.24%	2.6
25	**Niagara 18**		60.0	10/24/2011	10.0	10/22/2021	5.74%	3.4
26	**Niagara 19**		40.0	1/22/2012	10.0	1/22/2022	5.50%	2.2
27	**Niagara 20**		35.0	4/22/2012	10.0	4/22/2022	5.36%	1.9
28	**Niagara 21**		45.0	7/22/2012	10.0	7/22/2022	5.51%	2.5
29	**Niagara 22**		30.0	10/22/2012	10.0	10/22/2022	5.52%	1.7
30	**Niagara 23**		20.0	1/22/2013	10.0	1/22/2023	5.35%	1.1
31	**Niagara 24**		20.0	4/22/2013	10.0	4/22/2023	5.37%	1.1
32	**Total**		458.2				5.40%	24.7
	Total Regulated Funded Long-Term Debt							
33	Line 17+32		3,527.6				4.49%	158.5

See Ex. C1-1-2 Table 9a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 9a
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2020
Notes to Ex. C1-1-2, Table 9

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Issue 37	3/22/2020	300.0	284.0	233.4
Note 2	Issue 38	9/22/2020	250.0	100.0	68.5
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 3	Issue 23	3/22/2020	230.0	82.0	51.7
Note 4	Issue 25	9/22/2020	230.0	266.0	167.6
Note 5	Niagara 11	1/22/2020	50.0	22.0	3.0
Note 6	Niagara 12	4/22/2020	65.0	113.0	20.1
Note 7	Niagara 13	7/22/2020	35.0	204.0	19.6
Note 8	Niagara 14	10/22/2020	50.0	296.0	40.5

Note 9 See Ex. C1-1-2 Table 5a, Note 4
Note 10 See Ex. C1-1-2 Table 2a, Note 4
Note 11 Future issue rate reference Global Insight (January 2016).

Issue 37 & 38

GOC & OPG Spread	
GOC Q1-20	3.32%
OPG Spread	1.61%
Effective Rate	4.93%

Numbers may not add due to rounding.

Table 10
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2021

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 and 2 Matured During 2007							
	Issues 3 and 4 Matured During 2008							
	Issues 5 and 6 Matured During 2009							
	Issues 7, 8, 11, 12, 13, 14, 15 Matured During 2010							
	Issues 9 and 10 Matured During 2011							
	Issue 16 Matured During 2012							
	Issues 22 and 24 Matured During 2015							
	Issues 17, 18 and 19 Matured During 2017							
	Issues 20 Matured During 2018							
	Issues 21 Matured During 2019							
	Issues 23 and 25 Matured During 2020						**(Note 8)**	
1	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
2	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
3	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
4	**Issue 29**		200.0	3/22/2016	10.0	3/22/2026	3.59%	7.2
5	**Issue 30**		200.0	9/22/2016	10.0	9/22/2026	3.81%	7.6
6	**Issue 31**		700.0	3/22/2017	10.0	3/22/2027	3.93%	27.5
7	**Issue 32**		800.0	9/22/2017	10.0	9/22/2027	4.00%	32.0
8	**Issue 33**		400.0	3/22/2018	10.0	3/22/2028	4.23%	16.9
9	**Issue 34**		450.0	9/22/2018	10.0	9/22/2028	4.68%	21.1
10	**Issue 35**		300.0	3/22/2019	10.0	3/22/2029	4.93%	14.8
11	**Issue 36**		300.0	9/22/2019	10.0	9/22/2029	4.93%	14.8
12	**Issue 37**		300.0	3/22/2020	10.0	3/22/2030	4.93%	14.8
13	**Issue 38**		250.0	9/22/2020	10.0	9/22/2030	4.93%	12.3
14	**Issue 39**	1,9	38.9	3/22/2020	10.0	3/22/2030	4.93%	1.9
15	**Issue 40**	2,9	13.7	9/22/2020	10.0	9/22/2030	4.93%	0.7
16	**Total**		4,452.6				4.39%	195.5
	Regulated Portion of Company-Wide Borrowing							
17	**Allocation**	7	3,126.6				4.39%	137.3
	Project Financing--Regulated Projects							
	Niagara 1 Matured during 2016							
	Niagara 2 and 3 - Matured during 2017							
	Niagara 4, 5 and 6 - Matured during 2018							
	Niagara 7, 8, 9 and 10 - Matured during 2019							
	Niagara 11, 12, 13 and 14 - Matured during 2020							
18	**Niagara 15**	3	2.4	1/24/2011	10.0	1/22/2021	5.18%	0.1
19	**Niagara 16**	4	10.7	4/26/2011	10.0	4/22/2021	5.34%	0.6
20	**Niagara 17**	5	27.8	7/22/2011	10.0	7/22/2021	5.24%	1.5
21	**Niagara 18**	6	48.5	10/24/2011	10.0	10/22/2021	5.74%	2.8
22	**Niagara 19**		40.0	1/22/2012	10.0	1/22/2022	5.50%	2.2
23	**Niagara 20**		35.0	4/22/2012	10.0	4/22/2022	5.36%	1.9
24	**Niagara 21**		45.0	7/22/2012	10.0	7/22/2022	5.51%	2.5
25	**Niagara 22**		30.0	10/22/2012	10.0	10/22/2022	5.52%	1.7
26	**Niagara 23**		20.0	1/22/2013	10.0	1/22/2023	5.35%	1.1
27	**Niagara 24**		20.0	4/22/2013	10.0	4/22/2023	5.37%	1.1
28	**Total**		279.5				5.47%	15.3
	Total Regulated Funded Long-Term Debt							
29	Line 17+28		3,406.0				4.48%	152.6

See Ex. C1-1-2 Table 10a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 10a
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2021
Notes to Ex. C1-1-2, Table 10

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Issue 39	3/22/2020	50.0	284.0	38.9
Note 2	Issue 40	9/22/2020	50.0	100.0	13.7
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 3	Niagara 15	1/22/2021	40.0	22.0	2.4
Note 4	Niagara 16	4/22/2021	35.0	112.0	10.7
Note 5	Niagara 17	7/22/2021	50.0	203.0	27.8
Note 6	Niagara 18	10/22/2021	60.0	295.0	48.5

Note 7 See Ex. C1-1-2 Table 5a, Note 4
Note 8 See Ex. C1-1-2 Table 2a, Note 4
Note 9 Future issue rate reference Global Insight (January 2016).

Issue 39 & 40

GOC & OPG Spread	
GOC Q1-21 & Q3-21	3.32%
OPG Spread	1.61%
Effective Rate	4.93%

COST OF SHORT-TERM DEBT

1.0 PURPOSE

This evidence details OPG's annual short-term borrowing and associated costs for the bridge year and test period. It also provides actual short-term debt costs for 2013 to 2015.

2.0 DESCRIPTION OF SHORT-TERM DEBT

OPG's cost of short-term debt for the test period was determined using the methodology approved by the OEB in EB-2007-0905, EB-2010-0008 and EB-2013-0321. The short-term debt component of OPG's capital structure reflects its forecast amount of short-term borrowings, and the cost of short-term debt reflects its forecast short-term borrowing cost.

OPG's short-term debt is comprised of a commercial paper program backstopped by a bank credit facility.

OPG's commercial paper program is used to fund intra-month working capital requirements. OPG expects to continue to use this source of financing in the test period. OPG forecasts that a daily average borrowing of $40M is required to finance OPG's normalized intra-month working capital requirements in the test period.

In addition, a bank credit facility continues to be used as the backstop to the commercial paper program. The bank credit facility also provides liquidity support in the event that OPG is unable to issue commercial paper as OPG would be able to borrow by way of bankers' acceptances under the bank credit facility. Access to adequate liquidity is an important element that credit rating agencies consider when reviewing credit ratings. The bank facility is $1B in size, comprised of two $500M multi-year tranches. In May 2016, OPG extended both tranches to May 2021.

OPG does not expect any borrowing during the bridge or test periods under its accounts receivable securitization program.

3.0 SHORT-TERM DEBT COST

OPG's borrowing rate under the commercial paper program is market-based, comprised of a 10 basis point dealer fee and a corporate spread over the bankers' acceptances rate for OPG. The corporate spread forecast over the test period is based on the current corporate spread of 5 basis points.

Consistent with the approach used in EB-2010-0008 and EB-2013-0321, OPG has used the Global Insight forecast as the basis for the bankers' acceptances interest rate forecast after adjusting for the spread differential between bankers' acceptances and the yield on treasury securities. The bankers' acceptances rate used is 0.64 per cent for 2016, 1.26 per cent for 2017, 2.58 per cent for 2018, 3.60 per cent for 2019, 3.65 per cent for 2020, and 3.50 per cent for 2021.

The bank credit facility is forecast to cost $2.6M in each of 2016 to 2021, which is a small increase over the actual cost in 2015. As in EB-2007-0905, EB-2010-0008 and EB-2013-0321, these costs are included with OPG's short term debt costs, as the bank credit facility is required to support OPG's commercial paper program.

Ex. C1-1-3 Table 2 summarizes OPG's forecast company-wide cost of short-term debt.

4.0 ALLOCATION TO REGULATED OPERATIONS

For the test period, OPG has used the same allocation methodology approved by the OEB in EB-2007-0905, EB-2010-0008 and EB-2013-0321. In summary, the ratio of the construction work in progress and non-cash working capital amounts (fuel inventory and materials/supplies) for OPG's regulated operations to the total construction work in progress and non-cash working capital amounts reported in OPG's audited financial statements is used as the basis for allocating company-wide short-term borrowing. This allocation ratio reflects OPG's use of short-term borrowing to finance its working capital requirements and to assist with managing the cash flow variability of capital projects.

