CAPITAL STRUCTURE AND RETURN ON EQUITY

1.0 PURPOSE

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

2.0 CAPITAL STRUCTURE

OPG is seeking approval of the IR term cost of capital as presented in Ex. C1-1-1, Tables 1 through 5. In determining the cost of capital, OPG has applied the capital structure of 50% equity and 50% debt. The proposed capital structure is supported by the findings of the Common Equity Ratio Study carried out by Concentric Energy Advisors at Attachment 1 to this exhibit. The engagement letter executed with Concentric Energy Advisors is filed as Attachment 2 to this exhibit.

The proposed capital structure reflects the material increase in OPG's business risks since EB-2016-0152, primarily driven by: the Darlington Refurbishment Program; the aging and retirement of the Pickering nuclear generating station; the continued shift of OPG's rate base to reflect a greater portion of nuclear assets, combined with the decline in nuclear generation; and increasing climate change risks.

The debt component of OPG's capital structure is determined using the methodologies approved by the OEB in EB-2007-0905, EB-2010-0008, EB-2013-0321, and EB-2016-0152. These are described in Ex. C1-1-2 and Ex. C1-1-3 for long-term and short-term debt, respectively. The capitalization and cost of capital for the 2016-2026 period is summarized in Ex. C1-1-1, Tables 1-11. OPG has applied this capitalization to the rate base, as adjusted to reflect the application of the "lesser of Asset Retirement Costs and Unfunded Nuclear Liabilities" provision applied by the OEB in EB-2007-0905, EB-2010-0008, EB-2013-0321, and EB-2016-0152.

3.0 RETURN ON COMMON EQUITY FOR IR TERM

OPG's Application incorporates an ROE of 8.34% as this is the latest rate published by the OEB (November 9, 2020) pursuant to the ROE formula as set out in *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 2009, EB-2009-0084* ("Cost of Capital Report").

OPG proposes to establish the ROE for the IR term using the prevailing ROE specified by the OEB in accordance with the OEB's Cost of Capital Report as of the effective date of the Payment Amounts Order. Consistent with the OEB's decision and order in the EB-2016-0152 proceeding, OPG proposes to use the same ROE throughout the IR period.[1]

[1] EB-2016-0152, Decision and Order, pp. 110-111.

ATTACHMENTS

Attachment 1: Ontario Power Generation Common Equity Ration Study by Concentric Energy Advisors.

Attachment 2: Executed Engagement Letter for Concentric Energy Advisors

ONTARIO POWER GENERATION COMMON EQUITY RATIO STUDY

DECEMBER 31, 2020

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SECTION 1:
EXECUTIVE SUMMARY

Concentric Energy Advisors, Inc. ("Concentric") was retained to prepare this independent report as to whether the application of the cost of capital approved by the Ontario Energy Board ("OEB" or "Board") in EB-2016-0152 is an appropriate basis for setting Ontario Power Generation's ("OPG's") payment amounts in its next rate application. As the OEB has traditionally accounted for differences in risk through the deemed equity ratio for each regulated utility under its jurisdiction, rather than the authorized return on equity ("ROE"), Concentric's analysis specifically focuses on OPG's capital structure. OPG's next rate application will cover the five-year period from 2022 to 2026.

In our analysis, OPG's risk profile will increase materially during the 2022 to 2026 period, as compared to its risk profile at the time of EB-2016-0152. The most significant risk factors contributing to the increase are: the Darlington Refurbishment Project ("DRP") entering a critical stage of execution; the continued operation of aging nuclear units; the retirement of the Pickering nuclear station; the continued shift of OPG's rate base to reflect a greater portion of nuclear assets, combined with an increase in the financial value of each unit of nuclear output; and increasing climate change impacts. Given the increased risk profile, and OPG's higher risk relative to other utilities that have equity ratios at the regulated operating company level that average from 49.5% to 55.9%, Concentric recommends that an equity ratio of no less than 50% be set for OPG in the upcoming proceeding.

Concentric followed the OEB's preferred approach to assessing capital structure for the utilities it regulates by performing a detailed risk analysis of OPG, along with the changes to OPG's risk profile and an assessment of the impact of current market conditions on the cost of capital. Concentric also examined OPG's relative risk and equity ratio compared to other utilities. In addition, Concentric considered OPG's current capital structure for consistency with the three components of the fair return standard: (1) the comparable investment standard; (2) the financial integrity standard; and (3) the capital attraction standard. Concentric's analysis also included a review and consideration of the Board's prior findings with regard to OPG's equity thickness. In consideration of those findings, Concentric's report provides further context and analysis regarding the drivers of risk for OPG and the comparability of U.S. and Canadian regulatory regimes.

Our recommended equity ratio for OPG in the upcoming rate setting period is set at a level that balances the results of our analysis, which indicates heightened risk for OPG on an absolute basis and

in comparison to peer companies and supports an equity ratio at the high end of the range of reasonable results (*i.e.*, 55% to 56%), with the OEB's prior findings. In our view, the recommended 50% is the minimum appropriate equity ratio for OPG. This is particularly important as the allowed return on equity ("ROE") by the OEB, currently 8.34%, is below the allowed ROEs for the proxy group companies.

Canadian Versus U.S. Historical Equity Ratios

The OEB found in EB-2016-1052 that an adjustment was appropriate for U.S.-derived equity ratios due to the historical difference between authorized equity levels for Canadian and U.S. utilities. As discussed herein, Concentric's conclusion in this report is that an adjustment for differences in the allowed equity ratios between Canada and the U.S. is not necessary at this time (and on a forward-looking basis) because the business risk, including regulatory risk, for regulated utilities in the two countries is comparable, and the investment community's view is that any regulatory risk differential between the countries has narrowed significantly, if not disappeared. This view is supported by our interviews with equity and credit analysts covering the North American utility industry who indicated that any differences in business risk, including regulatory risk, between utilities in Canada and the U.S. are not sufficient to justify the historically wide gap in equity ratios between the two countries.

Based on this analysis, it is Concentric's view that an adjustment based on the existence of a historical difference between Canadian and U.S. deemed equity ratios would be inconsistent with the market's current views on cross-border business risk comparability, including regulatory risk, and would be inappropriate for purposes of setting OPG's regulatory capital structure on a forward-looking basis.

Business and Financial Risk Analysis

Concentric's risk analysis focuses on: (a) the impact of current economic conditions on the cost of capital; (b) changes to OPG's business and financial risks since EB-2016-0152; (c) expected changes to OPG's risk profile and financial integrity on a forward-looking basis, consistent with how an investor would analyze OPG; and (d) for comparative purposes, a review of capital structure data for similar North American electric utilities. Because OPG's regulated capital structure is reflective of its overall risk profile related to the regulated operations, Concentric's analysis considered both the nuclear and hydroelectric businesses and their attendant risks.

Economic Environment

In terms of the current economic environment and its impact on the cost of capital, several factors are at work. On the equity side, and notwithstanding the low government bond yields discussed below, sustained volatility in publicly traded equity markets in both Canada and the U.S. has made investors more risk-adverse and safety conscious. In prior periods of market disruption, utilities have served as a safe haven for investors, but the ongoing COVID-19 pandemic, along with slumping demand and disruption to business plans, has left investors uncertain of the outlook for utilities. Utility betas, which measure the movement of individual stock prices in relation to the overall market, are well above their historical norms, and market indicators signal that the cost of equity for utilities has increased during the pandemic.

Applied to the OEB's framework for determining the cost of capital, the decline in the government bond yields is reflected in a decrease in allowed ROE from 8.52% for the 2020 year to 8.34% for the 2021 year, per the OEB's most recent update to the cost of capital parameters. This will place the allowed ROE in Ontario below that of any other North American regulatory jurisdiction, at a time when market views of utility risk appear to be increasing. For OPG specifically, the reduction in the allowed ROE will negatively affect OPG's credit metrics at a time when they are already expected to be pressured.

Business and Financial Risks

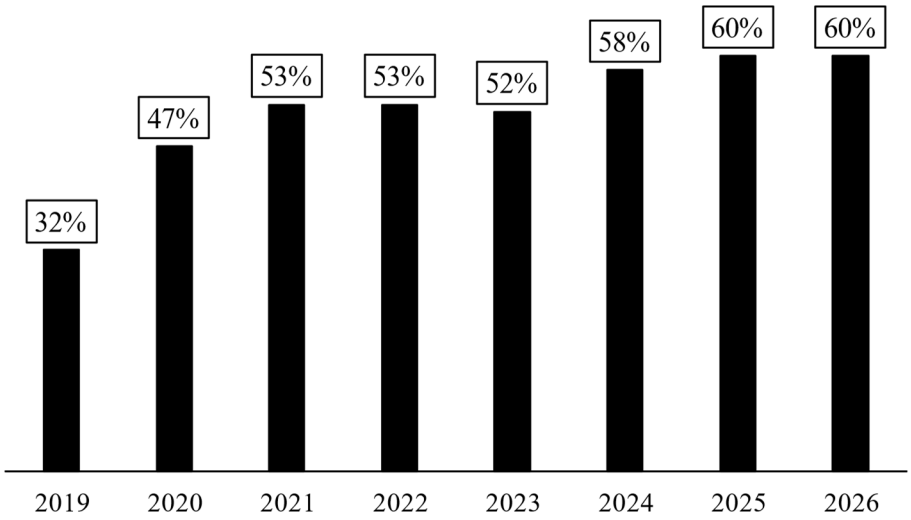
With regard to business and financial risks, Concentric reaches the following summary conclusions.

- OPG continues to be at risk for variability in the output at its nuclear plants, a factor that distinguishes OPG from other North American regulated generators. This risk pervades and compounds OPG's other nuclear risks, discussed below.
- OPG is in the process of refurbishing the four-unit Darlington nuclear station as part of a $12.8 billion "megaproject". OPG is subject to increased risk related to the DRP, compared to EB-2016-0152, due to new project execution risks in the upcoming rate-setting period, including the execution of new first-of-a-kind ("FOAK") scope, managing overlapping unit refurbishments, trades availability and constraints due to the COVID-19 pandemic.
- While the OEB found in EB-2016-0152 that the protections provided by Ontario Regulation 53/05 ("O. Reg. 53/05") mitigate OPG's risk related to the DRP, Concentric observes that the same is true for other North American nuclear generation owners that are undergoing large nuclear construction projects and have higher equity ratios than OPG. This report provides a

summary of legislative and regulatory mechanisms available in other jurisdictions, and how those mechanisms have protected (or failed to protect) the utility nuclear owners. As such, Concentric's recommended minimum equity ratio for OPG takes into account the risk reducing provisions for the DRP under O. Reg. 53/05. The recommendation also considers the impact of OPG's other material deferral and variance accounts related to the nuclear business.

- The majority of OPG's nuclear fleet is nearing the end of its current operating life, with the Pickering station set to end commercial operation during the upcoming rate period and Darlington units requiring refurbishment as they reach end of 'first' life during the period. Therefore, OPG faces an inherently increasing risk related to variability in generation output due to the aging of its nuclear stations, which can lead to significant revenue shortfalls.
- In addition to the increased generation risk leading up to the end of the station's commercial operations, the shutdown and retirement of Pickering, comprising 60% of the company's operating nuclear reactors and served by thousands of employees, in the upcoming rate period presents new and unique challenges for OPG related to significant disruptive organizational changes that can impact operational performance, increase forecast risk and reduce the diversification of OPG's nuclear fleet.
- OPG's regulated asset mix will continue to shift towards a higher proportion of nuclear assets, which, as the OEB previously found, are riskier than the hydroelectric business. Upon completion of the DRP in 2026, nuclear generation operations are projected to comprise approximately 60% of OPG's overall regulated rate base, compared to 32% as of December 31, 2019.

Figure 1: Nuclear Portion of OPG's Rate Base Over Time[1]



The OEB found in EB-2016-0152 that, because *output* from OPG's nuclear fleet was not increasing, the risk of OPG had not necessarily increased as a result of the changing rate base mix.[2] This report discusses that the *investment in plant*, which is ultimately recovered over output through the payment amounts, is the critical determinant of risk, notwithstanding changes in the relative output. In OPG's case, the significant increase in relative investment in the nuclear fleet to be recovered drives the additional risk, even though the ratio of nuclear to hydroelectric generation output is not expected to increase.

This report also discusses that the *decline* in nuclear generation output due to the DRP and ultimately from the retirement of the Pickering station over the upcoming rate period creates *additional risk*. This is because each MWh of nuclear generation will become more financially valuable to OPG as the nuclear generation output that recovers the nuclear revenue requirement is reduced, while continuing to be more financially valuable than each MWh of hydroelectric generation.

For the above reasons, Concentric concludes that the increase in OPG's nuclear rate base (both in absolute terms and relative to the total) combined with the decline in nuclear

1 Excluding the provision for lesser of nuclear asset retirement costs and unfunded nuclear liability, which is consistent with the OEB-approved methodology for calculating OPG's rate base subject to the weighted average cost of capital for purposes of setting payment amounts. Nuclear rate values are subject to filing of OPG's final rate application with the OEB. Hydroelectric rate base is estimated based on OPG's Amended 2020-2026 Business Plan.

2 EB-2016-0152 Decision and Order, at 101-102.

generation will increase OPG's risk profile over the next five years over-and-above its level of business risk in the prior payments amounts application.

- Risks to both OPG's prescribed nuclear and hydroelectric operations from climate change have increased from the prior rate proceeding, including the risk of increased capital expenditure needs due to the threat of climate driven impacts on the company's infrastructure and systems. The maintenance of hydroelectric base payment amount at the 2021 levels pursuant to a recent amendment to O. Reg. 53/05 will also increase inflationary risk for OPG.
- Concentric believes OPG's financial risk will increase in the period from 2022 to 2026, as illustrated by the pressure on, and potential decline below current credit rating thresholds of, key credit metrics in the earlier years of the period. The credit metrics will be impacted by rate smoothing outcomes in the upcoming rate application.

Concentric concludes that, taken as a whole, this shift in risk profile since the time of EB-2016-0152 is sufficient to warrant a reassessment of OPG's equity ratio.

Equity Ratio Analysis and Recommendation

In terms of the comparable return requirement of the fair return standard, Figure 2 and Figure 3 below provide the average and median range of common equity ratios for two proxy groups of comparable utilities, including actual book equity ratios and regulated authorized equity ratios.

Figure 2: Summary of Comparative Analysis Results (Concentric Proxy Group)

Analytical Approach	Mean Equity Ratio	Median Equity Ratio
Holding Company Equity Ratios: 5-Year Avg.	45.7%	47.4%
Operating Company Equity Ratios: 5-Year Avg.	52.8%	53.0%
Operating Company Equity Ratios: Authorized	49.5%	49.6%

Figure 3: Summary of Comparative Analysis Results (Moody's Peer Group)

Analytical Approach	Mean Equity Ratio	Median Equity Ratio
Holding Company Equity Ratios: 5-Year Avg.	50.6%	49.1%
Operating Company Equity Ratios: 5-Year Avg.	55.9%	53.6%
Operating Company Equity Ratios: Authorized	50.7%	50.1%

As shown in the Figure 2 and Figure 3, the average range of equity ratios is from 45.7% to 55.9%. This range includes equity ratios at both the holding company level (i.e., reflecting a diverse mix of

regulated entities and some non-regulated risk) and the exclusively regulated operating company level, which is the appropriate point of comparison for OPG's regulated operations. Focusing only on equity ratios at the regulated operating company level provides a narrower range of 49.5% to 55.9%, and even a narrower range of regulatory authorized equity ratios from 49.5% to 50.7%.

OPG's current equity ratio of 45% is below those ranges despite OPG's elevated level of risk relative to the proxy groups. The relative elevated risk reflects OPG's significant nuclear concentration, as well as its status as the only pure generation utility in the group, particularly when combined with its financial risks relative to the proxy groups and the revenue risk it faces related to nuclear output variability. On this latter point, OPG's being entirely at risk related to variability in the output of its nuclear facilities distinguishes it from other utilities, as the companies in the proxy group do not face comparable risk. On this basis, we believe OPG falls toward the upper end of the risk spectrum, reasonably supporting an equity ratio of 55% to 56% (*i.e.*, at the upper end of the proxy group results).

For this upcoming rate setting period, however, Concentric conservatively recommends an equity ratio of no less than 50% for OPG. This recommendation balances considerations related to OPG's heightened risk profile and proxy group position with the Board's findings in EB-2016-0152, as discussed herein.

Witness Duty

We acknowledge that it is our 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 OEB may reasonably require, to determine a matter in issue.

We acknowledge that the duty referred to above prevails over any obligation which we may owe to any party by whom or on whose behalf we are engaged.

SECTION 2:
SCOPE OF ANALYSIS AND OVERVIEW OF CONCENTRIC

Scope

Concentric was retained to prepare this independent report as to whether the application of the cost of capital approved by the OEB in EB-2016-0152 is an appropriate basis for setting payment amounts in OPG's next rate application. Concentric's analysis specifically focused on OPG's capital structure. In preparing this report, Concentric performed the following assessment:

1. Examined the OEB's decisions in EB-2007-0905, EB-2010-0008, EB-2013-0321 and EB-2016-0152 to understand the OEB's analysis and findings in past cases regarding OPG's cost of capital;
2. Analyzed OPG's business and financial risks since EB-2016-0152 and on a forward-looking basis consistent with how an investor would analyze OPG's risk profile;
3. Examined the capital structures of a proxy group of comparable companies; and
4. Determined an appropriate capital structure for OPG.

Overview of Concentric

Concentric is a management consulting and economic advisory firm, focused on the North American energy industry. Based in Marlborough, Massachusetts, Washington, D.C., and Calgary, Alberta, Concentric specializes in regulatory and litigation support, transaction-related financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses. The firm provides financial, economic and regulatory advisory services to clients across North America, including utility companies, regulatory and public agencies, and utility sector investors. Concentric has advised energy industry participants on the purchase and sale of nuclear facilities, hydroelectric facilities, and other generation assets, and we have served in an independent monitoring or project advisory function on major capital projects at several nuclear generating units in North America. Concentric also has experience relating to major refurbishment work on nuclear power life cycle management and extended power uprates in the U.S. and Canada. Concentric has provided expert testimony on the cost of capital in more than 100 regulatory proceedings in Canada and the U.S. over the past five years.

James Coyne, Senior Vice President at Concentric, and Daniel Dane, also a Senior Vice President at Concentric, coauthored this report with assistance from other Concentric staff. Mr. Coyne is a senior

expert who provides testimony before Canadian provincial and U.S. federal and state agencies on matters pertaining to economics, finance, and public policy in the energy industry. He regularly advises utilities, generating companies, public agencies and private equity investors on business issues pertaining to the utilities industry. This work includes determining the cost of capital for the purpose of ratemaking and providing expert testimony and studies on matters pertaining to incentive regulation, rate policy, valuation, capital costs, fuels and power markets. He has advised both buyers and sellers in numerous transactions involving hydroelectric, nuclear, fossil and renewable generation facilities, and worked with companies to develop strategies for acquiring these assets. He has testified or provided expert evidence before state, provincial and federal jurisdictions across Canada and the U.S. This work has been provided on behalf of utilities, regulatory commissions and staff.

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

He holds a B.S. in Business Administration from Georgetown University and a M.S. in Resource Economics from the University of New Hampshire.

Mr. Dane has advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of those assignments have included the determination of the cost of capital. Mr. Dane has also provided expert testimony on regulated ratemaking matters, including the cost of capital, for investor-owned utilities and regulatory agencies. Mr. Dane coauthored "A Comparative Analysis of Return on Equity of Natural Gas Utilities" with Mr. Coyne on behalf of the OEB, as discussed above. Mr. Dane has provided sell-

side support for approximately $2 billion in generating asset transactions in the U.S., including nuclear generating facilities, and has been a significant contributor to numerous assignments at Concentric involving independent evaluations of nuclear plant construction project commercial strategies, project controls and management oversight, and new power plant development. Mr. Dane has an MBA from Boston College in Chestnut Hill, Massachusetts and a BA in Economics from Colgate University in Hamilton, New York. Mr. Dane is a certified public accountant, and is a licensed securities professional (Series 7, 28, 63, 79, and 99). Mr. Dane also serves as the Financial and Operations Principal of CE Capital Advisors, a FINRA-Member firm and a subsidiary of Concentric.

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

SECTION 3:
BACKGROUND ON PRIOR OEB DECISIONS

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

EB-2007-0905

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

With regard to the capital structure, the OEB stated: "The Board finds that the approach to setting the capital structure should be based on a thorough assessment of the risks OPG faces, the changes in OPG's risk over time and the level of OPG's risk in comparison to other utilities."[3] The OEB further concluded that it would apply the stand-alone principle in establishing the capital structure for OPG, noting that "[t]he stand-alone principle is a long-established regulatory principle,"[4] and that "Provincial ownership will not be a factor to be considered by the Board in establishing capital structure."[5] The OEB determined that a 47% equity ratio was appropriate for OPG, finding that OPG was of higher risk than any other Ontario energy utility but of lower risk than merchant generators.[6]

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

At the time of EB-2007-0905, OPG owned and operated six prescribed hydroelectric generating stations (Sir Adam Beck I and II, Sir Adam Beck Pump Generating Station, DeCew Falls I and II, and R.H. Saunders), and three prescribed nuclear generating stations (Pickering A, Pickering B, and Darlington).[7]

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3 EB-2007-0905, Decision with Reasons, November 3, 2008, at 136.
4 *Ibid.*, at 140.
5 *Ibid.*, at 142.
6 *Ibid.*, at 149-150.
7 References to the "Pickering station" throughout the report encompass the Pickering A and Pickering B stations as prescribed under O. Reg. 53/05.

EB-2009-0084

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

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

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

With respect to capital structure, the OEB found that its current policy for all regulated utilities, which was developed in March 1997, continued to be appropriate. The decision in EB-2009-0084 states:

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8 EB-2009-0084, Report of the Board, December 11, 2009, at i.
9 *Ibid.*, at 19-20.

