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BY E-MAIL

November 23, 2016

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

Dear Ms. Walli:

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

In accordance with Procedural Order No. 1 issued on August 12, 2016, and a letter issued by the OEB on November 22, 2016, please find attached the report prepared by Bente Villadsen of the Brattle Group Inc. entitled "Common Equity Ratio for OPG's Regulated Generation".

The report was prepared at the request of OEB staff and is being filed for the purpose of assisting the OEB in the current proceeding. The report is marked as Exhibit M3.

OPG and all intervenors have been copied on this filing.

Yours truly,

Original signed by

Violet Binette
Project Advisor, Applications

Attach

EB-2016-0152:

Common Equity Ratio for OPG's Regulated Generation

PREPARED FOR

Ontario Energy Board

PREPARED BY

Bente Villadsen

November 23, 2016

THE Brattle GROUP

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I. Summary of Report

The Brattle Group (Brattle) is an economic consulting firm with global reach and more than 80 staff dedicated to our utility practice. Brattle has state-of-the-art skills in estimating corporate or project-specific cost of capital, assessing the impacts of alternative capital structures, and regulatory initiatives on required rates of return.

Brattle was retained by Staff of the Ontario Energy Board (OEB) to prepare an analysis of Ontario Power Generation's capital structure as well as to provide commentary on Concentric Energy Advisors' (Concentric) report, "Common Equity Ratio: For OPG's Regulated Generation," (OPG Ex. C1-1-1/Attachment 1).

Dr. Bente Villadsen, who has worked on regulatory finance and accounting issues in the regulated electric, natural gas, transportation, and water industry for more than 16 years, authored this report. I have prepared evidence and reports on cost of capital and capital structure for regulators and regulated utilities in North America, Europe and Australia. In Canada, I have previously prepared reports for the British Columbia Utilities Commission and the Canadian Transportation Agency and evidence on behalf of regulated utilities before the Alberta Utilities Commission. I have not previously prepared evidence or reports submitted to the OEB. A detailed resume is attached to this report as is the signed Form A.

This report approaches the task of evaluating OPG's capital structure in three steps. First, I review and assess Concentric's report submitted by OPG. Second, I evaluate the business risk of OPG and focus on (i) whether it has changed since the EB-2013-0321 decision and (ii) how the business risks are likely to develop going forward. Third, I consider the impact of OPG's operations and capital investments on its credit metrics going forward.

In my review of Concentric's report, I concur that nuclear generation and large capital expenditures increase the operating and execution risks of a company. I also concur that a switch from cost of service regulation to incentive regulation will increase the variability around a regulated entity's income over the short to interim horizon. I disagree that OPG "is at risk of non-recovery for close to $450 million," as the amount is the accrued difference between accrual and cash cost of pension and OPEB, and thus primarily is an issue of timing. Concentric determines the equity percentage it recommends for OPG using 20 investor-owned electric utilities it deems comparable. I find that some of the companies included lack comparability as they have substantial exposure to power prices, which OPG does not. I also find that these companies on average have about a third of their generation fleet fueled by coal, which is a risk factor due to the pressure on coal plants and the potential for needing large capital investments to meet environmental regulations.

Having reviewed and evaluated the approach by Concentric, approach the task of determining an appropriate capital structure for OPG using two additional steps. First, evaluate the business risk of OPG and the changes herein to find that OPG's prescribed facilities have minimal supply and competition risk and no price risk, whereas operation and regulatory risks merit further evaluation. Further, I evaluate OPG's risk relative to a refined sample of proxy companies, whose generation and regulatory characteristics more closely match OPG than do those of Concentric's sample. This sample is characterized by having very little non-regulated operations, little to no market risk exposure, nuclear generation, and an investment grade credit rating. As a second step, I estimate and evaluate the development in credit metrics for OPG.

First, the risk characteristics that merit the most attention are regulatory and operation risks. Compared to the time around EB-2013-0321, OPG is exposed to larger variability in its income due to the move from cost of service to incentive regulation for regulated hydroelectric facilities. However, this exposure is likely to be reduced over time as the hydroelectric portion of rate base will become smaller and as the details of the incentive regulation and its implementation become known. The regulatory risk from the methodology used to recover pension and OPEB cost is minimal. I agree that OPG faces some credit metric, construction and execution risk during the Darlington Refurbishment Program period, but also note that some of these risks are mitigated by the currently very strong balance sheet of OPG as well as by the provincial government's explicit commitment to the refurbishment.

Second, several companies in the proxy sample constructed by Concentric have generation that is neither regulated nor subject to contract and is therefore exposed to market prices. I therefore reduce the sample to consist of only companies with substantial nuclear (or hydroelectric) generation and to only those that have in excess of 90 percent of generation assets subject to regulation. On average, the companies in this sample have 96 percent of their generation assets subject to regulation and very limited-to-no market price risk. Further, this sample owns nuclear assets, but are not necessarily in the midst of a construction program. As for the regulatory regime, all companies have a fuel adjustment account (deferral) as well as multiple other deferral accounts. I therefore believe, the sample is comparable to OPG in terms of regulatory, market, and generic generation risk. This refined sample has an average equity thickness of 48 percent and an average credit rating of about BBB+.

Third, I determine the credit metrics that OPG would plausibly have, given the data provided in the application and using both Standard & Poor's and DBRS' methodology. I find that during the upcoming regulatory period, OPG's credit metrics will weaken absent an increase in cash flow.

Based on the three assessments above, I find that it would be reasonable to increase OPG's equity thickness and recommend an equity thickness of 48 percent based on the sample I select to be more comparable to OPG. This recommendation is slightly higher than the Board's deemed capital structure for OPG in EB-2010-0008.[1] I note that, because a substantial risk for OPG over the next several years is construction risk, a review of OPG's capital structure would be merited at the end of the 2017-21 regulatory period. At that time, OPG's credit metrics and other risk characteristics may have stabilized and a re-consideration of its equity thickness would be reasonable.

II. Review of Concentric's Assessment

A. Summary of Concentric's approach

As part of OPG's upcoming rate application before the Ontario Energy Board (Board), OPG retained Concentric Energy Advisors (Concentric) to develop a report assessing the business and financial risks associated with the Darlington Refurbishment Program and future Pickering operations, and to analyze whether changes in these risks justify an increase in the equity portion of OPG's capital structure. In OPG's most recent payment amounts application (EB-2013-0321),[2] the Board decided on a capital structure with 45% equity and approved OPG's request to increase the rate base related to hydroelectric generation, which then increased to 76.5% of total rate base.

Since that decision, OPG has embarked on the Darlington Refurbishment Program, which is estimated to add approximately $4.8 billion to OPG's rate base related to nuclear generation

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1 Ontario Energy Board, "EB-2010-0008: Ontario Power Generation Inc., Payment Amounts for Prescribed Facilities for 2011 and 2012," March 10, 2011 (EB-2010-0008), p. 116.

2 Ontario Energy Board, "EB-2013-0321: Ontario Power Generation Inc., Payment Amounts for Prescribed Facilities for 2014 and 2015, Decision with Reasons," November 20, 2014 (EB-2013-0321).

capital spending between 2017 and 2021. This would result in an increase in the nuclear portion of total rate base from 24% in 2014 to 32% in 2018 and further to 50% in 2020.[3] In its report for OPG, Concentric discusses the risks associated with nuclear generation and emphasizes that the combined effect of increased nuclear regulation and safety requirements, the implementation of incentive based regulation, the potential production loss at Pickering, and the task of coordinating multiple stages of refurbishment together represent an increase in OPG's business risk.[4]

In estimating changes in financial risk of OPG, Concentric focuses on changes to OPG's business and financial risk since EB-2013-0321 and expected changes to OPG's risk profile and financial metrics going forward. Regarding changes, Concentric focuses on changes in regulatory risk due to potential changes to the recovery of pension and OPEB cost and the transition from cost of service to incentive regulation for hydroelectric facilities along with the effect of the Darlington Refurbishment Program and Pickering Extended Operations. For the latter, Concentric focuses on the impact of OPG's increased capital expenditure, debt issuances for the Darlington Refurbishment Program, and operating risk on OPG's financial metrics including credit metrics.

Looking first to the regulatory risks, Concentric focuses on the treatment of pension and OPEB costs, which is currently being heard as part of a consultation in EB-2015-0040. In EB-2013-0321, OPG was allowed to recover its cash requirements for pensions and OPEB, and a deferral account was created to record the difference between the accrual and cash valuations of pensions and OPEB. The Board would decide on the disposition of the deferral account in a generic proceeding.[5] At the time of this report, the generic pension and OPEB proceeding (EB-2015-0040) is ongoing. Concentric states that OPG "is at risk of non-recovery for close to $450 million," which is the expected balance of the deferral account at the end of 2016.[6] However, the difference between recovering accrual or cash based pension and OPEB cost is one of timing, so only if $450 million of pension and OPEB costs were disallowed would the $450 million be lost.[7]

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3 OPG Ex. L, Tab 3.1, Attachment 1, Table 5 p. 1.

4 OPG Ex. C1-1-1, Attachment 1, p. 12-24, *Common Equity Ratio: For OPG's Regulated Generation*, Concentric Energy Advisors, May 2016.

5 EB-2013-0321, pp. 87-89.

6 OPG Ex. C1-1-1, Attachment 1, p. 29.

7 In EB-2013-0321 p. 89, the Board stated that it was "not setting aside the difference between the cash and accrual amounts for this [2014-2015] test period, for purposes of another future prudence review

Continued on next page

However, the reliance on accrual or cash pension and OPEB cost for OPG's payment determination will impact the timing of the recovery and hence the timing of cash inflows. OPG's exposure is thus the time value of the funds and, if applicable, disallowance risk for amounts outside the 2014-2015 test years. Such amounts are magnitudes smaller than $450 million.

As a second regulatory risk, Concentric looks to a change from determining the payments for hydroelectric facilities for two years using a cost of service approach to determining the payments for a five year period using incentive regulation. Concentric concludes that

> 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 [OPG's prior payment amounts proceedings] EB-2007-0905, EB-2010-0008 and EB-2013-0321.[8]

Concentric bases its view primarily on credit agencies' perception and does not investigate the degree to which the comparable companies in its proxy group have similar arrangements in place, nor does Concentric review the experience with performance based regulation in Canada. While I agree that performance based regulation leads to larger variations in revenue and income than does traditional cost of service, the difference depends mainly on the exact implementation of each and the stability of the environment in which the regulated entity operates.

Looking next to the going forward risks associated with the change in generation mix and needed capital expenditures, Concentric states that S&P Global Ratings and OPG's own business plan predict a weakening in OPG's credit metrics over the next six years; however, Concentric does not present its own quantitative analysis of key credit metrics employed by rating agencies such as S&P, DBRS or Moody's to assess going-forward financial risks of OPG although OPG does provide some credit metrics based on S&P's methodology.[9] A credit metrics analysis is an integral part of appropriately assessing the credit risk of OPG during the Darlington

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Continued from previous page

of these costs." The Board in the same decision disallowed $100 million in general operating and administrative costs related to "excessive compensation" in each of 2014 and 2015; that compensation includes pensions (EB-2013-0321) pp. 68-70.

8 OPG Ex. C1-1-1, Attachment 1, p. 24.

9 OPG Ex A1-3-3, Chart 3 (updated 2016-11-10), and Technical Conference Transcript, Vol. 3, (November 16, 2016) p. 87 (response by Mr. Mauti).

Refurbishment Program (2017-2021). Credit metrics assessments are used by credit rating agencies to determine solvency and liquidity risks associated with borrowing entities, such as OPG, and provide a strong indication of the financial strain brought about by increased leverage or changes to earning capabilities or cash flow of borrowing entities. In later sections of this report (section IV), I estimate forward-looking credit metrics using DBRS' and Standard & Poor's methodology. These measures are used to evaluate the credit worthiness of regulated electric utilities. I acknowledge that OPG, in some aspects, differs from a classical regulated electric utility in that it is a generation-only entity, and its ownership structure and ability to borrow funds differ somewhat from that of investor-owned utilities (IOU) and especially from those that own non-regulated assets or assets that are substantially different from those of OPG. For these reasons, the latter part of the report considers an alternative sample, which narrows the interpretation of comparable and also looks to non-investor owned utilities, (e.g., Tennessee Valley Authority).

The final section of Concentric's report performs a Comparative Analysis to assess whether OPG's capital structure and risk are consistent with those of a selected group of electric utilities in Canada and the U.S. In its Comparative Analysis, Concentric constructs a proxy group of 20 companies, based on five screening criteria that require the proxy company to:

1. own regulated generation assets that are included in its rate base,
2. own regulated nuclear or hydroelectric generation,
3. have regulated revenue and regulated net income greater than 60% of total revenue and total net income,
4. have regulated electric revenue and regulated electric net income greater than 80% of total revenue and total net income, and
5. have an investment grade credit rating similar to that of OPG's.[10]

Using this proxy group, Concentric calculates the arithmetic mean and the median equity capitalization levels for the proxy group to impute the appropriate going forward capital structure for OPG.

10 OPG Ex. C1-1-1, Attachment 1, p. 30-31.

The mean and median equity capitalization level for the proxy group was estimated to be 49.06% and 49.95%.[11] The Comparative Analysis then discusses the difference in asset mix of the proxy group and that of OPG, and points to an earlier finding from the OEB that OPG's nuclear business is riskier than regulated Transmission & Distribution businesses from an operational and production risk perspective. The Concentric Report then concludes that OPG – which owns generation assets only – is riskier than the average company in its proxy group, which has only about 47% generation assets. Concentric further notes that while all companies in its proxy group own some hydroelectric or nuclear generation, many own very little of either. They use this fact to conclude that the difference in hydroelectric and nuclear assets concentration exacerbates OPG's business and financial risk relative to the proxy group of comparable companies. Concentric concludes that OPG should be allowed a capitalization that includes at least 49% equity – the average equity capitalization level observed for the proxy group. In reaching this conclusion, Concentric references the fair return standard and the need to support OPG's financial integrity and its access to capital. OPG has adopted this recommendation, and it forms part of its proposal for the current application.

I consider the comparison to comparable companies to be a reasonable approach as an evaluation of the business risks inherent in OPG's capital expenditure programs, recovery of costs, and regulatory mechanisms. However, the Concentric Report does not discuss the degree to which OPG versus the proxy group face power price risk through, for example, un-contracted non-regulated generation. In addition, I believe it may be helpful to quantify the credit risks associated with the expected capital expenditure program and to consider how OPG's business risks compare to not just investor-owned utilities but also to Crown corporations or U.S.-based federal agencies such as Bonneville Power Administration or Tennessee Valley Authority. Finally, I consider what lessons, if any, can be learned from the Vogtle and V.C. Summer nuclear construction projects in the U.S, which involve new construction as opposed to refurbishment.