For all company-wide short-term borrowing prior to December 31, 2015, the allocation ratio is determined based on actual year-end values in the corresponding years. Consistent with the approach approved in EB-2007-0905, EB-2010-0008 and EB-2013-0321, OPG continues to use the most recent available audited information to determine the allocation factor for the company's short-term debt for 2016 to 2021. The calculation of the allocation ratio for 2013 to 2015 is provided in Ex. C1-1-3 Table 1.

Table 1
Capitalization and Cost of Capital
Allocation of Existing Short-term Debt ($M)

Line No.	Asset	Note	Amount 2013 [1]	2014	2015
			(a)	(b)	(c)
	Company-Wide:				
1	**Adjusted Construction Work-In-Progress (CWIP)**	2	3,161.9	1,872.4	2,594.9
2	**CWIP Using Short-term Project Financing**	3	(1,982.1)	0.0	0.0
3	**Fuel**		390.1	334.1	343.5
4	**Materials/Supplies**		424.6	431.4	433.3
5	**CWIP + Non Cash Working Capital**		1,994.6	2,637.9	3,371.7
	Regulated Operations:				
6	**Adjusted Construction Work-In-Progress (CWIP)**	4	854.5	1,740.7	2,391.7
7	**Fuel**	5	333.8	298.5	304.3
8	**Materials/Supplies**	6	416.7	425.8	428.6
9	**CWIP + Non Cash Working Capital**		1,605.0	2,464.9	3,124.6
10	**Total Regulated/Company-Wide CWIP + Non Cash Working Capital** (line 9/ line 5)		80.5%	93.4%	92.7%

Notes:
1 Newly regulated hydroelectric assets are not included in 2013 as they were not prescribed until 2014, and are included starting in 2014.

2 Ex. C1-1-2 Table 1, line 2
3 Relates wholly to OPG's unregulated operations.
4 Ex. C1-1-2 Table 1, line 8
5 From Ex. B3-5-1 Table 1, col. (b).
6 Sum of Ex. B3-5-1 Table 1, col. (b) (Nuclear) and the Regulated Hydroelectric closing balance reflected in actual rate base.

Table 2
Capitalization and Cost of Capital
Summary of OPG's Actual and Forecast Cost of Short-term Debt ($M)

Line No.	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Commercial Paper Amount**[1]	13.3	77.8	49.1	40.0	40.0	40.0	40.0	40.0	40.0
2	**Interest Rate**	1.17%	1.20%	1.01%	0.79%	1.41%	2.73%	3.75%	3.80%	3.65%
3	**Commercial Paper Cost**	0.2	0.9	0.5	0.3	0.6	1.1	1.5	1.5	1.5
4	**Facility Cost**[2]	2.6	2.9	2.5	2.6	2.6	2.6	2.6	2.6	2.6
5	**Total Short-term Debt Cost** (line 3 + line 4)	2.8	3.8	3.0	2.9	3.2	3.7	4.1	4.1	4.1
	Regulated Portion of Short-Term Debt									
6	**Allocation Factor**[3]	80.5%	93.4%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%	92.7%
7	**Short Term Debt Amount** (line 1 x line 6)	10.7	72.7	45.5	37.1	37.1	37.1	37.1	37.1	37.1
8	**Short-term Debt Cost** (line 5 x line 6)	2.2	3.6	2.8	2.7	2.9	3.4	3.8	3.8	3.8

Notes:

1 Actual daily weighted average balance shown for 2013 to 2015. Working Capital funding with commercial paper is assumed to be outstanding for the first 20 days of each month in the forecast period.

2 2013 value is from EB-2013-0321, L-1.0-1, Staff-002, Att. 1, Table 5, Note 1.

3 Allocation factor determined at Ex. C1-1-3 Table 1 line 10. 2016-2021 allocation is based on 2015 actual allocation.

NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING – REVENUE REQUIREMENT IMPACT OF NUCLEAR LIABILITIES

1.0 PURPOSE

The purpose of this evidence is to outline the OEB-approved revenue requirement treatment of OPG's liabilities for nuclear waste management and decommissioning ("nuclear liabilities") and to present the forecast amounts of nuclear liabilities costs included in the proposed revenue requirement for the 2017 to 2021 test period. This evidence also presents the projected financial impacts of the year-end 2015 adjustment to the nuclear liabilities recorded by OPG to reflect changes in accounting assumptions for nuclear station end-of-life ("EOL") dates effective December 31, 2015 ("2015 nuclear liabilities adjustment"), as anticipated in EB-2015-0374.

2.0 OVERVIEW

OPG is seeking recovery of $2,293.4M, after-tax, over the test period in respect of the nuclear liabilities for both prescribed and Bruce facilities. This reflects the approved 2012 Ontario Nuclear Funds Agreement ("ONFA") Reference Plan, as well as projected financial impacts of $372.1M over the test period resulting from the 2015 nuclear liabilities adjustment.

For the prescribed facilities, OPG is seeking recovery of a total pre-tax test period amount in respect of the nuclear liabilities of $707.7M consisting of $147.7M, $147.1M, $156.9M, $144.1M and $111.9M for years 2017 to 2021, respectively (Ex. C2-1-1 Table 1, line 6). The associated income tax impacts are ($2.8M), ($9.4M), ($36.3M), $36.3M and $25.6M for years 2017 to 2021, respectively (Ex. C2-1-1 Table 1, line 7).

For the Bruce facilities, OPG is seeking recovery of a total pre-tax test period amount in respect of the nuclear liabilities of $1,179.3M as a reduction to Bruce Lease net revenues, consisting of $232.0M, $234.3M, $238.9M, $244.2M and $229.8M for years 2017 to 2021, respectively (Ex. C2-1-1 Table 1, line 15). The associated income tax impacts are $77.3M,

$78.1M, $79.6M, $81.4M and $76.6M for years 2017 to 2021, respectively (Ex. C2-1-1 Table 1, line 16).

The 2015 nuclear liabilities adjustment increased the nuclear liabilities by approximately $2.3B, primarily on account of the planned refurbishment of the not-yet-refurbished Bruce units as announced by the Province of Ontario in December 2015 (see Ex. F4-1-1). The 2016 impacts of the 2015 nuclear liabilities adjustment are projected to be a credit to ratepayers of $65.2M for the prescribed facilities and a decrease of $69.9M in Bruce Lease net revenues (i.e. amount to be recovered from ratepayers). These impacts are being recorded in the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account established in EB-2015-0374 and the Bruce Lease Net Revenues Variance Account, respectively.

For the purposes of determining the 2017 to 2021 test year revenue requirement and amounts recorded in the above deferral and variance accounts with respect to the 2015 nuclear liabilities adjustment, OPG is maintaining the nuclear liabilities revenue requirement methodology approved by the OEB in EB-2007-0905, EB-2010-0008 and EB-2013-0321.

Section 3.0 describes OPG's financial accounting for the asset retirement obligation ("ARO") related to nuclear waste management and decommissioning and sets out the OEB-approved revenue requirement methodology for the nuclear liabilities. Section 4.0 discusses changes in the ARO, the corresponding unamortized asset retirement costs ("ARC") and the segregated fund balances set aside for discharging the nuclear liabilities in accordance with the Ontario Nuclear Funds Agreement ("ONFA"). Section 5.0 presents the impact of the 2015 nuclear liabilities adjustment. Section 6.0 provides a status update for the 2017 ONFA Reference Plan update, which is under development and has not been reflected in the proposed test period revenue requirement. Once finalized and implemented, the revenue requirement impact of the 2017 ONFA Reference Plan will be subject to the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account.

3.0 APPROVED METHODOLOGY FOR RECOVERY OF NUCLEAR LIABILITIES

3.1 Summary Background

3.1.1 Obligations for Nuclear Waste Management and Decommissioning

OPG is responsible for the ongoing and long-term management of radioactive wastes, including used nuclear fuel and less radioactive materials categorized as low level waste and intermediate level waste ("L&ILW"), and decommissioning of its nuclear generating facilities. These obligations are tracked by the following five programs:

- Decommissioning – OPG's nuclear station decommissioning plans consist of preparation and placement of stations into a safe state condition at the end of their useful lives, including removal of fuel and heavy water from the reactors, followed by an assumed 30-year safe store period and subsequent station dismantlement and site restoration.
- Used Fuel Storage – The program encompasses the interim storage of used nuclear fuel in dry storage containers at nuclear station sites prior to their ultimate long-term disposal.
- Used Fuel Disposal – The program encompasses the long-term management of used nuclear fuel, which is based on the Adaptive Phased Management ("APM") concept previously accepted by the Government of Canada on recommendation of the Nuclear Waste Management Organization ("NWMO") in response to the *Nuclear Fuel Waste Act*. The NWMO is responsible for the design and implementation of Canada's plan for the safe long-term management of used nuclear fuel. The APM approach includes the isolation and containment of used nuclear fuel in a deep geologic repository.
- L&ILW Storage – The program includes the transportation, processing, and interim storage, at the OPG-owned and operated Western Waste Management Facility situated at the Bruce nuclear site, of the L&ILW generated at the sites during and following the operation of the nuclear stations, prior to its ultimate long-term disposal.
- L&ILW Disposal – The program encompasses the long-term management of the L&ILW generated at the nuclear sites. OPG's current long-term disposal strategy

entails the permanent emplacement of L&ILW into a proposed deep geologic repository adjacent to the Western Waste Management Facility.