"As noted in the Board's draft guidelines, capital structure should be reviewed only when there is a significant change in financial, business or corporate fundamentals."[10]

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

In 2016, the OEB issued an OEB Staff Report regarding the OEB's cost of capital policy. In that report, OEB Staff concluded that no changes were to be made to the policy at that time.[12]

EB-2010-0008

OPG's generation asset mix as of EB-2010-0008 was at approximately 38% nuclear and 62% hydroelectric, based on OEB-approved rate base for the prescribed facilities (excluding the lesser of nuclear asset retirement costs and unfunded nuclear liability), which was approximately the same as it had been as of EB-2007-0905. In its March 11, 2011 decision in EB-2010-0008, the OEB found that "there is no evidence of any material change in OPG's business risk and that the deemed capital structure of 47% equity and 53% debt, after adjusting for the lesser of Unfunded Nuclear Liabilities or Asset Retirement Costs, remains appropriate."[13]

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

In addition, while the issue was identified by the OEB in the context of technology-specific capital structures, the OEB recognized an emerging issue, noting that "[a]s the relative size of the hydroelectric and nuclear businesses changes (through major additions to rate base, for example) the issue will arise as to whether the overall ratio of 47% is to remain unchanged."[14]

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10 *Ibid.*, at 49.
11 *Ibid.*, at 25.
12 EB-2009-0084, OEB Staff Report, January 14, 2016, at 1.
13 EB-2010-0008, Decision with Reasons, March 10, 2011, at 116.
14 *Ibid.*, at 117.

EB-2013-0321

In EB-2013-0321, the OEB found that OPG's business risks had changed, primarily pointing to the addition of 48 hydroelectric assets to OPG's regulated assets and the then recently completed Niagara Tunnel Project. Specifically, the OEB found that the addition of hydroelectric assets and the Niagara Tunnel Project "increase the proportionate share of rate base related to hydroelectric facilities from about half in 2010 to approximately two-thirds now [*i.e.*, as of EB-2013-0321]."[15]

As a result of these findings, the OEB lowered the equity ratio for OPG from 47% to 45%. Specifically, the OEB stated, "…[t]he Board has determined that business risk has changed for this payment setting period, and that the business risk is reduced. The business risk is reduced because of the addition of significant hydroelectric assets to rate base, which are less risky than nuclear assets."[16]

In addition, the OEB found that, at the time of EB-2013-0321, moving to incentive regulation did not significantly increase risks to OPG such that the capital structure should be reset, noting that the capital structure for Ontario's electricity and gas distributors had not been reset when they moved to incentive regulation. The OEB did note, however, that part of its decision was based on the fact that OPG was not moving to incentive regulation in EB-2013-0321, and that "any potential changes to business risk this may entail could be considered in the incentive regulation proceeding."[17]

EB-2016-0152

The OEB left OPG's equity ratio unchanged in its decision and order in EB-2016-0152. The OEB continued to find that nuclear generation presents more business risks than hydroelectric generation, and that OPG's nuclear rate base would "increase substantially over the five-year term of [of the period over which rates were being set],"[18] but noted that nuclear generated MWh will not increase relative to hydroelectric MWh. The OEB further found that OPG's nuclear-specific risks were mitigated by factors including "various protections provided by O. Reg. 53/05 and the variance and deferral accounts that allow OPG to recover substantially all their unexpected or unforeseen costs."[19] The OEB also found that the move to incentive regulation would not add significant risk to OPG noting that there was no new evidence to the contrary, and that given OPG's planning of the DRP and certain regulatory protections under O. Reg. 53/05, the risks of the DRP were also controlled. Additionally, the OEB commented on the use of U.S. companies in the proxy group for OPG, noting that Canadian

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15 EB-2013-0321, Decision with Reasons, November 20, 2014, at 113. Clarification added.
16 *Ibid*., at 114.
17 *Ibid*.
18 EB-2016-0152, Decision and Order, December 28, 2017, at 102. Clarification added.
19 *Ibid*.

ratemaking equity ratios tend to be lower that U.S. ratemaking equity ratios and that, in EB-2016-0152, an adjustment should have been made to the U.S. companies' equity ratios to account for that divergence. The OEB also noted that given its findings in the decision related to OPG's plan for Pickering extended operations beyond 2020 and the regulatory protections under O. Reg. 53/05, the associated risks, including a determination that Pickering extended operations may not proceed, were unlikely to materialize.

SECTION 4:
PRINCIPLES FOR A FAIR RETURN

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

> *By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.*[20]

As stated by Major and Priddle in 2008, this definition remains in full legal effect today.[21]

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

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

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

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

[20] Northwestern at 193.

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

assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

With the passage of time, the fair return standard has been interpreted many times in both Canada and the U.S. In Canada, the National Energy Board ("NEB", predecessor to the Canadian Energy Regulator) summarized its interpretation of the "fair return standard" in its RH-2-2004 Phase II Decision and more recently reiterated that interpretation in its Trans Québec & Maritimes Pipelines Inc. RH-1-2008 Decision, at pp. 6-7.

The [NEB] is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:

- *be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);*
- *enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and*
- *permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).*

In the [NEB]'s view, the determination of a fair return in accordance with these enunciated standards will, when combined with other aspects for the Mainline's revenue requirement, result in tolls that are just and reasonable.[22]

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

The Board affirms its view that the Fair Return Standard frames the discretion of a regulator, by setting out the three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. Notwithstanding this obligation, the Board notes that the Fair Return Standard is sufficiently broad that the regulator that applies it must still use informed

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

> *judgment and apply its discretion in the determination of a rate regulated entity's cost of capital.*

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> *… all three standards or requirements (comparable investment, financial integrity, and capital attraction) must be met and none ranks in priority to the others. The Board agrees with the comments made to the effect that the cost of capital must satisfy all three requirements which can be measured through specific tests and that focusing on meeting the financial integrity and capital attraction tests without giving adequate comparability to the comparable investment test is not sufficient to meet the [Fair Return Standard].*[23]

Canadian regulatory authorities, including the OEB, have also determined that another key principle in establishing a fair return on equity for a regulated utility is the "stand-alone" principle. The OEB's specific findings with regard to the stand-alone principle for OPG are included above in the summary of EB-2007-0905.

Furthermore, the OEB has recognized that the cost of capital is a forward-looking concept. For example, in its decision in EB-2009-0084, the OEB referenced a presentation by Dr. Bill Cannon at CAMPUT's 2009 Energy Regulation Conference during which Dr. Cannon explained the forward-looking nature of the cost of capital as follows: "First, it [the cost of capital] is forward looking. Investment returns are inherently uncertain and the ex post, actual returns experienced by investors may differ from those that were expected ahead of time. The cost of capital is therefore an *expected* rate of return."[24] Elsewhere in that same decision, the OEB stated: "First, the Board notes that the [Fair Return Standard] expressly refers to an opportunity cost of capital concept; one that is prospective rather than retrospective."[25] In other words, investors establish their return requirements based on expectations regarding economic growth, inflation, interest rates, the market risk premium and other factors affecting future risks and opportunity costs.

Investors also consider the business and financial risks of a particular company relative to other similarly situated companies in the same industry. For example, as mentioned previously, the OEB has expressed its view that "the capital attraction standard, indeed the [Fair Return Standard] in totality, will be met if the cost of capital determined by the Board is sufficient to attract capital on a

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[23] Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at i and 19.
[24] *Ibid.*, at 25.
[25] *Ibid.*, at 19.

long-term sustainable basis given the opportunity costs of capital."[26] Further, the OEB has determined that "[t]he comparable investment standard requires empirical analysis to determine the similarities and differences between rate-regulated utilities." However, the assessment of comparability "does not require that those entities be 'the same'."[27]

[26] *Ibid.*, at 20.
[27] *Ibid.*, at 21.

SECTION 5:
CANADIAN VERSUS U.S. HISTORICAL EQUITY RATIOS

In its EB-2016-0152 decision and order, the OEB determined that "on balance an increase in OPG's equity thickness is not necessary in order for the fair return standard to be met."[28] With respect to the information presented by both Concentric (on behalf of OPG) and the Brattle Group (on behalf of the OEB Staff) regarding the allowed equity ratio for the U.S. proxy group and the authorized equity ratios for Canadian investor-owned utilities, the OEB wrote: "The OEB finds that an adjustment to the comparator group data should have been made by both experts to account for the substantially lower common equity ratios allowed regulated utilities in Canada."[29]

In considering this matter in this report, Concentric's analysis is that while the average allowed equity ratio for U.S. utilities is higher than the average deemed equity ratio for Canadian utilities, this wide differential is not currently explained by differences in business risk, including regulatory risk. For example, equity and credit analysts have acknowledged that while they previously considered U.S. utilities to have higher business and regulatory risk than Canadian regulated utilities, that perception has changed in recent years as U.S. utilities have been granted a broader suite of cost recovery mechanisms and adjustment clauses that reduce regulatory lag and provide similar risk mitigation to that of their Canadian counterparts. Equity analysts have also indicated that they view the regulatory environment in Canada and the U.S. as being similar, and that U.S. regulation has been providing more timely cost recovery and reducing regulatory lag in recent years.

For example, a March 2019 report by equity analysts at Scotiabank indicated that they view the regulatory environments in Canada and the U.S. as being similar for regulated utilities. In explaining why they expect the valuations of Canadian and U.S. utilities to converge, Scotiabank observed:

> *Historically, the Canadian utilities have traded at a discount to their mid-cap U.S. peers. We attribute this to the historical view that Canadian regulation was superior to U.S. regulation (we no longer have that view) as well as to strong earnings growth in part due to M&A.*[30]

This continues a trend that started approximately ten years ago. For example, in a September 2013 report, Moody's Investors Service ("Moody's") explained its changing view on the relative risk of U.S.

[28] EB-2016-0152, Decision and Order, December 28, 2017, at 109.
[29] *Ibid*.
[30] Scotiabank Equity Research Spotlight, Energy Infrastructure, March 18, 2019, at 9. Emphasis added.

and Canadian utilities as follows:

> *Based on our observations of trends and events, we propose to adopt a generally more favorable view of the relative credit supportiveness of the US regulatory environment. Our updated view considers improving regulatory trends that include the increased prevalence of automatic cost recovery provisions, reduced regulatory lag, and generally fair and open relationships between utilities and regulators.*[31]

In support of this changing view on the relative risk of the US regulatory environment, Moody's noted the following developments:

- "We believe that many US regulatory jurisdictions have become more credit supportive of utilities over time and that the assessment of the regulatory environment in the US that has been incorporated in the ratings may now be overly conservative."[32]
- "While we had previously viewed individual state regulatory risks for US utilities as being higher than utilities in most other developed countries (where regulation usually occurs at the national level), we have observed an overall decrease in regulatory risk in the US."[33]
- "There have been a number of favorable regulatory changes in recent years. For example, the increasing prevalence of riders, trackers and other automatic cost recovery provisions in the US has reduced the amount of time between when a utility incurs and recovers costs, or 'regulatory lag.' These changes have happened incrementally – jurisdiction by jurisdiction or even issuer by issuer. We now believe that these changes, in aggregate, represent a significant improvement in the timeliness of cost recovery."[34]
- "We believe the majority of US utilities enjoy relatively fair and open relationships with their regulators, and that most regulators strive to maintain reliable, financially viable utilities in their states while balancing the needs of the state's commercial, industrial and residential utility customers."[35]
- "A comparison of key financial ratios used under the Regulated Electric and Gas Utilities Rating Methodology in rating utilities across developed international jurisdictions with credit supportive regulatory frameworks (including Canada and Japan) shows that US regulated

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31 Moody's Investors Service, Proposed Refinements to the Regulated Utilities Rating Methodology and Our Evolving View of US Utility Regulation, September 23, 2013, at 1.
32 *Ibid*., at 4.
33 *Ibid*.
34 *Ibid*.
35 *Ibid*.

utilities in recent years have exhibited stronger financial ratios relative to similarly rated regulated international utility peers."[36]

In order to supplement our assessment of how investors perceive the regulatory environment for utilities in Canada and the U.S., Concentric conducted interviews in October and November 2020 with equity and credit analysts who cover the North American utility industry to discuss their views regarding the regulatory environment in Canada and the U.S.[37] The interviews focused on the following questions: 1) whether the analysts factor country risk into their analysis/rating; 2) whether they see the Canadian regulatory environment as providing any more or less risk protection and support to utilities than the U.S. regulatory environment, and if so, what specific factors lead to this conclusion; 3) whether they factor in state/provincial level regulatory risk in their analysis; 4) whether they view the Ontario regulatory environment as more or less favorable than other Canadian provinces and U.S. states; 5) whether they view electric generation as more or less risky than electric transmission and distribution ("T&D"); 6) whether they view nuclear generation as more or less risk than other types of electric generation; and 7) whether they see differentials in equity ratios between Canadian and U.S. utilities as being justified by differences in business and regulatory risk in Canada or Ontario as compared to the U.S.

Importantly, while many analysts continue to view the Canadian regulatory environment as somewhat more favorable for regulated utilities than the U.S. regulatory environment, the situation in Canada is seen as being static, while the U.S. landscape is viewed as having improved in recent years through the more frequent use of forward test years, revenue decoupling mechanisms, and capital cost recovery mechanisms that have reduced regulatory lag and enhanced the ability of U.S. utilities to earn their authorized ROE. Further, equity and credit analysts do not see the differential in deemed equity ratios between Canada and the U.S. as being justified by differences in business or regulatory risk. In addition, it was clear from our interviews that equity and credit analysts see the utility industry as a North American industry, and that any differences are more likely to be observed between specific provinces/states than between the two countries. The differences between specific provinces and states are viewed as being very narrow, and most Canadian provinces and U.S. states are seen as credit supportive for regulated utilities, with only minor gradations between those that are most credit supportive and those that are less credit supportive. Lastly, equity and credit analysts

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36 *Ibid*., at 5.

37 Survey participants included: Robert Hope, equity analyst – Scotiabank; Robert Kwan, equity analyst – RBC Capital Management; Ben Pham, equity analyst – Bank of Montreal; Andrew Ng, Gerrit Jepsen, and Obioma Ugboaja, credit analysts – S&P Global Ratings; and Gavin MacFarlane, credit analyst – Moody's Investors Service

agreed that ownership of electric generation assets is more risky than electric transmission and distribution operations, and that nuclear generation is the riskiest type of generation. The last finding is further supported by Appendix A, in which excerpts from S&P Global Ratings ("S&P") reports illustrate that agency's views on the high-risk nature of nuclear operations.

The following section provides more specific details regarding how the analysts we interviewed view the risk profiles of the utilities they cover and the regulatory environment in which those utilities operate.

> Country risk: Equity and credit analysts who participated in the survey indicated that they view Canada and the U.S. as having the same or very similar country risk. They do not distinguish between the two countries on the basis of country risk unless there is a large divergence in the risk-free rate (i.e., wider than the current gap of 20 basis points for the 10 year government bond). They tend to consider country risk as a factor in their investment analysis when they are comparing Canada and the U.S. to other countries outside North America, in particular emerging markets.
>
> Comparing Canadian and U.S. regulatory environment: Equity and credit analysts tend to see the Canadian regulatory environment as somewhat more favorable than in the U.S. However, most analysts noted that the U.S. regulatory environment has improved in recent years U.S. due to the increased use of forward test years, revenue decoupling mechanisms, and approval of cost recovery mechanisms that improve the timeliness of cost recovery for capital investments and infrastructure replacement projects. Several analysts expressed the view that it is more important to consider differences between specific jurisdictions instead of drawing more general conclusions about the two countries. Also, it was observed that the regulatory environments in Canadian provinces are more homogeneous than in the U.S., and that there are a number of U.S. jurisdictions that compare favorably to Canadian jurisdictions in terms of providing support for timely cost recovery and the ability to earn the authorized return. Credit analysts in particular were more focused on whether the regulatory environment provided regulatory and financial stability, and whether there was regulatory independence and a lack of political interference, than on whether one jurisdiction was more supportive than another. Equity analysts tended to focus on whether the utility is able to earn its authorized return and generate predictable earnings and cash flows. One analyst commented that he believes the higher authorized ROEs in the U.S. help to offset the greater regulatory lag in certain states. The prevalence of cost disallowances was another factor noted by both equity and credit analysts as a consideration (and as a concern for OPG in particular).
>
> Influence of regulatory risk on investment analysis: One equity analyst observed that utilities in more favorable jurisdictions receive higher valuations, while those in less favorable jurisdictions receive lower valuations. Another equity analyst indicated

that his firm's top utility recommendation was a Canadian company that had more than half its assets in a U.S. subsidiary that operates in a state that allows relatively high ROEs, support for rate base investment, and strong customer relationships that result in settlement agreements. At the same time, they have a less favorable outlook on another Canadian utility company given its material exposure to a jurisdiction that has among the lowest authorized ROEs in the country and stranded asset risk. Credit analysts reiterated their view that differences in regulatory risk between jurisdictions were relatively small and that regulation provides an overall credit supportive environment for all utilities in both Canada and the U.S.

Equity ratio differential: The equity analysts expressed the view that the equity ratio differential between Canada and the U.S. is not justified by differences in business or regulatory risk between the two countries. In particular, one equity analyst commented that the equity thickness and ROE in Ontario are inferior to many other jurisdictions, especially those in the U.S. While this difference historically was acceptable, the analyst saw the improving regulatory framework in the U.S. as cause for concern that the low equity thickness and ROE in Ontario could lead to challenges in incenting capital to flow to the province. Another equity analyst observed that the equity thickness gap has not narrowed between Canada and U.S., and that he would prefer that the equity ratio gap be lowered.

Generation vs. T&D operations risk: The equity and credit analysts who we interviewed agreed that companies that own electric generation assets have greater risk than T&D utility companies. Among the reasons cited for this higher risk profile were: increased operational risk, greater risk of economic obsolescence, higher risk of forced outages, and higher environmental risk. An equity analyst commented that with the emergence of environmental, social and governance ("ESG") considerations in late 2018, investors now tend to prefer companies with less generation and more T&D assets. A credit analyst explained that generation has higher risk under their stated credit criteria, and that generation ownership specifically affects the financial risk profile of a utility company because it determines what financial benchmarks are used to assess financial risk.

Nuclear risk: Nuclear generation is viewed as the riskiest type of generation by the equity and credit analysts we interviewed. Among the reasons for this assessment were: the possibility of catastrophic failure and loss of life, damage to the environment, risk around decommissioning and spent fuel disposal, construction cost overruns, more unplanned outages, negative sentiment around the technology following the nuclear incident in Japan, and higher safety requirements. One equity analyst commented that the Ontario government has been supportive of nuclear generation being part of the fuel mix, as evidenced by the ongoing refurbishment of the Darlington and Bruce reactors, and that the risk of economic obsolescence is generally lower for nuclear as compared to other generation types. Another equity analyst indicated that certain investors have investment policy statements that

> restrict any exposure to nuclear energy. Lastly, a credit analyst expressed the view that nuclear risk is company specific and that state legislation to support nuclear capital cost recovery does not always provide protection depending on the company's circumstances.

The results of the analyst interviews support Concentric's view that an adjustment for differences in the allowed equity ratios between Canada and the U.S. would be inconsistent with the market's current views, namely that cross-border business and regulatory risk for regulated utilities in the two countries is comparable. As such, Concentric believes that the historical differential between authorized equity ratios in Canada and the U.S. cannot be currently applied on the basis of differences in these risks and that it is appropriate to compare OPG's allowed equity ratio to that of risk comparable utilities in both countries without adjustment when setting OPG's regulatory capital structure on a forward-looking basis.

SECTION 6:

CHANGES IN CAPITAL MARKETS SINCE THE EB-2016-0152 DECISION AND ORDER

Capital markets impact the appropriate regulatory capital structure as they have a direct impact on the required ROE that, when combined with the equity ratio, determines the allowed return on equity. Since the OEB's last major decision on OPG's payment amounts (EB-2016-0152) in December 2017, and through the early months of 2020, North American capital markets reflected a period of slow economic growth, coupled with low inflation and historically low government bond yields. Stock markets in both the U.S. and Canada responded with continued growth in the major indices as investors grew comfortable with the prospects for slow but steady economic growth and improving corporate profitability. That, of course, all changed in March 2020 with the onset of the COVID-19 pandemic and upheaval of the global economy. In response, stock prices declined sharply, before subsequently beginning to recover, and stimulative economic policies have pressed government bond yields even lower. These fundamental market indicators are captured in Figure 4 below.