B. TIMING OF CHANGES TO OPG'S GENERATION AND IMPACT ON RISK PROFILE

Looking to the expected spend related to the Darlington Refurbishment Program as well as other nuclear operations,[12] I depict the annual nuclear capital expenditures along with the nuclear rate

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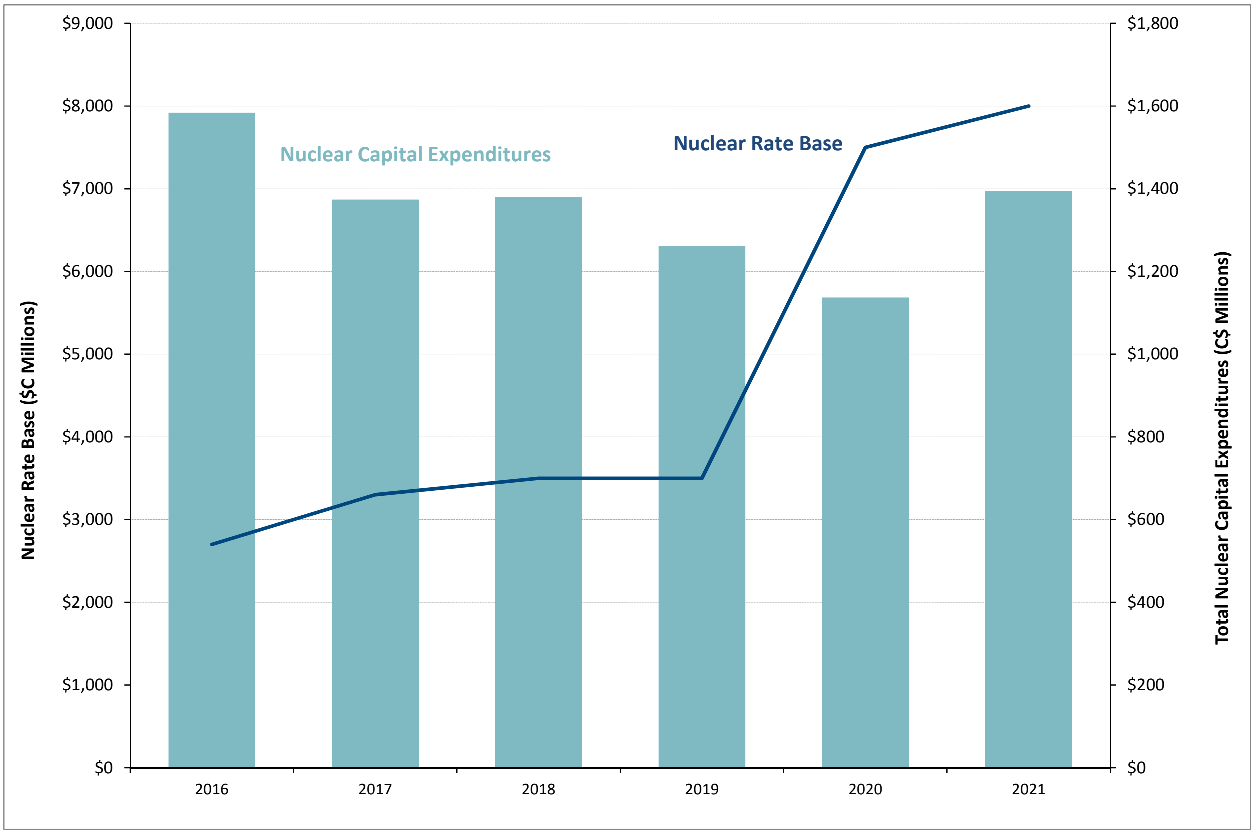
11 *Ibid.*, p. 37.

12 OPG Ex. D2-1-1, *Project and Portfolio Management – Nuclear*, p. 2.

base in Figure 1 below. The figure illustrates Nuclear Capital Expenditure, including the Darlington Refurbishment Program costs for the years 2017-2021.

Figure 1: Illustration of Nuclear Capital Expenditures and Change in Rate Base



Sources: Ex. D2-1-2 Table 1 and Ex. C1-1-1

The figure illustrates that, while capital expenditures occur annually (the bar charts), the nuclear rate base (depicted as a line) shows more volatility with a large jump in 2020. This reflects the fact that, due to the scale of the DRP, there is a delay between when capital expenditures are incurred and when the asset created by the capital expenditure is put in rate base. A delayed recovery of expended capital is normal in capital intensive industries – wherein capital intensive assets have longer lead times for development and operationalization. Therefore, in such industries, there is generally an increased strain on the utility's credit metrics during major capital development programs, leading to upward pressure on the utility's financial risk profile. I expect OPG's DRP related capital spending will have an adverse impact on its credit metrics between 2017 and 2021 and discuss the impact on OPG's credit metrics in greater detail in latter sections of this report.

C. CONCENTRIC'S CREDIT METRIC CONSIDERATIONS

Concentric provides a qualitative discussion of several factors that could threaten OPG's credit metrics and credit rating during the upcoming period of high capital expenditures. First, they note that the spread between the A-rated and BBB-rated Canadian utility bonds has widened substantially since early 2015, meaning that a credit downgrade of OPG's debt would disproportionately increase their cost of borrowing relative to the historical norm.[13,14] Second, Concentric describes the cash flow risk due to delayed recovery of amounts deferred for a decade related to the Darlington Refurbishment Program. They also note cash flow risk stemming from the regulatory treatment of pension and OPEB costs, where a deferral account is estimated to include $450 million at year-end, 2016.[15] In Concentric's view these cash flow risks along with the possibility for a higher cost of capital, if downgraded, could put downward pressure on OPG's credit metrics. Concentric cites OPG's 2016-2018 business plan (see OPG Ex. A1-3-3), which forecasts a Debt / EBITDA ratio between 6.1x and 6.4x between 2017 and 2021. Concentric also references S&P's most recent rating report on OPG (see OPG Ex. A2-3-1 Attachment 5) from July 2015 which predicted a Debt / EBITDA of 4x to 5x for 2016 and 2017 – note that S&P would not have had an operational forecast related to the Darlington Refurbishment Program at the time of this rating report. Although I agree that OPG's credit metrics are likely to come under pressure, the Concentric Report did not perform a stand-alone, <u>quantitative</u> analysis of future expected cash flows or debt ratios but relied on certain metrics calculated by OPG.[16] In section IV below, I present a forecast of a number of credit metrics based on OPG's application as of May 2016.

Concentric further cites recovery of pension and OPEB costs and cites DBRS' ranking of cost-of-service versus incentive regulation as a reason why OPG's risk is increasing.[17] I discuss this in Section III below.

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13 Note that I have reviewed the credit ratings of Ontario to observe how it compares with that of OPG. Currently, S&P rates the province A+ while it rates OPG three notches lower at BBB+ for its long-term debt offerings.

14 OPG Ex. C1-1-1 Attachment 1, p. 25. I note that OPG currently carries a BBB+ rating from Standard & Poor's (A low from DBRS).

15 *Ibid.*, p. 27.

16 OPG Ex A1, Tab 3, Chart 3, Amendment to Pre-Filed Evidence and Interrogatory Responses, 11-10-2016

17 OPG Ex. C1-1-1, Attachment 1, p. 23.

D. CONCENTRIC'S PROXY GROUP AND COMPARABILITY ANALYSIS

Concentric selected a sample of 20 investor-owned electric utilities in Canada and the U.S.[18] The sample was selected to (i) own regulated generation, (ii) own nuclear and/or hydroelectric generation, (iii) have regulated revenue and net income in excess of 60% of total revenue and income for the consolidated company, (iv) have electric revenue and income in excess of 80% of regulated revenue and income, and (v) have an investment grade credit rating similar to that of OPG.[19] I generally agree with looking to both Canadian and U.S. companies as well as with an emphasis on finding companies having regulated generation, a high level of regulated income / revenue and an investment grade credit rating. However, I would consider not only the nuclear and/or hydroelectric generating assets but also the exposure to other generation fuels (e.g., coal) and find that (a) some of the included proxy companies may not be comparable to OPG, and (b) there may be other entities that merit consideration.

Preliminarily, OPG is owned by the Province of Ontario and obtains "the majority of its long-term funding requirements through the OEFC [Ontario Electricity Financial Corporation], a government financing arm for the provincial power companies."[20] The comparable companies are investor-owned utilities, which generally raise capital in financial markets – although the U.S. Federal Government has provided guarantees for financing of the ongoing nuclear construction at Vogtle in Georgia.[21] Second, there are nuclear/hydroelectric generators that are publicly owned, such as Bonneville Power in the State of Oregon and Tennessee Valley Authority in Tennessee, which may merit a comparative look. Further, as shown in Exhibit BV-1 many of the proxy companies used by Concentric own substantial coal generation, which faces its own challenges and may require substantial capital investments to adhere to current and impending environmental regulation.

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18 OPG Ex. C1-1-1, Attachment 1, p. 32.

19 OPG Ex. C1-1-1, p. 30-31.

20 DBRS, "Ontario Power Generation Inc.," April 25, 2016 (OPG Ex. L, Attachment 2 to OPG Response to Board Staff Interrogatory #17) (DBRS April 2016).

21 At the time of writing, I am not aware that guarantees have been provided for SCANA's ongoing nuclear construction at the V.C. Summer site in South Carolina.

As for the individual companies, I note that FirstEnergy Corporation has operations in Maryland, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia of which only Virginia and West Virginia have regulated generation.[22] According to FirstEnergy's 2015 10-K, the holding company has a total of 16,952 MW of generation of which 3,790 MW are regulated,[23] so that the regulated portion constitutes only 22.3%. Therefore, FirstEnergy may not be a good comparator for OPG.

III. Business, Financial & Credit Risks of OPG

Business risk refers to the underlying risks inherent in a company's operations. An analysis of OPG's business risk relative to those of the proxy companies is critical to evaluate how it compares. Although there are several ways to approach a business risk analysis, it helps to use some structure in the analysis; an approach that is sometimes used considers five elements:[24] supply risk, demand (or market) risk, competitive risk, operating risk and regulatory risk.

Supply risk refers to the ability of the utility to produce sufficient power at a reasonable price. Factors that could impede OPG's ability to produce power would include limitations on water supply for usage in its hydroelectric plants and unavailability of nuclear fuel. I see this as being a minimal risk for OPG.

Demand or market risk refers to the ability of the utility to sell power to its customers. For example, if the demand for electricity were to drop substantially, then OPG would face larger demand risk. I see this as a modest risk for OPG given its status as a predominantly regulated entity, with much of its generation being base load in nature. While OPG's asset portfolio also includes some unregulated generation assets such as Lennox Generating Station and a 50% equity interest in both Brighton Beach and Portlands Energy Centre, a large majority of the capacities of these assets are protected from demand and price risk through long-term contracts currently in place. My assessment indicates that less than 1% of OPG's total generation capacity is both

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22 FirstEnergy's 2015 10-K. Also see: https://www.firstenergycorp.com/content/fecorp/our_electric_companies_home.html

23 FirstEnergy's 2015 10-K p. 3 states that "As of February 16, 2016, FirstEnergy's generating portfolio consists of 16,952 MW of diversified capacity (CES — 13,162 MW and Regulated Distribution — 3,790 MW)."

24 These elements have been used by, for example, the National Energy Board (NEB).

unregulated and unhedged through long-term power supply agreements, and therefore only a very small proportion of OPG's total capacity is exposed to demand risks.[25]

Competitive risk refers to the prospect of competition between power generators or between power generators and other sources of electricity. Given the regulatory regime and the inclusion of key assets (e.g., nuclear generation) in the Government of Ontario's Long Term Energy Plan, I find this to be a minimal risk for OPG.

Operating risk refers to the risk that a utility may experience operating difficulties, which either reduces its ability to earn revenue, or which require additional cost to maintain its service levels. For example, other things equal, should OPG experience difficulties in keeping its refurbishment of the Darlington plant on schedule, it would experience operating risks. I see operating risk as the largest risk facing OPG.

Regulatory risk refers to the risk that regulatory decisions may have an adverse impact on the utility's ability to earn the revenue requirement and meet its debt obligations. Regulatory risks are necessarily linked to other risks as, for example, the regulator may be able to increase rates sufficiently to cover decreasing demands for electricity, but there are limits to how much rates can increase. OPG has some regulatory risks deriving from the fact that the regulation of hydroelectric assets is expected to change. Because the impact of the implementation of the incentive regulation has yet to be determined, it will create uncertainty about the impact on OPG in at least the near term. Incentive regulation tends to increase the variability of net income relative to cost of service regulation although the details of the implementation vary widely and can impact the degree to which cost of service and incentive regulation vary.[26] The decision on the treatment of pension and OPEB cost is pending at the time of this writing, so the outcome of that proceeding is not known. However, the issue, which Concentric did not address, is primarily whether there is any risk of disallowances. These risks are mitigated by regulatory precedence for including pension and OPEB costs in rates,[27] so I consider the risk low

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[25] It is my understanding that the OEB has stated in past proceedings that it relies on the stand alone principle for OPG's Payment Amounts. See, for example, EB-2013-0321 p. 102.

[26] See also DBRS, "Ontario Power Genration Inc.," April 25, 2016, p. 1.

[27] While EB-2013-0321 disallowed some costs including pension costs, these cost related to what the Board deemed "excessive compensation."

in the long term and modest in the near term as the incentive regulation is being implemented for the first time. The reasons are provided in Section III below.

Note that, in the following, by assets I am referring to rate base and in discussing the composition of OPG's assets, I am referring to the rate base as opposed to MW unless otherwise stated. This is because the dollar amount invested in rate base is what OPG has invested.

Below, I focus on OPG's operating and market risks relative to those of the proxy companies as I view that as the largest risks faced by OPG and plausibly the largest differences. I discuss the operating risks in two sections below. First, OPG's composition of rate base assets is set to change, so that in the long-term, its operating characteristics will be different from today. Second, OPG will experience construction risks and will have large capital expenditures, between now and 2021, which marks the end of the regulatory period under consideration in this application. Generally, I view the longer term risks as more consequential especially given that the need for the Darlington Refurbishment Program has been well established by the provincial government in both Ontario's LTEP and in O.Reg 53/05. Furthermore, per O.Reg 53/05, any prudent deferred revenue requirement associated with the DRP is guaranteed recovery in the long-run, reducing regulatory risks during the construction phase of DRP.[28] Towards the end of Section III, I discuss other business risk aspects of OPG and the comparable group of sample companies.

A. OPG's Asset Composition and Changes to Current Asset Mix

i. Long-Term Operating Risks

According to OPG Ex. B1 Table 2, OPG's nuclear net plant is expected to increase from $2.916 billion in 2015 to $7.915 billion in 2021[29] (about a 170 percent increase) while the hydroelectric plant assets are expected to increase from about $7.5 billion in 2015 to $7.7 billion in 2021 (less than 3 percent).[30] During this time, nuclear plant as a percentage of total plant would go from

[28] Ontario Regulation O.Reg. 53/05 under the *Ontario Energy Board Act, 1998*.

[29] OPG Ex. B1-1-1, Table 2, *Rate Base,* May 2016.

[30] OPG Ex. C1-1-1, Attachment 1, p. 14.

being about 26% in 2015 to about 51% in 2021. As of 2012, prior to the increase in hydroelectric plant in 2014, nuclear plant constituted approximately 39% of total plant.[31]

Compared to the sample companies proposed in the Concentric Report, OPG has a larger percentage of nuclear and hydroelectric generation, but no coal-fired generation.[32] On average the companies in the Concentric Report have approximately 31 percent of coal-fired generation.[33] Coal-fired generation has come under pressure, and many plants are currently facing closure or significant cost to adhere to environmental legislation. Coal exposure is especially a concern for non-regulated entities, which may face stranded assets or environmental liabilities that are non-recoverable.[34] As OPG no longer burns coal and its prescribed facilities are either hydroelectric or nuclear, it has no exposure to coal-related legislation and has no requirement for capital to spend on environmental remediation on existing coal plants. It is important to recognize that, relative to Concentric's proxy group, OPG has greater exposure to nuclear generation, but no exposure to coal generation. In particular, there will be no need for OPG to make capital expenditures related to coal-fired generation.

To further assess the generation mix, I reviewed some entities with a large proportion of hydroelectric generation and some with ownership structures that are comparable to that of OPG. Specifically, I considered the generation mix of Bonneville Power Administration, Tennessee Valley Authority (TVA), BC Hydro and Hydro-Quebec. Of these, BC Hydro and Hydro-Quebec rely almost exclusively on hydroelectric facilities, whereas Bonneville Power has about 69 percent hydroelectric generation, and the remainder spread across coal, natural gas,

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31 *Ibid.*, p. 14. Percentages are calculated as the percentage of nuclear to the total of nuclear and hydro reported in Figure 1.

32 According to OPG's website, OPG stopped using coal to generate electricity in 2014 and has converted two plants to using biomass, one plant to natural gas / oil, while two plants are currently not in use. Source: http://www.opg.com/generating-power/thermal/Pages/thermal.aspx

33 Details are provided in Exhibit BV-1 attached to this report.

34 Among Concentric's proxy companies, Duke Energy has faced several lawsuits concerning coal ash, and FirstEnergy recently announced that it seeks to exit the unregulated market, which will involve the closing down or sale of coal plants. Sources: Roanoke River Basin Association v. Duke Energy Progress (United States District Court for the Middle District of North Carolina, No. 1:16-cv-607), SNL, "FirstEnergy won't pressure lawmakers as it seeks merchant exit," November 8, 2016.

nuclear and other renewable resources. TVA generating facilities consist of 32 percent coal, 31 percent natural gas, 22 percent nuclear, and 15 percent hydroelectric generating facilities. The details are summarized in Exhibit BV-2. BC Hydro and Hydro-Quebec are crown corporations located in British Columbia and Quebec, respectively, while Bonneville Power and Tennessee Valley are U.S. federal agencies located in Oregon and Tennessee, respectively. The equity capitalization of these entities is displayed in Figure 2 below.