OPG's obligations include used fuel and L&ILW generated at the Bruce stations and the decommissioning of the Bruce stations.

OPG's nuclear liabilities represent the present value of OPG's obligation for the lifecycle costs of the five nuclear waste management and decommissioning programs. The baseline cost estimates for these programs are determined through the ONFA Reference Plan update process. The present value of the committed portion of the costs for OPG's nuclear liabilities is recorded as an ARO on OPG's balance sheet in accordance with US GAAP. The committed costs include the fixed cost components of each program as well as the lifetime variable costs for waste generated to date.

OPG maintains a station-level continuity of the ARO balances. The ARO is attributed at the station level for each of the five programs described above. For the Decommissioning and Used Fuel Storage programs, the underlying cost estimates are prepared directly at the station level, with individual estimates prepared for each station. The remaining programs involve central facilities, with cost estimates prepared at the program level and allocated to individual stations in proportion to the lifecycle waste volume estimates.

In accordance with US GAAP, the current ARO balance consists of six different tranches. The tranches represent the initial ARO and each of the five subsequent adjustments (in present value terms), with the latest tranche recorded at December 31, 2015 related to the 2015 nuclear liabilities adjustment (Ex. C2-1-1 Table 4, line 6). In accordance with US GAAP, each tranche is calculated using a discount rate determined at the time of the adjustment and is not revalued for subsequent changes in the discount rate.

Each of the ARO tranches increases over time due to accretion expense, which represents growth in the present value of the obligation at the discount rate used to establish each tranche, due to the passage of time. Accretion expense is recognized as a cost in OPG's income statement in accordance with US GAAP. The December 31, 2015 tranche was calculated using an accounting discount rate of 3.21 per cent.

To the extent that the ARO increases or decreases from a change in cost estimates resulting from an approved ONFA Reference Plan or from a change in the accounting estimate or assumptions, an equal amount is recorded as an increase or decrease in the net book value of the assets to which the ARO relates. This addition to net book value is known as ARC. ARC represents a substantial portion of the net book value of the Pickering, Darlington and Bruce nuclear facilities. Like other capital costs, the ARC is amortized over the useful life of these assets. This amortization gives rise to depreciation expense. Under the OEB-approved nuclear liabilities recovery methodology for the prescribed facilities discussed in section 3.2, ARC is included in OPG's nuclear rate base. The present value of the incremental committed lifetime variable costs attributable to new wastes generated during a given period is recorded as an increase to the ARO and an expense of the period.

3.1.2 Ontario Nuclear Funds Agreement

The ONFA between OPG and the Province of Ontario sets out OPG's obligations for funding the long-term programs of the nuclear liabilities, through contributions to two segregated funds, the Decommissioning Segregated Fund ("Decommissioning Fund") and the Used Fuel Segregated Fund ("Used Fuel Fund") (collectively, "segregate funds").[1] OPG's quarterly contributions to the segregated funds are determined based on the current approved ONFA Reference Plan lifecycle cost estimates (in present value terms) for the nuclear liabilities. The costs of the Used Fuel Storage and L&ILW Storage programs incurred during the stations' operating lives are not drawn from the segregated funds and are funded from OPG's operating cash flow. The difference between the ARO and the balance of the segregated funds represents the unfunded nuclear liability ("UNL").

[1] In accordance with the ONFA, the Decommissioning Segregated Fund is established to pay for costs associated with the Decommissioning program, the L&ILW Disposal program, certain costs of the Used Fuel Storage program incurred after the stations are shut down, and the costs of the L&ILW storage program incurred after the stations are shut down. The Used Fuel Segregated Fund funds the costs of the Used Fuel Disposal program and certain costs of the Used Fuel Storage program after the stations are shut down.

ONFA contribution requirements are calculated, at the station level, based on the difference between the station level ONFA lifecycle liabilities (in present value terms) and segregated fund balances, using the general principle that such differences are to be paid into the funds over the remaining life of the applicable stations. The balance of the segregated funds at the station level represents the cumulative balance since the inception of the ONFA, taking into account contributions, disbursements and fund returns tracked by station using a funds continuity schedule. The distribution of the opening fund balances and ongoing contributions to the stations is pursuant to the ONFA.

The ONFA Reference Plan is required to be updated every five years or whenever there is a significant change as determined under the ONFA, and is subject to approval by the Province. The current approved ONFA Reference Plan, which is reflected in the proposed test period revenue requirement, has been in effect since January 1, 2012. Pursuant to the 2012 ONFA Reference Plan, OPG is currently making contributions to the Used Fuel Fund.

Under the ONFA, OPG's financial exposure with respect to the cost of long-term management of used fuel is capped for the first 2.23 million used fuel bundles, and the Province guarantees the rate of return earned for the portion of the Used Fuel Fund attributed to the first 2.23 million used fuel bundles at a specified rate of 3.25 per cent plus the change in the Ontario consumer price index ("CPI") as defined in the ONFA ("committed return"). The difference between the committed return and the actual market return determined based on the fair value of the fund assets related to the first 2.23 million used fuel bundles is recorded in OPG's financial statements as due to or due from the Province in accordance with generally accepted accounting principles. The portion of the fund attributed to used fuel bundles in excess of 2.23 million is not guaranteed by the Province and reflects market returns as long as the fund is in an underfunded position, which continues to be the case. Upon termination of the ONFA, the Province has a right to any excess funds in the Used Fuel Fund, as measured by the excess of the fair market value of the fund assets over the corresponding ONFA used fuel liability (referred to in ONFA as the Used Fuel Balance to Complete Cost Estimate) as per the current approved ONFA Reference Plan.

There is no Provincial guarantee with respect to the Decommissioning Fund. As such, when the Decommissioning Fund is underfunded, OPG records fund earnings based on the market value of the fund assets. Upon termination of the ONFA, the Province has a right to any excess funds in the Decommissioning Fund, as measured by the excess of the fair market value of the fund assets over the corresponding ONFA decommissioning liability (referred to in ONFA as the Decommissioning Balance to Complete Cost Estimate) as per the current approved ONFA Reference Plan. Prior to the termination of the ONFA, OPG has the right to direct up to 50 per cent of the excess above 120 per cent, if any, in the Decommissioning Fund to the Used Fuel Fund (but not vice versa) upon approval of a new ONFA Reference Plan. As in EB-2013-0321, these provisions result in OPG limiting the earnings it recognizes on its consolidated financial statements for the Decommissioning Fund, when the Decommissioning Fund is between 100 per cent and 120 per cent funded, by recording an amount due to the Province such that the balance of the fund is equal to the current approved ONFA decommissioning liability.[2] OPG does not have the right or access to the "due to the Province amounts".[3] When the Decommissioning Fund is more than 120 per cent funded, OPG recognizes 50 per cent of the excess amount above the 120 per cent threshold as fund earnings in its financial statements (up to the amount by which the Used Fuel Fund is underfunded). As at December 31, 2015, the Decommissioning Fund was overfunded at less than 120 per cent.

The segregated fund balances and earnings are presented in the Application on the above basis, which reflects the findings in the OEB's EB-2013-0321 Decision with Reasons (p. 110) with respect to the excess earnings.

Continuity schedules showing the opening, closing and average balances of the segregated funds, ARO, UNL and ARC are provided in Ex. C2-1-1 Table 2 (for the prescribed facilities)

---

[2] This results in OPG recording earnings on the Decommissioning Fund at the rate of growth in the current approved ONFA Reference Plan, which is 5.15 per cent per the 2012 ONFA Reference Plan.
[3] Specific ONFA provisions limiting OPG's right or access to excess amounts in the Decommissioning Fund are as outlined in EB-2013-0321 Ex. J11.8.

and Ex. C2-1-1 Table 3 (for the Bruce facilities).[4] The main changes in these balances during the bridge and test periods are discussed in section 4.0.

3.2 Approved Revenue Requirement Methodology for the Prescribed Facilities

Under the OEB-approved methodology for the prescribed facilities, OPG recovers:

- depreciation expense,
- incremental used fuel variable costs,
- incremental L&ILW variable costs,
- return at the weighted average accretion rate on the portion of the nuclear rate base equal to the lesser of the average unamortized ARC and average UNL, and a
- return on the portion of the unamortized average ARC in excess of the average UNL, if any, at the approved weighted average cost of capital ("WACC").

Each of these components is discussed separately below. The associated income tax impacts are described in Ex. F4-2-1. Accounting accretion expense on the ARO and earnings on the segregated funds do not form part of the revenue requirement for the prescribed facilities.

3.2.1 <u>Depreciation Expense</u>

Depreciation on the unamortized ARC is treated in the same manner as depreciation associated with other capital assets; it is included in annual nuclear depreciation expense presented in Ex. F4-1-1 Table 2. The ARC is depreciated over the station life. Actual amounts of ARC depreciation expense for the 2013 to 2015 period and the forecast amounts for the 2016 to 2021 period are presented in Ex. C2-1-1 Table 1, line 1.

3.2.2 <u>Incremental Used Fuel Variable Expenses</u>

A portion of the nuclear fuel expense in Ex. F2-5-1 Table 1 is attributable to the present value of the variable costs related to incremental quantities of used fuel generated in each period.