Figure 4: Capital Market Trends 2017-2020

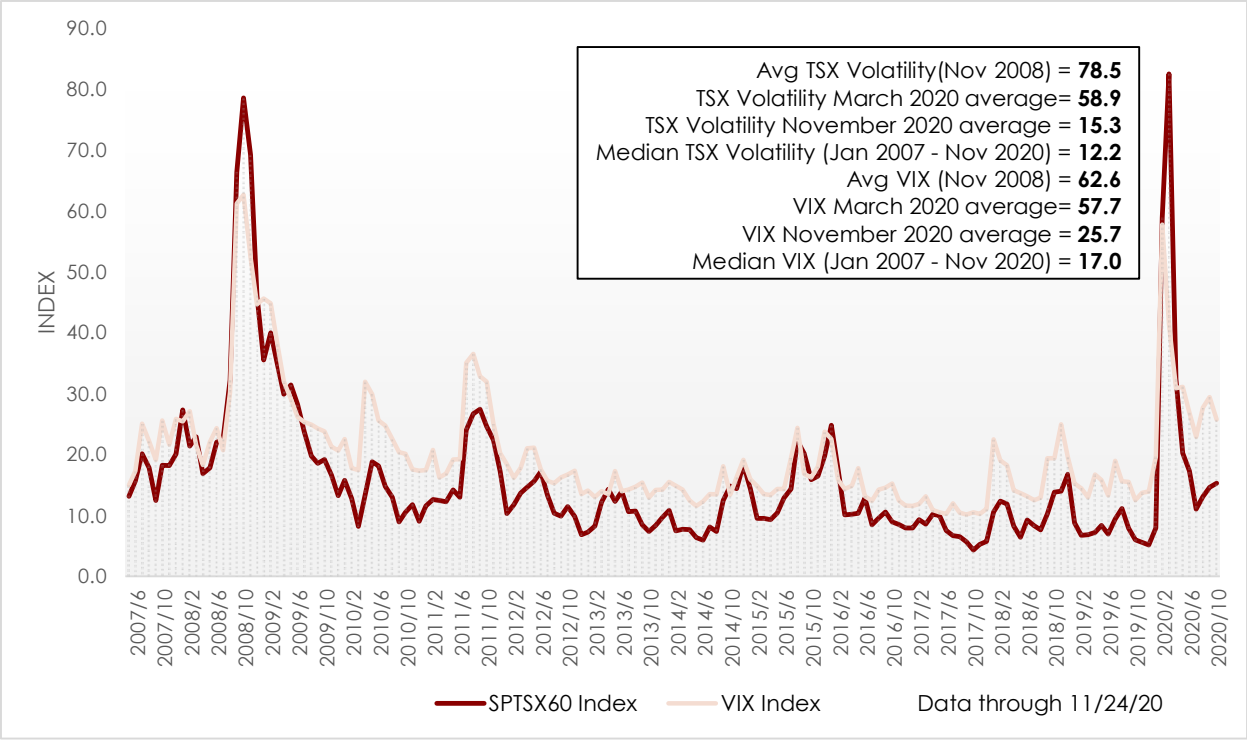
Description	2017	2018	2019	YTD 2020	Current (12/24/2020)	Source
TSX Index	15,545	15,738	16,317	15,999	17,624	[1]
S&P 500 Index	2,448	2,744	2,912	3,210	3,703	[1]
30-Year Bond Yield (Canadian)	2.28%	2.36%	1.80%	1.22%	1.26%	[1]
30-Year Bond Yield (U.S.)	2.89%	3.11%	2.58%	1.56%	1.66%	[1]
10-Year Bond Yield (Canadian)	1.79%	2.28%	1.59%	0.76%	0.72%	[1]
10-Year Bond Yield (U.S.)	2.33%	2.91%	2.14%	0.89%	0.92%	[1]
30-Year Utility Bond Yield (Canadian)	3.65%	3.74%	3.30%	2.78%	2.62%	[1]
30-Year Utility Bond Yield (U.S.)	4.01%	4.25%	3.78%	2.99%	2.73%	[1]
Real GDP Growth (Canadian)	3.04%	2.43%	1.86%	-6.18%	-3.44%	[2]
Real GDP Growth (U.S.)	2.33%	3.00%	2.16%	-4.13%	-2.18%	[3]

Notes:
[1] Source: Bloomberg Professional; Values reflect average over indicated period
[2] Source: Statistics Canada. Table 36-10-0104-01 Gross domestic product, expenditure-based, Canada
"Current" value compares 2020 Q3 value to 2020 Q1 value with no annualization
[3] Source: Bureau of Economic Analysis, Table 1.1.6. Real Gross Domestic Product
"Current" value compares 2020 Q3 value to 2020 Q1 value with no annualization

As investors have been adapting to the new norms of the pandemic, stock markets have surpassed pre-pandemic levels, as government bond yields remain at or near newly established historic lows.

Although one could conclude that the cost of equity for utilities is lower in such an environment, there is evidence to the contrary. In particular, equity markets remain in a heightened state of volatility, as seen below.

Figure 5: Equity Market Volatility 2007-2020[38]

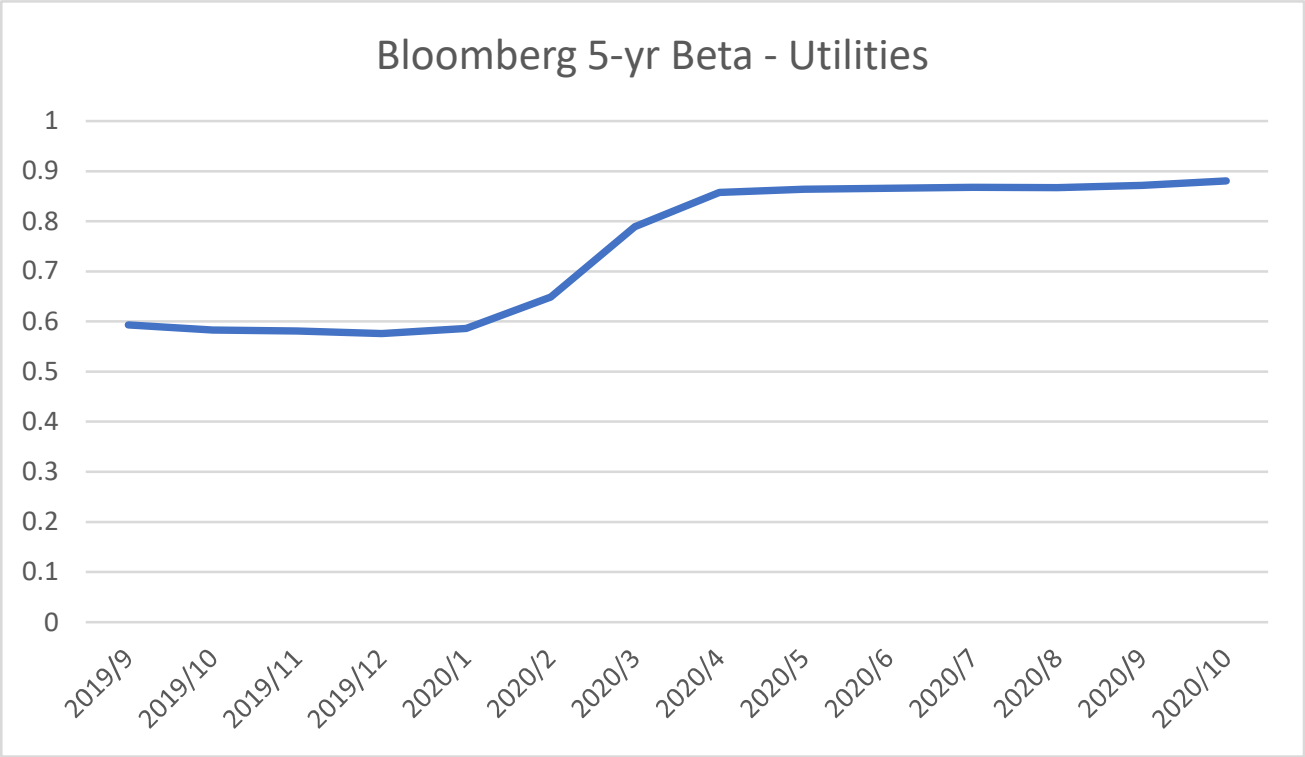


Stock market volatility for both the TSX60 and S&P500 (as measured by its volatility index, or "VIX") are presented. The spike that occurred in March 2020 was unprecedented, and even though markets have since then stabilized, volatility remains above historical levels for the past two decades. Higher volatility is generally considered a sign of increased risk in the broad markets.

Looking at utilities specifically, Figure 6 below illustrates a significant upshift in the betas for utility stocks over the past twelve months, centered in the March/April 2020 timeframe. Beta is broadly considered a measure of risk, and this upward shift in utility betas signals that investors are not considering utilities at the same low levels of relative risk as they have in the past. In the context of the current pandemic, we believe this is likely driven, at least in part, by an uncertain economic outlook and a recognition that even regulated utilities face increased risk exposure in the current and foreseeable environment.

[38] Source: Bloomberg Professional. Data for 2020 updated through November 24, 2020.

Figure 6: Utility Stock Betas – Sept. 2019 through Oct. 2020



The above trend is unlike prior periods of market disruption where utilities have typically served as a safe haven for investors. It appears that the pandemic has left investors uncertain of the outlook for the sector amid concerns for slumping demand and disruption to business plans, with utility betas in both the U.S. and Canada increasing substantially since January 2020. This indicates that the cost of equity for regulated utilities has increased. In contrast, when the OEB recently updated the cost of capital parameters for the 2021 rate year, the authorized ROE was reduced from 8.52% to 8.34% due to the decline in the government bond yields. Notably, this currently places the allowed ROE in Ontario below that of any other North American regulatory jurisdiction and negatively affects OPG's credit metrics at a time when they are already expected to be pressured.

SECTION 7:

CHANGES IN BUSINESS AND FINANCIAL RISKS SINCE THE EB-2016-0152 DECISION

Business risk for a regulated utility results from variability in cash flows and earnings that impact the ability of the utility to recover its costs including a fair return on, and of, its capital in a timely manner. Concentric includes operating risk and regulatory risk under this broad definition of business risk. Financial risk relates to a company's debt leverage and liquidity and is measured by its credit profile. Both business and financial risk have a direct bearing on a utility's cost of capital.

The cost of capital is a forward-looking concept, and utility investors tend to be long-term providers of capital. For these reasons, it is important to not only review OPG's current business and financial risk profile, but also to assess how that risk profile has changed and will change going forward. This approach is consistent with the OEB's findings in prior decisions regarding OPG's capital structure.[39]

This section contains an overview and analysis of OPG's business and financial risks, with a focus on how those risks have changed since EB-2016-0152 and how they are forecast to change over the 2022 to 2026 rate-setting period.

To evaluate OPG's business risks, Concentric performed an independent review of OPG and its regulatory environment, building on Concentric's previous assignment in EB-2016-0152. The review included: (1) risks related to the prescribed hydroelectric facilities; (2) risks related to the prescribed nuclear facilities, including the DRP and upcoming retirement of the Pickering station; (3) OPG's projected regulated business mix between those two types of generation, and how that mix is expected to change over the rate-setting period; and (4) the external influence of climate change and its impact on OPG's generation fleet and operations.

Our experience in assessing business and financial risks and the effect on the cost of capital in Ontario and other regulatory jurisdictions, as well as our prior roles as an independent monitor and advisor to the power industry, informed our review. Our additional experience advising buyers and sellers of generation facilities, including hydroelectric and nuclear facilities, further informs our views on the investor perspective regarding the business risk of these assets. Our evaluation process included research on equity and credit analyst views regarding OPG and the regulated generation industry,

[39] For example, in EB-2013-0321, the Board determined that because the business risk for OPG's regulated operations had changed in the specific payment-setting period in that proceeding, the capital structure should reflect that change.

relevant industry data, other publicly-available materials such as Ontario's December 2017 Long-Term Energy Plan and the IESO's 2020 Annual Planning Outlook, regulatory filings made by OPG, OPG's Amended 2020-2026 Business Plan, OPG's financial reports, OPG's Climate Change Plan and interviews with OPG subject matter experts.

Concentric concludes in this section that while OPG's risk level for its regulated operations will remain the same in some areas of the business, the overall risk for these operations will significantly increase, due to the following factors:

- OPG continues to be at risk for variability in the output at its nuclear plants, a factor that distinguishes OPG from other North American regulated generators. This risk pervades and compounds OPG's other nuclear risks, discussed below.
- The DRP, as OPG is entering a period of acute risk beyond what it has experienced historically, with three units coming offline in the upcoming rate setting period with overlapping outages, new FOAK scope being added to the refurbishment, competition for resources with the Bruce Power refurbishment, and ongoing constraints and risks presented by the COVID-19 pandemic;
- The majority of OPG's nuclear fleet is nearing the end of its current operating life, with Pickering planned to end commercial operation during this upcoming rate period and Darlington units requiring refurbishment as they reach their end of 'first' life. Therefore, OPG is at inherently higher risk related to variability in the generation output due to the aging of the nuclear stations. This could lead to significant revenue shortfalls for OPG;
- In addition to the increased generation risk leading up to the end of the station's commercial operations, the shutdown and retirement of Pickering, comprising six of the Company's ten operating nuclear reactors and served by thousands of employees, in this upcoming rate period presents new and unique challenges for OPG related to disruptive organizational changes that can impact operational performance, increased forecast risk and reduce the diversification of OPG's nuclear fleet;
- Risks to both OPG's nuclear and hydroelectric operations from climate change have increased considerably from its prior rate proceeding, including the risk of increased capital expenditure needs due to the threat of climate driven impacts on the company's infrastructure and systems;

- OPG's asset mix will continue to shift towards a higher proportion of riskier nuclear assets, combined with an increase in relative value of each nuclear MWh due to declining generation over which revenue requirement is recovered on a variable basis; and
- OPG's financial risk will increase in the period from 2022 to 2026, as illustrated by the pressure on, and potential decline below current credit rating thresholds of, key credit metrics in the earlier years of the rate setting period.

Concentric concludes that, taken as a whole, this shift in risk profile is sufficient to warrant a reassessment of OPG's equity ratio.

OPG Overview

OPG is an electricity generation company established under the Ontario Business Corporations Act and is wholly owned by the Province of Ontario ("Province"). As of December 31, 2019, OPG's regulated generation portfolio included two nuclear generating stations (*i.e.*, Pickering and Darlington) as well as 54 hydroelectric generating stations. OPG's regulated facilities are the prescribed facilities under O. Reg. 53/05.

Since 2017, OPG is a public debt issuer in Canada. OPG, as a corporation, has a split "A (low)" issuer and unsecured debt rating (with stable trend) (as of April 16, 2020) from DBRS Morningstar ("DBRS"), a "BBB+" issuer and unsecured debt credit rating (with stable outlook) (as of July 17, 2020) from S&P, and an "A3" senior unsecured debt rating from Moody's (with stable outlook) (as of December 21, 2020).

Both S&P and Moody's note that they rate OPG three notches below their respective OPG corporate credit ratings on a stand-alone basis (that is, before considering support by the Province), namely as "BB+" and "baa3", respectively.

Changes in Business Risk

1. **Hydroelectric Facilities**

OPG has 54 hydroelectric stations that are subject to OEB regulation and that supply approximately 6,400 MW of generating capacity. The remainder of OPG's hydroelectric stations are not regulated by the OEB. The hydroelectric system is comprised of a diverse set of assets. OPG's hydroelectric stations vary in size, location, age, operating and hydrological characteristics (*i.e.*, base load, intermediate, peaking). Because of the geographic diversity of the system, the hydroelectric assets are subject to numerous federal, interprovincial, and provincial regulations, international treaties, agreements, and waterpower leases. OPG plans to invest approximately $2.0 billion of capital in its

hydroelectric system over the 2022 to 2026 period. Those investments are being made primarily to replace aging infrastructure and upgrade/redevelop certain sites.

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

OPG's hydroelectric business is expected to remain relatively stable from an operating risk perspective relative to the experience and conditions as they existed at the time of EB-2016-0521, subject to the impact of climate change impacts and increased inflationary risk, as discussed further below.

OPG's hydroelectric operations are subject to variances in water flow and surplus baseload generation ("SBG") curtailments. However, while the availability of water to power the stations can vary significantly from year to year, Concentric is not aware of any reason why variances in water flow over the rate period are more or less at risk of being higher or lower than at the time of EB-2016-0152 (subject to the climate change risk discussed below). In addition, with respect to SBG, Concentric understands that a reduction in nuclear generation capacity in the Province through the period of refurbishments and Pickering retirement is generally expected to result in a gradual decline in SBG conditions, although this may be offset by inherent near-term risks to electricity demand associated with the COVID-19 pandemic.

Further, OPG has a Hydroelectric Water Conditions Variance Account that records and mitigates the financial impact of differences between forecast and actual water conditions, and a Hydroelectric Surplus Baseload Generation Variance Account that records and mitigates the financial impact of SBG related curtailments, subject to the OEB's approval. On balance, Concentric is of the view that the risks related to the availability of water to power the stations and SBG related curtailments have not changed significantly since EB-2016-0152. Concentric understands that OPG's rate application will propose that these and other currently-approved deferral and variance accounts related to its prescribed hydroelectric facilities remain in place. Assuming this proposal is approved, there should be no overall change in risk for OPG.

Similar to the risks related to the availability of water flows, Concentric is not aware of any significant changes in risks related to water management and environmental regulations affecting OPG's regulated hydroelectric power production relative to the risk levels at the time of EB-2016-0152.

OPG's hydroelectric system is a mature system, with an average age of approximately 80 years and the oldest facility being over 120 years old. This means that, while the risk of equipment failure is higher, the risk of discovering new operational issues or the intervention of new stakeholders is generally lower than it would be for a newer system. In addition, Concentric understands that OPG is not planning to add any significant amount of new hydroelectric capacity during the period, beyond upgrading or redeveloping certain existing sites. Because of this, Concentric expects OPG's need to obtain waterpower leases or rights for new regulated hydroelectric capacity should not materially deviate from recent experience, leaving associated risks at similar levels as at the time of EB-2016-0152.

OPG's hydroelectric base payment amounts are legislatively set at the 2021 amount and as such will not increase over the 2022-2026 period. As a result, OPG will be exposed to a level of incremental inflationary risk over the upcoming period, relative to a hydroelectric payment amount set under a price-cap incentive regulation model applied in EB-2016-0152.

Based on the above, Concentric concludes that although some incremental risks have emerged, OPG's operational risks and regulatory risks related to its prescribed hydroelectric facilities have not changed significantly since EB-2016-0152, other than additional risks from rising threat of climate-driven impacts (discussed further below) and incremental inflationary risk.

2. Nuclear Facilities

OPG has two prescribed nuclear facilities: Darlington and Pickering. Operating since the early 1990s, Darlington is a CANDU, four-unit station with a generating capacity of about 3,500 MW. Pickering has been in operation since the early 1970s and is a CANDU, six-unit station with a generating capacity of about 3,100 MW, with two additional units in a permanent safe shutdown state. OPG's nuclear operations, including nuclear waste management activities, are subject to federal regulation by the Canadian Nuclear Safety Commission ("CNSC") on all matters pertaining to the development, production and use of nuclear energy, including matters of safety, security and the environment. Supported by the Province, OPG plans to operate Pickering Units 1 and 4 to 2024 and, subject to CNSC's regulatory approval, Units 5-8 until the end of 2025, under an optimized shutdown schedule. The current CNSC operating licence for the Darlington station expires on November 30, 2025 and for the Pickering station on August 31, 2028. The Pickering operating licence currently allows

commercial operation of the station until December 31, 2024. All of OPG's operating licences for its nuclear waste facilities are also current and up to date.

OPG's sustaining capital investment program for the nuclear fleet is primarily focused on ensuring the Darlington station is well positioned to transition to steady state 'second life' operations following refurbishment, including investments in life cycle and aging management projects, facility upgrades and work in support of regulatory commitments. Over the 2022 to 2026 period, OPG plans to make sustaining capital investments totaling approximately $1.8 billion into the nuclear fleet, in addition to the DRP.

OPG is responsible for the ongoing and long-term management of nuclear fuel and other nuclear waste from its operations as well as for the eventual decommissioning of its nuclear generating stations and waste management facilities. Under the Ontario Nuclear Funds Agreement ("ONFA") with the Province, OPG is required to set aside funding in segregated funds toward the long-term management of nuclear waste and decommissioning obligations. Subject to certain exposures assumed by the Province, OPG bears the risk of future cost increases and fund investment performance related to these obligations. Canada's plan for long-term management of spent nuclear fuel is being implemented by a federally-mandated organization, established and funded by nuclear fuel owners including OPG. OPG is responsible for a plan for long-term disposal of its low and intermediate level waste material.

Under the current rate plan, OPG recovers the cost of its nuclear facilities under a custom incentive rate-setting ("Custom IR") framework established in EB-2016-0152. Under the Custom IR framework, OPG continues to be at risk related to the variability in the generating output of its nuclear facilities. OPG's risk related to the variability in nuclear generating output compounds its nuclear-specific business risks, as discussed herein, and also distinguishes OPG from other regulated North American generators.

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

Consistent with the OEB's prior findings, nuclear generation is viewed by the investment community to be riskier than other forms of generation, including hydroelectric generation.[40] Furthermore, for large nuclear construction projects, regulatory support for timely cost recovery is critical given the complexity of building this type of generation, as highlighted by a history of industry project delays and cost overruns, as well as a shortage of skilled labor.[41] Appendix A provides additional information regarding the investment community's views on the high-risk nature of nuclear operations.

Before turning to the changes in OPG-specific nuclear risks, we note that recent events in the nuclear construction business since EB-2016-0152 have further raised the perceived risk of large nuclear facility projects among investors and credit rating agencies. In particular, two new nuclear projects in the U.S. (*i.e.*, the Vogtle Plant in Georgia and the now-cancelled Summer Plant in South Carolina), both of which were being pursued under favorable legislative and regulatory frameworks, have run into cost and schedule issues. One of the projects (*i.e.*, the V.C. Summer plant in South Carolina) resulted in the bankruptcy of a major vendor, the downgrading of the credit rating of the owners, the eventual merger of one of the owners (*i.e.*, SCANA Corporation) into a larger utility (*i.e.*, Dominion Energy), and the potential to require the sale of the other owner (*i.e.*, Santee Cooper, a state-owned corporation) to an investor-owned utility in order to eliminate a reported billions in interest charges to customers for a plant that was never completed. These projects and their regulatory and political environment are discussed in greater detail in a subsequent section of the report.

The major changes in the operational and financial risks faced by OPG's nuclear facilities are as follows:

a. Darlington Refurbishment

OPG is refurbishing the Darlington station for 30-plus additional years of operations. The four-unit DRP is a "megaproject" with a budget of $12.8 billion, lasting approximately a decade in execution.

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[40] *See*, *e.g.*, Moody's Investors Service, "Rating Methodology: Regulated Electric and Gas Utilities," June 23, 2017, at 42-43, in which Moody's highlighted risks related to nuclear ownership that include: (1) safety, regulatory, and operational issues; (2) lasting regulatory and safety consequences from the March 2011 Fukushima nuclear accident in Japan, leading to increased operating costs; and (3) an aging fleet and early retirements due to station failures that require uneconomic repairs.