Figure 2: Book Capitalization of Selected Entities with Hydroelectric Facilities

	Bonneville Power (USD thousands)	Tennessee Valley Authority (USD thousands)	BC Hydro (CAD thousands)	Hydro-Quebec (CAD thousands)
Book Equity	3,487,400	7,736,000	4,604,000	21,455,000
Non Current Long Term Debt	15,430,600	23,963,000	15,988,000	43,263,000
Current Portion of Long Term Debt	862,200	602,000	3,033,000	1,358,000
Short Term Debt	0	1,542,000	0	1,291,000
Equity Capitalization	17.6%	22.9%	19.5%	31.8%
Debt Capitalization	82.4%	77.1%	80.5%	68.2%

Source: SNL Financial

Moody's rates BC Hydro and Tennessee Valley Aaa (AAA in S&P terminology), while Bonneville Power and Hydro-Quebec are rated Aa (AA in S&P terminology).[35] Thus, these four government-affiliated power generators are all highly rated (and above the rating of OPG) with a relatively low equity ratio. However, none of the entities are directly comparable because either their generation mix is more mixed than that of OPG (as in the case of BPA and TVA), or they are much more concentrated in hydroelectric assets (as is the case BC Hydro and Hydro-Quebec) compared to OPG's asset mix. Hydro-Quebec is particularly a poor comparable because much of its generation is not subject to regulation, unlike that of OPG. In addition, the credit metrics and equity capitalization in the figure above are not necessarily on a stand-alone basis. Therefore, while I present results for this set of companies, I do not include them in my alternate sample of comparable companies.

With reference to long-term risks, the Darlington Refurbishment Program is expected to increase OPG's generation rate base, especially its nuclear generation rate base, which is expected

35 Neither Fitch nor Standard & Poor's rate all four entities. However, Bonneville Power has a comparable rating from Fitch and S&P and Hydro-Quebec has a comparable rating from Fitch.

to change OPG's rate base from being composed mostly of hydroelectric generating assets to having a much larger component of nuclear generation (in between rate base will have an almost equal mix of hydroelectric and nuclear assets).[36] As a result, OPG's operating activities and risk will change. There are several types of risk that OPG will face going forward. First and foremost, during the refurbishment period, OPG will face construction, delay and budgeting risk. Second, following the refurbishment, the long-term risk associated with the operation of a nuclear facility will continue at close to the same level as today until Pickering retires. In addition to environmental risks, the fact that nuclear generation facilities are large, so that any outage necessarily will involve a large amount of MW albeit the refurbishment presumably will enhance reliability so that the probability of an outage is reduced. Further, because OPG's nuclear generation is fully regulated, OPG's exposure to risks associated with outages is mitigated.

However, as OPG has no coal exposure and importantly, since it receives regulated prices for all electricity generated from its nuclear facilities as well as for most of its hydroelectric facilities, its operating risks, even though changing due to construction phase risks and as rate base becomes dominated by nuclear assets, it is tempered by no coal risks, unlike many of the comparable sample companies that have of coal-fired assets with exposure to recovery risks.[37] I discuss this issue next.

ii. Market Risk

Fully regulated nuclear generating facilities can expect revenues to fluctuate less than non-regulated generating facilities. In addition, OPG is uniquely positioned in that it currently generates more than half of Ontario's power,[38] so that the power from OPG is essential to the province. This makes OPG less vulnerable to revenue fluctuations than non-regulated revenue

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36 It is my understanding that the nuclear generation capacity in terms of MW will remain fairly constant until Pickering is retired (see Figure 4 for details).

37 DBRS, "Ontario Power Generation Inc.," April 25, 2016 (Attachment 2 to OPG Response to Board Staff Interrogatory #17) (DBRS April 2016), p. 4.

38 *Ibid.*, p. 2.

that is created by the sample companies' non-regulated generation. The degree to which the sample companies are exposed to non-regulated market prices is determined by two factors: (i) the relative size of the companies' non-regulated generation plant, and (ii) the degree to which non-regulated generation is subject to contracts and the time horizon of such contracts.

Looking first to the magnitude of the non-regulated generation plant, I observe that the proxy companies in Concentric's Report vary regarding the percentage of generation that is subject to regulation. For example, FirstEnergy has only about 22% of its generation subject to regulation[39] ignoring the potential virtual power purchase contracts between FirstEnergy's distribution utilities in Ohio and FirstEnergy's generation facilities. In contrast, Portland General Electric has little non-regulated generation and instead procures power through power purchase contracts.[40] The percentage of generation that is regulated versus what is non-regulated is important because non-regulated generation is exposed to market risk; i.e., the fact that prices will fluctuate so that the power generator may or may not recover the full cost of power generation (including the cost of capital). Regulated entities in turn expect to recover the cost of generation plus the invested capital and a return on invested capital. OPG's prescribed facilities are fully regulated and therefore have no market risk under cost of service regulation.[41]

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39 FirstEnergy 2015 10-K p. 3.

40 According to Portland General Electric's website, the company got 32% of its electricity from power purchase contracts in 2014. Source: https://www.portlandgeneral.com/our-company/energy-strategy/how-we-generate-electricity

41 While OPG has some unregulated facilities and only a small amount is non-regulated and non-contracted per Velocity Suite, these facilities are irrelevant for the purpose of determining the capital structure for OPG's prescribed facilities.

Figure 3: Select Comparables Net Summer Capacity (MW)

	Total Net Summer Capacity	Regulated	% Regulated of Total	Unregulated		
				Contracted	Not Contracted	% Not Contracted
Ameren Corporation[1]	10,362	10,265	99.1%	0	77	0.7%
DTE Energy Company[1]	11,454	10,676	93.2%	167	399	3.5%
El Paso Electric Company[2]	2,269	2,267	99.9%	0	2	0.1%
Entergy Arkansas, Inc.	5,617	5,112	91.0%	500	5	0.1%
Entergy Louisiana, LLC[3]	11,774	10,622	90.2%	0	1,152	9.8%
PG&E Corporation[1]	7,813	7,760	99.3%	49	0	0.0%
Pinnacle West Capital Corporation[1]	6,049	5,988	99.0%	0	0	0.0%
Average			96.0%			2.0%

Sources & Notes:
Velocity Suite, ABB Inc. (EV)
SNL Financial (for El Paso Electric Company)
Entergy Utility Fossil/Renewable Generating Assets; -Accessed at:
http://entergy.com/content/operations_information/Utility_Fossil_and_Renewable_Portfolio.pdf
Entergy Utility Nuclear Generating Assets; Accessed at: http://entergy.com/content/operations_information/Utility_Nuclear_Portfolio.pdf
Notes:
1: These firms have total net summer capacities greater than the sum of their regulated and unregulated net summer capacities because EV does not provide a categorization for portions of their capacity.
2: El Paso Electric Company's Montana Power Station has been categorized as regulated, per SNL.
3: Entergy Louisiana, LLC was the result of a merger between Entergy Louisiana, Inc., and Entergy Gulf States Louisiana, LLC. This row is the sum of generating units from each former subsidiary.

a. Power Plant Little Gypsy, Unit 1 has been removed from the EV data because it has been retired.
b. Power Plant Willow Glen, Units 1, 3, and 5 have been added to the results from EV because they are listed by Entergy Louisiana, LLC on their website.
c. Louisiana 1 plant has not been removed from the EV data, despite not appearing the Entergy Louisiana, LLC list, because no data could be found regarding its retirement. The La Station 2 plant has not been added because no data could be found for it.
d. Where discrepancies between EV and the Entergy Louisiana, LLC document exist, we have defaulted to data from EV.

Second, only a portion of the proxy companies' non-regulated generation may in effect be exposed to market prices (and risk) as many power generators sign contracts for the power they generate, so that the price is locked in as opposed to being exposed to market prices.[42] The presence of contracts is important as they reduce the demand risk of power producers. To the degree that the proxy companies have signed power purchase contracts for their non-regulated power, the risk-differential between non-regulated and regulated generation is reduced. Looking

42 Locked-in in this context is to be interpreted broadly as many contracts are indexed in some form.

at the proxy companies presented by Concentric, I note that data from Velocity Suite[43] shows that AEP and FirstEnergy have 36 percent and 67 percent of their coal generation subject to price risk.[44] Therefore, these two companies have substantial price risk.

As indicated above, OPG's risks from generation and especially nuclear generation will be higher than that of the average proxy company, but it is exposed to no price risk, while some of the Concentric comparable companies have non-trivial exposure. Further, OPG has no risk from coal generation, whereas Concentric's proxy companies face both potential stranded assets and capital expenditure risks.

iii. Summary

Importantly, the risks discussed in this section are all longer term with the nuclear generation and lack of coal generation likely to impact OPG's operating risk for a very long time.[45] Relative to the time of EB-2013-0321, the key change to OPG's risk is the large construction program and to a lesser extent the expected switch to incentive regulation for OPG's prescribed hydroelectric facilities. Both of these increased risk factors will be reduced over time as the construction program reduces and as the incentive regulation matures.Overall, OPG's rate base generation mix is at least as risky as that of Concentric's proxy group. However, OPG has no exposure to market prices for its nuclear generation,[46] which is expected to increase from 31% of rate base in 2017 to about 51% in 2021.[47] Because some of Concentric's comparable companies face market risk, I select a refined sample of comparable companies, which (i) own non-trivial nuclear generation,

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43 Velocity Suite is a subscription service that provides data on commodity markets and prices.

44 See Exhibit BV-3 attached to this report.

45 According to OPG's 2015 Consolidated Financial Statements (OPG 2015 Financials) p. 15 and 19, the service life of Darlington was extended to 2052 to reflect the approval of the refurbishment schedule and hydroelectric generating facilities are expected to have long service lives.

46 Going forward it is expected that OPG's prescribed hydroelectric facilities will be subject to price-cap incentive regulation using a five-year period instead of the current cost of service regulation for two years at the time (OPG Ex. C1-1-1, p. 3).

47 OPG Ex. C1-1-1, p. 1.

(ii) have almost all assets (including generation) subject to regulation, and (iii) have little or no market risk.

Figure 3 shows that the Refined Comparables have trivial market exposure – i.e., more than 90 percent of the generation is regulated and the remainder is mostly under contract. Thus, I conclude that OPG has lower market exposure than Concentric's comparable companies, but comparable to slightly lower market exposure than the Refined Sample.

B. Risk Associated with Large CapEx and Nuclear

This section discusses the risks and plausible effect on OPG of ongoing construction programs. Thus, it focuses on temporary changes in risk as opposed to the long-term changes that occur due to changes in generation mix from about 2021 onward.

i. Darlington Refurbishment Program

By way of introduction, the Darlington Refurbishment Program was approved in 2015 and, as of year-end 2015, OPG had incurred capital expenditures of $1,868M related to the Darlington Refurbishment Program.[48] The amount spent on the Darlington Refurbishment Program is considered Construction Work in Progress (CWIP) until the associated assets re-enter service and are included in rate base, which is expected to occur starting in 2020. Under standard rate making, OPG is allowed to earn an Allowance for Funds Used During Construction (AFUDC) on accumulated CWIP, and AFUDC is capitalized. OPG will capitalize the return on CWIP until the capital spend on the Darlington Refurbishment Program enters rate base – at that point in time it will be amortized over the service life of the asset. Thus, OPG's cash outlays for the Darlington Refurbishment Program will occur several years earlier than the cash inflows associated with the capital spend will occur.

The timing of the cash flow impacts OPG's liquidity, credit metrics and possibly its leverage. The credit metric aspects of the Darlington Refurbishment Program is studied in detail below, but in

48 OPG 2015 Consolidated Financial Statement, p. 19 and p. 23.

brief, OPG's interest coverage as measured by DBRS is low until the construction costs enter rate base, while the measures relied upon by Standard & Poor's remain within the intermediate level.

In addition to the possibility of quantifying the impact of the construction program on OPG's credit metrics, it is important to note that there are also other and less quantifiable factors. First, because any capital expenditure program is expected to result in assets that eventually will enter rate base, such programs indicate growth opportunities in the form of higher future income or net cash flow. Thus, the Darlington Refurbishment Program is expected to allow OPG to generate higher cash flows going forward and to maintain its dominant position in the Ontario power market. Second, during the construction phase, OPG faces construction or execution risks,[49] and many complex construction programs have in the past failed to meet deadlines or cost targets.[50] Cost overruns are inherently challenging because they (i) require additional prudence review and (ii) necessitate additional funding.

Even though the LTEP and O.Reg. 53/05 indicate that the need for DRP has been established, potential cost overruns in project completion will still be reviewed for prudence by the OEB before OPG will be allowed to fully recover such unexpected expenses, exacerbating execution risks for the company. For example, Southern Company's Vogtle project is currently about 3 years behind schedule with a cost overrun of almost US $1.749 billion.[51] In addition to construction and execution risks, large construction projects often face political risks in the sense that there may be *ex post* interventions by government agencies.[52] However, this risk is mitigated by the fact that the refurbishment was confirmed in the Ontario government's Long

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[49] See, DBRS, "Ontario Power Generation Inc.," April 25, 2016 (Ex. L, Attachment 2 to OPG Response to Board Staff Interrogatory #17) (DBRS April 2016).

[50] Roger Miller and Donald R. Lessard, "The Strategic Management of Large Engineering Projects: Shaping Institutions, Risk and Governance," MIT Press 2000, p. 14.

[51] Testimony of Philip Hayet, Georgia Power Company's Fifteenth Semi-Annual Vogtle Construction Monitoring Report before the Georgia Public Service Commission, Docket 29849, 11-17-2016

[52] *Ibid.*, p. 14.

Term Energy Plan[53], and due to the regulated nature of OPG's generation.[54] Moreover, the November 2015 amendment to O.Reg. 53/05 provides assurance that any deferred revenue (the amount tracked between the revenue requirement and the revenues from the smoothed payments) found to prudent by the Board will be recoverable by the company.[55]

The amended O.Reg. 53/05, effective since January 1, 2016, notes the following:

> *"The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs and firm financial commitments incurred in respect of the Darlington Refurbishment Project or incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,*
>
> > *i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or*
> >
> > *ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made."*

Further, the amended O.Reg. 53/05 also confirms the need for the DRP noting that:

> *"The Board shall accept the need for the Darlington Refurbishment Project in light of the Plan of the Ministry of Energy known as the 2013 Long-Term Energy Plan and the related policy of the Minister endorsing the need for nuclear refurbishment. O. Reg. 23/07, s. 4; O. Reg. 27/08, s. 2; O. Reg. 312/13, s. 4; O. Reg. 353/15, s. 3."*

Put differently, the Ontario government is committed to the Darlington Refurbishment Program.

In summary, I agree, as do credit rating agencies, that OPG faces some credit metric, construction and execution risk during the construction period ,[56] but I also note that some of these risks are mitigated by the currently very strong balance sheet of OPG as well as by the provincial

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53 OPG, "Semi-Annual Performance Report: Refurbishment of Darlington Nuclear Generation Station, Overview and Updated Project Status," August 2016 as reported on OPG's website.

54 Standard & Poor's, "Ontario Power Generation Inc. Rating Lowered to 'BBB+' From 'A-' On Province of Ontario Downgrade," July 7, 2015 (OPG Exhibit L, Tab 3.1, Schedule 20 VECC 008) (S&P July 2015).

55 Ontario Regulation 53/05.

56 DBRS, "Ontario Power Generation Inc.," April 25, 2016 (Attachment 2 to OPG Response to Board Staff Interrogatory #17) (DBRS April 2016), p. 2.

government's explicit commitment to the refurbishment. I note that the rate smoothing proposal, which contemplates "deferring recovery of a portion of a substantial portion of the OEB-approved revenue requirement until after the end of the DRP"[57] will reduce OPG's cash flow during the construction period, but this will be offset by the proposal to increase nuclear payments by 11 percent annually to 2021 (to avoid rate shock) and provide cash flow to OPG.[58] In evaluating the proposed increase in OPG's equity component, it is important to consider not just qualitative risk factors but also the impact on credit metrics[59] and, as necessary, the recovery of cash flow over time. For example, a deferral for recovery to after the completion of the refurbishment program does increase recovery risk, but the structure of the deferral and the regulatory framework can reduce the risk of non-recovery. As noted above, the Concentric Report focuses on the qualitative risk factors.[60]

ii. Effect of Aging Pickering plant

OPG announced plans to pursue continued operation of all six units at the Pickering Station until 2022, when two units would be shut down, while the remaining four would continue operations to 2024.[61] According to the Concentric Report, a relicensing process is expected in 2017/2018, and incremental OM&A costs will amount to about $300 million plus the costs of additional outages at the Pickering nuclear generating facility. Based on this evaluation, Concentric concludes that "risks related to Pickering operations have increased since EB-2013-0321."[62]

I acknowledge that any large construction project is subject to the risk of delays and cost overruns, but the key risk facing OPG is timely cost recovery. Given that the Pickering nuclear

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57 OPG Ex. C1-1-1, Attachment 1, p. 24.