---

[4] The average ARO, ARC and UNL balances are provided for the prescribed facilities but not the Bruce facilities as these values are required to determine rate base values and the return on rate base used only in the approved revenue requirement methodology for the prescribed facilities.

The used fuel expense is calculated by reference to the difference between the lifecycle cost estimate and the amount of committed costs included in the nuclear liabilities for the corresponding nuclear waste management programs. This difference represents the variable costs of future fuel waste. The present value of this cost difference is then divided by the forecast number of future fuel bundles to calculate the per bundle cost rate. Incremental used fuel variable expenses are calculated by applying the per bundle cost rate to the forecast used fuel volume. The actual used fuel expenses for the 2013 to 2015 period and the forecast amounts for the 2016 to 2021 period are presented in Ex C2-1-1 Table 1, line 2. The accounting discount rate of 3.21 per cent associated with the latest ARO tranche was used to determine the forecast used fuel expenses for the 2016-2021 period.

3.2.3 Incremental Low and Intermediate Level Waste Variable Expenses

The L&ILW variable expenses are a component of the OM&A expenses reflected in Ex. F2-2-1 Table 1 and Ex F2-7-1 Table 1. The L&ILW variable expenses represent the present value of the variable costs related to incremental volumes of L&ILW produced in each period. Similar to used fuel, the difference between the lifecycle cost estimate and the amount of committed costs included in the nuclear liabilities for the corresponding nuclear waste management programs represents the variable costs of future waste. The present value of this cost difference is then divided by the forecast future L&ILW volume estimates to calculate the dollar per cubic metre rate. L&ILW variable expenses are calculated by applying the dollar per cubic metre rate to the forecast waste volumes. The actual L&ILW expenses for the 2013 to 2015 period and the forecast amounts for the 2016 to 2021 period are presented in Ex. C2-1-1 Table 1, line 3. The year-end 2015 discount rate of 3.21 per cent was used to determine the forecast L&ILW expenses for the 2016-2021 period.

3.2.4 Return on Rate Base

The OEB-approved nuclear liabilities recovery methodology requires that the return on a portion of the rate base be limited to the weighted average accretion rate. This portion is equal to the lesser of: (i) the average UNL related to the Pickering and Darlington facilities, and (ii) the average unamortized ARC included in the fixed asset balances for these facilities. The remainder of OPG's rate base, including the amount, if any, by which average ARC exceeds average UNL, earns the OEB-approved WACC. The average UNL and the average unamortized ARC, including the apportionment of the ARC between amounts subject to the weighted average accretion rate and the WACC rate, are provided for the 2013-2021 period in Ex. C2-1-1 Table 1a.

The UNL balances for 2016-2021 are projected based on forecast ARO and segregated fund balances, taking into account forecast activity for future years. For the ARO, forecast activity includes accretion expense on the ARO balance, used fuel and L&ILW variable expenses, and expenditures against the ARO. For the segregated funds, forecast activity includes segregated fund contributions per the 2012 ONFA Reference Plan contribution schedule, fund earnings at a target rate of 5.15 per cent consistent with the growth rate per the approved 2012 ONFA Reference Plan, and fund disbursements. The forecast activity for the prescribed facilities' portion of the ARO and segregated funds is shown in Ex. C2-1-1 Table 2.

As seen in Ex C2-1-1 Table 1a, Note 1, the amount of the average unamortized ARC is projected to be less than the amount of the average UNL during the test period. Therefore, the full amount of the forecast average unamortized ARC earns the weighted average accretion rate for the 2017-2021 period. The weighted average accretion rate is 5.37% for the 2013 to 2015 period and is forecast to decrease to 5.11% after taking into accounting the latest ARO tranche recorded at year-end 2015. The resulting return on rate base amounts are shown in Ex. C2-1-1 Table 1, lines 4 and 5, respectively.

3.3 Approved Revenue Requirement Methodology for the Bruce Facilities

Starting with the EB-2007-0905 Decision with Reasons (p. 109), the OEB has applied a financial accounting approach, in accordance with generally accepted accounting principles for non-regulated entities, for determining the revenue requirement impact for the nuclear liabilities associated with OPG's Bruce facilities. Under this approach, OPG recovers depreciation expense, incremental used fuel and L&ILW variable costs and accounting accretion expense, less segregated fund earnings. Each of these components is discussed separately below.

3.3.1 Depreciation Expense

Depreciation on the unamortized ARC for the Bruce facilities is treated in the same manner as the depreciation associated with other capital assets and the ARC for the prescribed facilities. Total depreciation expense for the Bruce facilities is presented in Ex. G2-2-1 Table 4. Included in these amounts are actual amounts of ARC depreciation expense for 2013 to 2015 and the 2016-2021 forecast amounts period presented in Ex. C2-1-1 Table 1, line 9.

3.3.2 Incremental Used Fuel Variable Expenses

The nuclear used fuel variable expense for the Bruce facilities are determined in the same manner as described in section 3.2.2 for the prescribed facilities. Nuclear used fuel expense for the Bruce facilities is presented in Ex. G2-2-1 Table 5. Actual amounts of the expense for the 2013 to 2015 period and the 2016-2021 forecast amounts are also found in Ex C2-1-1 Table 1, line 10.

3.3.3 Incremental Variable Low and Intermediate Level Waste Expense

L&ILW variable expenses for the Bruce facilities are determined in the same manner as described in section 3.2.3 for prescribed facilities. The L&ILW expenses for the Bruce facilities are included in amounts shown in Ex. G2-2-1 Table 5. Actual amounts of the expense for the 2013 to 2015 period and amounts forecast for the 2016 to 2021 period are presented in Ex. C2-1-1 Table 1, line 11.

3.3.4 Accretion Expense

The accretion expense represents the growth in the present value-based ARO due to the passage of time. The attribution of the ARO balances between prescribed facilities and Bruce facilities is discussed in section 3.1 above. For the 2016 to 2021 period, forecast accretion expense for the Bruce facilities is derived using the same methodology as in EB-2010-0008 and EB-2013-0321, by applying the corresponding accretion rates to the year-end balance of each tranche. The forecast amounts were derived by reference to the December 31, 2015 ARO balances from OPG's 2015 audited consolidated financial statements, taking into account, using the half-year rule, projected changes in the Bruce station portion of the ARO due to additional used fuel and L&ILW variable expenses and expenditures against the ARO during the forecast period, as shown in Ex. C2-1-1 Table 3. Actual amounts of the accretion expense for the 2013 to 2015 period and the 2016-2021 forecast amounts are presented in Ex. C2-1-1 Table 1, line 12 as well as Ex. G2-2-1 Table 5, line 3.

3.3.5 Earnings on the Segregated Funds

The station-level attribution of the segregated fund balances is discussed in section 3.1 above. Actual segregated fund earnings for the 2013 to 2015 period and amounts forecast for the 2016 to 2021 period are presented in Ex. C2-1-1 Table 1, line 13 as well as Ex. G2-2-1 Table 5, line 4. Forecast segregated funds earnings for the bridge and test period were determined using the same methodology as in EB-2010-0008 and EB-2013-0321. In particular, earnings were determined by applying a return rate of 5.15%, based on the approved 2012 ONFA Reference Plan, to the opening fund balances. Such earnings take into account, using the half-year rule, contributions to the segregated funds pursuant to the approved 2012 ONFA Reference Plan contribution schedule and disbursements from the funds, as shown in Ex. C2-1-1 Table 3. The forecast amounts were derived by reference to the December 31, 2015 segregated fund balances from OPG's 2015 audited consolidated financial statements.

4.0 CHANGES IN ARO, UNAMORTIZED ARC AND SEGREGATED FUND BALANCES

With the exception of 2015, which includes a year-end ARO balance adjustment reflecting changes in nuclear station EOL dates, the actual and forecast growth in the ARO for the 2013 to 2021 period is primarily the result of accretion expense. Similarly, with the exception of the year-end ARC balance adjustment in 2015 corresponding to the above ARO adjustment, depreciation is the driver of the otherwise declining trend in the ARC balances from 2013 to 2021. The revenue requirement impact of the year-end 2015 ARO/ARC adjustment on prescribed and Bruce facilities is discussed in section 5.0.

The actual and forecasted growth in the segregated funds balance for the 2013 to 2021 period is the result of actual and forecasted fund earnings and contributions to the funds in accordance with the approved 2012 ONFA Reference Plan.

5.0 REVENUE REQUIREMENT IMPACT OF YEAR-END 2015 NUCLEAR LIABILITIES ADJUSTMENT

As anticipated in EB-2015-0374 and discussed in Ex. F4-1-1, section 3.2, OPG implemented changes to accounting EOL assumptions for its nuclear stations effective December 31, 2015. The main change was the extension of the average service life of the Bruce B station, from 2019 to 2061, to reflect the expected unit EOL dates set out in the updated refurbishment agreement between the Independent System Electricity Operator and Bruce Power.

Effective December 31, 2015, in accordance with US GAAP, OPG recorded increases in the carrying values of the ARO and ARC of $2,330 million, comprising an increase of $2,747.5 million for the Bruce facilities and a decrease of $417.5 million for the prescribed facilities, to reflect the changes in the nuclear station EOL assumptions. The net change in the total ARO and total ARC balances is primarily due to the increase in the committed costs associated with used fuel disposal activities resulting from the extension of the Bruce B units' operating period and related additional used fuel. Additionally, as the costs of nuclear liability programs involving central facilities are shared across the OPG-owned nuclear fleet, the increase in the expected used fuel and other waste volumes for the Bruce facilities resulted in a rebalancing of certain nuclear liability costs from the prescribed facilities to the Bruce facilities.