[41] In its 2013 rating methodology for utilities, Moody's also commented on legislative and regulatory support for nuclear construction projects, noting specifically SCANA Corporation in South Carolina: "For SCANA Corporation, the South Carolina Base Load Review Act provides strong credit support for companies engaging in nuclear new-build, which also affects the scoring for consistency and predictability of regulation. However, SCANA's rating also considers the size and complexity of the nuclear construction project, which is out of scale to the size of the company, as well as structural subordination." Moody's Investors Service, "Rating Methodology: Regulated Electric and Gas Utilities," December 23, 2013, at 43.

At the time of writing, OPG had completed the refurbishment of the first unit, Unit 2, and has commenced the refurbishment of the second unit, Unit 3. The remaining two units are scheduled to commence execution early in the 2022 to 2026 period, with the entire project completed by the end of 2026. Capital expenditures totaling approximately $4.8 billion were placed in service upon Unit 2 returning to service, including overall DRP definition phase costs incurred prior to commencement of execution.

i. DRP Risk Profile

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

Specifically, the DRP includes multiple complex work packages, including the removal and replacement of the reactor calandria tubes and pressure tubes from each reactor, replacement of all feeders, refurbishment of the existing fuel handling equipment, refurbishment of the existing turbine generators, refurbishment of the existing steam generators, and a set of supporting refurbishment projects aligned with existing station systems. The project involves numerous third-party vendors and the coordination of multiple scopes of work, all within the highly regulated and safety-conscious environment of a nuclear facility. In addition, the Canadian marketplace for nuclear construction firms is limited, increasing the risks related to vendor management and performance. Furthermore, the DRP is currently being executed during the global COVID-19 pandemic, which places constraints on and could pose additional risks for the project, as further discussed below.

The inherently high execution risks associated with the DRP have been noted by the investment community. For example, Moody's stated in its December 2020 OPG credit rating report, "[t]he company is also pursuing a CAD12.8 billion nuclear refurbishment project across 4 units at its Darlington nuclear generation station that carries a very high level of execution risk."[42] Similarly, DBRS observed in its April 2020 OPG credit rating report, "[t]he Company also faces significant execution risk as well as the potential for cost overruns associated with the Darlington Refurbishment because of the project's complexity and scale."[43] In EB-2016-0152, the OEB similarly stated that, "[t]here is no question that successful execution of the DRP is a challenge for OPG during the term of [the 2017-2021 rate] plan."[44]

OPG successfully completed the refurbishment of Unit 2 earlier in 2020, which has been positively noted by the credit rating agencies. For example, S&P stated in its July 2020 OPG credit rating report, "[t]he company's on-time and on-budget record [on Unit 2] increases our confidence that the other three units will be also be completed without incurring project delays or materially higher costs."[45] However, it is known that prior CANDU refurbishments and large nuclear construction projects in the U.S. have encountered significant challenges. As demonstrated by those prior projects, schedules can slip, outage durations can be different than expected, and there are risks related to the performance and output of the nuclear facilities post-refurbishment.

While OPG has carefully planned the refurbishment of the three remaining units, including applying lessons learned from the Unit 2 refurbishment, Concentric concludes that there are a number of additional risks that the Company is facing during the remaining project period, as discussed below. In Concentric's opinion, notwithstanding a decrease in certain risks resulting from the experience gained on Unit 2, the additional risks result in an overall increase to the Company's risk profile as it relates to the remainder of the project.

First, the DRP is entering a period of acute execution risk beyond what it has experienced historically. The refurbishment of Unit 2 took place when there were no other units undergoing refurbishment in Ontario. In contrast, three of the Darlington units are planned to be offline for refurbishment during the upcoming rate setting period. Critically, the refurbishments for the units will overlap; for a period of time in 2023 all three units are planned to be offline. Also during OPG's upcoming rate setting period, Bruce Power is planning to have four of its units offline for refurbishment, some with their

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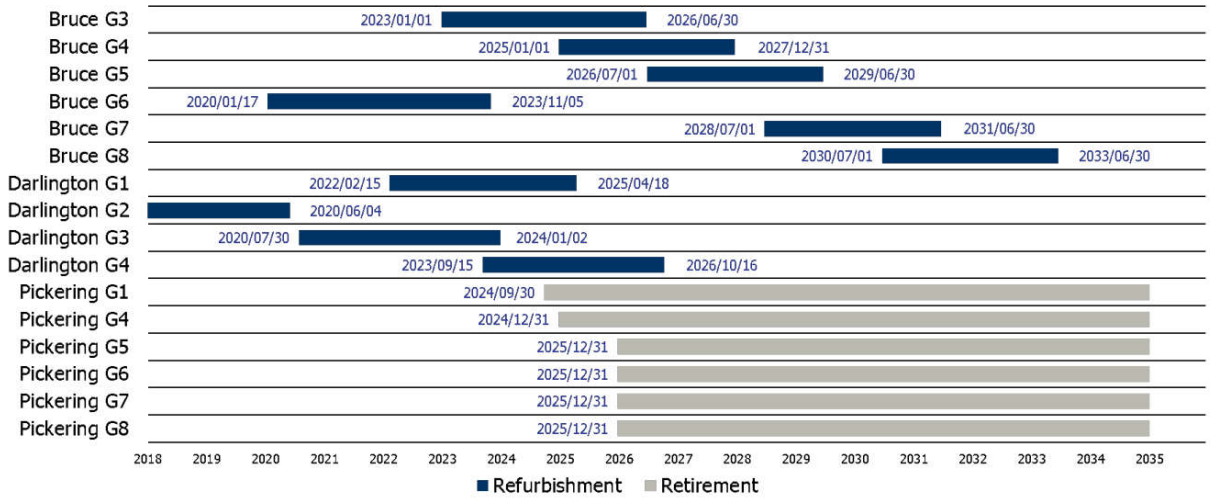
42 Moody's Investors Service, "Ontario Power Generation Inc.," December 21, 2020, at 1.
43 DBRS Limited (DBRS Morningstar), "Rating Report: Ontario Power Generation Inc.," April 16, 2020, at 3.
44 EB-2016-0152, Decision and Order, December 28, 2017, at 104. Clarification added.
45 S&P Global Ratings, "Research Update: Ontario Power Generation Inc.," July 17, 2020, at 1.

own overlapping outages.[46] These circumstances will place a high demand on the highly skilled resources required to support both projects that rely on certain of the same vendors and key tradespeople. As such, there are inherently higher risks related to project execution during this period of significantly increased sector activity. The schedule of the OPG and Bruce Power projects (along with Pickering retirements) is shown in Figure 7 below.

Figure 7: Ontario Nuclear Refurbishment and Retirements Schedule[47]



Second, OPG plans to execute new scope during the refurbishment of Units 3, 1 and 4 in the form of digital turbine controls and generator excitation controls. This scope was excluded from the Unit 2 refurbishment for two main reasons: (1) there was still useful life left in the existing control systems on Unit 2; and (2) to mitigate risk, given that Unit 2 was the first unit to be refurbished and that this large FOAK modification would have introduced additional risk into the planning and execution of the refurbishment. The addition of this scope with which OPG does not yet have experience brings with it increased challenges and risks for the remaining units.

Third, OPG is at increased risk related to the potential for vendor default. The risk of vendor default is already heightened in the context of OPG's nuclear operations as a result of the small pool of qualified vendors available to perform nuclear engineering and construction. In particular, vendors SNC Lavalin Nuclear Inc. ("SNC") and Aecon Construction Group Inc. ("Aecon") represent the most material of OPG's vendor default risk because of the volume of work they perform for OPG, including acting in a joint-venture (CanAtom) as the main vendor for the DRP. In May 2020, SNC's credit rating

46 Bruce Power refers to its nuclear refurbishment program as Major Component Replacement.
47 Independent Electricity System Operator, 2020 Annual Planning Outlook, at 28.

by S&P was affirmed at "BB+" (with a negative outlook), following a downgrade from "BBB-" in August 2019. S&P's outlook on SNC remains "negative" based primarily on uncertainty in the company's ability to improve earnings and cash flow, especially in context of the COVID-19 pandemic that is resulting in weaker than expected earnings, a weaker economic environment and lower construction activity.[48]

Fourth, the COVID-19 pandemic is an unforeseen 'black-swan' event. OPG did not allocate any DRP contingency to the risk of a pandemic outbreak. Concentric understands that OPG continues to seek ways to manage the currently known impacts of the pandemic, including the incremental costs incurred to date. The inherent uncertainty of the pandemic's evolving course, however, makes it difficult to predict the full range of response actions that may become necessary in the future and any ultimate impact on the DRP cost or schedule. For example, in response to the pandemic and Ontario's state-of-emergency declaration in mid-March 2020, OPG made the following decisions with respect to the refurbishment schedule: (i) continue to return Unit 2 to service (Unit 2 was safely returned to service on June 4, 2020); and (ii) defer the start dates of the refurbishment outages of Units 3, 1 and 4 by four months each.

In response to the pandemic, OPG conducted a risk review to identify any new or increased risks arising both from the pandemic itself, and also from OPG's decision to delay the refurbishment start dates of Units 3, 1 and 4. This risk review resulted in new or increased risks being identified, which can be summarized as follows:

1. Productivity risk: risk of decreased productivity as a result of the COVID-19 protocols (such as physical distancing, enhanced cleaning, use of masks, etc.) associated with working during a pandemic.
2. Resource availability risk: risk of resource conflicts and shortages in the form of both human and equipment resources, including managing of staff and equipment as a result of new overlaps with station planned outages, travel restrictions for specialized resources required on the DRP, and risk of loss of critical project resources due to the overall extended schedule (further compounding the significant anticipated demand for resources during the multiple overlapping refurbishments with Bruce Power).

[48] S&P Global Ratings, Research Update: SNC-Lavalin Group Inc. 'BB+' Ratings Affirmed; Outlook Remains Negative On Slower-Than-Expected Deleveraging, May 2020.

Depending on the course of the COVID-19 pandemic, these factors may have an impact on the ultimate cost and schedule of the DRP.[49]

We note that OPG does continue to employ robust risk mitigation strategies related to the DRP. From the outset, OPG has approached the project strategically and methodically, including performing numerous front-end planning and preparation activities, such as completion of detailed designs and construction of a full-scale model training reactor, and sophisticated contracting strategies. Through the execution of the Unit 2 refurbishment, OPG has been identifying, reviewing and applying a number of lessons learned and strategic improvements in planning the work on subsequent units. However, notwithstanding these practices, significant execution risks associated with the DRP remain as noted above and cannot be fully offset by mitigation strategies.

ii. Cost Recovery Protections Available to Nuclear Owners

As noted in the OEB's decision in EB-2016-0152, provisions of O. Reg. 53/05 provide important protection to OPG, reducing the company's future recovery risk by establishing the overall need for the DRP in the regulatory context and requiring the OEB to authorize recovery of incurred costs (including if the units are not ultimately returned to service), subject to a prudence review. However, Concentric finds that similar risk reducing properties are also or have been present in other jurisdictions that have undergone large-scale nuclear construction projects, including among the proxy companies considered by Concentric in Section 8, and thus are taken into account in this report's recommendations for OPG's equity ratio.

To make this assessment, Concentric compared O. Reg. 53/05 from a risk mitigation perspective to similar legislation and regulatory rules that have enabled nuclear construction in other jurisdictions, focusing on whether: 1) the relevant regulator must approve the need for the new generating plant before construction begins (*i.e.*, the utility does not face the risk of not being subsequently allowed to close the project to rate base upon completion); 2) the utility is allowed to recover prudently-incurred construction and financing costs before the plant goes into service; 3) the utility is allowed to recover costs that exceed the originally approved projections, subject to a prudence review by the regulator; and 4) the utility is able to recover prudently incurred construction costs if the project is abandoned. In particular, Concentric reviewed legislation in the following three jurisdictions where large scale nuclear projects are underway or have been completed (or abandoned): Georgia, South

[49] Concentric understands that OPG does not intend to seek recovery of any pandemic-related cost impacts through the 2022-2026 rate application but rather will propose to record the impacts in the Capacity Refurbishment Variance Account for the OEB's review at the conclusion of the DRP.

Carolina and Florida. The following is a brief summary of the relevant legislation and statutes in each jurisdiction.

Figure 8: Summary of Generation Construction Enabling Legislation

	South Carolina[50]	Georgia	Florida
Does commission approve need for new generation before construction begins?	Yes	Yes	Yes
Is utility allowed to recover prudently incurred construction and financing costs before plant goes into service?	Yes	Yes	Yes
Is utility able to recover prudently incurred construction costs if plant is abandoned before completion?	Yes	N/A[51]	Yes

As demonstrated in Figure 8, the legislation and statutes in South Carolina, Georgia and Florida include regulatory protection and assurance of cost recovery for nuclear construction projects comparable to that available to OPG through O. Reg. 53/05. Additionally, all three of the jurisdictions allow recovery of prudently incurred construction and financing costs for the projects prior to the plant going into service (*i.e.*, the utility is allowed to place CWIP in rate base and earn a cash return), a provision not available to OPG under O. Reg. 53/05 and not granted by the OEB.[52] On that basis, Concentric concludes that the regulatory mitigation for the DRP is not unique to OPG, and that construction or refurbishment projects in other jurisdictions may not have been feasible without legislative and regulatory support. Further, because these states offer similar risk protection for nuclear projects, it is reasonable to compare the authorized equity ratios for these operating utilities (*i.e.*, South Carolina Electric and Gas, Georgia Power, and Florida Power and Light) to the deemed equity ratio for OPG. Concentric's analysis of comparable utilities in Section 8 includes data from two of the three of major developers of nuclear plants in those states.[53]

With regard to whether other North American utilities have been allowed to recover cost overruns on large nuclear projects subject to prudence review, Concentric has identified several instances

50 The Base Load Review Act in South Carolina was repealed in 2017.
51 The legislation in Georgia does not appear to address this issue directly.
52 EB-2010-0008, Decision with Reasons, March 10, 2011, at 78.
53 The third developer, Dominion Energy (which acquired SCANA in 2019), is excluded from the analysis due to a lower percentage of regulated operations than the screening criteria used by Concentric.

where regulators in Florida, South Carolina and Georgia have approved recovery of such cost overruns. While this provision is not explicitly included in the enabling legislation in these three states, our research demonstrates that there has been implicit support for cost recovery when the need arises. The following is a brief summary of examples in each jurisdiction:

- Florida – Florida Power and Light Company ("FPL") was allowed to recover costs associated with an Extended Power Uprate project at St. Lucie and Turkey Point following a prudence review, despite cost overruns. In 2011, FPL experienced "cost variances" of more than $60 million in total in two particular cost categories. The Florida Public Service Commission further indicated that "FPL's cost estimates have increased each year." However, despite these cost increases, the Commission approved those costs as prudently incurred.[54]
- South Carolina – In November 2016 (before the Base Load Review Act was repealed), the Public Service Commission of South Carolina approved a settlement agreement in which South Carolina Electric & Gas increased the anticipated cost of constructing two units at the VC Summer Nuclear Station by $831 million following a prudence review.[55]
- Georgia – The Georgia Public Service Commission issued an order in which it "verifies and approves" Georgia Power's expenses for Vogtle Units 3 & 4. The order further states "[t]he Commission finds and concludes, based on the evidence presented, that the Vogtle Project remains the most economic option available for supplying the identified capacity need, even taking in to account the sources of speculated cost overruns known at this time."[56]

Concentric further observes that legislative protections related to nuclear construction projects have not eliminated recovery risk for utilities. Indeed, as noted earlier, recent events in the nuclear construction industry in two of the above jurisdictions, South Carolina and Georgia, have, in fact, increased the investors' perceived risk over such projects.

In particular, in South Carolina, SCANA started construction of the V.C. Summer Plant under the Base Load Review Act ("BLRA"), which, as discussed below, provided regulatory support for cost recovery of new nuclear facilities during construction. The project experienced construction delays, cost overruns and the bankruptcy of the engineering, procurement and construction contractor (Westinghouse). This led SCANA to ultimately abandon the project in July 2017. SCANA sought recovery of its prudently incurred costs up to that time under the provisions of the BLRA. However, SCANA's credit rating was downgraded by S&P in September 2017 when the consumer advocate in South Carolina challenged the constitutionality of the BLRA, which was ultimately repealed by the South Carolina legislature, and SCANA was eventually acquired by Dominion Energy in order to avoid

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[54] Florida Public Service Commission, Docket No. 120009-EI, Order No. PSC-12-0650-FOF-EI, issued December 11, 2012, at 68, 73, and 75.

[55] Public Service Commission of South Carolina, Docket No. 2016-223-E, Order No. 2017-118, issued February 28, 2017, at 24.

[56] Georgia Public Service Commission, Docket No. 29849, issued February 26, 2013, at 6.

further financial distress. In addition, Santee Cooper, the co-owner of the V.C. Summer plant, is being considered for sale in order to eliminate $3.6 billion in future interest payments tied to the nuclear construction program.[57]

In Georgia, Georgia Power undertook the construction of Vogtle plant units 3 and 4 after receiving Georgia Public Service Commission ("Georgia PSC") approval for the new nuclear facilities under the Georgia Nuclear Energy Financing Act. S&P noted in an August 2020 report that Staff of the Georgia PSC have expressed concern that Georgia Power's stated schedule for completing construction on the units and bringing those units into service appears to be overly aggressive, although Georgia Power continues to report that construction is on schedule for the two units to be in service by June 2021 and June 2022, respectively.[58] In addition, S&P has expressed concern with whether additional costs will be deemed to have been prudently incurred by the Georgia PSC, or if some portion of those costs might be disallowed.[59] The possibility of disallowance associated with cost overruns related to project execution risks similarly exists for OPG's DRP under O. Reg. 53/05.

In light of recent "megaproject" experiences such as those in South Carolina and Georgia, the investment community continues to consider the DRP as a major source of risk, even taking into account the O. Reg. 53/05 protections. In fact, other recent regulated nuclear mega-projects in North America have only moved forward with enabling legislation that mitigates risks to the utility, including pre-construction finding of need for the project, ability to recover financing costs during construction, approval of costs in excess of original projections, subject to prudence, and protections in the event the project is abandoned. Absent such legislative and regulatory support, other North American utilities have generally not been willing to undertake nuclear mega-projects.

b. Nuclear Facilities Aging Risks

The majority of OPG's nuclear fleet is nearing the end of its current operating life, with the Pickering station set to end commercial operation during the upcoming rate period and Darlington units requiring refurbishment as they reach end of 'first' life during the period. Both stations therefore face an inherent risk of experiencing increased effects of aging on their operations and output over the upcoming rate period.

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[57] Meyers, Ellen, "SC agency recommends Dominion Energy, NextEra to reform Santee Cooper," S&P Global Market Intelligence, February 11, 2020.

[58] S&P Ratings Direct, "Research Update: Southern Company and Subsidiaries Outlooks Remain Negative on Higher Nuclear Construction Costs, Ratings Affirmed," August 6, 2020.

[59] *Ibid*.

The CANDU reactors at Darlington have limited remaining design life, thus necessitating the DRP to ensure the generating units are fit for service for another 30 years. As the units continue to age toward their end of 'first' life, there is a greater risk of emerging equipment issues necessitating incremental repair and maintenance expenditures, as well as generation interruptions.

Additionally, Concentric understands that OPG continues to monitor a fitness-for-service risk for the last two units to be refurbished, Units 1 and 4, whereby their effective full-power hours may potentially expire prior to the planned refurbishment dates, necessitating potential idling of the units. This risk has been marginally increased by the deferral of start dates of the refurbishment outages for the Units 3, 1 and 4 in response to COVID-19 conditions.

Finally, over the last several years, Darlington has experienced variable forced loss rate ("FLR") levels that may suggest less predictable performance in the pre-refurbishment period, due to equipment issues. The most recent completed year, 2019, resulted in a 4.8% FLR, notably higher than the 2018 year's 1.1% FLR and OPG's EB-2016-0152 target of 1%. Similarly, the FLR of 4.9% in 2015 was higher than in 2016 (2.3%) and 2017 (1.7%), as well as OPG's target.[60]

For Pickering, OPG has announced its intention to optimize the shutdown sequence of four of the station's units through to the end of 2025, extending their life for one year beyond 2024. OPG has forecast its nuclear generation for the upcoming rate application to reflect that assumption. The extension beyond December 31, 2024, however, requires approval from the CNSC through a public hearing process. In addition to inherent risks associated with the regulatory approval process, for the extension to be achieved, OPG must undertake technical analysis and inspections to validate continued fitness-for-service of the plant's components. Notably, this extension is the latest in the series implemented by OPG over the last number of years. Given the aging of the plant, the technical and regulatory risks associated with achieving an extension would be expected to increase with each successive instance, as would the ongoing operating cost and generation revenue risks for a station operating closer to its ultimate shutdown date. In fact, no other CANDU plant has operated as long as the planned life of Pickering, which remains the longest operating plant among CANDU peers. On this basis, Concentric believes that the currently planned extended operating period carries increased risk over that of the planned extension at the time of EB-2016-0152.

[60] 2016 – 2019 Data: EB-2020-0290, Ex. E2-1-2, Table 1; 2015 Data: EB-2016-0152, Ex. E2-1-2 Table 1.

Additionally, there is recent evidence of increased equipment aging issues that are necessitating more frequent unbudgeted planned outages, with three such outages occurring to date in 2020 related to primary heat transport system and other leaks.[61]

Finally, OPG has reduced the FLR target for the upcoming rate period to 3.5%, which is lower than the OPG's EB-2016-0152 target.[62] While Pickering had a FLR performance of 1.6% in 2019, this is notably better than OPG's EB-2016-0152 target of 5% and several prior years of close-to-target performance.

On balance, the older plant, recently increased incidence of aging issues and the more aggressive FLR target relative to EB-2016-0152 lead Concentric to conclude that Pickering is at higher risk for increased expenditures and generation revenue shortfall than at the time of EB-2016-0152.