58 OPG Ex. A1-3-1, p. 7 of 12, *Administrative Documents - Exhibit List*, PDF p. 42.

59 I note that it is challenging to interpret the credit ratings reports because they necessarily look at OPG's accounting balance sheet, which differs from the regulatory capital structure by a non-trivial amount.

60 See also the Response to Board Staff Interrogatory #21.

61 Ontario Ministry of Energy News Release, "Ontario Moving Forward with Nuclear Refurbishment at Darlington and Pursuing Continued Operations at Pickering to 2024," January 11, 2016.

62 OPG Ex. C1-1-1, Attachment 1, p. 22.

facility is a regulated facility, the risk of recovery is substantially reduced and especially so given that the "Province has also approved OPG's plan to pursue continued operation of the Pickering Generating Station beyond 2020 up to 2024."[63] Any pre-commitment to the continued operation from officials reduces the risk of undertaking the capital expenditures. Therefore, I consider this risk to be less than the risks faced by other regulated nuclear generators engaged in construction programs.

iii. Summary: Effects of Interim Risks

Looking to the risk between now and the date the Darlington Refurbishment Program will be completed, OPG will see some pressure on its cash flow as it engages in large capital expenditures without associated revenues. At the same time, it will face construction and execution risks and risks associated with the implementation of the hydroelectric incentive rate-setting. Relative to other large construction projects, OPG has the benefit that the Province of Ontario has included the program in Ontario's Long Term Energy Plan (LTEP), enacted a regulation (O.Reg. 53/05 as amended in November 2015) and thereby affirmed the commitment to the project. Further, OPG's nuclear generation as well as most of its hydroelectric generation is subject to regulation, so that the Company is exposed to minimal price risks. Because of the regulated nature of OPG's business, the temporary reduction in production at the Darlington generating station is mitigated as are the risks associated with an extended operation of Pickering.

Figure 4 below shows Ontario's current and planned nuclear fleet capacity through 2021 and beyond. As illustrated, the Pickering Generating Station is planned for continued operation at its current capacity levels through year 2022, allowing staged refurbishment of Darlington units and minimizing supply impact on Ontario's production capacity during the Darlington Refurbishment Project. Furthermore, the LTEP notes that the shutdown of Pickering Generating Station, planned to begin in 2020, will depend on several factors, including the progress of Ontario's [nuclear] fleet refurbishment program.[64]

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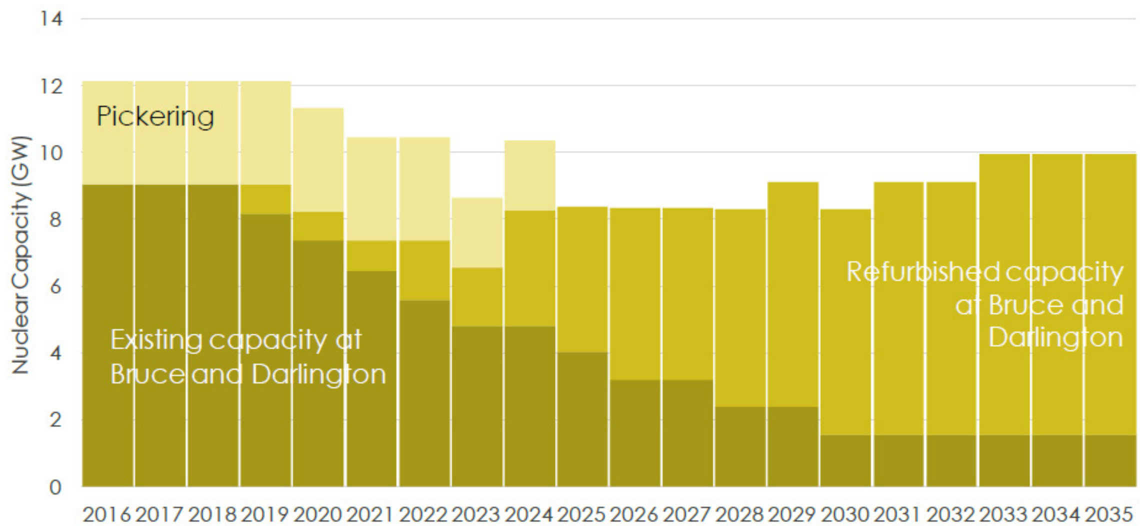
63 Source: Ministry of Energy News Release, dated January 11, 2016, accessed from here: https://news.ontario.ca/mei/en/2016/01/ontario-moving-forward-with-nuclear-refurbishment-at-darlington-and-pursuing-continued-operations-at.html

64 Ontario's Long-Term Energy Plan (LTEP), 2013, pg. 47. The LTEP recognizes Ontario's projected electricity demand, the progress of the refurbishment programs, and the time of completion of the

Continued on next page

Figure 4: Ontario Nuclear Fleet Installed Capacity (GW), 2016-2035



Source: IESO Planning Supply Outlook, August 2016, pg. 9

Figure 5 below illustrates risk factors and risk mitigators for OPG relative to my refined sample. As discussed above, OPG will have elevated operating, and construction and execution risks during the Darlington Refurbishment Program. During this period, OPG will have large capital expenditures without associated revenues, and will experience increase in its credit risks. The timing of the delayed cash flow will impact OPG's liquidity, credit metrics and likely, its leverage. In contrast, the refined sample of comparable companies is not engaged in capital expenditure programs at this scale and thus – on this dimension – have lower risk compared to OPG. However, the inclusion of DRP in the provincial LTEP, establishing the need for the refurbishment program, and enacting of regulation to assure regulatory support and recovery of prudent costs, are substantial mitigating factors for OPG's elevated construction and execution risks. I believe that, as a result of these mitigating factors, OPG's risk during the refurbishment program will be comparable to the average company in my refined sample.

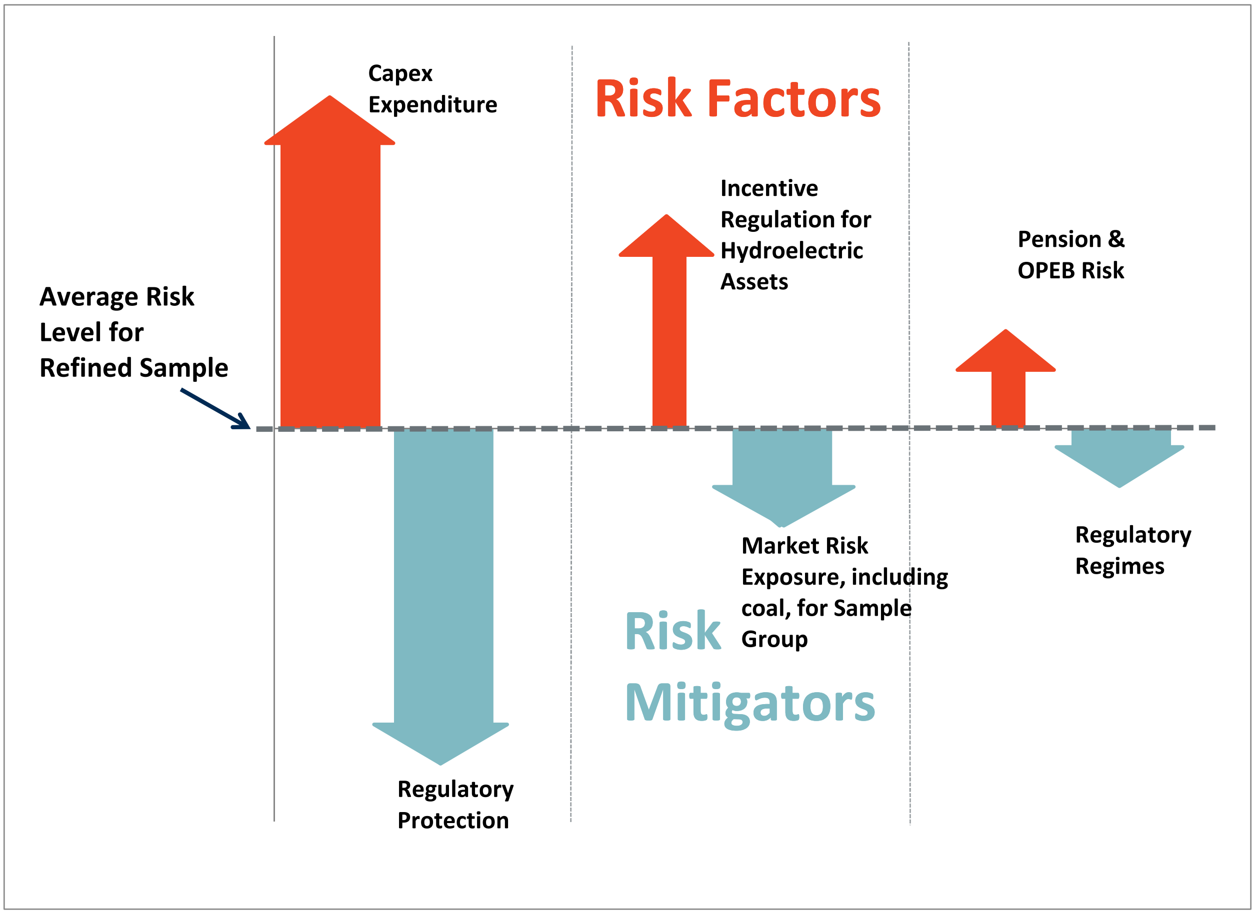
Continued from previous page

Clarington Transformer Station all as factors in deciding when to shutdown the Pickering Generating Station.

I illustrate these counteracting risk and mitigating factors visually below in Figure 5 wherein the height of the arrows indicates the extent of increase/decrease in risk exposure relative to the sample average, while the width reflects the impact of each risk factor and any mitigating construct in place. As shown, OPG's elevated construction and execution risks are mitigated by the regulatory protections in place. Similarly, the incentive regulation mechanism (price cap) plan on hydroelectric assets also under consideration in this application imposes an increase in risk for OPG relative to the sample, however the sample's exposure to relatively greater market risk (price risk and risk related to higher coal resource concentration) roughly balances this increased OPG's risk. Note that I view the overall impact of each risk as a blend of the level of risk deviation (i.e., increase or decrease in OPG's risk relative to the sample), and the extent of impact of such risk (greater the width of the arrows, greater the impact). Therefore, a greater deviation in a risk factor for OPG, such as Incentive Regulation, may be mitigated by a smaller, but high-impacting counter risk for the sample, such as market risk, in this case. Finally, I view the pension and OPEB recovery as one of timing and risk of disallowance noting that the OEB in the past has disallowed, what they deemed "excessive compensation" and that other regulators also conduct a prudence review of costs. Thus, the impact is minimal.

The larges change from EB-2013-0321 is the increase in capital expenditure and the associated construction, delay, and recovery risks, which are mitigated by the support of the province.

Figure 5: OPG Risk Comparisons with Refined Sample of Comparable Companies[65]



C. Regulatory Risks: Effect of Changes in Rate-Setting

OPG's application includes a move to use incentive-based payments for OPG's regulated hydroelectric assets. Specifically, for the five years, 2017-2021, the payments OPG receive for hydroelectric power generation will be determined by an indexed price-cap, so that OPG's hydroelectric revenue is decoupled from its cost.[66] Because the incentive-based mechanism adjusts payments annually for inflation and other specified items, OPG will benefit relative to a pure cost-based system if it is able to control costs. However, if OPG is unable to control costs or faces lower demand than forecast, it may realize less income than under a cost-based system.

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65 The figure is for illustrative purposes and not an intended to provide a quantification of each risk component.

66 OPG Ex A1-3-1, p. 2 of 12, *Administrative Documents - Exhibit List*, p. 37

Therefore, the variability in OPG's income may increase although there is no *ex ante* reason why incentive-based rate setting would systematically lead to over- or under-earning relative to a pure cost-based system if properly designed. Put differently, there is no *ex ante* reason why incentive-based rate setting would impact the ability to earn the allowed return, although it may increase the variability in achieved annual returns around the allowed ROE.

Among the benefits from incentive rate setting is that it: (i) provides the utility with incentives to control costs and increase revenues; and (ii) provides larger regulatory certainty as rates are set mechanically. In turn, unforeseeable circumstances may prevent the utility from controlling costs. However, because OPG has proposed to continue all existing deferral and variance accounts approved by the OEB,[67] the exposure is lower than under a more conventional incentive regulation mechanism (i.e., a pure price or revenue cap).

For the nuclear generation assets, the nuclear rate smoothing proposal recommends increasing rates by 11 percent annually until 2021 to avoid rate shock in 2017, when the Darlington Refurbishment Program will reduce nuclear production. The proposal will result in the deferral of a non-trivial amount to later years and thus reduces OPG's near-term cash flow. However, it will provide OPG with a "guaranteed" increase year-over-year and hence provide a type of revenue insurance. In addition, it has the benefit of avoiding rate shock for customers, which could negatively impact public perception – the consequences of which are hard to measure.

As noted above, the OEB is currently reviewing the regulatory treatment of pension and OPEB cost going forward. In EB-2013-0321, OPG was allowed to recover the cash cost of its pension and OPEB obligations, while the difference between accrual and cash cost were accrued in a deferral account for later disposition. Because the accrual cost of OPG's pension and OPEB are currently larger than its cash costs, the regulatory treatment defers recovery to future periods. Thus, the distinction between accrual and cash recovery of cost is one of timing, so while OPG's current cash flow is impacted, the total cash flow is not (absent future disallowances). Therefore, the notion that the accrued difference between the accrual amount and the cash amount is "at

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67 OPG Ex. A1-3-2, "Rate-Setting Framework," p. 22-23.

risk" exaggerates OPG's regulatory risk. The amount would only be lost if disallowed. Thus, there is a timing difference and as the going forward treatment has yet to be determined, OPG faces some uncertainty, but Concentric's statement that the full amount is "at risk" substantially exaggerates the risk.

In Canada, both Alberta and Ontario have had versions of incentive-based rate setting for electricity and natural gas distribution entities for a number of years, as have the United Kingdom and Australia. However, in the U.S. most jurisdictions do not rely on incentive rate-setting although there are exceptions.[68] Thus, incentive rate-setting is not new. Having said that, I acknowledge that it is new to OPG (but not to the OEB), and there will inherently be a "learning curve." Income to OPG may vary more than under a more traditional rate-setting methodology, but to a large degree the impact will depend on the design of the incentive regulation. Thus, I agree that incentive regulation in the near term will make OPG's variation around earnings (change in net position) larger. However, it is not clear that it impacts either the credit worthiness of OPG, its ability to earn the allowed ROE or the **long-term** business risks.

I note that Concentric's report does not compare how OPG vs. the proxy companies recover pension and OPEBs expenses; neither did Concentric present information on incentive or other regulation among the proxy companies. [69]

However, looking to U.S. regulated companies, the majority of those owning generation or exposed to market risk have a fuel or purchased power adjustment clause (a deferral account) and the majority have full or partial decoupling mechanisms (a deferral account) in place, so that two large expenses or revenue risks are eliminated (or reduced in the case of partial decoupling). I discuss the specifics of the refined sample in more detail below.

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68 For example, Southern Company subsidiaries' Alabama Power and Mississippi Power operates under a version of incentive regulation as does FortisAlberta.

69 To my knowledge none of the companies in the comparable sample have a pension adjustment clause.

D. Competitive and Supply Risks

Lastly, looking to the competitive and supply risks for OPG, I note that OPG accounts for approximately 51 percent of the electricity produced in Ontario,[70] which gives OPG a dominant position in the Ontario market. In addition, OPG is a rate-regulated entity for the prescribed hydroelectric and nuclear generation assets and therefore is not exposed to fluctuation in market prices. As a result, I view OPG's competitive risk as relatively low and comparable to that of the fully regulated generation in Concentric's proxy group. As not all generation owned by proxy group companies is regulated, I view OPG's competitive risk as lower than that of the proxy group.