The financial impacts of the above change in the ARO and ARC balances for 2016 to 2021 are summarized below. The methodologies used to derive these impacts are as described in section 3.0 and are unchanged from those applied in EB-2010-0008, EB-2012-0002 and EB-2013-0321. The impacts are:

1) With respect to the prescribed facilities, a reduction in the 2017-2021 after-tax revenue requirement of $245.7M as detailed in Ex. C2-1-1 Table 5, line 8, including a decrease of $61.4M in income taxes, as shown in Ex. C2-1-1 Table 5, line 7.
2) With respect to the Bruce facilities, a reduction in the 2017-2021 Bruce Lease net revenues of $463.4M as detailed in Ex. C2-1-1 Table 5, line 15 and discussed in Ex. G2-

2-1. The reduction in the Bruce Lease net revenues results in a corresponding pre-tax increase in the test period revenue requirement.

3) Projected 2016 financial impact for the prescribed facilities, which results in a forecast customer credit of approximately $65.2M to the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account established in EB-2015-0374, as detailed in Ex. C2-1-1 Table 6 line 8.
4) Projected 2016 financial impact for the Bruce facilities, which results in forecast additions to be recovered from ratepayers of approximately $69.9M to the Bruce Lease Net Revenues Variance Account, as shown in Ex. C2-1-1 Table 6, line 16.

The above impacts arise primarily as a result of the following:

- Lower ARC depreciation for the prescribed facilities due to the reduction in the ARC balance
- Lower return on rate base for the prescribed facilities due to the reduction in the ARC balance and a lower weighted average accretion rate
- Higher accretion expense for the Bruce facilities due to the increase in the ARO balance
- Higher used fuel variable expenses for both prescribed and Bruce facilities due to higher per bundle cost rates, discussed below
- Lower income taxes for the prescribed facilities resulting from above decreases in prescribed facilities' nuclear liability costs
- Lower income taxes included in the Bruce Lease net revenues

The above impacts include those due to the reduction in depreciation expense for prescribed and Bruce facilities' ARC balances recorded prior to December 31, 2015, as a result of the extensions in the estimated service lives of the nuclear stations.

The weighted average accretion rate of 5.11% applied to calculate the return on rate base for the prescribed facilities for 2016-2021 takes into account the year-end 2015 ARO adjustment. This is lower than the rate of 5.37% that would have been applied for 2016-2021 in the illustrative case without the 2015 ARO adjustment. The detailed calculations of the return on rate base for the prescribed facilities in the illustrative case are shown in Ex. C2-1-1, Tables 5a and 6a, Note 2.

The impact on the variable expenses is calculated by multiplying the forecast number of used fuel bundles by the differences between the forecast per bundle cost rates and the comparable rates in the illustrative cases without the 2015 ARO adjustment. The forecast per bundle rate is higher than in the illustrative case, as a result of the lower discount rate of 3.21 per cent compared to the discount rate of 3.43 per cent used to calculate per bundle cost rates based on the last ARO tranche recorded prior to the 2015 adjustment.

There are no changes to segregated fund contributions under the ONFA in the illustrative case without the 2015 ARO adjustment, as OPG continues to operate under the approved 2012 ONFA Reference Plan until the updated reference plan discussed in section 6.0 is completed and approved by the Province.

6.0 2017 ONFA REFERENCE PLAN STATUS UPDATE

As required by the ONFA, OPG reviews and updates the ONFA Reference Plan and associated lifecycle cost estimates at least every 5 years. Updated ONFA Reference Plans are submitted to the Province for review and approval. The next Reference Plan update, effective for years 2017 to 2021, is expected to be finalized in 2016 for the Province's approval. The updated ONFA Reference Plan will reflect the changes in the nuclear station EOL dates made effective December 31, 2015 for accounting purposes.

The proposed test period revenue requirement reflects the approved 2012 ONFA Reference Plan. The corresponding revenue requirement impact of the approved 2017 Reference Plan will be recorded in the Nuclear Liability Deferral Account for the prescribed facilities and the Bruce Lease Net Revenue Variance Account for the Bruce facilities, using the methodologies previously applied in recording the 2012 ONFA Reference Plan revenue requirement impact in these accounts during 2012 to 2014.

Table 1
Revenue Requirement Impact of OPG's Nuclear Liabilities ($M)
Years Ending December 31, 2013 to 2021

Line No.	Description	Note or Reference	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	PRESCRIBED FACILITIES										
1	**Depreciation of Asset Retirement Costs**	Ex. C2-1-1 Table 2	80.7	80.7	80.7	50.3	50.3	50.3	50.3	50.3	18.7
2	**Used Fuel Storage and Disposal Variable Expenses**	Ex. C2-1-1 Table 2	49.0	53.6	53.1	62.0	53.0	55.2	66.7	56.3	56.5
3	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. C2-1-1 Table 2	3.3	2.1	2.0	3.2	4.8	4.5	5.4	5.6	6.5
	Return on ARC in Rate Base:										
4	**Return on Rate Base at Weighted Average Accretion Rate**	Ex. C1-1-1 Tables 1-9	78.9	74.6	70.3	42.2	39.6	37.1	34.5	31.9	30.2
5	**Return on Rate Base at Weighted Average Cost of Capital**	Note 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**Pre-Tax Revenue Requirement Impact**		212.0	211.0	206.1	157.6	147.7	147.1	156.9	144.1	111.9
7	**Income Tax Impact**	Note 2	38.0	13.6	11.1	(6.3)	(2.8)	(9.4)	(36.3)	36.3	25.6
8	**Total Revenue Requirement Impact - Prescribed Facilities** (line 6 + line 7)		249.9	224.6	217.2	151.3	144.9	137.7	120.6	180.4	137.5
	BRUCE FACILITIES										
9	**Depreciation of Asset Retirement Costs**	Ex. C2-1-1 Table 3	101.2	100.4	100.4	100.2	100.2	100.2	100.2	100.2	100.2
10	**Used Fuel Storage and Disposal Variable Expenses**	Ex. C2-1-1 Table 3	54.0	58.9	61.0	65.1	71.4	70.8	74.9	81.7	64.2
11	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. C2-1-1 Table 3	2.8	1.5	1.5	2.5	2.1	2.6	2.4	2.9	4.1
12	**Accretion Expense**	Ex. C2-1-1 Table 3	369.0	386.7	404.7	511.0	531.4	552.4	573.9	595.6	617.8
13	**Less: Segregated Fund Earnings (Losses)**	Ex. C2-1-1 Table 3	337.1	411.8	338.6	379.8	395.7	413.7	432.8	454.8	479.8
14	**Impact on Bruce Facilities' Income Taxes**	Note 3	(47.5)	(33.9)	(57.2)	(74.8)	(77.3)	(78.1)	(79.6)	(81.4)	(76.6)
15	**Pre-Tax Revenue Requirement Impact (Impact on Bruce Lease Net Revenues)**		142.4	101.7	171.7	224.3	232.0	234.3	238.9	244.2	229.8
16	**Income Tax Impact on Revenue Requirement** (line 15 x tax rate / (1-tax rate))	Note 4	47.5	33.9	57.2	74.8	77.3	78.1	79.6	81.4	76.6
17	**Total Revenue Requirement Impact - Bruce Facilities** (line 15 + line 16)		189.9	135.7	228.9	299.0	309.4	312.4	318.5	325.6	306.5
18	**Total Revenue Requirement Impact - Prescribed and Bruce Faciliites**		439.8	360.3	446.1	450.3	454.3	450.1	439.1	506.0	444.0
	(line 8 + line 17)										

Notes:
See Ex. C2-1-1 Table 1a for notes

Table 1a
Revenue Requirement Impact of OPG's Nuclear Liabilities ($M)
Years Ending December 31, 2013 to 2021
Notes to Ex. C2-1-1, Table 1

Notes:

1 If average Unfunded Nuclear Liabilities (UNL) is less than average Asset Retirement Costs (ARC) for the prescribed facilities, the funded portion of average ARC (i.e. the amount by which average ARC exceeds average UNL) earns WACC as follows:

Table to Note 1

Line No.	Year	(from Ex. C2-1-1 Table 2, line 26) Average ARC ($M)	(from Ex. C2-1-1 Table 2, line 20) Average UNL ($M)	(a)-(b) ARC-UNL ($M)	Annual WACC	(c) x (d) if >0 Return on Rate Base ($M)	WACC Reference
		(a)	(b)	(c)	(d)	(e)	
1a	2013	1,470.2	1,719.6	(249.4)	7.40%	0.0	EB-2010-0008 Payment Amounts Order, App. A, Table 5b
2a	2014	1,389.4	1,659.2	(269.8)	6.86%	0.0	EB-2013-0321 Payment Amounts Order, App. A, Table 5b
3a	2015	1,308.7	1,562.7	(254.0)	6.85%	0.0	EB-2013-0321 Payment Amounts Order, App. A, Table 6b
4a	2016	825.7	1,056.5	(230.8)	6.85%	0.0	EB-2013-0321 Payment Amounts Order, App. A, Table 6b
5a	2017	775.4	954.5	(179.1)	7.01%	0.0	Ex. C1-1-1 Table 5
6a	2018	725.1	860.7	(135.5)	6.86%	0.0	Ex. C1-1-1 Table 4
7a	2019	674.9	725.4	(50.5)	6.83%	0.0	Ex. C1-1-1 Table 3
8a	2020	624.6	682.1	(57.5)	6.81%	0.0	Ex. C1-1-1 Table 2
9a	2021	590.1	764.8	(174.7)	6.80%	0.0	Ex. C1-1-1 Table 1