The above risks were noted by DBRS in their 2020 credit rating report on OPG, stating "[n]uclear generation faces higher operating risks than other types of power generation because of its complex technology (approximately 56% of OPG's production in 2019). Financial implications of forced outages, especially with older units (e.g., the Pickering Nuclear GS), are greater given the high fixed-cost nature of these plants and since lost revenues resulting from outages are not recoverable through rates."[63]

In reaching its conclusion on the increased aging risks for the Darlington and Pickering stations, Concentric has considered that, under the EB-2016-0152 Custom IR framework that Concentric understands the company will propose to continue in this rate term, OPG may have the ability to seek regulatory relief from the OEB in the case of a radical change to its nuclear business. For example, the OEB noted in its EB-2016-0152 Decision and Order that "[s]hould the outcome of the technical assessments or system planning decisions significantly impact operation of Pickering in 2021 [the year of planned extension], OPG shall return to the OEB to seek direction."[64] Such a potential regulatory outcome, however, while putting an upper bound on the potential risk faced by OPG does not negate it, nor does it, by itself, mitigate the incremental risks faced by OPG related to its aging units.

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61 EB-2020-0290, Ex. E2-1-2, Table 1; Ex. E2-1-1.
62 EB-2020-0290, Ex. E2-1-2, Table 1
63 DBRS, "Ontario Power Generation Inc.," April 16, 2020, at 3.
64 EB-2016-0152 Decision and Order, December 28, 2017, at 61. Clarification added.

c. Pickering Retirement

For the first time in OPG's history, the rate application will encompass a period of significant reduction in OPG's regulated operations, due to the wind down and shutdown of the Pickering station. The station represents six out of ten of the company's operating nuclear reactors and up to approximately 35% of the company's operating costs, and is served by over 3,000 employees out of the Company's 9,000-plus total workforce. With plans to pursue an extension of Pickering operations for four out of the six operating units through 2025, the planned station shutdown date is at the end of 2025. This introduces a number of unique additional risks and significant challenges that must be taken into account in assessing the risk profile of the regulated business relative to EB-2016-0152. Among others, these risks and challenges include organizational and potential operational disruption, increased forecasting risk and reduced nuclear fleet diversification.

Organizationally, the end of Pickering commercial operations will require OPG to downsize 3,000-plus employees, which will be a complex undertaking. The inevitable disruption that will be caused by the large scale reorganization carries risks to the operational effectiveness and efficiency of the Company's nuclear business through the upcoming rate term.[65]

In addition to the risk of increased operating costs or decreased output associated with the organizational disruption, the upcoming Pickering shutdown creates considerable new forecasting risk for OPG as its nuclear cost-based rates are set on a forward-looking basis. Namely, for at least the years 2025 and 2026, OPG must forecast its operating profile as a very different organization, without the benefit of historical experience. In addition, planning for the immediately preceding years involves making assumptions about organizational changes and strategies to prepare for the shutdown and the post-shutdown operations. For example, OPG's business plan lays out targets of increased cost efficiencies in such areas as technology solutions, organization redesign, work site relocation and others to mitigate, to a large extent, the need to reallocate corporate and operations support costs currently assigned to Pickering to the remaining operations after the Pickering shutdown.

In Concentric's opinion, the business transformation and workforce redeployment brought about by the retirement of Pickering increase the incremental risks that either one of the two initiatives – transformation and redeployment – would carry on its own. Under the current regulatory

[65] Concentric understands that based on current collective agreement provisions, the hydroelectric business is unlikely to be significantly affected by the downsizing and redeployment exercise.

framework, OPG bears the financial risks associated with forecasting the outcome of its transformation efforts.[66]

In addition, the retirement of Pickering will reduce OPG's diversification among its nuclear fleet, meaning the company's ability to recover nuclear costs will be fully tied to the Darlington output. While Darlington units have historically been more reliable than the Pickering plant, due to Pickering's early age and design, the countervailing risk is that of asset concentration. For example, occurrence of an unanticipated issue at Darlington, including as the last of the units return from refurbishment over 2025 and 2026, could cause large revenue shortfalls for OPG in light of reduced or eliminated Pickering generation. As noted by Moody's, "[OPG's nuclear] segment also benefits from diversification across 2 nuclear generating stations, with 6 and 4 operating reactors respectively, that enable the company to maintain high levels of generation and cash flow while undertaking the nuclear refurbishment. The shutdown of the Pickering nuclear generating station in 2024 will reduce diversity and, with fewer operating nuclear units, heighten the impact of any unplanned outages."[67] This risk is related to the generation mix risk, which is discussed in further detail in a subsequent section of the report.

Concentric also notes that OPG anticipates that it will incur a significant amount of severance and workforce transition costs, currently estimated in the order of $1 billion, related to the Pickering closure. A recent amendment to O. Reg. 53/05 has established a deferral account to record and subsequently recover such costs, subject to the OEB's approval through a prudence review. As Concentric assumes that this mechanism will allow for the substantial full recovery of those costs by OPG, this did not have a material impact on our assessment of OPG's risk profile.

3. Climate Risks

Since EB-2016-0152, the intensifying risk of climate change has been an important source of incremental business risk for the regulated generating industry generally, including OPG's generating assets. Specifically, increased climate risks have been observed through direct impacts to OPG's assets, more pronounced environmental trends, recognition of impacts on the overall electricity system, and recognition of impacts on financial markets and broader economy. The ultimate

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[66] Concentric understands that OPG previously undertook a Business Transformation initiative over the 2011-2015 period, which was a subject of OPG's payment amounts proceeding in EB-2013-0321. However, unlike the upcoming rate application, that initiative was well advanced at the time OPG sought to set rates reflecting its outcome and did not involve a significant redeployment or downsizing, instead relying on attrition-based workforce reductions. It also predominantly focused on support functions rather than core generating station operations.

[67] Moody's Investors Service, "Ontario Power Generation Inc.," December 21, 2020, at 5. Clarification added.

response to these risks, whether in the form of after-the-fact action or proactively increased resilience, can entail increased expenditures, reduced flexibility and/or reduced output for OPG's regulated businesses in the future.

Some of the developments are summarized below:

- OPG's Calabogie Hydroelectric Generating Station, a five MW regulated facility that OPG had been planning to rebuild, was struck and largely destroyed by a tornado in September 2018.[68]
- OPG has documented risks of maintaining cooling for various plant systems due to warmer Lake Ontario temperatures.[69] For the nuclear stations, primary, secondary and auxiliary systems use lake water to maintain cooling. As lake water temperatures increase in the summer months, the ability to maintain cooling of system components becomes increasingly difficult and may result in lower output through unit derates. Additionally, warmer lake temperatures encourage the growth of aquatic life, thus increasing the risk of algae bloom events as was experienced at Pickering in 2018, forcing four units offline over a span of a number of days.[70]
- The Ottawa River, which hosts a substantial portion of OPG's regulated hydroelectric fleet (four facilities with a total capacity of 912 MW), has seen record floods in recent years.[71] A recent report[72] released by Ottawa predicts more intense precipitation, increased risk of tornadoes and wildfires in the Ottawa area due to climate change.
- Other general environmental trends include increasing air temperature in Canada, which, per Canada's Changing Climate Report has been at approximately twice the global average rate, with extreme warm temperatures becoming hotter.[73] This warming can be expected to contribute to an increased risk of extreme fire weather,[74] which would put utilities such as OPG at a range of risks including disrupted station access/operations, interrupted telecommunications and bottlenecked transmission. These risks have the potential to impact

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68 OPG.com, "Century-old Calabogie Generating Station set to be rebuilt," July 3, 2019.
69 OPG, Quarterly Risk Report – Q2 FY2020, August 11, 2020.
70 Gilligan, Keith, "Is Algae the New Nuisance Neighbor for the Pickering Nuclear Station?" durhamregion.com, August 8, 2018.
71 The National Capital Commission's Climate Change Adaptation Initiative - National Capital Commission (ncc-ccn.gc.ca).
72 *Ibid*.
73 Canada's Changing Climate Report, 2019.
74 *Ibid*.

station output. Scientists have also expressed high confidence that streamflow regimes will shift and that daily extreme precipitation will increase in Canada.[75]

- Consideration of extreme weather demand has been integrated into the IESO's Reliability Outlook[76] and capacity assessment criteria. Going forward, OPG may be impacted by associated changes in the IESO's outage approval process where extreme weather may potentially restrict OPG's ability to take outages at otherwise optimal times.

Risks influenced by climate change, such as severe weather events, or resulting directly from climate change, such as those due to higher lake temperatures and changing precipitation patterns are, therefore, increasing for OPG. Furthermore, investors, central banks and financial regulators are increasingly recognizing the risk of climate change to the economy, the stability of the financial system, and specific industries and investments. Examples include:

The Bank of Canada has indicated that it views climate change as an emerging risk for the Canadian economy and financial system. Specifically, the Bank of Canada has observed that:

> *Climate change continues to pose risks to both the economy and the financial system. These include physical risks from disruptive weather and events and transition risks from adapting to a lower carbon global economy.*[77]

The Bank of Canada indicates that it is incorporating climate change risk into its analysis of the Canadian economy and financial system, that climate change creates important physical risks in Canada and globally, and that the move to a low carbon economy involves complex structural adjustments, creating new opportunities as well as transition risk.[78]

In September 2020, the Commodity Futures Trading Commission ("CFTC"), the financial regulator that oversees the trading of futures and options in the U.S., published a report concluding that climate change is a risk to the U.S. financial system.[79] In particular, the CFTC noted the economic risk of changes that are required to mitigate climate change and the disruptive effect those changes might

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[75] Cohen, S., Bush, E., Zhang, X., Gillett, N., Bonsal, B., Derksen, C., Flato, G., Greenan, B., Watson, E (2019): Synthesis of Findings for Canada's Regions; Chapter 8 in Canada's Changing Climate Report, (ed.) E. Bush and D.S. Lemmen; Government of Canada, Ottawa, Ontario, at 424–443.

[76] IESO Reliability Outlook, From April 2019 to September 2020, at 1, 20.

[77] Bank of Canada Financial System Review-2019, May 2019, at 28.

[78] *Ibid*., at 28-29.

[79] U.S. Commodity Futures Trading Commission, "Managing Climate Risk in the U.S. Financial System," September 9, 2020.

have on the stability of the financial system itself. The key conclusions of the CFTC report are as follows:[80]

> *Climate change poses a major risk to the stability of the U.S. financial system and to its ability to sustain the American economy. Climate change is already impacting or is anticipated to impact nearly every facet of the economy, including infrastructure, agriculture, residential and commercial property, as well as human health and labor productivity. Over time, if significant action is not taken to check rising global average temperatures, climate change impacts could impair the productive capacity of the economy and undermine its ability to generate employment, income, and opportunity.*
>
> *This reality poses complex risks for the U.S. financial system. Risks include disorderly price adjustments in various asset classes, with possible spillovers into different parts of the financial system, as well as potential disruption of the proper functioning of financial markets. In addition, the process of combating climate change itself—which demands a large-scale transition to a net-zero emissions economy—will pose risks to the financial system if markets and market participants prove unable to adapt to rapid changes in policy, technology, and consumer preferences. Financial system stress, in turn, may further exacerbate disruptions in economic activity, for example, by limiting the availability of credit or reducing access to certain financial products, such as hedging instruments and insurance.*

S&P has incorporated ESG criteria into its credit rating analysis, while other investment firms and pension funds have adopted restrictions that prohibit them from owning equity or debt in companies seen as contributing to climate change. For example, in January 2020, investment manager BlackRock sent a letter to its clients announcing a number of initiatives to place sustainability at the center of its investment approach, including: making sustainability integral to portfolio management; exiting investments that present a high sustainability-related risk, and strengthening its commitment to sustainability and transparency in investment stewardship activities.[81]

McKinsey and Company published a report in April 2019 in which the consulting firm makes specific recommendations to the utility industry with regard to managing climate change risk. While noting that severe weather events such as hurricanes and wildfires are getting worse, McKinsey writes: "In other ways, too, utilities are more vulnerable to extreme weather events than in the past."[82] The report goes on to observe: "Unless utilities become more resilient to extreme weather events, they put themselves at unnecessary risk, in both physical and financial terms. Repairing storm damage

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80 *Ibid*., at i and ii.

81 BlackRock Letter to CEOs, "A Fundamental Reshaping of Finance," January 20, 2020.

82 McKinsey and Company, "Why, and how, utilities should start to manage climate change risk," April 2019, at 3.

and upgrading infrastructure after the fact is expensive and traumatic."[83] McKinsey also quotes from a 2018 report by the National Climate Assessment which stated that "utilities could see negative impacts from increased temperatures and heat waves, as well as sea level rises even in the absence of storms. This will increase the financial cost to utilities of climate change and increase the benefits of being prepared."[84]

In summary, the risks associated with changing climate parameters and severe weather events have increased for OPG since EB-2016-0152, at the asset, industry, electricity system and macroeconomic levels. Investors are keenly focused on how such risks are being managed by organizations. While we expect that the risks will continue to manifest over time, current trends point to a greater and potentially more urgent likelihood of incremental expenditures and operational impacts over the upcoming rate setting period. Unless they also happen to increase the output, refurbish or add operating capacity to a regulated facility, such incremental expenditures would not be subject to existing protections under O. Reg. 53/05 or other deferral or variance accounts currently in place for OPG.

4. Generation Asset Mix

The OEB has consistently recognized that nuclear generation assets are a higher risk than hydroelectric generation assets. For example, in support of its findings in EB-2013-0321 that OPG's business risk had changed between EB-2010-0008 and EB-2013-0321, the OEB cited the "increase [in the] proportionate share of rate base related to hydroelectric facilities from about half to approximately two-thirds now [*i.e.*, as of EB-2013-0321]," while noting that the "relative business risk of hydroelectric generation versus nuclear has been accepted by the Board as being lower in previous proceedings."[85] The OEB similarly stated in EB-2016-0152 that "[t]he OEB accepts the opinions of both experts that, in general, there are more business risks associated with nuclear generation than with hydroelectric."[86]

The OEB further clarified its view in EB-2016-0152 that it was not only rate base that drove the risk profile of OPG, but also the relative contributions of nuclear and hydroelectric generation. Specifically, the OEB found, "while the nuclear rate base will increase substantially over the five-year term, the MWh generated by nuclear will not increase, and in fact will decrease at times as units are taken out of service at Darlington. The relative contributions of revenue from hydroelectric and

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83 *Ibid*.
84 *Ibid*., at 4.
85 EB-2013-0321, Decision with Reasons, November 20, 2014, at 113. Clarification added.
86 EB-2016-0152, Decision and Order, December 28, 2017, at 102.

nuclear will not change in favour of nuclear, so it is not axiomatic that the equity thickness should be increased on this basis."[87]

With the expansion of OPG's regulated nuclear investment over the upcoming rate term due to the $12.8 billion DRP, the nuclear generation business is projected to comprise a comparatively larger portion of OPG's overall regulated rate base. In Concentric's opinion, this increase in nuclear rate base alone, with its attendant risk, continues to be supportive of a need for an increased equity thickness, notwithstanding that there is no relative increase in the nuclear versus hydroelectric MWh. In reaching this conclusion, Concentric carefully considered the OEB's prior findings that recognized both rate base and generation output as relevant to assessing the impact of relative proportions of nuclear and hydroelectric business on OPG's overall risk profile. In recognition of these findings, we also discuss below how the decline in nuclear generation will create *additional* risk, more than offsetting any reduction in risk that can be attributed to the relative decline in overall nuclear revenue after the Pickering shutdown.[88]

First, while MWh generated is one indicator of the relative proportions of OPG's business comprised of nuclear versus hydroelectric generation, it is ultimately the investment in plant, not the output itself, that drives the need for capital. For example, if a utility were to invest in low capacity factor peaking facilities to meet periods of high demand, measuring the operating risk related to those facilities based on their output would significantly understate their associated risk. Based on its experience, Concentric does not believe that investors and rating agencies will reduce their risk view of OPG when it is seeking investment to support a nuclear capital program because of a reduction in the nuclear generation output. In fact, as noted earlier, at least one rating agency, Moody's, has stated that OPG's risk will in fact increase due to lower diversification of its nuclear portfolio after Pickering shutdown.[89]

Second, it is the precise sources of OPG's increased risk (*i.e.*, the DRP and the retirement of Pickering) that are leading to decreased levels of nuclear generation over the upcoming rate period. In other words, nuclear risk is rising while nuclear generation is decreasing (and rate base is increasing).

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87 *Ibid*.

88 In its Decision and Order in EB-2016-0152, at 101, the Board stated that "[t]he EB-2013-0321 decision deals with more than one aspect of the impact of the increase in the hydroelectric generation portfolio. The two factors were the increase in annual MWh generated by hydroelectric with the addition of 48 previously unregulated facilities to the regulated portfolio and the completion of the Niagara Tunnel, and the increase in hydroelectric rate base by the addition of these assets to the regulated portfolio."

89 Moody's Investors Service, "Ontario Power Generation Inc.," December 21, 2020, at 5.

Third, the decline in nuclear generation and therefore the ratio of nuclear to hydroelectric generation creates *additional* risk from a cost recovery perspective over the upcoming period. This is because each unit of nuclear generation output will become more financially valuable to OPG as the nuclear generation that recovers the nuclear revenue requirement (including the increased nuclear rate base) is reduced, while continuing to be more financially valuable than each unit of hydroelectric generation. The greater relative cost recovery associated with each unit of nuclear output will put OPG at greater risk related to its nuclear generation operations, both relative to EB-2016-0152 and to its hydroelectric generation.

The increasing value of each unit of nuclear output (on an absolute basis and in relation to each unit of hydroelectric output), is demonstrated in Figure 9 below.

Figure 9: Value of Nuclear and Hydroelectric Output

	Value of TWh of Output ($millions)	
	Nuclear	Hydroelectric
EB-2016-0152 Rate Term	$82	$43
2022-2026 Rate Term	$108	$44
As of 2026	$121	$44

As shown in the Figure 9 above, each nuclear TWh had a value of approximately $80 million during the EB-2016-0152 rate term, compared to approximately $43 million for a hydroelectric TWh.[90] Over 2022 to 2026, based on OPG's draft rate filing at the time of writing, the value of a nuclear TWh has increased to approximately $108 million, compared to approximately $44 million for a hydroelectric TWh.[91] This represents an approximately 32% increase in the value of each unit of nuclear output and an approximately 64% increase in the amount by which the nuclear unit of output is more valuable than the hydroelectric unit of output. By 2026, the financial value of a nuclear TWh increases further, to approximately $121 million, or approximately 48% higher than in EB-2016-0152 and an approximately 97% increase in the amount by which the nuclear MWh is more valuable than the hydroelectric MWh. To put those figures into further perspective, foregone revenues from a hypothetical seven-day outage at one of OPG's Darlington nuclear reactors would have been

[90] For nuclear, based on EB-2016-0152 approved smoothed base payment amounts, arithmetically averaged over 2017 to 2021. For hydroelectric, based on approved base payment amounts pursuant to the IRM formula in EB-2016-0152 and subsequent annual proceedings, arithmetically averaged over 2017 to 2021.

[91] For nuclear, based on draft proposed smoothed base payment amounts, arithmetically averaged over 2022 to 2026. For hydroelectric, based on the approved 2021 base payment amount that will be held constant over the period pursuant to O. Reg. 53/05.

approximately $12 million during the EB-2016-0152 period, rising to $15 million in the upcoming rate setting period, and ending at approximately $17 million in 2026. This risk will be even more pronounced for OPG when Pickering retires, as an outage at one of OPG's remaining reactors would result in a loss of a quarter of OPG's nuclear generating capacity.

To further illustrate our analysis with respect to relative rate base and per unit-of-output cost recovery value, the following information is provided below:

- Figure 10 provides the relative nuclear and hydroelectric rate base from the start of OPG rate regulation by the OEB through to the upcoming rate period, as well as OPG's common equity ratio, as approved for the historical period and the minimum proposed ratio in this report for the upcoming rate term.
- Figure 11 shows a combination of the actual and forecast generation for the prescribed nuclear and hydroelectric facilities over the EB-2016-0152 rate term and the 2022-2026 forecast period
- Figure 12 is a graphical representation of the changes in generation and rate base mix over time. Figure 12 shows that nuclear generation decreases over the upcoming rate period while hydroelectric generation stays relatively flat. Meanwhile, nuclear rate base increases over the rate period, which, when combined with decreasing output, increases the value to OPG of each unit output, for which it is at risk.
- Figure 13 demonstrates this outcome, providing the unit prices for nuclear and hydroelectric generation output and the relationship between the two. Figure 13 shows that the unit price of each MWh of nuclear output increases significantly over the upcoming rate period while that for hydroelectric output is fixed.

As can be seen from Figure 10, the portion of OPG's total rate base that is nuclear was at its lowest (*i.e.*, 23%) during the period for which rates in EB-2013-0321 were set, which was also the period for which the OEB lowered OPG's common equity ratio to 45%. However, starting in 2017, the nuclear portion of rate base began to increase significantly. By 2026, *i.e.*, the end of the proposed five-year rate period, the nuclear portion of rate base is expected to be at an all-time high.