As for OPG's supply risk, there could be supply disruptions for nuclear, thermal and/or hydroelectric generation. Because of the close trading relationships between Canada and the U.S., I see no difference between OPG's and the proxy companies' access to natural gas or nuclear fuel that is used to produce power. There may be a difference in the actual availability of access and availability to water used in hydroelectric generation as it is location- and weather-dependent. While I do not have access to information that would allow an assessment of the relative risks faced by OPG and the proxy companies from exposure to water supply risk, I note that for the proxy companies considered by Concentric, the median percentage of hydroelectric generation is about 3 percent and the average is about 10 percent,[71] while OPG has a water condition variance account. Thus, neither the proxy companies nor OPG has much exposure to water condition risks.

E. Results from Refined Proxy Group

In Section I, I described Concentric's Comparative Analysis developed to assess OPG's business risk relative to a proxy group. Related to this assessment, I discussed OPG's Asset Composition and Changes to its Asset Mix in the preceding section of this report wherein I concluded that, overall, OPG's generation mix is at least as risky as that of Concentric's proxy group. I noted,

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70 DBRS, "Ontario Power Generation Inc.," April 25, 2016 (Attachment 2 to OPG Response to Board Staff Interrogatory #17)

71 OPG Ex. L, Tab 3.1, Response to Staff 014 in IRR Issue 3, Exhibit 1 (Excel spreadsheet).

however, that, because OPG has little to no exposure to market prices for its nuclear generation[72] and since nuclear generation's share in OPG's asset mix is set to increase, OPG's exposure to market risk is lower than that of the proxy companies.

To further assess OPG's business risk and to be consistent with Concentric's Comparative Analysis methodology, I looked to a different sample of comparable companies. My refined sample controls for differences in levels of assets under regulation, and is composed of companies with greater concentration in regulated nuclear and hydroelectric assets than what is present in Concentric's proxy group. The refined sample, along with the asset composition and related data for each firm in this sample group, is shown in Figure 6 below. From my analysis, I observe that the book value equity capitalization levels for my refined sample comprising regulated Investor Owned Utilities[73] ranges from 41.7% to 56.8%, with an average of 47.8% and a median of 47.4%. I also present equity capitalization percentages for Tennessee Valley Authority and for predominantly hydroelectric generation owning companies for reference and comparisons, even though I do not include them in my refined sample as I do not consider these companies to be directly comparable to OPG.[74] Based on results from my refined alternate sample, I find the appropriate equity capitalization percentage for OPG to be slightly lower than those presented in the Concentric Report. Because the refined sample was chosen to include only companies that are almost fully regulated, own nuclear generation, and broadly speaking have regulatory protection in the form of true-up accounts for fuel and possibly other variances, I believe these are comparable to OPG over the next regulatory period.

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72 Going forward it is expected that OPG's hydroelectric facilities, which under the proposal will be subject to price-cap incentive regulation (OPG Ex. C1-1-1, p. 3).

73 Note that the comparable companies in my refined sample comprises of utilities with more than 90% of their assets subject to regulation

74 I also considered Hydro Quebec, but eliminated it because of its has less than 90% of its assets subject to regulation.

Figure 6: Refined Sample of Regulated Comparable Companies

	Composition[2]	S&P Rating	Book Value Equity Capitalization
[1]	[2]	[3]	[4]
Companies with Nuclear Generation:	**% Nuclear of Total MWh Generation**		
Investor Owned Utilities:			
[a] Ameren Corporation	23%	BBB+	47.4%
[b] DTE Energy Company	17%	BBB+	47.4%
[c] El Paso Electric Company	47%	BBB	44.6%
[d] Entergy Arkansas, Inc.	54%	BBB	41.7%
[e] Entergy Louisiana, LLC	27%	BBB	48.6%
[f] PG&E Corporation	23%	BBB	49.4%
[g] Pinnacle West Capital Corporation	27%	A-	55.3%
[h] **Mean of Investor Owned Utilities**	**31%**		**47.8%**
[i] **Median of Investor Owned Utilities**	**27%**		**47.4%**
[j] Tennessee Valley Authority	34% nuclear / 9% hydroelectric	None	22.1%
Companies with Hydroelectric Generation:	**% Hydro of Total MWh Generation**		
[k] BC Hydro and Power Authority	75%	None	19.6%
[l] Bonneville Power Administration	84%	None	15.5%
[n] IDACORP, Inc.	36%	BBB	54.1%
[o] **Mean of Hydroelectric sample**	**65%**		**29.7%**
[p] **Median of Hydroelectric sample**	**75%**		**19.6%**

Sources:
Composition Data in rows [a]-[c], [f],[g],[n] from Value Line, Inc
Composition Data in rows [d],[e] from Entergy Corporation 2015 10-K
Composition Data in row [j] from Tennessee Valley Authority 2016 10-K
Composition Data in row [k] from BC Hydro and Power Authority 2016/17-2018/19 Service Plan; accessed at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/service-plans/bchydro-service-plan-2016-17-2018-19.pdf
Composition Data in row [l] from BPA Fuel Mix Percent Summary. CY 2015 Data; accessed at: https://www.bpa.gov/power/BPA_Fuel_Mix/docs/BPA_Official_Fuel_Mix_2015.pdf
S&P Rating from SNL Financial
Book Value Equity Capitalization calculated by The Brattle Group using data from SNL Financial
Notes:

1. All companies have at least 90% of their assets regulated.
2. The percentages in the Composition column represent percent of total generation (MWh) reported for 2015, except for Tennessee Valley Authority (TVA) and BC Hydro and Power Authority (BC Hydro). TVA's data reflects their fiscal year ending September 30, 2016 and BC Hydro's reflects data for 2014/2015 year. Total Generation reported includes purchased power.
3. In the same column, percentages for Ameren Corporation, El Paso Electric Company, PG&E Corporation, and Pinnacle West Capital Corporation from Value Line and have been verified with company 10-Ks.
4. The percentage for DTE Energy Company was verified using SNL Financial data as company 10-K did not provide 2015 generation data. Note -DTE composition presented does not include purchased power.
5. The percentages for Entergy Arkansas, Inc. and Entergy Louisiana, LLC are taken from the Entergy Corporation 10-K, as Value Line only provides data at the holding company level.

IV. Credit Metric Analysis and Discussion

A. Credit Metrics

Credit metrics provide a useful assessment of capital structure for regulated utilities. In some jurisdictions, regulatory commissions expect credit metrics of utilities to be such that the utilities could achieve "A" rating on their unsecured debt offerings.[75] Credit metrics, which are used by credit rating agencies to determine solvency and liquidity risks associated with borrowing entities, provide a good indication of the strain brought about by increased leverage or cash flow pressure. Therefore, such analysis is useful in assessing the credit worthiness of the borrowing entity. Rating agencies typically employ a blend of <u>qualitative</u> and <u>quantitative</u> credit risk assessments to determine the appropriate credit worthiness of borrowing entities. In this analysis, I focused solely on the quantitative assessment that rating agencies perform as it provides a uniform way to compare regulated utilities and to assess developments in credit risk. Such a quantitative analysis cannot be done without also considering the qualitative risk factors discussed above.

In addition to my quantitative analysis (discussed below), I also reviewed the credit rating of the province of Ontario on its long-term debt offerings. The province is currently rated A+ by S&P, which is three notches above OPG's current credit rating of BBB+.[76] The last change to the credit ratings occurred in July of 2015, when S&P downgraded the ratings of both the Province and OPG from their previous credit ratings of AA- and A- respectively. Generally, credit rating agencies would consider the province's current credit rating of A+ to be advantageous to OPG's solvency if it were to experience any extraordinary financial distress. Therefore, from a financial risk perspective, the province's high quality credit rating would help mitigate some of credit risk for OPG.

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75 For example, the Alberta Utilities Commission as recently in Decision 20622-D01-2016 (issued October 7, 2016) stated that it "will, consistent with its approach in past GCOC decisions, award common equity ratios that are, on a stand-alone basis, consistent with credit ratings in the A category."

76 Historically, from 2001 to 2004 OPG's credit rating remained at BBB+, while during the same time Ontario's credit rating remained at AA. In August 2008, S&P raised OPG's rating by one notch to A-, and around the same time – in October 2009, it downgraded Ontario's credit rating from AA to AA-. The most recent change to ratings occurred in July 2015, when S&P downgraded both OPG and Ontario from their respective A- and AA- ratings to BBB+ and A+ ratings. These ratings remain current for OPG and Ontario.

For my quantitative assessment of credit risk I evaluated five key financial metrics and compared those against published benchmarks for each metric for different tranches of credit rating. Different rating agencies employ slightly different financial metrics, but all look to evaluate financial performance based interest and debt coverage as well as leverage. Key financial credit metrics employed by DBRS, and Standard & Poor's, along with the benchmarks for each major tranche of credit rating, are discussed below:

Standard & Poor's Key Credit Metrics

- Debt / EBITDA Coverage Ratio (Core Ratio)
- FFO / Debt Leverage Ratio (Core Ratio)
- CFO / Debt & FFO / Interest (Supplemental Ratios)

DBRS Credit Metrics

- EBIT / Interest

It should be noted that credit rating agencies such as Standard & Poor's and Moody's focus on the Debt to EBITDA coverage, FFO interest coverage, and FFO to debt leverage ratios.[77] For example, Moody's assigns 40% of its ratings weight to leverage and coverage of which 31% is FFO to Debt and another 31% is net debt to rate base (or net debt to fixed assets), while FFO interest coverage accounts for 25%. The ratios that are relied upon by the credit rating agencies and market participant are the most important ones, and I consider it vital that utilities' capital structures are such that the credit ratios in expectation are near the middle of the range rather than at the bottom, to allow for some flexibility during times of financial hardship. Figure 7 below summarizes the expectations for an A rating as used by the major credit rating agencies.

Figure 7: Summary of Credit Metrics Benchmarks

	EBIT Coverage	FFO Coverage	FFO to Debt
DBRS Range[78]	1.8- 2.8	n/a	12.5 – 17.5%
Standard & Poor's[79]	n/a	3-5	13 – 23%

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77 Moody's, "Regulated Electric and Gas Networks," November 25, 2014. S&P, "Corporate Methodology: Ratios And Adjustments," November 19, 2013.

78 DBRS, "Rating Companies in the Regulated Electric, Natural Gas and Water utilities Industry," October 2014. DBRS provides a Cash Flow to Debt measure rather than FFO to Debt.

Debt / EBITDA Coverage Ratio:

Debt / EBITDA ratio measures a company's ability to pay off its debt. This ratio approximates the number of years that the company would need to pay off the debt on its balance sheet using pre-tax net operating cash flows, excluding non-cash expenses such as depreciation and amortization. All else equal, a high debt / EBITDA ratio suggests it could take a firm longer to pay off its debt and therefore normally would be associated with a lower credit rating. Conversely, a low ratio suggests that a firm may quickly pay off its debt and potentially take on additional debt as needed, and corresponds to a higher credit rating. OPG's debt / EBITDA ratio for the year ending December 31, 2015 was approximately 5.11, which corresponds to a "Significant" financial risk in S&P's criteria for low volatility industries.[80]

Our forward-looking analysis[81] – covering the 2017–2021 period – estimates that OPG's debt / EBITDA ratio will average 6.03x, and remain generally at the "Significant to Aggressive" level benchmark for financial risk per S&P'S Ratings Guidelines. Our analysis indicates worsening financial risk exposure for OPG in 2018-2019, during which the company's Debt / EBITDA ratio is expected to be at over 6.0x, which would conform to the "Aggressive" financial risk level per S&P's rating guidelines. Detailed results of our forward-looking assessment are presented in Exhibit BV-4a attached to this report. This finding is generally consistent with analysis presented by OPG.[82]

Continued from previous page

79 Standard & Poor's, "How Regulatory Advantage Scores Can Affect Ratings on Regulated Utilities," April 23, 2015, p. 4 for FFO to Debt. The range uses S&P's "significant financial" risk profile. S&P has a lower metric that pertains only to utilities with a "strong regulatory advantage score." S&P notes that with a less strong advantage score the FFO-to-debt is in the range of 13-23 to warrant a profile that is consistent with an "A" range rating.

80 S&P has six possible tranches of financial risk with rating companies: minimal, modest, intermediate, significant, aggressive, and highly leveraged. *Standard and Poor's General Corporate Methodology*, 2013.

81 The results uses the current equity ratio of 45% and the most recently allowed ROE of 8.78%.

82 OPG Ex. A1-3-3, p. 8 (Updated 2016-11-10).

FFO / Debt Ratio:

The FFO / Debt ratio is a leverage ratio that is used by rating agencies to assess the leverage of borrowing entities. All else equal, a lower FFO / Debt ratio indicates higher leverage, and therefore, a higher credit risk - hence a lower credit rating. In contrast, a higher FFO / debt ratio indicates that the borrowing entity is in a stronger position to pay off its debt using its operating income. OPG's FFO / Debt ratio during the year ending December 31, 2015 was approximately 14.8%, which corresponds to "Intermediate" financial risk for S&P low volatility industries. Our forward-looking analysis (2017–2021 period) estimates that this ratio for the company will average at about 11.8%, and remain largely at the "Significant" level benchmark for financial risk per S&P guidelines. I observe worsening financial risk exposure for OPG starting in 2017 and remaining at the Significant level through much of the DRP refurbishment phase, with the exception of 2020, during which the jump in rate base drives an improved FFO / Debt ratio. Detailed results of our forward-looking assessment are presented in Exhibit BV-4a.

FFO / Interest and EBIT / Interest Coverage Ratios:

FFO / interest expense ratio is used to assess the company's ability to use its operating cash flows to service its interest payments. This is a key measure of financial flexibility of the borrowing entity, and therefore a key metric relied upon by rating agencies assessing financial risks. All else equal, a higher FFO / interest ratio indicates the company generates more than sufficient operating cash flow to provide interest coverage, resulting in a higher credit rating. OPG's FFO / interest ratio for the year ending December 31, 2015 was approximately 4.64x, which corresponds to the "Intermediate" financial risk for S&P's low volatility industry rating criteria. My forward-looking analysis for the 2017–2021 period estimates that OPG's FFO / Interest ratio will average 2.78x, and remain largely at the "Significant" level benchmark for financial risk per S&P's Ratings Guidelines. Similar to the trends I observe for credit ratios of Debt / EBITDA and FFO / Debt, wherein I observe worsening ratios during the construction phase of DRP, with improvement expected in 2020 due to the large increase in OPG's rate base, I estimate that the FFO interest coverage for the company will also worsen beginning in 2017. OPG's FFO interest coverage will however improve to 3.08x as a result of a large increase in rate base in 2020. Note that, at 3.08x interest coverage ratio, OPG's financial risk would be deemed "Intermediate" per S&P's rating guidelines, but would still be borderline. As I have noted previously in this report, I consider it vital that the utilities' capital structures be such that these key credit ratios remain near the middle of the range of acceptable benchmarks rather than at the bottom. Detailed results of our forward-looking assessment are presented in Exhibit BV-4a and Exhibit BV-4b.

Similar to the FFO / Interest Coverage ratio relied upon by S&P, DBRS evaluates the EBIT / Interest coverage ratio. The EBIT / Interest coverage ratio estimates the number of times the borrowing entity can cover its interest obligations with its available pre-tax earnings. In the forward-looking assessment of financial risk for OPG, I included the estimation of the EBIT to interest coverage ratio, which for the company is expected to average 0.59x for the 2017-2021 period, which is below the investment-grade level. As expected, I observe that the company's EBIT / interest coverage ratio will increase in the latter years (2020-21), when Darlington Unit 2 is expected to be in-service after refurbishment. Detailed results are presented in Exhibit BV-4b.

CFO / Debt leverage Ratio:

Cash Flow from Operations to Debt is a type of debt coverage ratio, which DBRS and S&P employ in assessing credit risk of borrowing utilities. While DBRS employs this financial ratio as one of the three key metrics it looks to in its ratings determination, S&P relies on this metric as a supplement to its two core ratios – FFO / Debt leverage ratio and Debt / EBITDA coverage ratios discussed above. Similar to the FFO / Debt ratio, CFO / Debt ratio provides an indication of the amount of time it would take the borrowing entity to repay its debt obligations if it were to dedicate all its cash flows from operations to debt repayment.