2 The income tax impact for prescribed facilities is calculated as follows:

Table to Note 2 ($M)

Line No.	Item	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1b	Regulatory Taxable Income Before Impact of Segregated Fund Contributions (Ex. C2-1-1, Table 1, line 6)	212.0	211.0	206.1	157.6	147.7	147.1	156.9	144.1	111.9
2b	Contributions to Nuclear Segregated Funds for Prescribed Facilities (Ex. C2-1-1 Table 2, line 14)	98.1	170.1	172.8	176.7	156.1	175.3	265.7	35.2	35.2
3b	Net Increase in Regulatory Taxable Income (line 1b - line 2b)	113.9	40.9	33.3	(19.0)	(8.4)	(28.3)	(108.8)	108.9	76.7
4b	Income Tax Rate (Ex. F4-2-1 Table 3, line 31 and Ex. F4-2-1 Table 3a, line 29)	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
5b	Income Tax Impact (line 3b x line 4b / (1 - line 4b))	38.0	13.6	11.1	(6.3)	(2.8)	(9.4)	(36.3)	36.3	25.6

3 The impact on Bruce facilities' income taxes relates to higher deductible temporary differences associated with expenses not deductible for tax purposes, as follows:

Table to Note 3 ($M)

Line No.	Item	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1c	Increase in Temporary Differences (Ex. C2-1-1 Table 1, lines 9 through 13)	189.9	135.7	228.9	299.0	309.4	312.4	318.5	325.6	306.5
2c	Income Tax Rate (Ex. G2-2-1 Table 7, line 49 and Ex. G2-2-1 Table 8, line 33)	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
3c	Impact on Bruce Facilities' Income Taxes (line 1c x line 2c)	(47.5)	(33.9)	(57.2)	(74.8)	(77.3)	(78.1)	(79.6)	(81.4)	(76.6)

4 Income tax rates are from Ex. F4-2-1 Table 3, line 31 (2013-2016), and Ex. F4-2-1 Table 3a, line 29 (2017-2021).

Table 2
Prescribed Facilities - Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
Years Ending December 31, 2013 to 2021

Line No.	Description	Note	2013 Actual[1]	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	ASSET RETIREMENT OBLIGATION										
1	**Opening Balance**	2	8,034.1	8,424.3	8,836.5	8,836.3	9,233.0	9,640.3	10,060.7	10,493.5	10,909.2
2	**Used Fuel Storage and Disposal Variable Expenses**	3	49.0	53.6	53.1	62.0	53.0	55.2	66.7	56.3	56.5
3	**Low & Intermediate Level Waste Management Variable Expenses**	4	3.3	2.1	2.0	3.2	4.8	4.5	5.4	5.6	6.5
4	**Accretion Expense**		442.7	464.3	486.5	493.7	515.5	538.0	561.2	584.6	608.5
5	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(104.7)	(109.1)	(126.3)	(162.2)	(166.0)	(177.4)	(200.6)	(230.7)	(228.0)
6	**Consolidation and Other Adjustments**		(0.1)	1.2	(0.6)	0.0	0.0	0.0	0.0	0.0	0.0
7	**Closing Balance Before Year-End Adjustments** (lines 1 through 6)		8,424.3	8,836.5	9,251.2	9,233.0	9,640.3	10,060.7	10,493.5	10,909.2	11,352.8
8	**Year-End 2015 Adjustment Reflecting Nuclear Station End of Life Changes**	5	0.0	0.0	(417.5)	0.0	0.0	0.0	0.0	0.0	0.0
9	**2012 CNSC Requirements Adjustment**	6	0.0	0.0	2.6	0.0	0.0	0.0	0.0	0.0	0.0
10	**Closing Balance** (line 7 through 10)		8,424.3	8,836.5	8,836.3	9,233.0	9,640.3	10,060.7	10,493.5	10,909.2	11,352.8
11	**Average Asset Retirement Obligation** ((line 1 + line 7)/2)		8,229.2	8,630.4	9,043.8	9,034.6	9,436.6	9,850.5	10,277.1	10,701.3	11,131.0
	NUCLEAR SEGREGATED FUNDS BALANCE										
12	**Opening Balance**	2	6,316.5	6,702.8	7,239.6	7,722.6	8,233.7	8,730.6	9,249.0	9,854.3	10,184.2
13	**Earnings (Losses)**		332.9	409.0	351.3	400.6	425.9	451.4	479.6	503.1	520.5
14	**Contributions**		98.1	170.1	172.8	176.7	156.1	175.3	265.7	35.2	35.2
15	**Disbursements**		(44.7)	(42.3)	(41.1)	(66.1)	(85.0)	(108.3)	(140.0)	(208.4)	(191.6)
16	**Closing Balance** (line 12 through 15)		6,702.8	7,239.6	7,722.6	8,233.7	8,730.6	9,249.0	9,854.3	10,184.2	10,548.3
17	**Average Nuclear Segregated Funds Balance** ((line 12 + line 16)/2)		6,509.6	6,971.2	7,481.1	7,978.2	8,482.2	8,989.8	9,551.7	10,019.3	10,366.2
	UNFUNDED NUCLEAR LIABILITY BALANCE (UNL)										
18	**Opening Balance** (line 1 - line 12)		1,717.6	1,721.5	1,596.8	1,113.7	999.3	909.7	811.7	639.1	725.0
19	**Closing Balance** (line 7 - line 16)		1,721.5	1,596.8	1,528.6	999.3	909.7	811.7	639.1	725.0	804.5
20	**Average Unfunded Nuclear Liability Balance** ((line 18 + line 19)/2)		1,719.6	1,659.2	1,562.7	1,056.5	954.5	860.7	725.4	682.1	764.8
	ASSET RETIREMENT COSTS (ARC)										
21	**Opening Balance**	2	1,510.5	1,429.8	1,349.0	850.8	800.5	750.3	700.0	649.7	599.5
22	**Depreciation Expense**		(80.7)	(80.7)	(80.7)	(50.3)	(50.3)	(50.3)	(50.3)	(50.3)	(18.7)
23	**Closing Balance Before Year-End Adjustments** (line 21 + line 22)		1,429.8	1,349.0	1,268.3	800.5	750.3	700.0	649.7	599.5	580.7
24	**Year-End 2015 Adjustment Reflecting Nuclear Station End of Life Changes**	5	0.0	0.0	(417.5)	0.0	0.0	0.0	0.0	0.0	0.0
25	**Closing Balance** (line 23 + line 24)		1,429.8	1,349.0	850.8	800.5	750.3	700.0	649.7	599.5	580.7
26	**Average Asset Retirement Costs** ((line 21 + line 23)/2)		1,470.2	1,389.4	1,308.7	825.7	775.4	725.1	674.9	624.6	590.1
27	**LESSER OF AVERAGE UNL OR ARC** (lesser of line 20 or line 26)		1,470.2	1,389.4	1,308.7	825.7	775.4	725.1	674.9	624.6	590.1

Notes:
1 As shown in EB-2013-0321 Ex. L-1.0-1 Staff-002, Table 7, col. (a)
2 Opening balances in col. (a) from EB-2013-0321, Ex. C2-1-1 Table 2, col. (c)
3 In 2019, includes expenses associated with the one-time new fuel load for the refurbished Darlington Unit 2 prior to start-up (discussed in Ex. F2-5-1 section 2.0).
4 Starting in 2016, a portion of expenses relates to OM&A costs charged to the Darlington Refurbishment Program for disposal of low and intermediate level waste.
5 Adjustment recorded on December 31, 2015 reflecting the changes to station end-of-life date assumptions underlying the ARO calculation, see Ex. C2-1-1 Table 4.
6 Adjustment recorded on December 31, 2015 associated with the change to the 2012 cost estimates (see EB-2013-0321 Ex. C2-1-1 Table 2, Note 4) related to the implementation of new CNSC requirements in 2012 to include certain facilities with Waste Nuclear Substance Licences not included in the 2012 ONFA Reference Plan due to timing of notification by the CNSC.
As a result, ARO increased by $5.2M as at December 31, 2015, of which $2.6M was attributed to prescribed facilities and $2.6M was attributed to Bruce facilities. In accordance with GAAP, this amount was expensed (i.e. not included in ARC) as the amount relates to a legacy facility that is not used to support OPG's current operations.