Figure 10: OPG's Prescribed Facilities Rate Base ($ billions)

	EB-2007-0905 Payment Order		EB-2010-0008 Payment Order		EB-2013-0321 Payment Order		EB-2016-0152 Rate Period[92]					EB-2020-0290 Rate Period				
	2008	2009	2011	2012	2014	2015	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hydro	$3.9	$3.8	$3.8	$3.7	$7.5	$7.5	$7.5	$7.5	$7.5	$7.6	$7.7	$7.8	$8.0	$8.2	$8.5	$8.9
Nuclear	$2.5	$2.3	$2.4	$2.3	$2.3	$2.3	$2.9	$3.0	$3.0	$7.1	$7.5	$8.8	$8.8	$11.3	$12.5	$13.4
Nuclear Portion of Rate Base	39%	38%	39%	38%	23%	23%	28%	29%	29%	48%	49%	53%	52%	58%	60%	60%
Rate Term Ratio Avg	38%				23%		38%					57%				
Common Equity Ratio	47%	47%	47%	47%	45%	45%	45%	45%	45%	45%	45%	50%[93]	50%	50%	50%	50%

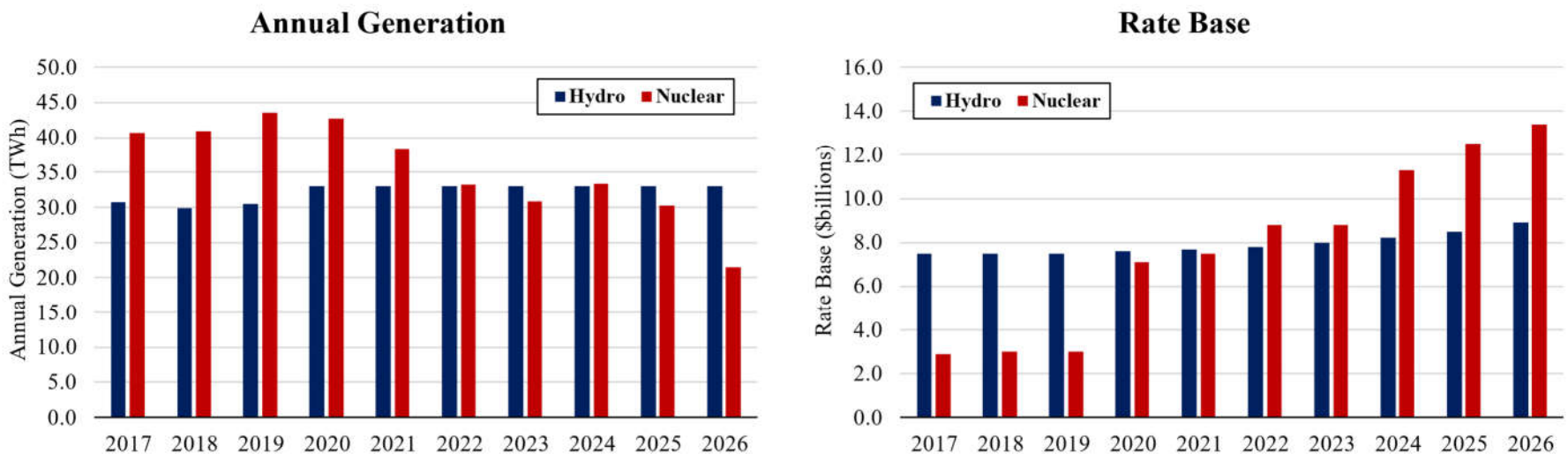
[92] Hydroelectric values as stated in EB-2016-0152, Ex. L, Tab 3.1, Schedule 20 VECC-005, Table 5; nuclear values as stated in EB-2016-0152 Payment Amounts Order, Appendix A, Tables 1-5.

[93] Proposed minimum equity ratio for 2022-2026 rate-setting period.

Figure 11: OPG's Prescribed Facilities Generation (TWh)

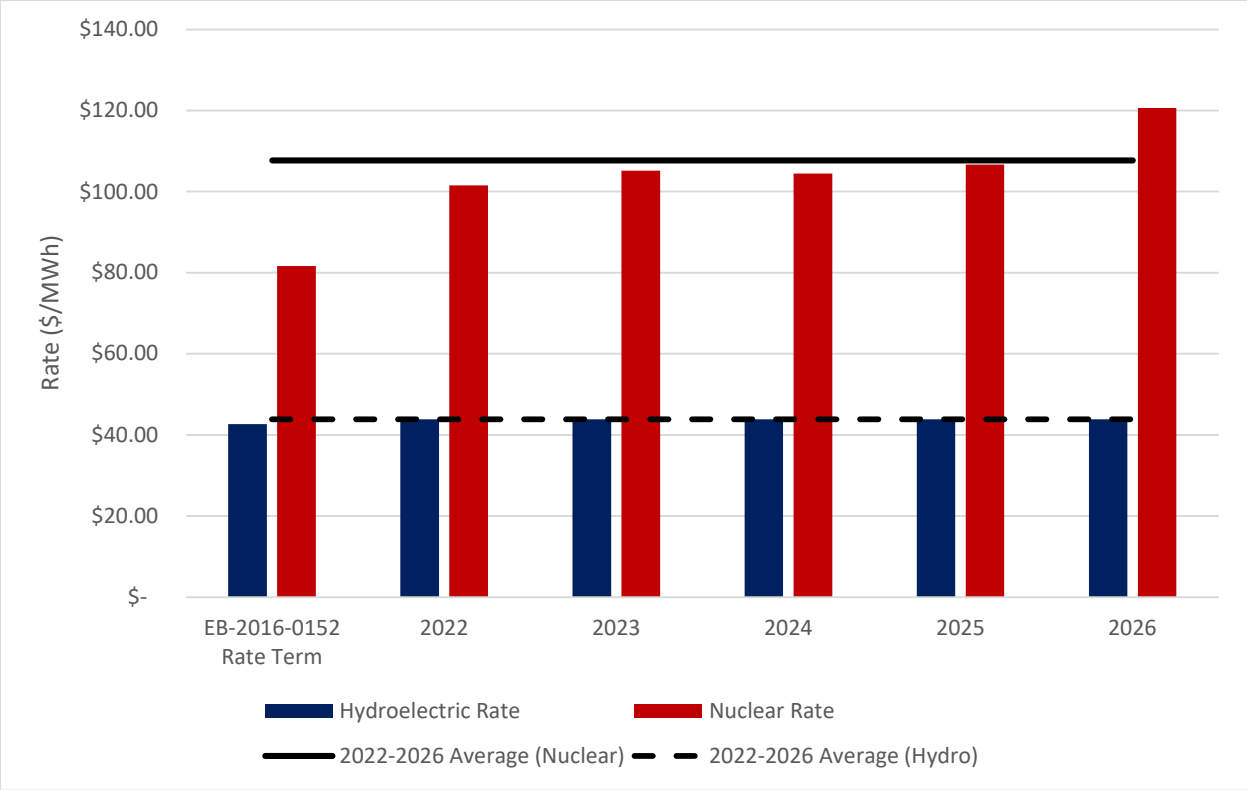
	EB-2016-0152 Rate Period					EB-2020-0297 Rate Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Hydro [94]	30.7	29.9	30.5	33.0	33.0	33.0	33.0	33.0	33.0	33.0
Nuclear	40.7	40.9	43.5	42.7	38.3	33.2	30.8	33.3	30.2	21.5

Figure 12: OPG's Generation and Rate Base Over Time, by Fuel Source



[94] Regulated Hydroelectric production for 2020 - 2026 is the 2014 and 2015 average OEB approved hydroelectric production per EB-2013-0321 Decision and Order, at 9, and EB-2016-0152 PAO, App. I, Table 2, line 3.

Figure 13: Comparative Value of Nuclear vs. Hydroelectric Output



Concentric has considered the value-of-MWh analysis above in the context of the overall level of revenue requirement to be recovered by each of the generation businesses. This approach recognizes the OEB's prior findings, including that, in the presence of changing "relative contributions of revenue from hydroelectric and nuclear," the increase in relative rate base alone "is not axiomatic that the equity thickness should be increased on this basis."[95] For example, in a scenario where the price per MWh is significantly higher for one technology but the overall revenue requirement to be recovered for that technology represents a small portion of the total regulated revenue, the overall risk profile is unlikely to be significantly impacted. In OPG's circumstances, however, the estimated nuclear revenue requirement for the upcoming rate period remains at levels substantially similar and in fact higher, due to the DRP, than in EB-2016-0152, until the Pickering retirement at the end of 2025.

While the nuclear revenue requirement does decline in 2026, due to the elimination of Pickering operating costs, it continues to account for 65% of total regulated revenues, in addition to reflecting a significantly higher rate base than the hydroelectric business. It is Concentric's view that these factors, when combined with the increased diversification risk for the nuclear fleet discussed above

[95] EB-2016-0152, Decision and Order, December 28, 2017, at 102.

and the higher relative value of each nuclear unit of output, result in additional risk that is at least equal to, if not greater than, the notional reduction in risk that can be attributed to the relatively lower overall nuclear revenue requirement by 2026.

In conclusion, by the end of the upcoming rate period, nuclear rate base is projected to be 60% of OPG's total prescribed generation rate base, as compared to 49% at the end of the EB-2016-0152 rate period (and less than 40% during the period in which OPG's deemed equity ratio was 47%). As it is the level of investment that drives the need for capital, given that nuclear business is higher risk, this factor supports the need for a higher equity ratio for OPG. In the context of the OEB's prior findings on the relative output and revenue contributions of each regulated business, Concentric also finds that the increased relative cost recovery risk for each unit of nuclear output versus hydroelectric, $39 per MWh average difference in EB-2016-0152 to $77 per MWh difference by the end of upcoming rate period, is a source of additional risk relative to EB-2016-0152. This, coupled with the increase in nuclear-specific business risks discussed earlier, including lower diversification of the nuclear fleet, indicates a substantial increase in OPG's overall business risk for its regulated operations.

Changes in Financial Risk

Financial risk is an important component of a company's overall risk profile. Financial risk, which is focused on solvency and liquidity, is often measured through credit metrics, and a utility's credit rating provides a widely-accepted opinion from a third party credit rating agency of the utility's overall creditworthiness. Concentric's consideration of OPG's financial risk therefore focused on the review of the company's credit rating.

In adopting this approach, Concentric was mindful of the OEB's findings in EB-2016-0152 that "credit risk is not an independent factor in assessing whether business risk has changed – it is the credit rating agencies' assessment of those risks as to how they may affect solvency and liquidity."[96] Concentric agrees that financial risk and business risk are often interrelated. However, Concentric is also guided by the OEB's previous findings distinguishing between financial risk and business risk, in the context of their relationship with capital structure, and specifically that "capital structure should be reviewed only when there is a significant change in *financial*, business or corporate fundamentals."[97] Additionally, Concentric is guided by the fact that, as discussed in the "Background on Prior OEB Decisions" (Section 3 of this report), maintenance of financial integrity is a key component of the fair return standard.

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[96] EB-2016-0152, Decision and Order, December 28, 2017, at 107.
[97] EB-2009-0084, Report of the Board, December 11, 2009, at 49. Emphasis added.

OPG's issuer rating from S&P remains at BBB+ and its stand-alone credit profile absent support from the Province is a bb+ rating (a non-investment grade level), both of which are the same as at the time of EB-2016-0152. Since 2019, OPG also has a Moody's issuer rating of A3, with a stand-alone profile of baa3 (the lowest investment grade rating level) absent support from the Province. With the majority of peer companies being assessed at the a- and bbb+ level on a stand-alone basis (as discussed in Section 8), OPG's stand-alone credit profile under both the S&P and Moody's frameworks suggests that its stand-alone business and financial risks are higher in comparison to peers.

Both S&P and Moody's expect OPG to maintain credit metrics at a certain level in order to maintain its current credit rating. For S&P, the Funds from Operations ("FFO")/Debt ratio is the key metric referred to in S&P's reports on OPG. According to S&P's most recent credit report on OPG, S&P has indicated a downside threshold for the current rating of 13%.[98] Moody's has indicated that its financial metrics assessment could lead to a downgrade if a decline of Cash From Operations pre-Working Capital (CFO)/ Debt ratio to below the 12% threshold on a sustained basis.[99]

These core ratios are expected to be under pressure during the earlier years of the upcoming rate period and OPG's business plan forecasts one or both of them will temporarily decline below the corresponding thresholds. Our understanding is that lower nuclear generation during the DRP, which is expected to impact the rate smoothing determinations and therefore OPG's future operating cash flows, coupled with a heighted capital investment program, including the DRP, contribute to this pressure.

While OPG's business plan indicates that it will continue to focus on communicating to the rating agencies the short-term nature of the potential decline in the metrics and that this decline is not reflective of OPG's ongoing financial strength, there remains an inherent risk of a credit rating action, which would result in a downgrade or a change in credit outlook.[100] In these circumstances and pending the outcome of the upcoming rate application proceeding, Concentric considers the pressure on the credit metrics to signify additional financial risk since EB-2016-0152. An increase in OPG's equity ratio, therefore, and particularly during this period, would be consistent with OPG's increased financial risk and the financial integrity component of the fair return standard.

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98 In its July 2020 report, S&P stated "[w]e could take a negative rating action on OPG over the next 12-18 months if the company's financial measures weaken, reflecting FFO to debt consistently below 13%." S&P Global Ratings, "Research Update: Ontario Power Generation Inc.," July 17, 2020, at 3.

99 Moody's Investors Service, "Ontario Power Generation Inc.," December 21, 2020, at 3.

100 The credit rating action risk discussed is in addition to the impact of any rating change for the Province that would be expected to affect OPG's rating in a corresponding manner, as was the case in 2015.

SECTION 8:
PROXY GROUP COMPARATIVE ANALYSIS

1. Overview

In addition to assessing changes to OPG's business and financial risk profile since EB-2016-0152, Concentric also analyzed the equity ratios of other North American utilities screened for risk characteristics similar to OPG's. To identify companies with risk characteristics similar to OPG, Concentric selected publicly-traded investor-owned utility companies that passed a series of screening criteria based on OPG's operational profile. Concentric reviewed three separate measures of the equity ratios of those similarly-situated regulated utilities: (1) the historical equity ratios maintained by comparable publicly-traded holding companies; (2) the historical equity ratios maintained by the operating subsidiaries of those holding companies; and (3) the equity ratios authorized by the regulators of those operating subsidiaries. Those measures provide context for where, within a reasonable range, OPG's equity ratio should be set by the OEB, with the regulated operating company equity ratios being most relevant for purposes of assessing OPG's regulated equity thickness. Concentric also analyzed two different proxy groups. The first proxy group (the "Concentric Proxy Group") was a broader group of companies that met the screening criteria described herein. The second proxy group (the "Moody's Peer Group") included the companies identified as OPG's peers by Moody's.[101] The results for those two proxy groups are provided in the Figure 14 and Figure 15 below.

Figure 14: Summary of Comparative Analysis Results (Concentric Proxy Group)

Analytical Approach	Mean Equity Ratio	Median Equity Ratio
Holding Company Equity Ratios: 5-Year Avg.	45.7%	47.4%
Operating Company Equity Ratios: 5-Year Avg.	52.8%	53.0%
Operating Company Equity Ratios: Authorized	49.5%	49.6%

[101] Moody's Credit Opinion, Ontario Power Generation Inc., December 21, 2020, at 9.

Figure 15: Summary of Comparative Analysis Results (Moody's Peer Group)

Analytical Approach	Mean Equity Ratio	Median Equity Ratio
Holding Company Equity Ratios: 5-Year Avg.	50.6%	49.1%
Operating Company Equity Ratios: 5-Year Avg.	55.9%	53.6%
Operating Company Equity Ratios: Authorized	50.7%	50.1%

Our analysis of comparable regulated utilities with significant regulated generation assets indicates that OPG's current deemed equity thickness is low relative to comparable companies, despite OPG falling towards the upper end of the spectrum of risk profiles established by the proxy companies. Taken together, the analyses support an equity ratio of no less than 50% for OPG.

2. Use of Proxy Company Analysis for Cost of Capital Determinations

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

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

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

> *during the six-month study period; (4) the inclusion of companies with no major merger activity during the six-month study period; and (5) companies whose DCF results pass threshold tests of economic logic.*[102]

While the individual screens require modification based on the subject company to which proxy companies are being compared,[103] the goal of screening companies based on their risk characteristics increases both the comparability of the group and the confidence that the analyst (or regulator) can have in drawing conclusions based on analyses of the proxy group. Therefore, for consistency with the above considerations, Concentric relied on a screening process similar to that we typically apply in cost of capital analyses to narrow the list of potential companies in order to establish a proxy group of North American electric utility companies that are risk appropriate for comparison to OPG.

Given the unique characteristics of OPG, and, in particular, the fact that its regulated operations consist of 100% generating assets, it is not possible to find proxy companies that are perfectly comparable from a risk perspective. At issue, then, is how to determine an appropriate equity ratio in the context of that range. That determination must be based on an assessment of OPG-specific risks relative to the proxy group and informed judgment. For example, the National Energy Board (predecessor to the Canada Energy Regulator), in discussing the cost of capital for the TransCanada Mainline, stated, "[t]o the greatest extent possible, comparable companies have to face similar business risk as the Mainline. If they do not, judgment needs to be applied to the cost of capital estimates to reflect business risk differences." [104] In other words, whereas a subject company of average risk relative to the proxy group potentially would warrant an equity ratio equal to the average or median result of the proxy group, a company of greater risk potentially would warrant an equity ratio above the mean or median result, and a company of lower risk potentially would warrant an equity ratio below the mean or median result.

In summary, the use of comparable companies to benchmark business and financial risks in the context of cost of capital determinations is a common practice among North American regulatory jurisdictions, and it is a method Concentric has applied to our evaluation of OPG's capital structure. In the discussion that follows, we present Concentric's analysis of OPG's level of business and

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

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

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

financial risk relative to a proxy group of electric utilities, as well as our review of equity ratios authorized for the proxy group to provide context for where, within a reasonable range, OPG's equity ratio should be set by the OEB.

3. Selection of Proxy Companies

As discussed above, Concentric studied data derived from two separate proxy groups, the Concentric Proxy Group and the Moody's Peer Group.

As a starting point for our screening process for the Concentric Proxy Group, Concentric reviewed data related to both Canadian and U.S. utilities, including the following Canadian utilities: Algonquin Power & Utilities Corp ("Algonquin"), Canadian Utilities Limited, Emera Inc. ("Emera"), Enbridge Inc., Fortis Inc. ("Fortis"), and TC Energy Corporation, and the 37 U.S. companies that Value Line classifies as "Electric Utilities."[105]

From that group, Concentric screened for companies that:

- **Own regulated generation assets that are included in rate base**. As it relates to the rate setting process, OPG's assets represent 100% rate-regulated generation. As such, it is important to exclude companies from the proxy group that bear no risks related to regulated generation. The reason for this is the generation function is generally regarded by investors as being higher risk than electric transmission or distribution. As stated by Moody's in its 2017 ratings methodology for regulated electric and gas utilities, "[g]eneration utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays;" [106]

[105] Precedent for the consideration of U.S. proxy companies in Canadian cost of equity analyses is discussed in Appendix C.

[106] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, at 21.

- **Own regulated nuclear and/or hydroelectric generation**.[107] As noted earlier, OPG's rate regulated facilities consist of the Pickering and Darlington nuclear stations, as well as 54 hydroelectric generating stations. In addition, as previously noted, the OEB has recognized that nuclear assets are higher in risk than hydroelectric assets. Therefore, it is important to compare OPG against a group of companies that also own regulated nuclear and/or hydroelectric generation facilities;

- **Have regulated revenue and regulated net income that make up greater than 60% of total revenue and total income for the consolidated company**. This screen, in combination with the screen below regarding electricity revenue and net income, serves to exclude companies that do not derive a significant portion of their financial results from regulated electric operations. While rates in this proceeding are being set for OPG's 100% rate-regulated nuclear operations, these two screens are set at levels below 100% so that the resulting proxy group is not unduly small. Including only those companies that derive more than 60% of their revenues and net income from regulated operations ensures that the proxy companies are protected by regulation rather than being subject to substantial merchant or market-related risks. While 60% is not a "bright line" percentage for separating regulated from non-regulated companies, in Concentric's experience, using a screening criteria of around 60% increases the comparability of the proxy group to the regulated utility without unduly limiting the size of the group

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

[107] Excludes utilities with only a minimal (*i.e.*, less than 5% of their total generation portfolio) amount of nuclear or hydroelectric generation.

- **Have an investment grade credit rating similar to that of OPG**. As noted earlier, OPG has an "A (low)" issuer and unsecured debt rating from DBRS, a "BBB+" corporate and unsecured debt credit rating from S&P, and an "A3" senior unsecured debt rating from Moody's. As also noted earlier, S&P and Moody's rate OPG as "BB+" and "baa3" (*i.e.*, three notches below its corporate credit rating) on a stand-alone basis, before consideration of support by the Province. As credit ratings are based on the utility's business risk profile (including an assessment of its regulatory environment) and financial risk profile, companies with similar credit ratings have been determined by the rating agency to have similar levels of business and financial risk. This concept has been adopted by regulatory agencies, including the FERC, which has found that "it is reasonable to use the proxy companies' corporate credit rating as a good measure of investment risk, since this rating considers both financial and business risk."[108] Concentric's credit rating screen selects electric utility companies with investment-grade credit ratings (an S&P credit rating of BBB- or above or a Moody's credit rating of Baa3 and above), which reduces the need to adjust the results to account for any perceived differences in business or financial risk compared to OPG. Further, selecting proxy companies that, like OPG, have an investment grade credit rating ensures that the proxy companies are generally in sound financial condition. Because credit ratings consider business and financial risks, the ratings provide a broad measure of investment risk that is widely referenced by investors.[109]

4. Proxy Group Summary

None of the publicly traded Canadian companies that Concentric reviewed met all of our screening criteria. Emera, however, only failed the screen that each utility should have more than a minimal amount of regulated hydroelectric and/or nuclear generation.[110] Fortis only failed the screens that each utility should have regulated electricity revenue and net income that make up greater than 80% of the consolidated company's regulated operations and that each utility should have more than a minimal amount of regulated hydroelectric and/or nuclear generation.[111] Algonquin failed the screens that each utility should own more than a minimal amount of regulated nuclear and/or

[108] See, for example, Potomac-Appalachian Transmission Highline, LLC, 122 FERC ¶ 61,188 (2008), at 97.
[109] The only utility removed from the proxy group due to this screening criterion is PG&E Corporation, which has a sub-investment grade credit rating due to its recent bankruptcy.
[110] Specifically, Emera currently owns no regulated hydroelectric or nuclear generation.
[111] Fortis has 76% regulated electricity revenue and regulated net income, while only owning a minimal amount of regulated hydroelectric generation (and no nuclear generation).

hydroelectric generation and that each utility should derive greater than 80% of consolidated regulated revenue from regulated electricity operations.[112]

In order to broaden the proxy group to include at least a minimal number of Canadian utilities, Concentric included Emera, Fortis, and Algonquin in the proxy group, as they otherwise meet our screening criteria. Figure 16 presents the sixteen U.S. companies that met our screening criteria, along with OPG and the three Canadian companies noted above. In addition to the company name, Concentric also provides the S&P rating, as well as S&P's business risk and financial risk rating summary for each company. Exhibit 1 details how each proxy company meets the screening criteria above.