OPG's CFO / Debt ratio during the year ending December 31, 2015 was approximately 20.1%, which corresponds to the lower end of the "Modest" level financial risk for S&P's low volatility industries. Our forward-looking analysis (for 2017–2021 period) estimates that OPG's CFO / Debt ratio for the company will average at about 17.1%, and largely remain at the "Intermediate" level for financial risk, per S&P guidelines. Consistent with estimated results observed for other leverage ratios, I estimate slightly worsening financial risk exposure for OPG during the construction phase of DRP, but improving in 2020 owing to increased rate base for the company. Detailed results of our forward-looking assessment are presented in Exhibit BV-4a.

In summary, the forecasted stand-alone credit metrics for OPG are such that its key leverage and coverage credit ratios worsen during the construction phase of DRP when the amount of new debt and debt provision continue to increase due to ongoing construction without offsetting revenues. Obviously, the intention is for OPG and the Province of Ontario to obtain long-term benefits – in the form of a larger rate base and hence enhanced income.

B. Review of Assessment of Risks by Market Participants

Credit rating agencies including DBRS and Standard and Poor's have recently commented on financial risks associated with OPG's Darlington Refurbishment Program. In April 2016, DBRS confirmed the A rating on OPG's unsecured debt, but noted that high capital expenditures during the Darlington Refurbishment Program will require OPG to assume higher leverage, which in turn could weaken OPG's credit metrics. Our review of DBRS' credit rating for OPG indicates that, to maintain an A rating going forward, the Company will need to have three key credit metrics within DBRS's defined benchmarks for A-rated Canadian utilities:

- Earnings before Interest and Taxes (EBIT) coverage of 1.8x to 2.8x
- Cash Flow from Operations to Debt of 12.5% to 17.5%
- Debt to Total Capital of 55% to 65%

For 2015, DBRS estimated OPG's EBIT-coverage ratio as negative 0.86x, which is outside DBRS's range for A-rated utilities, noting that it expects this ratio to continue to weaken as OPG adds additional debt to finance its capital spending during the Darlington Refurbishment Program. DBRS considers capital spending a primary factor when rating utilities that are planning multi-year capital expansion programs, especially when those plans involve nuclear generation.[83]

Similar to the Darlington Refurbishment Program, at least two US electric utilities are currently engaged in development of new nuclear generating power plants. These are Southern Company's Vogtle nuclear Unit 3 & 4 in Georgia, and SCANA Corporation's V.C. Summer nuclear Units 2 & 3 in South Carolina. Both of these projects involve the development of new nuclear generating facilities, while OPG's Darlington Refurbishment Program is refurbishment. Therefore the projects may not be exactly comparable as some of the challenges will differ. However, I believe

[83] DBRS, "Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry," October 2016.

that the views of investors and credit rating agencies provide insights into their view of nuclear generation and construction risk of such facilities.

Major credit rating agencies have opined on the impact of development of these nuclear generating facilities on Southern Company and SCANA Corporation's financial risks. I provide a brief summary of relevant discussions below.

Credit Market Participant Discussions on Southern Company / Vogtle

Moody's has noted that it views the Vogtle nuclear project as a key credit driver for Oglethorpe (a cooperative power supplier and one of the owners of the nuclear facility along with Southern Company).[84] Moody's further opined that "Oglethorpe's Baa1 senior secured rating reflects its materially increased business and operating risk profile due to the substantial multi-year capital spending plan and that this elevated risk profile has not, to date, been mitigated by any meaningful improvement in credit metrics or cash flows".[85]

Moody's has further opined on the Vogtle nuclear power plant project's impacts on other owners of the plant, noting that the Vogtle project has indeed increased business and operating risk profiles of the three utility partners of the project – Georgia Power Co., Oglethorpe Power Corp. and MEAG Power.[86] Until recently, all three companies had maintained their overall credit profiles, however, Moody's downgraded Georgia Power, and its parent Southern Company, by one notch (to A3 for Georgia Power, and to Baa2 for Southern Company) in May 2016.[87]

Another credit rating agency – Fitch - has noted that the Vogtle nuclear units have been recovering their financing costs on construction work in progress (AFUDC) through a tracker since 2011, and that "it expects that any adjustments to the overall project costs will be deemed

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[84] Moody's Investors Service Credit Opinion: Oglethorpe Power Corporation, pg. 1, 11/12/2015

[85] *Ibid.*, pg. 2, 11/12/2015

[86] "Moody's: Plant Vogtle nuclear expansion partners cope with risk", pg. 1, 10/21/2013

[87] *Ibid.*

recoverable by the Georgia PSC".[88] Fitch also notes that "significant project cost overruns that cannot be recovered in rates or unexpected long deferral periods for project cost recovery would be adverse credit factors"[89] to business and financial risk for Vogtle's owners. More important, Fitch notes that successful execution of nuclear plant construction and a continuation of keeping the nuclear generation in rate base and fully recovering costs are key to maintaining rating stability at Georgia Power."[90]

I note that Vogtle's owners were successful in securing loan guarantees from the U.S. Department of Energy in February 2014 for the construction of Vogtle units 3 and 4. This is a favorable outcome for the owners of Vogtle that alleviates some risks otherwise inherent in nuclear project development.

Credit Market Participant Discussions on SCANA / V.C. Summer

Moody's has viewed SCANA relatively more favorably, noting that developments surrounding the construction of the new V.C. Summer nuclear units have been favorable to its credit profile[91]. Moody's recently revised its outlook on SCANA Corp. and its subsidiaries to stable from negative,[92] and also affirmed the ratings of SCANA at Baa3, South Carolina Electric & Gas Co. at Baa2 and Public Service Co. of North Carolina Inc. at A3. On November 10, 2016, The Public Service Commission of South Carolina (PSC) approved a settlement between South Carolina Electric & Gas Co. (SCE&G) and SCANA Corp. that increases SCE&G's capital costs for V.C. Summer nuclear reactors by USD$831 million, from $6.83 billion to $7.66 billion.[93] This $831 million increase includes some $505.5 million related to SCE&G's "irrevocable" fixed price option

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[88] "Fitch Affirms Ratings for Southern Company and Subsidiaries", pg. 2, 8/06/2013

[89] *Ibid.*

[90] "Fitch Affirms Ratings for Southern Company and Subsidiaries," pg. 5, 8/06/2013

[91] "Lower risk from nuke expansion prompts Moody's to change outlook on SCANA," 10/31/2016

[92] *Ibid.*

[93] SNL Financial, "SC regulators approve agreement to cap V.C. Summer costs at $7.66B," 10 November 2016.

that had been approved in a prior settlement. The recovery of these cost increases reduces SCANA's recovery risk. As part of the agreement on November 10th, SCE&G's allowed return on equity will decrease from 10.5% to 10.25% beginning on January 1st, 2017.

In summary, the Vogtle and V.C. Summer commentary illustrates that from a credit metric perspective regulatory support in the form of recovery of costs and possibly federal or other loan guarantees are important in large scale nuclear construction programs.

V. Conclusions

Having considered the (i) supply risk, (ii) demand or market risk, (iii) competitive risk, (iv) operating risk, and (v) regulatory risk for OPG as they relate to the risk at the time of the EB-2013-0321 decision and as they relate to a refined sample of comparable companies, I conclude that OPG's supply risk and competitive risk are minimal and comparable to those as of the time of EB-2013-0321. Further, since OPG's regulated generating facilities plus contracted facilities – which together make up over 99% of OPG's total capacity – face no price risk, my refined sample of comparable companies with just about three percent of its capacity exposed to price risk, provides for a good proxy group for OPG. In contrast, several companies in Concentric's proxy group have much larger exposure to market prices.

Looking to the two components of business risk that have changed or will change: operating risk and regulatory risk, I find that the operating risk has increased relative to the time of EB-2013-0321 decision and that transitioning to incentive regulation increases OPG's exposure to income volatility (at least temporarily). As a result, OPG's business risk has increased since the EB-2013-0321 decision was issued. A comparison to the refined sample of comparable companies is more challenging as none of the companies have the same magnitude of a construction program ongoing and they do not have the same exposure to a nuclear rate base going forward (although in terms of MW, the exposure is more similar). Over the next five years, OPG will have a large construction program, whose risk is partially offset by the protections provided by the province. Compared to the refined sample, OPG has no coal exposure and no price risk. At the same time generation is only a part of their regulated asset mix – the other being distribution and transmission assets. Looking to Concentric's sample of comparable companies, comparability becomes even harder as several companies own non-trivial amounts of unregulated generation, unlike OPG. However, as discussed above, the regulatory regime in Ontario and for the companies in the refined sample share the fact that there are many true-up accounts and often larger construction projects are pre-approved although only rarely are U.S. pre-approvals at the legislative level.

Considering the credit metrics of OPG going forward, as calculated by OPG and myself, I conclude that the metrics will decline absent a change in the cash flows to OPG and that, based on a credit metric analysis of OPG as a stand-alone entity, it would face severe challenges going forward. However, there are substantial regulatory mechanisms in place that reduces the risk exposure – e.g., the established need for refurbishment and its inclusion in the provincial LTEP and, as noted by S&P Rating Services, which stated that there is a "high likelihood that the Province of Ontario would provide timely and sufficient extraordinary support to the company in the event of financial distress".[94] As a result, S&P rated its government-related entity criteria for OPG as "very strong" and adjusted OPG's credit rating upward by three notches.[95] This is the key for OPG maintaining a strong credit rating during the construction period.

Based on the business risk analysis and the evaluation of credit metrics for OPG going forward, I conclude that OPG on a stand-alone basis has more construction and nuclear generation risk, but less coal exposure than the refined comparable sample. I further find that while the regulatory risk may be different, I do not see substantial enough differences to the comparable companies to merit adjustments although I agree that incentive regulation in the near term will make OPG's variation around earnings (change in net position) larger. Relative to the refined sample and especially relative to Concentric's comparable sample, OPG's exposure to market or competitive risk is lower.

Considering the large exposure to construction risk and declining credit metrics, which to a degree are offset by the assurances that come from Ontario's LTEP and being a fully regulated

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[94] OPG Ex. A2-3-1, Attachment 6, Standard & Poor's Research Report for Ontario Power Generation Inc.
[95] *Ibid.*

entity, I recommend that OPG be allowed an equity thickness that is comparable to that of my refined sample of comparable companies – 48% over the next five years – and recommend that OPG's capital structure be re-evaluated at the end of the 2017-21 rate-setting plan considered in this application. Once the construction phase is over, OPG may, everything else being equal, face less business risk than over the construction phase.

APPENDIX: RESUME OF DR. BENTE VILLADSEN

Dr. Bente Villadsen's work concentrates in the areas of regulatory finance and accounting. Her recent work has focused on accounting issues, damages, cost of capital and regulatory finance. Dr. Villadsen has testified on cost of capital and accounting, analyzed credit issues in the utility industry, risk management practices as well the impact of regulatory initiatives such as energy efficiency and de-coupling on cost of capital and earnings. Among her recent advisory work is the review of regulatory practices regarding the return on equity, capital structure, recovery of costs and capital expenditures as well as the precedence for regulatory approval in mergers or acquisitions. Dr. Villadsen's accounting work has pertained to disclosure issues and principles including impairment testing, fair value accounting, leases, accounting for hybrid securities, accounting for equity investments, cash flow estimation as well as overhead allocation. Dr. Villadsen has estimated damages in the U.S. as well as internationally for companies in the construction, telecommunications, energy, cement, and rail road industry. She has filed testimony and testified in federal and state court, in international and U.S. arbitrations and before state and federal regulatory commissions on accounting issues, damages, discount rates and cost of capital for regulated entities.

Dr. Villadsen holds a Ph.D. from Yale University's School of Management with a concentration in accounting. She has a joint degree in mathematics and economics (BS and MS) from University of Aarhus in Denmark. Prior to joining The Brattle Group, she was a Professor of Accounting at the University of Iowa, University of Michigan, and at Washington University in St. Louis where she taught accounting. She has also taught graduate classes in econometrics and quantitative methods. Dr. Villadsen also worked as a consultant for Risoe National Laboratories in Denmark.

AREAS OF EXPERTISE

- Regulatory Finance
  - Cost of Capital
  - Cost of Service (including prudence)
  - Energy Efficiency, De-coupling and the Impact on Utilities Financials
  - Relationship between regulation and credit worthiness
  - Risk Management
  - Regulatory Advisory in Mergers & Acquisitions
- Accounting and Corporate Finance
  - Application of Accounting Standards
  - Disclosure Issues
  - Credit Issues in the Utility Industry
- Damages and Valuation
  - Utility valuation
  - Lost Profit

EXPERIENCE

Regulatory Finance

- On behalf of the Association of American Railroads, Dr. Villadsen appeared as an expert before the Surface Transportation Board and submitted expert reports on the determination of the cost of equity for U.S. freight railroads.
- For several electric, gas and transmission utilities in Alberta, Canada, Dr. Villadsen filed evidence and appeared as an expert on the cost of equity and appropriate capital structure for 2015-17. Her evidence was heard by the Alberta Utilities Commission.
- She has estimated the cost of equity on behalf of Arizona Public Service, Portland General Electric, Anchorage Water and Wastewater, American Water, California Water, and EPCOR in state regulatory proceedings. She has also submitted testimony before the Bonneville Power Authority. Much of her testimony involves not only cost of capital estimation but also capital structure, the impact on credit metrics and various regulatory mechanisms such as revenue stabilization, riders and trackers.
- In Australia, she has submitted led and co-authored a report on cost of equity and debt estimation methods for the Australian Pipeline Industry Association. The equity report was filed with the Australian Energy Regulator as part of the APIA's response to the Australian Energy Regulator's development of rate of return guidelines and both reports were filed with the Economic Regulation Authority by the Dampier Bunbury Pipeline. She has also submitted a report on aspects of the WACC calculation for Aurizon Network to the Queensland Competition Authority.
- In Canada, Dr. Villadsen has co-authored reports for the British Columbia Utilities Commission and the Canadian Transportation Agency regarding cost of capital methodologies. Her work consisted partly of summarizing and evaluating the pros and cons of methods and partly of surveying Canadian and world-wide practices regarding cost of capital estimation.
- Dr. Villadsen worked with utilities to estimate the magnitude of the financial risk inherent in long-term gas contracts. In doing so, she relied on the rating agency of Standard & Poor's published methodology for determining the risk when measuring credit ratios.
- For utilities that are providers of last resort, she has provided estimates of the proper compensation for providing the state-mandated services to wholesale generators.
- In connection with the AWC Companies application to construct a backbone electric transmission project off the Mid-Atlantic Coast, Dr. Villadsen submitted testimony before the Federal Energy Regulatory Commission on the treatment the accounting and regulatory treatment of regulatory assets, pre-construction costs, construction work in progress, and capitalization issues.
- On behalf of ITC Holdings, she filed testimony with the Federal Energy Regulatory Commission regarding capital structure issues.

- Testimony on the impact of transaction specific changes to pension plans and other rate base issues on behalf of Balfour Beatty Infrastructure Partners before the Michigan Public Service Commission.
- On behalf of financial institutions, Dr. Villadsen has led several teams that provided regulatory guidance regarding state, provincial or federal regulatory issues for integrated electric utilities, transmission assets and generation facilities. The work was requested in connection with the institutions evaluation of potential investments.
- For a natural gas utility facing concerns over mark to market losses on long term gas hedges, Dr. Villadsen helped develop a program for basing a portion of hedge targets on trends in market volatility rather than on just price movements and volume goals. The approach was refined and approved in a series of workshops involving the utility, the state regulatory staff, and active intervener groups. These workshops evolved into a forum for quarterly updates on market trends and hedging positions.
- She has advised the private equity arm of three large financial institutions as well as two infrastructure companies, a sovereign fund and pension fund in connection with their acquisition of regulated transmission, distribution or integrated electric assets in the U.S. and Canada. For these clients, Dr. Villadsen evaluated the regulatory climate and the treatment of acquisition specific changes affecting the regulated entity, capital expenditures, specific cost items and the impact of regulatory initiatives such as the FERC's incentive return or specific states' approaches to the recovery of capital expenditures riders and trackers. She has also reviewed the assumptions or worked directly with the acquirer's financial model.
- On behalf of a provider of electric power to a larger industrial company, Dr. Villadsen assisted in the evaluation of the credit terms and regulatory provisions for the long-term power contract.
- For several large electric utility, Dr. Villadsen reviewed the hedging strategies for electricity and gas and modeled the risk mitigation of hedges entered into. She also studies the prevalence and merits of using swaps to hedge gas costs. This work was used in connection with prudence reviews of hedging costs in Colorado, Oregon, Utah, West Virginia, and Wyoming.
- She estimated the cost of capital for major U.S. and Canadian utilities, pipelines, and railroads. The work has been used in connection with the companies' rate hearings before the Federal Energy Regulatory Commission, the Canadian National Energy Board, the Surface Transportation Board, and state and provincial regulatory bodies. The work has been performed for pipelines, integrated electric utilities, non-integrated electric utilities, gas distribution companies, water utilities, railroads and other parties.
- For a Canadian pipeline, Dr. Villadsen co-authored an expert report regarding the cost of equity capital and the magnitude of asset retirement obligations. This work was used in arbitration.