Table 3
Bruce Facilities - Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
Years Ending December 31, 2013 to 2021

Line No.	Description	Note	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	ASSET RETIREMENT OBLIGATION										
1	**Opening Balance**	2	7,125.5	7,461.2	7,814.5	10,946.0	11,362.0	11,794.8	12,234.0	12,677.3	13,120.4
2	**Used Fuel Storage and Disposal Variable Expenses**		54.0	58.9	61.0	65.1	71.4	70.8	74.9	81.7	64.2
3	**Low & Intermediate Level Waste Management Variable Expenses**		2.8	1.5	1.5	2.5	2.1	2.6	2.4	2.9	4.1
4	**Accretion Expense**		369.0	386.7	404.7	511.0	531.4	552.4	573.9	595.6	617.8
5	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(90.0)	(94.6)	(85.3)	(162.6)	(172.1)	(186.7)	(207.9)	(237.0)	(231.5)
6	**Consolidation and Other Adjustments**		(0.1)	0.8	(0.4)	0.0	0.0	0.0	0.0	0.0	0.0
7	**Closing Balance Before Year-End Adjustments** (lines 1 through 6)		7,461.2	7,814.5	8,195.9	11,362.0	11,794.8	12,234.0	12,677.3	13,120.4	13,575.0
8	**Year-End 2015 Adjustment Reflecting Nuclear Station End of Life Changes**	3	0.0	0.0	2,747.5	0.0	0.0	0.0	0.0	0.0	0.0
9	**2012 CNSC Requirements Adjustment**	4	0.0	0.0	2.6	0.0	0.0	0.0	0.0	0.0	0.0
10	**Closing Balance** (line 7 through 9)		7,461.2	7,814.5	10,946.0	11,362.0	11,794.8	12,234.0	12,677.3	13,120.4	13,575.0
11	**Average Asset Retirement Obligation** ((line 1 + line 7)/2)		7,293.3	7,637.8	8,005.2	11,154.0	11,578.4	12,014.4	12,455.6	12,898.8	13,347.7
	NUCLEAR SEGREGATED FUNDS BALANCE										
12	**Opening Balance**	2	6,400.1	6,792.7	7,139.1	7,413.8	7,714.3	8,050.7	8,430.9	8,812.0	9,304.7
13	**Earnings (Losses)**		337.1	411.8	338.6	379.8	395.7	413.7	432.8	454.8	479.8
14	**Contributions**		85.9	(31.3)	(29.4)	(26.9)	6.8	18.1	22.6	97.5	97.5
15	**Disbursements**		(30.4)	(34.0)	(34.6)	(52.4)	(66.1)	(51.7)	(74.5)	(59.4)	(72.8)
16	**Closing Balance** (line 12 through 15)		6,792.7	7,139.1	7,413.8	7,714.3	8,050.7	8,430.9	8,812.0	9,304.7	9,809.2
17	**Average Nuclear Segregated Funds Balance** ((line 12 + line 16)/2)		6,596.4	6,965.9	7,276.5	7,564.0	7,882.5	8,240.8	8,621.4	9,058.3	9,557.0
	ASSET RETIREMENT COSTS (ARC)										
18	**Opening Balance**	2	1,944.8	1,843.6	1,743.8	4,390.9	4,290.7	4,190.5	4,090.3	3,990.1	3,889.9
19	**Reconciliation Adjustment**		0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
20	**Depreciation Expense**		(101.2)	(100.4)	(100.4)	(100.2)	(100.2)	(100.2)	(100.2)	(100.2)	(100.2)
21	**Closing Balance Before Year-End Adjustments** (line 18 + line 19 + line 20)		1,843.6	1,743.8	1,643.5	4,290.7	4,190.5	4,090.3	3,990.1	3,889.9	3,789.7
22	**Year-End 2015 Adjustment Reflecting Nuclear Station End of Life Changes**	3	0.0	0.0	2,747.5	0.0	0.0	0.0	0.0	0.0	0.0
23	**Closing Balance** (line 21 + line 22)		1,843.6	1,743.8	4,390.9	4,290.7	4,190.5	4,090.3	3,990.1	3,889.9	3,789.7
24	**Average Asset Retirement Costs** ((line 18 + line 21)/2))		1,894.2	1,793.7	1,693.6	4,340.8	4,240.6	4,140.4	4,040.2	3,940.0	3,839.8

Notes:

1 As shown in EB-2013-0321 Ex. L-1.0-1 Staff-002, Table 7, col. (b)
2 Opening balances in col. (a) from EB-2013-0321, Ex. C2-1-1 Table 3, col. (c).
3 Adjustment recorded on December 31, 2015 reflecting the changes to station end-of-life date assumptions underlying the ARO calculation, see Ex. C2-1-1 Table 4.
4 See Ex. C2-1-1 Table 2, Note 6.

Table 4

Impact of Year End 2015 Adustment - Assignment of ARO Adjustment and Allocation of ARC to Nuclear Stations ($M)

Line No.	Description	Pickering A	Pickering B	Darlington	Prescribed Facilities Total	Bruce A	Bruce B	Bruce Facilities Total	OPG Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	December 31, 2015 Actual:								
1	**Decommissioning Program**	3.2	5.4	7.3	15.9	(42.9)	288.0	245.0	260.9
2	**Low and Intermediate Level Waste Storage Program**	(4.2)	(19.7)	168.4	144.5	(57.4)	109.4	52.0	196.5
3	**Low and Intermediate Level Waste Disposal Program**	(21.0)	(41.3)	149.2	86.9	(172.2)	157.6	(14.6)	72.3
4	**Used Fuel Disposal Program**	47.5	13.4	(668.7)	(607.8)	(258.5)	2,702.6	2,444.1	1,836.3
5	**Used Fuel Storage Program**	(28.7)	(37.0)	8.7	(57.1)	24.9	(4.0)	21.0	(36.1)
6	**ARO Adjustment Assignment to Station Level**	(3.1)	(79.2)	(335.2)	(417.5)	(506.2)	3,253.6	2,747.5	2,330.0
7	**Asset Retirement Cost Adjustment**	(3.1)	(79.2)	(335.2)	(417.5)	(506.2)	3,253.6	2,747.5	2,330.0

Numbers may not add due to rounding.

Table 5
Impact of Changes in Nuclear Station End-of-Life Dates on Nuclear Liabilities Costs - Test Period Revenue Requirement ($M)
Years Ending December 31, 2017 to 2021

Line No.	Description	Note or Reference (for cols. (a) to (e))	With Change in Nuclear Station End-of-Life Dates 2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan	Note or Reference (for cols. (f) to (j))	Without Changes in Nuclear Station End-of-Life Dates[1] 2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan	Sum (a) to (e) less **Sum (f) to (j)** **Impact on Nuclear Liabilities Costs**
			(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)	(i)	(j)	(k)
	PRESCRIBED FACILITIES													
1	**Depreciation of Asset Retirement Costs**	Ex. C2-1-1 Table 1	50.3	50.3	50.3	50.3	18.7	Note 2	80.7	80.7	80.7	60.5	28.5	(111.4)
2	**Used Fuel Storage and Disposal Variable Expenses**	Ex. C2-1-1 Table 1	53.0	55.2	66.7	56.3	56.5		48.9	51.0	61.7	52.4	52.7	21.0
3	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. C2-1-1 Table 1	4.8	4.5	5.4	5.6	6.5		4.6	4.4	5.3	5.4	6.4	0.7
	Return on ARC in Rate Base													
4	**Return on Rate Base at Weighted Average Accretion Rate**	Ex. C2-1-1 Table 1	39.6	37.1	34.5	31.9	30.2	Note 3	61.6	57.3	52.9	49.1	46.8	(94.5)
5	**Return on Rate Base at Weighted Average Cost of Capital**	Ex. C2-1-1 Table 1	0.0	0.0	0.0	0.0	0.0	Note 3	0.0	0.0	0.0	0.0	0.0	0.0
6	**Pre-Tax Revenue Requirement Impact**		147.7	147.1	156.9	144.1	111.9		195.8	193.5	200.7	167.4	134.4	(184.1)
7	**Income Tax Impact**	Ex. C2-1-1 Table 1	(2.8)	(9.4)	(36.3)	36.3	25.6	Note 4	13.3	6.0	(21.7)	44.1	33.1	(61.4)
8	**Total Revenue Requirement Impact - Prescribed Facilities** (line 6 + line 7)		144.9	137.7	120.6	180.4	137.5		209.1	199.5	179.0	211.5	167.5	(245.5)
	BRUCE FACILITIES													
9	**Depreciation of Asset Retirement Costs**	Ex. C2-1-1 Table 1	100.2	100.2	100.2	100.2	100.2	Note 5	100.3	100.3	100.3	42.8	42.8	114.5
10	**Used Fuel Storage and Disposal Variable Expenses**	Ex. C2-1-1 Table 1	71.4	70.8	74.9	81.7	64.2		65.8	65.6	69.4	76.0	59.8	26.5
11	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. C2-1-1 Table 1	2.1	2.6	2.4	2.9	4.1		2.1	2.6	2.4	2.8	4.0	0.4
12	**Accretion**	Ex. C2-1-1 Table 1	531.4	552.4	573.9	595.6	617.8		441.0	459.6	478.7	497.9	517.5	476.4
13	**Less: Segregated Fund Earnings (Losses)**	Ex. C2-1-1 Table 1	395.7	413.7	432.8	454.8	479.8		395.7	413.7	432.8	454.8	479.8	0.0
14	**Impact on Bruce Facilities' Income Taxes**		(77.3)	(78.1)	(79.6)	(81.4)	(76.6)	Note 6	(53.3)	(53.6)	(54.5)	(41.2)	(36.1)	
15	**Pre-Tax Revenue Requirement Impact** (lines 9 through 12 minus 13 plus 14)		232.0	234.3	238.9	244.2	229.8		160.0	160.8	163.4	123.5	108.2	463.4
16	**Income Tax Impact**	Ex. C2-1-1 Table 1	77.3	78.1	79.6	81.4	76.6	Note 7	53.3	53.6	54.5	41.2	36.1	154.5
17	**Total Revenue Requirement Impact - Bruce Facilities** (line 15 + line 16)		309.4	312.4	318.5	325.6	306.5		213.4	214.3	217.9	164.7	144.2	617.8
18	**Total Revenue Requirement Impact - Presecribed and Bruce Facilities** (line 8 + line 17)		454.3	450.1	439.1	506.0	444.0		422.5	413.8	396.9	376.2	311.7	372.3

Note:
See C2-1-1 Table 5a for notes

Table 5a
Impact of Changes in Nuclear Station End-of-Life Dates on Nuclear Liabilities Costs ($M)
Years Ending December 31, 2016 to 2021
Notes to Ex. C2-1-1, Table 5 and Table 6

Notes:

1 "Without Change in Nuclear Station End-of-Life Dates" amounts are presented for illustrative purposes and are derived from a base case using the same assumptions for baseline cost estimates, discount rates and accounting station end-of-life dates as those underlying amounts reflected in the payment amounts approved in EB-2013-0321.