[112] Algonquin owns just 16 MW of hydroelectric generation according to S&P Global Market Intelligence and has 49% regulated electricity revenue.

Figure 16: Concentric Proxy Group and OPG

Company	Ticker	S&P Summary: Credit Rating / Outlook	S&P Summary: Business Risk	S&P Summary: Financial risk
OPG	n/a	BBB+/Stable	Strong	Significant
ALLETE, Inc.	ALE	BBB/Stable	Strong	Significant
Ameren Corporation	AEE	BBB+/Stable	Excellent	Significant
American Electric Power Co., Inc.	AEP	A-/Stable	Excellent	Significant
Avista Corporation	AVA	BBB/Stable	Strong	Significant
Duke Energy Corporation	DUK	A-/Stable	Excellent	Significant
Edison International	EIX	BBB/Negative	Strong	Significant
El Paso Electric Company[113]	EE	Not Rated	Not Rated	Not Rated
Entergy Corporation	ETR	BBB+/Stable	Strong	Significant
FirstEnergy Corporation	FE	BBB/Negative	Excellent	Aggressive
Evergy, Inc.	EVRG	A-/Stable	Excellent	Significant
IDACORP, Inc.	IDA	BBB/Stable	Strong	Significant
NextEra Energy, Inc.	NEE	A-/Stable	Excellent	Intermediate
Pinnacle West Capital Corporation	PNW	A-/Stable	Excellent	Significant
PNM Resources, Inc.	PNM	BBB/Stable	Strong	Significant
Portland General Electric Company	POR	BBB+/Negative	Excellent	Significant
Southern Company	SO	A-/Negative	Excellent	Significant
Xcel Energy, Inc.	XEL	A-/Stable	Excellent	Significant
Algonquin Power & Utilities Corp	AQN	BBB/Stable	Strong	Significant
Emera, Inc.	EMA	BBB/Stable	Excellent	Aggressive
Fortis Inc.	FTS	A-/Negative	Excellent	Significant

As described above, Concentric also considered the Moody's Peer Group, which is a proxy group composed of companies identified by Moody's as OPG's peers.[114] Figure 17 presents those three companies along with OPG. Again, Concentric also provides the S&P rating, as well as S&P's business risk and financial risk rating summary for each Moody's peer.

[113] S&P withdrew its ratings on El Paso Electric Co. ("El Paso") on September 18, 2020, due to a lack of sufficient information. Previously, El Paso was rated BBB with a negative outlook, with "Strong" business risk and "Significant" financial risk.

[114] Moody's Credit Opinion, Ontario Power Generation Inc., December 21, 2020, at 9.

Figure 17: Moody's Proxy Group and OPG

Company	Ticker	S&P Summary: Credit Rating / Outlook	S&P Summary: Business Risk	S&P Summary: Financial risk
OPG	n/a	BBB+/Stable	Strong	Significant
Public Service Enterprise Group, Inc	PEG	BBB+/Stable	Strong	Significant
NextEra Energy, Inc.	NEE	A-/Stable	Excellent	Intermediate
Exelon Corporation	EXC	BBB+/Negative	Strong	Significant

5. Proxy Group Business Risk Analysis

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

Concentric focused on two primary business risk characteristics – operational profile, and generation percentage and mix.

a. Operational profile

Concentric examined the operations of each of the companies in the two proxy groups. Exhibits 5.1 and 5.2 provide summaries of several relevant indicators for the operating subsidiaries of the Concentric Proxy Group and the Moody's Peer Group, respectively, including: (1) the province or state in which the utility provides service; (2) the ratemaking mechanisms available to the utility (*e.g.*, fuel cost recovery, revenue decoupling, capital cost recovery, etc.); and (3) whether the jurisdiction relies on historical or forecast test years for ratemaking purposes.

In reviewing the comparability of the ratemaking mechanisms available to proxy group companies, Concentric specifically considered the OEB's statement in EB-2016-0152 that "in OPG's specific circumstances, there are a number of factors that substantially mitigate that risk [*i.e.*, higher business risks associated with nuclear generation]. These include the various protections provided by O. Reg. 53/05 and the variance and deferral accounts that allow OPG the opportunity to recover substantially all their unexpected or unforeseen costs."[115]

[115] EB-2016-0152, Decision and Order, December 28, 2017, at 102. Clarification added.

Based on a review of OPG variance and deferral account activity since the beginning of the current rate term, identified below are the main accounts applicable to OPG's regulated nuclear business.[116] Also provided is Concentric's consideration of the risk-reducing properties, if any, of the accounts, including in the context of the proxy group.

- *Nuclear Liability Deferral Account* (per O. Reg. 53/05) – allows OPG to recover actual revenue requirement impact of its nuclear decommissioning and waste management costs, which has a risk reducing effect. However, Concentric observes that US nuclear utilities are generally subject to recovery mechanisms that similarly facilitate recovery of nuclear decommissioning and waste management costs and therefore OPG's circumstances are considered comparable to the proxy group in this regard.[117]
- *Capacity Refurbishment Variance Account* (per O. Reg. 53/05) – for the nuclear business, allows OPG to recover prudently-incurred costs incurred to increase the output, refurbish or add operating capacity, which for the nuclear business primarily relates to the DRP and enablement of Pickering extended operations. The account has risk reducing properties. However, with the DRP being the larger component, Concentric reviewed and concluded in an earlier section that similar regulatory protections for large nuclear construction projects are in place in other jurisdictions. In addition, many of the proxy companies have in place capital tracker mechanisms that allow for rate base treatment between rate cases.
- *Nuclear Development Variance Account* (per O. Reg. 53/05) – allows OPG to recover prudently incurred costs incurred for planning and preparation for the development of new nuclear generation facilities. While this account has risk reducing properties, as noted above, other jurisdictions provide similar regulatory protection for large nuclear construction projects.
- *Income and Other Taxes Variance Account* – records the impact of changes in tax legislation, reassessments of tax returns and similar changes, which reduces risk.

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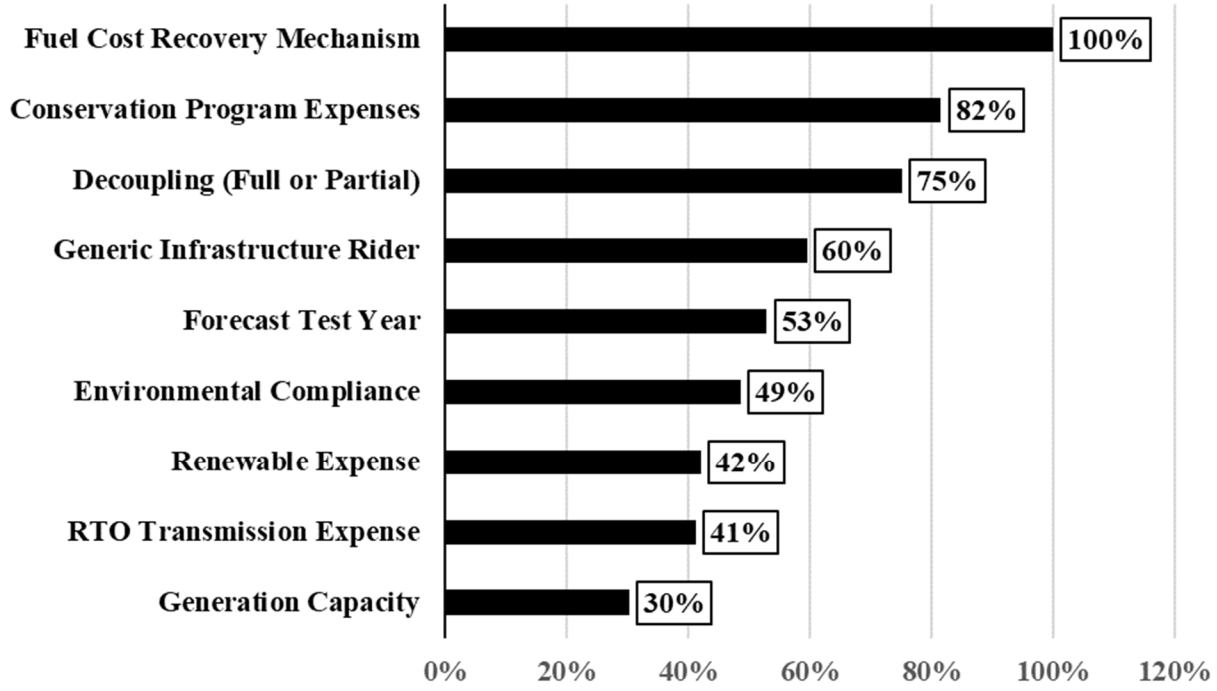
[116] Ancillary Services Net Revenues Variance Account – Nuclear sub-account was not reviewed as it has historically had immaterial balances. Also not listed is the Pickering Closure Costs Deferral Account required pursuant to recent amendments to O. Reg. 53/05. As noted in an earlier section, that account serves to mitigate what would otherwise be a significant additional risk relative to EB-2016-0152 (and the proxy group), being the recovery of downsizing costs in connection with the planned Pickering shutdown during the upcoming rate term. The Rate Smoothing Deferral Account is also not identified as it functions solely as a collection deferral mechanism.

[117] For spent nuclear fuel long-term disposal, U.S. utilities have been subject to a pass through charge from the U.S. Department of Energy, which bears the ultimate obligation. This is in contrast to OPG, which bears the ultimate obligation for spent fuel disposal, in addition to nuclear station decommissioning.

- *Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account* and *Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account* – established pursuant to an OEB requirement for OPG to bring forward accounting orders related to certain accounting changes to nuclear decommissioning and waste management liabilities and station end-of-life dates; these accounts have or are recording net credit balances to customers. On this basis, these accounts do not serve to reduce risk to OPG.
- *Bruce Lease Net Revenues Variance Account* (O. Reg. 53/05) – records variances in net earnings from OPG's unregulated lease arrangement for the Bruce nuclear generating stations with Bruce Power. As this account uniquely relates to unregulated operations, it is not considered in Concentric's risk profile analysis for OPG's prescribed assets.
- *Pension and OPEB Cash Versus Cash Differential Deferral Account* – established to record the difference between accrual costs and cash amounts for pension and other post-employment benefit ("OPEB") pending the outcome of the OEB's consultation on regulatory treatment of pension and OPEB costs. The consultation has concluded, confirming the accrual accounting method as the default method for ratemaking. The purpose of the account was to facilitate a more in-depth review of recovery methodologies on a sector-wide basis, which had the effect of delaying OPG's recovery of these amounts to the ultimate benefit of customers.

Additionally, as shown in Exhibit 5.1 and summarized in Figure 18 below, the operating utilities held by the proxy group companies have a number of different adjustment clauses and cost recovery mechanisms that provide risk mitigation.

Figure 18: Summary of Regulatory Mechanisms for Concentric's Proxy Group



On the basis of the above, Concentric concludes that in this respect OPG is risk comparable to the proxy companies, assuming OPG's existing deferral and variance accounts continue in the upcoming proceeding.

One important exception to this is OPG's being entirely at risk related to variability in the output of its nuclear facilities. The companies in the proxy group do not face comparable risk, and, in fact, many recover costs through a mix of fixed and variable charges, and/or have decoupling in place. For the proxy companies, revenue decoupling mechanisms further reduce exposure to volumetric risk.

In addition to proxy group comparability, Concentric also considered the general comparability of OPG's deferral and variance accounts to other regulated electric utilities in Ontario. In doing so, Concentric observed that the majority of OPG's accounts would be classified as "Group 2" accounts according to the OEB's Accounting Procedures Handbook. Group 2 accounts require a prudence review by the OEB before the utility is allowed to recover those costs. In contrast, Group 1 deferral and variance accounts do not require a prudence review.

Concentric reviewed the deferral and variance accounts for a sample of other regulated electric utilities in Ontario (including Hydro One Networks, Toronto Hydro, Hydro Ottawa, Niagara-on-the-Lake Hydro, and ENWIN) and determined that those companies have a mix of Group 1 and Group 2

accounts. Because the disposition of Group 2 deferral and variance accounts involves a greater degree of regulatory scrutiny than Group 1 accounts, Concentric concludes that OPG has relatively greater risk of cost recovery for its deferral and variance accounts than do other electric utilities in Ontario.

b. Generation percentage and mix

Concentric analyzed the generation percentage and mix of each proxy company to assess the percentage of each company's assets that is generation, and further, the percentage of generation capacity that is comprised of nuclear generation. As shown in Figure 19 and Figure 20, OPG is the only company in the proxy group that is a pure-play regulated generation company. OPG also has the highest percentages of nuclear and hydroelectric generation. As discussed above, the investment community generally considers the generation function to be higher risk than other regulated electric operations.

Figure 19: Generation versus Transmission and Distribution Assets

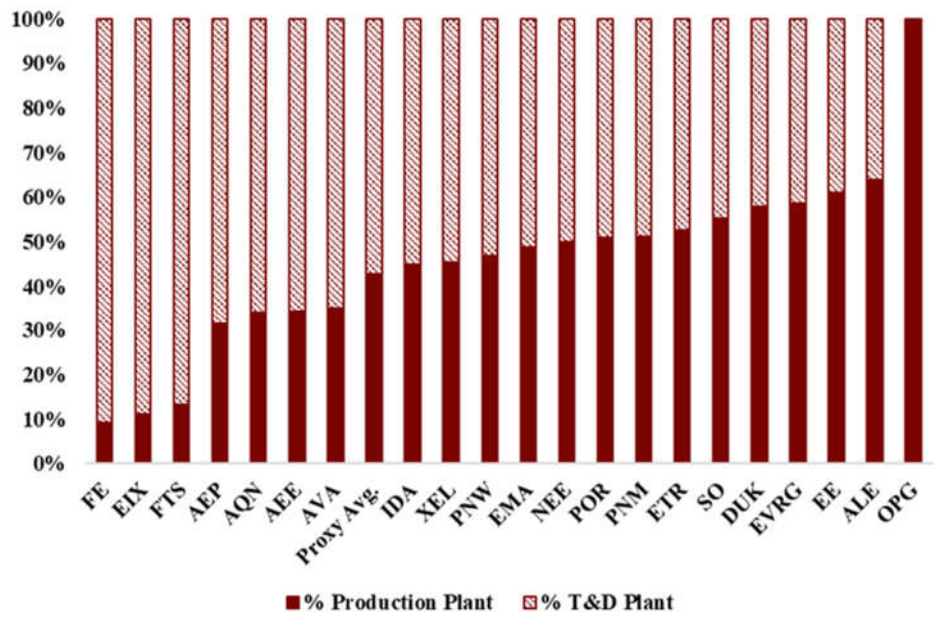
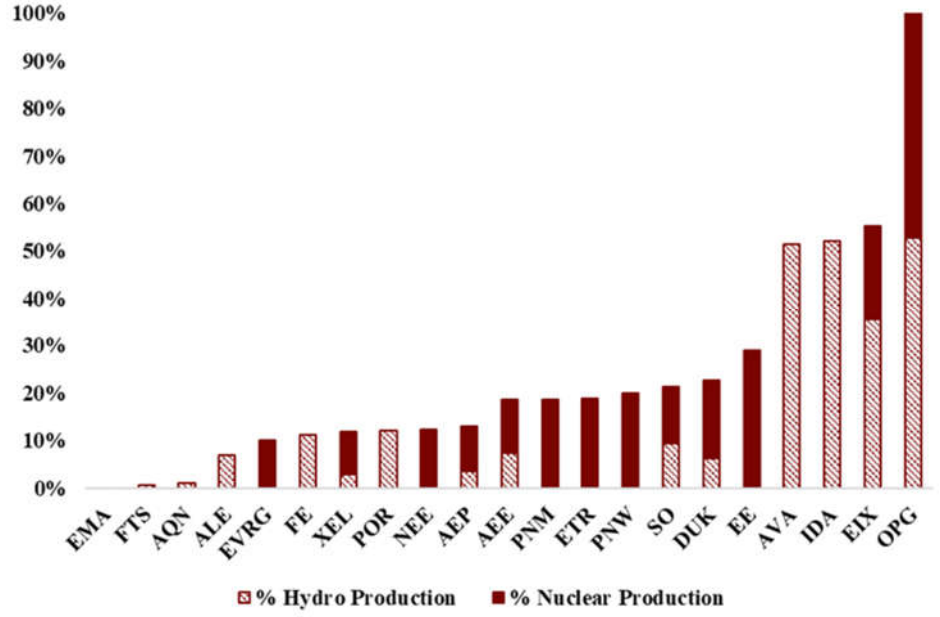


Figure 20: Generation Mix (MW), Percentage Hydro and Nuclear Generation



6. Proxy Group Financial Risk Analysis

In order to assess the financial risk of OPG relative to the proxy group, Concentric analyzed the allowed common equity ratios at the operating company level and the actual book equity ratios for these companies at both the holding company and operating company level. Concentric analyzed these different variants of equity ratios in order to provide a range of observations. Book equity ratios at the holding company level, however, reflect a different risk profile than pure regulated utility operations, and Concentric has applied less weight to those results.

The proxy group mean and median results are measures of central tendency for the proxy group from which inferences about a reasonable equity ratio can be made for OPG, after consideration of differences in risk profiles between OPG and the proxy group. Specifically, the mean is "generally the best measure of central location for purposes of statistical inference,"[118] while also being at risk of being "unduly influenced by extreme observations."[119] The median, or middle point of a set of observations at which half of the set of observations are above it and half and below it, is not subject to the same distortion due to extreme observations.[120] Figure 21 and Figure 22 summarize the

[118] Keller and Warrack, Statistics for Management and Economics, 5e ed., Duxbury Thompson Learning, 2000, at 92.
[119] *Ibid*.
[120] *Ibid*., at 93.

results in tabular format for the Concentric Proxy Group and Moody's Peer Group, respectively. Schedules 1 through 3 provide the analysis summarized in Figure 21 and Figure 22.

Figure 21: Concentric Proxy Group Equity Ratios

Company	Operating Subsidiaries: Avg. Authorized Equity Ratios (%)[121]	Operating Subsidiaries: 5-Year Avg. Actual Equity Ratios (%)[122]	Holding Company: 5-Year Avg. Actual Equity Ratios (%)[123]
ALE	53.81	58.79	58.44
AEE	50.00	52.90	49.34
AEP	46.07	48.91	47.88
AVA	49.36	50.56	50.34
DUK	52.26	53.00	47.02
EIX	52.00	55.36	43.98
EE	48.57	48.88	47.70
ETR	47.89	48.58	36.96
FE	48.00	55.63	26.82
EVRG	50.37	54.84	54.70
IDA	49.90	53.82	56.20
NEE	48.00	61.13	49.08
PNW	55.80	54.08	53.68
PNM	48.11	48.57	42.32
POR	50.00	50.05	51.18
SO	55.25	51.97	38.36
XEL	54.41	54.36	44.10
AQN	48.49	56.59	39.73
EMA	37.50	48.26	39.03
FTS	43.61	49.87	38.08
Mean	**49.47**	**52.81**	**45.75**
Median	**49.63**	**52.95**	**47.36**
OPG	45.00	45.00	45.00

121 *See*, Exhibit 2.1.
122 *See*, Exhibit 3.1.
123 *See*, Exhibit 4.1.

Figure 22: Moody's Proxy Group Equity Ratios

Company	Operating Subsidiaries: Avg. Authorized Equity Ratios (%)[124]	Operating Subsidiaries: 5-Year Avg. Actual Equity Ratios (%)[125]	Holding Company: 5-Year Avg. Actual Equity Ratios (%)[126]
PEG	54.00	53.55	54.46
NEE	48.00	61.13	49.08
EXC	50.05	53.06	48.24
Mean	**50.68**	**55.91**	**50.59**
Median	**50.05**	**53.06**	**49.08**
OPG	45.00	45.00	45.00

As shown in Figure 21 and Figure 22, OPG's deemed equity ratio of 45% is lower than the average and median equity ratios Concentric identified for both proxy groups and all three analytical approaches. The mean and median equity ratios at the operating company level exceed 49% for both proxy groups. Further, the mean and median equity ratios at the holding company level exceed 49% for the Moody's Peer Group. Only the mean and median equity ratios at the holding company level for the Concentric proxy group are lower than 49%. OPG's deemed equity ratio is 0.75 to 10.91 percentage points below the results of Concentric's analysis, depending on the proxy group and analytical approach employed.

The only authorized equity ratios lower than OPG's are those for Emera and Fortis, both with lower risk T&D operations and no nuclear generation.[127] Certain U.S. companies produce analytical results close to OPG's deemed equity ratio, but these companies also have substantial T&D assets to mitigate their generation risk. As discussed previously, generation assets are generally considered riskier from an investment perspective than T&D assets because generation assets typically have longer construction lead times, are subject to production risk and to risk from changes in environmental regulations and requirements and are more subject to technological obsolescence. For example, in EB-2007-0905, the OEB concluded: "OPG's nuclear business is riskier than regulated transmission and distribution utilities in terms of operational and production risk, but is less risky than merchant generation."[128] In that same decision, the OEB also commented on the relative risk of generation as

[124] *See*, Exhibit 2.2.
[125] *See*, Exhibit 3.2.
[126] *See*, Exhibit 4.2.
[127] In addition, both Emera and Fortis have substantial Canadian operations, and Canadian utilities have historically been authorized lower equity ratios than their U.S. counterparts, an outcome that Concentric does not believe reflects the converged risk profiles of Canadian and U.S. regulatory jurisdictions, as discussed earlier.
[128] EB-2007-0905, Decision with Reasons, November 3, 2008, at 149.

follows: "The Board has concluded that OPG is of higher risk than electricity LDCs, gas utilities and electric transmission utilities and of lower risk than merchant generation."[129]

Figure 19 presented earlier, provides the percentage of generation assets and T&D assets for OPG and the proxy group companies. As shown in Figure 19 100% of OPG's assets are dedicated to generation, while the proxy group companies have a mixture of generation assets and T&D assets. On that basis, we conclude that OPG has higher business risk than the proxy group companies, which suggests a higher deemed equity ratio is appropriate for OPG.