- In a matter pertaining to regulatory cost allocation, Dr. Villadsen assisted counsel in collecting necessary internal documents, reviewing internal accounting records and using this information to assess the reasonableness of the cost allocation.
- She has been engaged to estimate the cost of capital or appropriate discount rate to apply to segments of operations such as the power production segment for utilities.
- In connection with rate hearings for electric utilities, Dr. Villadsen has estimated the impact of power purchase agreements on the company's credit ratings and calculated appropriate compensation for utilities that sign such agreements to fulfill, for example, renewable energy requirements.
- Dr. Villadsen has been part of a team assessing the impact of conservation initiatives, energy efficiency, and decoupling of volumes and revenues on electric utilities financial performance. Specifically, she has estimated the impact of specific regulatory proposals on the affected utilities earnings and cash flow.
- On behalf of Progress Energy, she evaluated the impact of a depreciation proposal on an electric utility's financial metric and also investigated the accounting and regulatory precedent for the proposal.
- For a large integrated utility in the U.S., Dr. Villadsen has for several years participated in a large range of issues regarding the company's rate filing, including the company's cost of capital, incentive based rates, fuel adjustment clauses, and regulatory accounting issues pertaining to depreciation, pensions, and compensation.
- Dr. Villadsen has been involved in several projects evaluating the impact of credit ratings on electric utilities. She was part of a team evaluating the impact of accounting fraud on an energy company's credit rating and assessing the company's credit rating but-for the accounting fraud.
- For a large electric utility, Dr. Villadsen modeled cash flows and analyzed its financing decisions to determine the degree to which the company was in financial distress as a consequence of long-term energy contracts.
- For a large electric utility without generation assets, Dr. Villadsen assisted in the assessment of the risk added from offering its customers a price protection plan and being the provider of last resort (POLR).
- For several infrastructure companies, Dr. Villadsen has provided advice regarding the regulatory issues such as the allowed return on equity, capital structure, the determination of rate base and revenue requirement, the recovery of pension, capital expenditure, fuel, and other costs as well as the ability to earn the allowed return on equity. Her work has spanned 12 U.S. states as well as Canada, Europe, and South America. She has been involved in the electric, natural gas, water, and toll road industry.

Accounting and Corporate Finance

- On behalf of a construction company in arbitration with a sovereign, Dr. Villadsen filed an expert report report quantifying damages in the form of lost profit and consequential damages.
- In arbitration before the International Chamber of Commerce Dr. Villadsen testified regarding the true-up clauses in a sales and purchase agreement, she testified on the distinction between accruals and cash flow measures as well as on the measurement of specific expenses and cash flows.
- On behalf of a taxpayer, Dr. Villadsen recently testified in federal court on the impact of discount rates on the economic value of alternative scenarios in a lease transaction.
- In an arbitration matter before the International Centre for Settlement of Investment Disputes, she provided expert reports and oral testimony on the allocation of corporate overhead costs and damages in the form of lost profit. Dr. Villadsen also reviewed internal book keeping records to assess how various inter-company transactions were handled.
- Dr. Villadsen provided expert reports and testimony in an international arbitration under the International Chamber of Commerce on the proper application of US GAAP in determining shareholders' equity. Among other accounting issues, she testified on impairment of long-lived assets, lease accounting, the equity method of accounting, and the measurement of investing activities.
- In a proceeding before the International Chamber of Commerce, she provided expert testimony on the interpretation of certain accounting terms related to the distinction of accruals and cash flow.
- In an arbitration before the American Arbitration Association, she provided expert reports on the equity method of accounting, the classification of debt versus equity and the distinction between categories of liabilities in a contract dispute between two major oil companies. For the purpose of determining whether the classification was appropriate, Dr. Villadsen had to review the company's internal book keeping records.
- In U.S. District Court, Dr. Villadsen filed testimony regarding the information required to determine accounting income losses associated with a breach of contract and cash flow modeling.
- Dr. Villadsen recently assisted counsel in a litigation matter regarding the determination of fair values of financial assets, where there was a limited market for comparable assets. She researched how the designation of these assets to levels under the FASB guidelines affect the value investors assign to these assets.
- She has worked extensively on litigation matters involving the proper application of mark-to-market and derivative accounting in the energy industry. The work relates

to the proper valuation of energy contracts, the application of accounting principles, and disclosure requirements regarding derivatives.

- Dr. Villadsen evaluated the accounting practices of a mortgage lender and the mortgage industry to assess the information available to the market and ESOP plan administrators prior to the company's filing for bankruptcy. A large part of the work consisted of comparing the company's and the industry's implementation of gain-of-sale accounting.
- In a confidential retention matter, Dr. Villadsen assisted attorneys for the FDIC evaluate the books for a financial investment institution that had acquired substantial Mortgage Backed Securities. The dispute evolved around the degree to which the financial institution had impaired the assets due to possible put backs and the magnitude and estimation of the financial institution's contingencies at the time of it acquired the securities.
- In connection with a securities litigation matter she provided expert consulting support and litigation consulting on forensic accounting. Specifically, she reviewed internal documents, financial disclosure and audit workpapers to determine (1) how the balance's sheets trading assets had been valued, (2) whether the valuation was following GAAP, (3) was properly documented, (4) was recorded consistently internally and externally, and (5) whether the auditor had looked at and documented the valuation was in accordance with GAAP.
- In a securities fraud matter, Dr. Villadsen evaluated a company's revenue recognition methods and other accounting issues related to allegations of improper treatment of non-cash trades and round trip trades.
- For a multi-national corporation with divisions in several countries and industries, Dr. Villadsen estimated the appropriate discount rate to value the divisions. She also assisted the company in determining the proper manner in which to allocate capital to the various divisions, when the company faced capital constraints.
- Dr. Villadsen evaluated the performance of segments of regulated entities. She also reviewed and evaluated the methods used for overhead allocation.
- She has worked on accounting issues in connection with several tax matters. The focus of her work has been the application of accounting principles to evaluate intra-company transactions, the accounting treatment of security sales, and the classification of debt and equity instruments.
- For a large integrated oil company, Dr. Villadsen estimated the company's cost of capital and assisted in the analysis of the company's accounting and market performance.
- In connection with a bankruptcy proceeding, Dr. Villadsen provided litigation support for attorneys and an expert regarding corporate governance.

Damages and Valuation

- For the Alaska Industrial Development and Export Authority, Dr. Villadsen co-authored a report that estimated the range of recent acquisition and trading multiples for natural gas utilities.
- On behalf of a taxpayer, Dr. Villadsen testified on the economic value of alternative scenarios in a lease transaction regarding infrastructure assets.
- For a foreign construction company involved in an international arbitration, she estimated the damages in the form of lost profit on the breach of a contract between a sovereign state and a construction company. As part of her analysis, Dr. Villadsen relied on statistical analyses of cost structures and assessed the impact of delays.
- In an international arbitration, Dr. Villadsen estimated the damages to a telecommunication equipment company from misrepresentation regarding the product quality and accounting performance of an acquired company. She also evaluated the IPO market during the period to assess the possibility of the merged company to undertake a successful IPO.
- On behalf of pension plan participants, Dr. Villadsen used an event study estimated the stock price drop of a company that had engaged in accounting fraud. Her testimony conducted an event study to assess the impact of news regarding the accounting misstatements.
- In connection with a FINRA arbitration matter, Dr. Villadsen estimated the value of a portfolio of warrants and options in the energy sector and provided support to counsel on finance and accounting issues.
- She assisted in the estimation of net worth of individual segments for firms in the consumer product industry. Further, she built a model to analyze the segment's vulnerability to additional fixed costs and its risk of bankruptcy.
- Dr. Villadsen was part of a team estimating the damages that may have been caused by a flawed assumption in the determination of the fair value of mortgage related instruments. She provided litigation support to the testifying expert and attorneys.
- For an electric utility, Dr. Villadsen estimated the loss in firm value from the breach of a power purchase contract during the height of the Western electric power crisis. As part of the assignment, Dr. Villadsen evaluated the creditworthiness of the utility before and after the breach of contract.
- Dr. Villadsen modeled the cash flows of several companies with and without specific power contract to estimate the impact on cash flow and ultimately the creditworthiness and value of the utilities in question.

PUBLICATIONS AND REPORTS

"Report on Gas LDC multiples," with Michael J. Vilbert, *Alaska Industrial Development and Export Authority*, May 2015.

"Aurizon Network 2014 Draft Access Undertaking: Comments on Aspects of the WACC," prepared for Aurizon Network and submitted to the *Queensland Competition Authority*, December 2014

"Brattle Review of AE Planning Methods and Austin Task Force Report." (with Frank C. Graves) September 24, 2014.

Report on "Cost of Capital for Telecom Italia's Regulated Business" with Stewart C. Myers and Francesco Lo Passo before the *Communications Regulatory Authority of Italy* ("AGCOM"), March 2014. *Submitted in Italian.*

"Alternative Regulation and Ratemaking Approaches for Water Companies: Supporting the Capital Investment Needs of the 21st Century," (with J. Wharton and H. Bishop), prepared for the *National Association of Water Companies*, October 2013.

"Estimating the Cost of Debt," (with T. Brown), prepared for the Dampier Bunbury Pipeline and filed with the *Economic Regulation Authority*, Western Australia, March 2013.

"Estimating the Cost of Equity for Regulated Companies," (with P.R. Carpenter, M.J. Vilbert, T. Brown, and P. Kumar), prepared for the Australian Pipeline Industry Association and filed with the *Australian Energy Regulator* and the *Economic Regulation Authority*, Western Australia, February 2013.

"Calculating the Equity Risk Premium and the Risk Free Rate," (with Dan Harris and Francesco LoPasso), prepared for *NMa and Opta, the Netherlands*, November 2012.

"Shale Gas and Pipeline Risk: Earnings Erosion in a More Competitive World," (with Paul R. Carpenter, A. Lawrence Kolbe, and Steven H. Levine), *Public Utilities Fortnightly*, April 2012.

"Survey of Cost of Capital Practices in Canada," (with Michael J. Vilbert and Toby Brown), prepared for *British Columbia Utilities Commission*, May 2012.

"Public Sector Discount Rates" (with rank Graves, Bin Zhou), *Brattle* white paper, September 2011

"FASB Accounting Rules and Implications for Natural Gas Purchase Agreements," (with Fiona Wang), *American Clean Skies Foundation*, February 2011.

"IFRS and You: How the New Standards Affect Utility Balance Sheets," (with Amit Koshal and Wyatt Toolson), *Public Utilities Fortnightly*, December 2010.

"Corporate Pension Plans: New Developments and Litigation," (with George Oldfield and Urvashi Malhotra), Finance Newsletter, Issue 01, *The Brattle Group*, November 2010.

"Review of Regulatory Cost of Capital Methodologies," (with Michael J. Vilbert and Matthew Aharonian), *Canadian Transportation Agency*, September 2010.

"Building Sustainable Efficiency Businesses: Evaluating Business Models," (with Joe Wharton and Peter Fox-Penner), *Edison Electric Institute*, August 2008.

"Understanding Debt Imputation Issues," (with Michael J. Vilbert and Joe Wharton and *The Brattle Group* listed as an author), *Edison Electric Institute*, June 2008.

"Measuring Return on Equity Correctly: Why current estimation models set allowed ROE too low," *Public Utilities Fortnightly*, August 2005 (with A. Lawrence Kolbe and Michael J. Vilbert).

"The Effect of Debt on the Cost of Equity in a Regulatory Setting," (with A. Lawrence Kolbe and Michael J. Vilbert, and with "*The Brattle Group*" listed as author), *Edison Electric Institute,* April 2005.

"Communication and Delegation in Collusive Agencies," *Journal of Accounting and Economics*, Vol. 19, 1995.

"Beta Distributed Market Shares in a Spatial Model with an Application to the Market for Audit Services" (with M. Hviid), *Review of Industrial Organization*, Vol. 10, 1995.

SELECTED PRESENTATIONS

"Capital Structure and Liability Management," *American Gas Association and Edison Electric Institute Public Utility Accounting Course*, August 2016, 2015, 2014.

"Current Issues in Cost of Capital," *Edison Electric Institute Advanced Rate School*, July 2016, 2015, 2014 and 2013.

"Alternative Regulation and Rate Making Approaches for Water Companies," *Society of Depreciation Professionals Annual Conference*, September 2014.

"Capital Investments and Alternative Regulation," *National Association of Water Companies Annual Policy Forum*, December 2013.

"Accounting for Power Plant," *SNL's Inside Utility Accounting Seminar*, Charlotte, NC, October 2012.

"GAAP / IFRS Convergence," *SNL's Inside Utility Accounting Seminar*, Charlotte, NC, October 2012.

"International Innovations in Rate of Return Determination," *Society of Utility Financial and Regulatory Analysts' Financial Forum*, April 2012.

"Utility Accounting and Financial Analysis: The Impact of Regulatory Initiatives on Accounting and Credit Metrics," 1.5 day seminar, EUCI, Atlanta, May 2012.

"Cost of Capital Working Group Eforum," *Edison Electric Institute webinar*, April 2012.

"Issues Facing the Global Water Utility Industry" Presented to Sensus' Executive Retreat, Raleigh, NC, July 2010.

"Regulatory Issues from GAAP to IFRS," NASUCA *2009 Annual Meeting*, Chicago, November 2009.

"Subprime Mortgage-Related Litigation: What to Look for and Where to Look," *Law Seminars International: Damages in Securities Litigation*, Boston, May 2008.

"Evaluating Alternative Business / Inventive Models," (with Joe Wharton). *EEI Workshop, Making a Business of Energy Efficiency: Sustainable Business Models for Utilities*, Washington DC, December 2007.

"Deferred Income Taxes and IRS's NOPR: Who should benefit?" *NASUCA Annual Meeting*, Anaheim, CA, November 2007.

"Discussion of 'Are Performance Measures Other Than Price Important to CEO Incentives?'" *Annual Meeting of the American Accounting Association*, 2000.

"Contracting and Income Smoothing in an Infinite Agency Model: A Computational Approach," (with R.T. Boylan) *Business and Management Assurance Services Conference*, Austin 2000.

TESTIMONY

Pre-filed Direct Testimony on Cost of Equity and Capital Structure for Anchorage Municipal Wastewater Utility, *Regulatory Commission of Alaska*, Docket No. 158-126, November 2016.

Expert Report on damages (quantum) in exit arbitration (with Dan Harris), *International Center for the Settlement of Investment Disputes*, October 2016.

Direct Testimony on capital structure, embedded cost of debt, and income taxes for Detroit Thermal, Michigan Public Service Commission, Docket No. UE-18131, July 2016.

Direct Testimony on return on equity for Arizona Public Service Company, Arizona Corporation Commission, Docket E-01345A-16-0036, June 2016.

Written evidence, rebuttal evidence and hearing appearance regarding the cost of equity and capital structure for Alberta-based utilities, the Alberta Utilities Commission, Proceeding No. 20622 on behalf of AltaGas Utilities Inc., ENMAX Power Corporation, FortisAlberta Inc., and The ATCO Utilities, February, May and June 2016.

Verified Statement, Verified Reply Statement, and Hearing Appearance regarding the cost of capital methodology to be applied to freight railroads, the *Surface Transportation Board* on behalf of the Association of American Railroads, Docket No. EP 664 (Sub-No. 2), July 2015, September and November 2014.

Direct Testimony on cost of capital submitted to the Oregon Public Utility Commission on behalf of Portland General Electric, Docket No. UE 294, February 2015.