2 A continuity of ARC balances for the Prescribed Facilities in the illustrative case "Without Changes in Nuclear Station End-of-Life Dates" is as estimated as follows:

Table to Note 2 ($M)

Line No.	Amounts Without Change in Nuclear Station End-of-Life Dates	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1a	ARC Opening Balance (col. (a) from Ex. C2-1-1 Table 2, line 23, col. (c))	1,268.3	1,187.6	1,106.8	1,026.1	945.4	884.9
2a	Depreciation Expense (cols. (a) to (d): Ex. C2-1-1 Table 2, line 22, col. (c); cols. (e) to (f): Note #)	(80.7)	(80.7)	(80.7)	(80.7)	(60.5)	(28.5)
3a	ARC Closing Balance (line 1a - line 2a)	1,187.6	1,106.8	1,026.1	945.4	884.9	856.4
4a	Average ARC ((line 1a + line 3a) / 2)	1,227.9	1,147.2	1,066.5	985.7	915.1	870.6

\# For 2020, depreciation is estimated as follows, taking into account illustrative end-of-life date for Pickering Units 5-8 of April 30, 2020: line 2a, col. (d) less 8/12 x EB-2013-0321 Ex. L-8.1-2 AMPCO-079, Att. 1, Table 2, line 27, col. (f). For 2021, depreciation is estimated as follows, taking into account illustrative end-of-life dates for Pickering Units 5-8 of April 30, 2020 and Pickering Units 1 & 4 of December 31, 2020: line 2a, col.(d) less the sum of EB-2013-0321 Ex. L-8.1-2 AMPCO-079, Att. line 27, col. (f) and Ex. L-8.1-2 AMPCO-079 Att. 1, Table 1, line 27, col. (f).

3 If average UNL is less than average ARC for the prescribed facilities, the funded portion of average ARC (i.e., the amount by which average ARC exceeds average UNL) earns WACC as shown. The lesser of ARC and UNL earns the weighted average accretion rate as shown.

Table to Note 3 ($M)

Line No.	Year	Average ARC Without Changes in Nuclear Station End-of-Life Dates ($M)+	Average UNL Without Changes in Nuclear Station End-of-Life Dates ($M)	(a)-(b) ARC-UNL ($M)	Annual WACC++	(c) x (d) if >0 Return on Rate Base ($M)	Weighted Average Accretion Rate	(f) x lesser of (a) and (b) Return on Rate Base ($M) (f) x lesser of (a) and (b) Return on Rate Base ($M)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1b	2016	1,227.9	1,470.6	(242.6)	6.85%	0.0	5.37%	65.9
2b	2017	1,147.2	1,360.2	(213.0)	7.01%	0.0	5.37%	61.6
3b	2018	1,066.5	1,255.5	(189.1)	6.86%	0.0	5.37%	57.3
4b	2019	985.7	1,107.4	(121.7)	6.83%	0.0	5.37%	52.9
5b	2020	915.1	1,050.3	(135.2)	6.81%	0.0	5.37%	49.1
6b	2021	870.6	1,118.4	(247.7)	6.80%	0.0	5.37%	46.8

\+ From Note 2, line 4a
\++ Table 1a, Note 1, col. (d)

4 The income tax impact for prescribed facilities in the illustrative case "Without Changes in Nuclear Station End-of-Life Dates" is calculated as follows:

Table to Note 4 ($M)

Line No.	Item	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1c	Regulatory Taxable Income Before Impact of Segregated Fund Contributions (col. (a): Ex. C2-1-1 Table 6, line 6, col. (b); cols. (b) to (f): Ex. C2-1-1, Table 5, line 6, cols. (f) to (j))	206.7	195.8	193.5	200.7	167.4	134.4
2c	Contributions to Segregated Funds for Prescribed Facilities (Ex. C2-1-1 Table 2, line 14)	176.7	156.1	175.3	265.7	35.2	35.2
3c	Net Increase in Regulatory Taxable Income (line 1c - line 2c)	30.0	39.8	18.1	(65.0)	132.2	99.2
4c	Income Tax Rate (Ex. F4-2-1 Table 3, line 31 and Ex. F4-2-1 Table 3a, line 29)	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
5c	Income Tax Impact (line 3c x line 4c / (1 - line 4c))	10.0	13.3	6.0	(21.7)	44.1	33.1

5 Depreciation for the Bruce facilities in the illustrative case "Without Changes in Nuclear Station End-of-Life Dates" is from Ex. C2-1-1 Table 3 line 20, col. (c) for 2017 to 2019. For 2020 and 2021, depreciation is estimated as follows, taking into account illustrative end-of-life date of December 31, 2019 for the Bruce B station: Ex. C2-1-1 Table 3, line 20, col. (c) less Ex. L-8.1-2 AMPCO-079 Att. 1, Table 5, line 24, col. (f).

6 The impact on Bruce facilities' income taxes relates to higher deductible temporary differences associated with expenses not deductible for tax purposes, as follows:

Table to Note 6 ($M)

Line No.	Item	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1d	Increase in Temporary Differences (col. (a): Ex. C2-1-1 Table 6, line 14, col. (b); cols. (b) to (f): Ex. C2-1-1 Table 5, lines 9 through 13, cols (f) to (j))	205.8	213.4	214.3	217.9	164.7	144.2
2d	Income Tax Rate (Ex. G2-2-1 Table 7, line 49 and Ex. G2-2-1 Table 8, line 33)	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
3d	Impact on Bruce Facilities' Income Taxes (line 1d x line 2d)	(51.5)	(53.3)	(53.6)	(54.5)	(41.2)	(36.1)

7 Calculated as amount at Ex. C2-1-1 Table 5, line 15 x tax rate / (1 - tax rate). The income tax rates are from Ex. F4-2-1 Table 3a, line 29.

Numbers may not add due to rounding.

Table 6
Impact of Changes in Nuclear Station End-of-Life Dates on Nuclear Liabilities Costs - Projected Entries into Deferral and Variance Accounts ($M)
Year Ending December 31, 2016

Line No.	Description	Note or Reference (for col. (a))	With Changes in Nuclear Station End-of-Life Dates 2016 Budget	Note or Reference (for col. (b))	Without Changes in Nuclear Station End-of-Life Dates[1] 2016 Budget	(a) - (b) Projected Entry in Deferral and Variance Accounts
			(a)		(b)	(c)
	PRESCRIBED FACILITIES					
1	**Depreciation of Asset Retirement Costs**	Ex. C2-1-1 Table 1	50.3	Note 2	80.7	(30.5)
2	**Used Fuel Storage and Disposal Variable Expenses**	Ex. C2-1-1 Table 1	62.0		56.9	5.1
3	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. C2-1-1 Table 1	3.2		3.1	0.1
	Return on ARC in Rate Base					
4	**Return on Rate Base at Weighted Average Accretion Rate**	Ex. C2-1-1 Table 1	42.2	Note 3	65.9	(23.8)
5	**Return on Rate Base at Weighted Average Cost of Capital**	Ex. C2-1-1 Table 1	0.0	Note 3	0.0	-
6	**Pre-Tax Impact**		157.6		206.7	(49.0)
7	**Income Tax Impact**	Ex. C2-1-1 Table 1	(6.3)	Note 4	10.0	(16.3)
8	**Projected Entry in Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account** (line 6 + line 7)		151.3		216.6	(65.3)
	BRUCE FACILITIES					
9	**Depreciation of Asset Retirement Costs**	Ex. C2-1-1 Table 1	100.2	Note 5	100.3	(0.1)
10	**Used Fuel Storage and Disposal Variable Expenses**	Ex. C2-1-1 Table 1	65.1		59.9	5.2
11	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. C2-1-1 Table 1	2.5		2.4	0.1
12	**Accretion**	Ex. C2-1-1 Table 1	511.0		423.0	88.0
13	**Less: Segregated Fund Earnings (Losses)**	Ex. C2-1-1 Table 1	379.8		379.8	0.0
14	**Pre-Tax Impact on Bruce Lease Net Revenues**		299.0	Note 6	205.8	93.2
15	**Income Tax Impact on Bruce Lease Net Revenues**	Ex. C2-1-1 Table 1	(74.8)	Note 6	(51.5)	(23.3)
16	**Projected Entry in Bruce Lease Net Revenues Variance Account (line 14 + 15)**		224.3		154.4	69.9
17	**Total Projected Entries in Deferral and Variance Accounts**					4.6
	(line 8 + line 16)					

Note:
See Ex. C2-1-1 Table 5a for notes