Supplemental Direct Testimony and Reply Testimony on cost of capital submitted to the *Regulatory Commission of Alaska* on behalf of Anchorage Water and Wastewater utilities, Docket U-13-202, September 2014, March 2015.

Expert Report and hearing appearance on specific accrual and cash flow items in a Sales and Purchase Agreement in international arbitration before the *International Chamber of Commerce*. Case No. 19651/TO, July and November 2014. (*Confidential*)

Rebuttal Testimony regarding Cost of Capital before the *Oregon Public Utility Commission* on behalf of Portland General Electric, Docket No. UE 283, July 2014.

Direct Testimony on the rate impact of the pension re-allocation and other items for Upper Peninsula Power Company in connection with the acquisition by BBIP before the *Michigan Public Service Commission* in Docket No. U-17564, March 2014.

Expert Report on cost of equity, non-recovery of operating cost and asset retirement obligations on behalf of oil pipeline in arbitration, April 2013. (*Confidential*)

Direct Testimony on the treatment of goodwill before the *Federal Energy Regulatory Commission* on behalf of ITC Holdings Corp and ITC Midwest, LLC in Docket No. PA10-13-000, February 2012.

Direct and Rebuttal Testimony on cost of capital before the *Public Utilities Commission of the State of California* on behalf of California-American Water in Application No. 11-05, May 2011.

Direct Testimony, Rebuttal Testimony, and Hearing Appearance on cost of capital before the *New Mexico Public Regulation Commission* on behalf of New Mexico-American Water in Case No. 11-00196-UT, May 2011, November 2011, and December 2011.

Direct Testimony on regulatory assets and FERC accounting before the *Federal Energy Regulatory Commission* on behalf of AWC Companies, ER11-13-000/Eli-1-3-000, December 2010.

Expert Report and deposition in Civil Action No. 02-618 (GK/JMF) in the *United States District Court for the District of Columbia*, November 2010, January 2011. (*Confidential*)

Direct Testimony, Rebuttal Testimony, and Rejoinder Testimony on the cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-10-0448, November 2010, July 2011, and August 2011.

Direct Testimony on the cost of capital before *the New Mexico Public Regulation Commission* on behalf of New Mexico-American Water in Docket No. 09-00156-UT, August 2009.

Direct and Rebuttal Testimony and Hearing Appearance on the cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-09-0343, July 2009, March 2010 and April 2010.

Rebuttal Expert Report, Deposition and Oral Testimony re. the impact of alternative discount rate assumptions in tax litigation. *United States Court of Federal Claims*, Case No. 06-628 T, January, February, April 2009. (*Confidential*)

Direct Testimony, Rebuttal Testimony and Hearing Appearance on cost of capital before the *New Mexico Public Regulation Commission* on behalf of New Mexico-American Water in Docket No. 08-00134-UT, June 2008 and January 2009.

Direct Testimony on cost of capital and carrying charge on damages, U.S. Department of Energy, *Bonneville Power Administration*, BPA Docket No. WP-07, March 2008.

Direct Testimony, Rebuttal Testimony, Rejoinder Testimony and Hearing Appearance on cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-08-0227, April 2008, February 2009, March 2009.

Expert Report, Supplemental Expert Report, and Hearing Appearance on the allocation of corporate overhead and damages from lost profit. *The International Centre for the Settlement of Investment Disputes*, Case No. ARB/03/29, February, April, and June 2008 (*Confidential*).

Expert Report on accounting information needed to assess income. *United States District Court* for the District of Maryland (Baltimore Division), Civil No. 1:06cv02046-JFM, June 2007 (*Confidential*)

Expert Report, Rebuttal Expert Report, and Hearing Appearance regarding investing activities, impairment of assets, leases, shareholder' equity under U.S. GAAP and valuation. *International Chamber of Commerce* (ICC), Case No. 14144/CCO, May 2007, August 2007, September 2007. (Joint with Carlos Lapuerta, *Confidential*)

Direct Testimony, Rebuttal Testimony, and Hearing Appearance on cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-06-0491, July 2006, July 2007.

Direct Testimony, Rebuttal Testimony, Rejoinder Testimony, Supplemental Rejoinder Testimony and Hearing Appearance on cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-06-0403, June 2006, April 2007, May 2007.

Direct Testimony, Rebuttal Testimony, Rejoinder Testimony, and Hearing Appearance on cost of capital before *the Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-06-0014, January 2006, October 2006, November 2006.

Expert report, rebuttal expert report, and deposition on behalf of a major oil company regarding the equity method of accounting and classification of debt and equity, *American Arbitration Association*, August 2004 and November 2004. (*Confidential*).

EXHIBITS

Exhibit BV-1: Coal Generation (Nameplate MW)

	Coal Generation	Total Generation	Coal/Total
Allete, Inc.	961	2,394	40%
Ameren Corporation	5,379	11,462	47%
American Electric Power Company, Inc.	19,175	33,187	58%
Duke Energy Corporation	18,581	58,106	32%
Edison International	0	3,238	0%
El Paso Electric Company	0	2,383	0%
Emera Inc.	3,203	9,603	33%
Entergy Corporation	2,645	32,478	8%
FirstEnergy Corporation	10,119	17,098	59%
Fortis Inc.	1,514	4,145	37%
Great Plains Energy Inc.	4,308	7,427	58%
IDACORP, Inc.	1,154	3,649	32%
NextEra Energy, Inc.	1,248	47,560	3%
PG&E Corporation	0	7,675	0%
Pinnacle West Capital Corporation	1,909	7,124	27%
PNM Resources, Inc.	1,073	2,585	41%
Portland General Electric Company	889	4,171	21%
Southern Company	14,938	48,412	31%
Westar Energy, Inc	3,375	6,849	49%
Xcel Energy Inc.	7,709	19,919	39%
Mean	4,909	16,473	31%
Median	2,277	7,551	33%

Source:
SNL Financial

EXHIBIT BV-2: Operating Nameplate Capacity Mix (MW) for Crown and Federal Agencies

	Bonneville Power	Tennessee Valley Authority	BC Hydro	Ontario Power Generation
	[1]	[2]	[3]	[4]
Total Coal	1,704	12,128	0	0
Nuclear	1,190	8,355	0	6,836
Total Natural Gas	1,833	11,455	118	2,660
Oil & Other Petroleium products	0	23	51	0
Other Non-Renewable	0	0	1	0
Total Hydro	22,188	5,427	12,169	7,557
Other Renewable	5,242	2	0	364
Total	**32,157**	**37,390**	**12,338**	**17,417**

Sources:
[1]: https://transmission.bpa.gov/business/operations/wind/baltwg.aspx
[2],[3],[4]: SNL Financial

EXHIBIT BV-3: Net Summer Capacity (MW) data for Regulated, and Merchant generation, including capacity under Power Purchase Agreements

Holding Company	Regulated	Total	Merchant w/ PPA	Merchant w/o PPA	Merchant w/o PPA as a % of Total Capacity
	[1]	[2]	[3]	[4]	[5]
Allete, Inc.	1164	1164	0	0	0%
Ameren Corporation	5118	5118	0	0	0%
American Electric Power Company, Inc.	12406	19261	0	6856	36%
FirstEnergy Corporation	3052	9196	0	6144	67%
Great Plains Energy Inc.	3675	3675	0	0	0%
PNM Resources, Inc.	984	984	0	0	0%
Westar Energy, Inc	3276	3276	0	0	0%

Source:

Velocity Suite, ABB, Inc.

EXHIBIT BV-4a: Estimated Credit Metrics for OPG (based on S&P'S Rating Methodology)($C Millions)

		2015	2016	2017	2018	2019	2020	2021
		[1]	[2]	[3]	[4]	[5]	[6]	[7]
	Revenue Requirement Metrics:							
[a]	Total Rate Base	$9,800	$10,200	$10,800	$11,000	$10,900	$15,100	$15,600
[b]	Return on Equity	2.67%	8.78%	8.78%	8.78%	8.78%	8.78%	8.78%
[c]	Debt Share of Capital Structure	55%	55%	55%	55%	55%	55%	55%
[d]	Equity Share of Capital Structure	45%	45%	45%	45%	45%	45%	45%
[e]	EBITDA	$1,118	$1,158	$1,266	$1,313	$1,342	$1,759	$1,587
	Key Financial Metrics:							
[f]	Funds From Operations (FFO)	$844	$826	$903	$942	$944	$1,251	$1,083
[g]	Cash Flow from Operations (CFO)	$1,151	$1,191	$1,299	$1,346	$1,375	$1,792	$1,620
[h]	Total Debt	$5,713	$5,925	$7,426	$8,276	$8,873	$9,423	$9,523
[i]	Total Equity	$10,045	$10,045	$10,045	$10,045	$10,045	$10,045	$10,045
[j]	Net Interest Expense	$182	$237	$331	$338	$365	$406	$401
	Key Financial Ratios employed by S&P:							
[k]	Debt / EBITDA (x)	5.11	5.12	5.87	6.30	6.61	5.36	6.00
[l]	Predicted Financial Risk based on Debt / EBITDA	Significant	Significant	Significant	Aggressive	Aggressive	Significant	Aggressive
[m]	FFO / Interest (x)	4.64	3.48	2.73	2.79	2.58	3.08	2.70
[n]	Predicted Financial Risk based on FFO / Interest	Intermediate	Intermediate	Significant	Significant	Significant	Intermediate	Significant
[o]	FFO / Debt (%)	14.8%	13.9%	12.2%	11.4%	10.6%	13.3%	11.4%
[p]	Predicted Financial Risk based on FFO / Debt	Intermediate	Intermediate	Significant	Significant	Significant	Intermediate	Significant
[q]	CFO / Debt (%)	20.1%	20.1%	17.5%	16.3%	15.5%	19.0%	17.0%
[r]	Predicted Financial Risk based on CFO / Debt	Modest	Modest	Intermediate	Intermediate	Intermediate	Intermediate	Intermediate

Sources and Notes:
[a]: OPG Ex. L Tab 3.1 Schedule 20 VECC-005 Attachment 1 Table 5 (IRR Issue 3)
[b]: Allowed ROE set by OEB
[e]: Brattle Exhibit BV-5a
[h]: Brattle Exhibit BV-5b; note that we do not follow S&P's Corporate Methodology to deduct surplus cash from our calculation of total debt
[j]: Brattle Exhibit BV-5a
[k]: [h]/[e]
[m]: [f]/[j]
[o]: [f]/[h]
[q]: [g]/[h]

EXHIBIT BV-4b: Estimated Credit Metrics for OPG (based on DBRS' Methodology)($C Millions)

		2015	2016	2017	2018	2019	2020	2021
		[1]	[2]	[3]	[4]	[5]	[6]	[7]
	Revenue Requirement Metrics:							
[a]	Total Rate Base	$9,800	$10,200	$10,800	$11,000	$10,900	$15,100	$15,600
[b]	Return on Equity	2.67%	8.78%	8.78%	8.78%	8.78%	8.78%	8.78%
[c]	Debt Share of Capital Structure	55%	55%	55%	55%	55%	55%	55%
[d]	Equity Share of Capital Structure	45%	45%	45%	45%	45%	45%	45%
[e]	EBIT	$18	$63	$117	$132	$156	$432	$447
	Key Financial Metrics:							
[f]	Total Debt	$5,713	$5,925	$7,426	$8,276	$8,873	$9,423	$9,523
[g]	Total Equity	$10,045	$10,045	$10,045	$10,045	$10,045	$10,045	$10,045
[h]	Interest Expense on Long Term Debt	$285	$293	$384	$388	$414	$454	$449
[i]	Interest Expense on Short Term Debt	$8	$3	$3	$3	$4	$4	$4
[j]	Gross Interest Expense	$293	$296	$387	$391	$418	$458	$453
	Key Financial Ratio employed by DBRS:							
[k]	EBIT / Gross Interest Expense (x)	0.06	0.21	0.30	0.34	0.37	0.94	0.99
[l]	Predicted Credit Rating based on EBIT / Gross Interest Expense	BB/B	BB/B	BB/B	BB/B	BB/B	BB/B	BB/B

Sources and Notes:
[a]: OPG Ex. L Tab 3.1 Schedule 20 VECC-005 Attachment 1 Table 5 (IRR Issue 3)
[b]: Allowed ROE set by OEB
[e]: Brattle Exhibit BV-5a
[f]: Brattle Exhibit BV-5b
[g]: Held constant at 2015 level per OPG's financial statement
[f]: Calculations of The Brattle Group based on OPG forecasted Debt and expected future interest rates
[i]: 2015 value from financial statement; forecast based on OPG Ex. C1-1-3 Table 2
[j]: [h]+[i]
[k]: [e]/[j]

EXHIBIT BV-5a: Derivation of OPG's Forecasted EBITDA, Funds from Operations, and Cash Flow from Operations ($C Millions)

	2015	2016	2017	2018	2019	2020	2021
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
[a] Rate Base	$9,800	$10,200	$10,800	$11,000	$10,900	$15,100	$15,600
[b] ROE		8.78%	8.78%	8.78%	8.78%	8.78%	8.78%
[c] Equity Capitalization	45%	45%	45%	45%	45%	45%	45%
[d] Net Income	$417	$403	$427	$435	$431	$597	$616
[e] Net Income after nwf adjustment (See note)	-$256	-$270	-$246	-$238	-$242	-$76	-$57
[f] Net Interest Expense	$182	$237	$331	$338	$365	$406	$401
[g] Total Tax Liability	$92	$96	$33	$33	$33	$102	$103
[h] Total OPG Depreciation	$1,100	$1,096	$1,149	$1,181	$1,186	$1,327	$1,140
[i] EBIDTA	$1,118	$1,158	$1,266	$1,313	$1,342	$1,759	$1,587
[j] Funds from Operations	$844	$826	$903	$942	$944	$1,251	$1,083
[k] Cash Flow from Operations	$1,151	$1,191	$1,299	$1,346	$1,375	$1,792	$1,620

Sources and Notes:
[a]: OPG Ex. L Tab 3.1 Schedule 20 VECC-005 Attachment 1 Table 5 (IRR Issue 3)
[b]: 8.78% OEB approved ROE
[c]: OPG's allowed equity capitalization as of EB-2013-0321
[d]: [a]x[b]x[c]; 2015 value taken from financial statement
[e]: [d]-673, to be consistent with DBRS in their adjustment for earnings from nuclear waste management
[f]: Calculations of The Brattle Group based on OPG forecasted Debt and expected future interest rates
[g]: Calculations of The Brattle Group with reference to OPG Ex. F4-2-1 Table 2
[h]: Calculations of The Brattle Group with reference to OPG Ex. F4-1-1 Table 2
[i]: [e]+[f]+[g]+[h]
[j]: [i]-[g]-[f]; in accordance with S&P Corporate Methodology
[k]: [e]+[f]+[g]+[h]+33; 33 is the value of OPG's 2015 deferred income tax

EXHIBIT BV-5b: Derivation of OPG's Forecasted Debt ($C Millions)

	2015	2016	2017	2018	2019	2020	2021
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
[a] Planned New Debt Issues	$0	$400	$1,500	$850	$600	$550	$100
[b] Long Term Debt	$5,472	$5,872	$7,372	$8,222	$8,822	$9,372	$9,472
[c] Short Term Debt	$225	$37	$37	$37	$37	$37	$37
[d] Operating Lease Obligations	$16	$16	$17	$17	$14	$14	$14
[e] Total Debt	$5,713	$5,925	$7,426	$8,276	$8,873	$9,423	$9,523

Sources and Notes:
[a]: OPG Ex. C1-1-2 Page 5 of 6
[b]: 2015 value based on OPG Financial Statement; future values calculated as [a] of current year + [b] of prior year
[c]: 2015 value based on OPG Financial Statement; future years taken from OPG Ex. C1-1-3 Table 2
[d]: Forecast provided in 2015 OPG Financial Statement
[e]: [b]+[c]+[d]; we assume a worst case scenario in which debt issues maturing in each period (per Ex. C1-1-2 Page 5) are fully re-issued to pay back their principal amounts

FORM A

Proceeding:... EB-2016-0152...

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Bente Villadsen. I live at Arlington, in the Commonwealth of Massachusetts.

2. I have been engaged by or on behalf of Ontario Energy Board (OEB) to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date ....November 23, 2016.......

Bente Villadsen

Signature