With the lower deemed equity ratio of OPG compared to the proxy group companies, Concentric concludes that OPG has greater financial risk than the proxy group. Concentric also considers that OPG is rated three notches lower than its issuer rating on a stand-alone basis according to S&P and Moody's, which places it toward the low end or below the investment grade credit rating range relative to the proxy group. This higher financial risk profile of OPG suggests its deemed equity ratio should fall at the upper end of the proxy group.

Further, Concentric notes that Georgia Power has been allowed to maintain an equity ratio of 56% for ratemaking purposes during the construction of Vogtle plant units 3 and 4 in recognition of the cash flow pressure during this large construction project. In particular, on December 17, 2019, the Georgia PSC approved a settlement agreement for a three-year rate plan that included an ROE of 10.50% on 56% common equity. In its Order approving the settlement, the Commission noted that Staff had recommended an equity ratio of 51%; however, the Commission determined that: "[b]ased on the evidence presented, the Commission finds and concludes that a capital structure of 56% common equity level is just and reasonable, and will help to mitigate the risk of a credit rating downgrade."[130]

Comparative Analysis Conclusions

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

- OPG's generation mix is comprised of more nuclear generation than the proxy group, indicating that OPG is riskier than the group on this factor.
- OPG has an asset mix that is 100% generation in contrast to the proxy group companies with an average of 43%, indicating OPG is a riskier business.

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[129] *Ibid*.
[130] Docket 42516, Order, at 6.

- Unlike other proxy group companies with nuclear operations, OPG is fully subject to revenue variability risk on its nuclear generation, which significantly increases risk;
- OPG has several deferral and variance accounts for its operations, as do other proxy companies; therefore, OPG is considered to be risk comparable to the proxy group in this area. Several of OPG's accounts pertain to nuclear refurbishment and new nuclear planning, for which similar protections are provided for nuclear utilities in other jurisdictions;
- OPG's deemed equity ratio is lower and its stand-alone credit rating (by S&P) is weaker than the vast majority of the proxy companies, exposing OPG to more financial risk than the proxy companies.

On a relative risk basis, Concentric finds OPG, with its significant nuclear concentration, a pure generating company business profile, higher nuclear variability risk and higher financial risk, to fall towards the upper end of the spectrum of risk profiles established by the proxy companies. Depending on the analytical approach employed, and proxy group studied, the proxy group's mean equity ratio ranges between 45.75% and 55.91%. As discussed earlier in the report, however, Concentric places less weight on the equity ratios at utility holding companies (versus those at regulated operating companies) because those companies reflect a different risk profile than the regulated operations of OPG. Focusing on the results from the regulated operating companies, both actual and authorized equity ratios, produces a reasonable range of equity thickness for OPG of 49.47% to 55.91%.

OPG's current equity ratio of 45% is below those ranges despite OPG's elevated level of risk relative to the proxy groups. Given the risk factors noted above, OPG falls toward the upper end of the risk spectrum, and its equity ratio could reasonably be set at 55% to 56%, being the upper end of the proxy group results. In consideration of the results of our analysis together with the OEB's findings in EB-2016-0152, however, Concentric conservatively recommends an equity ratio of no less than 50% for OPG for this upcoming rate setting period.

APPENDIX A:
NUCLEAR RISK – CREDIT RATING AGENCIES

This appendix provides excerpts from S&P Global Ratings highlighting that ratings agency's views on the high-risk nature of utilities' nuclear businesses.

Ameren (AEE) – "Higher operational risk and material ESG considerations from owning and operating the Callaway nuclear plant… Nuclear generation increases operational risks and carries with it long-term storage concerns; this is partially offset by the technology's emission-free generation… Our negative comparable rating analysis modifier reflects the consolidated exposure to nuclear and coal generation... Environmental factors are material to our credit analysis primarily due to Ameren's exposure to nuclear and coal generation."[131]

Dominion Energy, Inc. (D) – "Overall, we assess most of the DEI utilities as very low risk and consistent with their effective management style of regulatory risk. The exception is DESC (Dominion Energy South Carolina) whose effectiveness in managing regulatory risk eroded after construction of two new nuclear units was cancelled. Despite DEI's acquisition of DESC, our assessment of DESC incorporates a much less supportive regulatory environment in South Carolina than before the company's cancellation of the nuclear plants… The company also has nuclear and renewable merchant generation businesses, which account for about 5% of EBITDA… We assess the merchant nuclear contracted asset as having the highest risk from the company's portfolio of contracted assets. The merchant nuclear exposes the company to higher operating risks, volumetric risks, counterparty credit risk, and commodity risks. "[132]

Duke (DUK) – "[T]he company's carbon-free nuclear generation portfolio increases its operating risk and exposes it to longer-term nuclear waste storage risks despite the company's long-term track record of achieving safe operational standards of its nuclear fleet."[133]

Entergy (ETR) – "Remaining exposure to nuclear generation increases operational risk… Entergy continues to shut down nuclear plants. The company is reducing its exposure to non-regulated nuclear power units. It shut down a unit at its Indian Point facility in New York in spring 2020, and it plans to shut down the remaining operating unit in spring 2021. Its Palisades facility

[131] S&P Ratings Direct, "Ameren Corp.," April 10, 2020.
[132] S&P Ratings Direct, "Dominion Energy Inc. and Subsidiaries Outlooks Revised To Positive Due On Planned Asset Sale and Cancelled Pipeline Project,"." July 7, 2020.
[133] S&P Ratings Direct, "Duke Energy Corp. And Subsidiaries Outlooks Affirmed Following Atlantic Cost Pipeline Exit; Outlook Stable," July 9, 2020.

in Michigan will close in 2022… The stable outlook over the next two years reflects our expectation that Entergy will successfully exit its higher-risk, non-utility nuclear power generation stations and grow through its lower-risk, rate-regulated utility businesses, leading to an improved business risk profile... We could lower our ratings on Entergy over the next 24 months if its non-utility-owned nuclear power generation stations, which we currently expect to close, remain open and we anticipate that its financial measures will weaken, including adjusted FFO to debt of consistently below 14%... We expect that Entergy will close its remaining non-utility nuclear generating units in New York and Michigan over the next several years. Its business will largely consist of lower-risk, rate-regulated utility operations. As it moves toward becoming a fully rate-regulated utility company, we expect that its business risk profile will improve. Entergy's complete exit from the merchant nuclear business depends on the receipt of various regulatory approvals, particularly to sell the nuclear units for decommissioning… The company's current generation capacity of about 22,70021 MW consists of 6665% natural gas, 2325% nuclear, and about 10% coal... the company's board structure includes a nuclear committee, members of which discuss safety risks and best practices for its nuclear fleet."[134]

NextEra (NEE) – "[W]e assess the company at the very low end of the range for this category, incorporating the company's other higher-risk businesses. These include nuclear merchant generation, proprietary trading, retail supply and wholesale full-requirements contracts, and natural gas exploration and production businesses."[135]

Pinnacle West Capital Corp (PNW) – "Environmental risks and potential liabilities associated with the company's coal-fired and nuclear generation capacity… Offsetting our assessment of PWCC's business risk profile are the company's limited regulatory diversity, the highly politicized regulatory environment in Arizona, environmental risks associated with the company's coal-fired generation, and operating risks associated with the company's nuclear generation. APSC owns 6,316 MW of regulated generating capacity, of which about 58% is from nuclear and coal-fired fuel sources. Because of these weaknesses, we assess PWCC's business risk profile as being in the lower half of its business risk profile category… The generation mix for APSC consists of about 57% natural gas, 21% coal, 18% nuclear, and 3% renewables… Additionally, APSC maintains sole management responsibility for the nation's largest nuclear plant, Palo Verde, with total generation capacity of

134 S&P Ratings Direct, "Entergy Corp.," July 7, 2020.
135 S&P Ratings Direct, "NextEra Energy Inc. Ratings Affirmed On Acquisition Of Gulf Power; Outlook Remains Stable," January 3, 2019.

almost 4,000 MW. Although it's carbon-free, the company's nuclear generation portfolio increases operating risk and exposes it to longer-term nuclear waste storage risks."[136]

Southern (SO) – "Atlanta-based Southern Co. announced its share of the Vogtle units 3 and 4 nuclear power construction project costs have increased by approximately $150 million… This follows a series of other related announcements by the company, including that it resequenced its planned construction activities for the units, and reduced its work force at the construction site by about 20%, primarily due to the outbreak of COVID-19, where multiple workers at the site have tested positive for the virus… We view these developments as indicative of potentially heightened business risk for Southern Co., and its key subsidiary, Georgia Power Co. given the challenging operating environment that COVID-19 presents, despite the company's view that it can achieve its required in-service date for units 3 and 4 by November 2021 and November 2022, respectively… The negative outlooks for Southern and its subsidiaries reflect the potential for increased business risk for Southern Co., given the scale of its nuclear construction activities at Vogtle units 3 and 4 amid the COVID-19 pandemic. The negative outlooks also reflect minimal financial cushion at the parent for the current rating, including consolidated FFO to debt of 16% for the next two years…"

"**We believe there is risk of delays to the project's regulatory in-service date.** While the company maintains that it can achieve its aggressive in-service date for units 3 and 4, we note that these estimates are based on several assumptions, including the company's view that the normal rate of absenteeism and its productivity targets can be met despite the temporary reduction in workers at the site, and despite the COVID-19 environment. The staff of the Georgia Public Service Commission (GPSC) has effectively cast doubt on the company's scheduled timeline to bring the units online, including for both the regulatory timeline, and the company's aggressive timeline. Furthermore, while the November 2021 and November 2022 regulatory in-service dates for units 3 and 4 remain the focus, the company is exposed to the risk of additional penalties on its nuclear construction cost recovery (NCCR) tariff, including a return on equity (ROE) that will be reduced by 10 basis points each month if units 3 and 4 are not commercially operational by June 1, 2021, and June 1, 2022."[137]

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136 S&P Ratings Direct, "Transaction Update: Pinnacle West Capital Corp.," November 3, 2020.

137 S&P Ratings Direct, "Research Update: Southern Company and Subsidiaries Outlooks Remain Negative on Higher Nuclear Construction Costs, Ratings Affirmed," August 6, 2020.

Xcel (XEL) – "Xcel's fuel mix consists of approximately 23% renewables, 13% nuclear, 23% natural gas, and 37% coal… Additionally, Xcel operates two nuclear plants, expected to remain open through 2034, that generate around 1,700 MW of power. Although carbon-free, the company's nuclear generation portfolio increases operating risk and exposes it to longer-term nuclear waste storage risks."[138]

[138] S&P Ratings Direct, "Xcel Energy Inc.," June 2, 2020.

APPENDIX B:
PRECEDENT FOR CONSIDERING U.S. DATA

There is precedent among Canadian regulators for considering U.S. data and a U.S. proxy group for cost of capital evaluations. In recent orders, other Canadian regulators have determined that it is appropriate to consider the use of U.S. data and U.S. proxy groups to estimate the allowed return on equity ("ROE") for a Canadian regulated utility. Regulators in Canada have noted several reasons that support consideration of U.S. data. First, the development of a proxy group comprised entirely of Canadian electric utilities is difficult due to the small number of publicly-traded utilities in Canada and the fact that many of those Canadian companies derive a significant percentage of their revenues and net income from operations other than the provision of regulated electric utility service. Second, this problem has been exacerbated by the continuing trend toward mergers and acquisitions in the utility industry, both within Canada and across the border with U.S. utility companies. The question for Canadian regulators has become: How do we account for any differences in risk between U.S. and Canadian utilities?

Concentric's research and analysis demonstrate that it is possible to select a group of U.S. electric utilities that is comparable to Canadian utilities in terms of business and operating risk. In that regard, Concentric agrees with the conclusion of the OEB that it is not necessary to find that utilities are the same, only that they are comparable,[139] and with the National Energy Board's ("NEB") (predecessor to the Canadian Energy Regulator) conclusion that it is possible to account for differences in risk that would influence an investor's required rate of return.[140]

A growing number of Canadian utility regulators have accepted the use of U.S. data or U.S. proxy groups in recent years. For example, in its TQM Decision, the NEB found that U.S. market returns are relevant to the cost of capital for Canadian firms, and that the regulatory regimes in Canada and the U.S. are sufficiently similar as to justify comparison. The NEB appears to view U.S. market returns as valuable information in establishing the cost of capital for Canadian utilities. Moreover, the NEB found that Canadian utilities are competing for capital in global financial markets that are increasingly integrated. The NEB recognized that it is no longer possible to view Canada as insulated from the remainder of the investing world, and that doing so would be detrimental to the ability of Canadian utilities to compete for capital.[141] Importantly, the NEB also found that the regulatory

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

regimes in the U.S. and Canada were sufficiently similar as to justify comparison between utilities in the two countries, stating:

> *The Board is not persuaded that the U.S. regulatory system exposes utilities to notable risks of major losses due either to unusual events or cost disallowances. The Board views the losses and disallowances experienced by U.S. regulated entities as a result of the restructuring that took place to terminate the merchant gas function of pipelines, as well as some other circumstances such as the Duquesne nuclear build, to be, to a large extent, unique events. The Board also finds that such instances are not likely to weigh significantly in investors' perceptions today, and would thus have little or no impact on cost of capital.*[142]

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

> *The Board is of the view that the U.S. is a relevant source for comparable data. The Board often looks to the regulatory policies of State and Federal agencies in the United States for guidance on regulatory issues in the province of Ontario. For example, in recent consultations, the Board has been informed by U.S. regulatory policies relating to low income customer concerns, transmission cost connection responsibility for renewable generation, and productivity factors for 3rd generation incentive ratemaking.*
>
> *Finally, the Board agrees with Enbridge that, while it is possible to conduct DCF and CAPM analyses on publicly-traded Canadian utility holding companies of comparable risk, there are relatively few of these companies. As a result, the Board concludes that North American gas and electric utilities provide a relevant and objective source of data for comparison.*[143]

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

> *In addition, the Commission Panel continues to be prepared to accept the use of historical and forecast data of U.S. utilities when applied: as a check to Canadian data, as a substitute for Canadian data when Canadian data do not exist in significant quantity or quality, or as a supplement to Canadian data when Canadian data gives unreliable results. Given the paucity of relevant Canadian data, the Commission Panel*

[142] *Ibid.*

[143] Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at 23.

> *considers that natural gas distribution companies operating in the US have the potential to act as a useful proxy in determining TGI's capital structure, ROE, and credit metrics.*[144]

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

> *The Commission Panel reaffirms the 2009 Decision determination on when to use historical and forecast data for US utilities. Canadian utilities need to be able to compete in a global marketplace and be allowed a return for them to do so. In addition, the Panel accepts that there continues to be limited Canadian data upon which to rely and considers that there may be times when natural gas companies operating within the US may prove to be a useful proxy in determining the cost of capital. Accordingly, we have determined that it is appropriate to continue to accept the use of historical and forecast data for US utilities and securities as outlined in the 2006 Decision and again in the 2009 Decision.*

And,

> *[I]n the view of the Commission Panel, the use of US data must be considered on a case by case basis and weighed with consideration to the sample being relied upon and any jurisdictional differences which may exist.*[145]

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

[144] British Columbia Utilities Commission, In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc., Return on Equity and Capital Structure, Decision G-158-09, December 16, 2009, at 16.

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

APPENDIX C:
RESUME OF JAMES M. COYNE

JAMES M. COYNE
Senior Vice President

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

AREAS OF EXPERTISE

Energy Regulation

- Rate policy
- Cost of capital
- Incentive regulation
- Fuels and power markets

Management and Business Strategy

- Fuels and power market assessments
- Investment feasibility
- Corporate and business unit planning
- Benchmarking and productivity analysis

Financial and Economic Advisory

- Valuation analysis
- Due diligence
- Buy and sell-side advisory

Litigation Support and Expert Testimony

- Rate and regulatory policy
- Fuels and power markets
- Contract litigation
- Valuation and damages

PROFESSIONAL HISTORY

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

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

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

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

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

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

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

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

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

EDUCATION

University of New Hampshire
M.S., Resource Economics, *with honors*, 1981

Georgetown University
B.S., Business Administration and Economics, *cum laude*, 1975

DESIGNATIONS AND AFFILIATIONS

Community Rowing Inc., Board of Directors, 2015 - 2019

Georgetown University, Alumni Admissions Interviewer, 1988 – current

NASD General Securities Representative and Managing Principal (Series 7, 63 and 24 Certifications), 2001

American Petroleum Institute, CEO's Liaison to Management and Policy Committees, 1994-1996

National Petroleum Council, Regulatory and Policy Task Forces, 1992

President, International Association for Energy Economics, Dallas Chapter, 1995

Gas Research Institute, Economics Advisory Committee, 1990-1993

NARUC, Advanced Regulatory Studies Program, Michigan State University, 1984

PUBLICATIONS AND RESEARCH

"Advancing FERC's Methodology for Determining Allowed ROEs for Electric Transmission Companies," submitted to FERC on behalf of EEI, James Coyne, Joshua Nowak and Julie Lieberman, May, 2020.

"Regulator Rationale for Ratepayer-Funded Electricity and Natural Gas Innovation", James M. Coyne, Robert C. Yardley, Jr. and Jessalyn G. Pryciak, Energy Regulation Quarterly, Volume 6, Issue 3, 2018.

"Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers" (with Robert Yardley), prepared for the Canadian Gas Association and Canadian Electricity Association, May 2015.

"Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with John Trogonoski), Public Utilities Fortnightly, May 2010

"A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Dan Dane and Julie Lieberman), prepared for the Ontario Energy Board, June 2007

"Do Utilities Mergers Deliver?" (with Prescott Hartshorne), Public Utilities Fortnightly, June 2006

"Winners and Losers: Utility Strategy and Shareholder Return" (with Prescott Hartshorne), Public Utilities Fortnightly, October 2004

"Winners and Losers in Restructuring: Assessing Electric and Gas Company Financial Performance" (with Prescott Hartshorne), white paper distributed to clients and press, August 2003

"The New Generation Business," commissioned by the Electric Power Research Institute (EPRI) and distributed to EPRI members to contribute to a series on the changes in the Power Industry, December 2001

Potential for Natural Gas in the United States, Volume V, Regulatory and Policy Issues (co-author), National Petroleum Council, December 1992

"Natural Gas Outlook," articles on U.S. natural gas markets, published quarterly in the Data Resources Energy Review and Natural Gas Review, 1984-1989

SELECTED SPEAKING ENGAGEMENTS

"Energy Sector in Transition", Ontario Energy Association, Toronto, ON, September 24, 2018.

"Understanding Regulated Utilities in Today's Capital Markets", NARUC Annual Meeting, La Quinta, CA, November 14, 2016.

"Rate of Return: Where the Regulatory Rubber Meets the Road," CAMPUT Annual Conference, Montreal, Quebec, May 17, 2016.

"Innovations in Utility Business Models and Regulation", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2015 Energy Regulation Course, Queens University, Kingston, Ontario, June 2015

"M&A and Valuations," Panelist at Infocast Utility Scale Solar Summit, September 2010

"The Use of Expert Evidence," The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2010 Energy Regulation Course, Queens University, Kingston, Ontario, June 2010

"A Comparative Analysis of Return on Equity for Utilities in Canada and the U.S.", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) Annual Conference, Banff, Alberta, April 22, 2008

"Nuclear Power on the Verge of a New Era," moderator for a client event co-hosted by Sutherland Asbill & Brennan and Lexecon, Washington D.C., October 2005

"The Investment Implications of the Repeal of PUCHA," Skadden Arps Client Conference, New York, NY, October 2005

"Anatomy of the Deal," First Annual Energy Transactions Conference, Newport, RI, May 2005

"The Outlook for Wind Power," Skadden Arps Annual Energy and Project Finance Seminar, Naples, FL, March 2005

"Direction of U.S. M&A Activity for Utilities," Energy and Mineral Law Foundation Conference, Sanibel Island, FL, February 2002

"Outlook for U.S. Merger & Acquisition Activity," Utility Mergers & Acquisitions Conference, San Antonio, TX, October 2001

"Investor Perspectives on Emerging Energy Companies," Panel Moderator at Energy Venture Conference, Boston, MA, June 2001

"Electric Generation Asset Transactions: A Practical Guide," workshop conducted at the 1999 Thai Electricity and Gas Investment Briefing, Bangkok, Thailand, July 1999

"New Strategic Options for the Power Sector," Electric Utility Business Environment Conference, Denver, CO, May 1999

"Electric and Gas Industries: Moving Forward Together," New England Gas Association Annual Meeting, November 1998

"Opportunities and Challenges in the Electric Marketplace," Electric Power Research Institute, July 1998

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Alberta Beverage Container Management Board				
Alberta Beverage Container Management Board	2016 2019-2020	Expert for the Board	N/A	Return Margin on Bottle Depots
Alberta Utilities Commission				
ATCO Utilities Group	2008 2009	ATCO Gas; ATCO Pipelines Ltd.; ATCO Electric Ltd.	Application No. 1578571 / Proceeding ID. 85	2009 Generic Cost of Capital Proceeding (Gas & Electric)
Enmax Power Corporation	2017	Enmax	22570	Cost of Common Equity
Enmax Power Corporation	2020	Enmax	24110	2021 Generic Cost of Capital
American Arbitration Association				
TransCanada Corporation	2004	TransCanada Corporation	AAA Case No. 50T 1810018804	Valuation of Natural Gas Pipeline
British Columbia Utilities Commission				
FortisBC	2012	FortisBC Utilities	G-20-12	Cost of Capital Adjustment Mechanisms
FortisBC	2015 2016	FortisBC Utilities	Project 3698852	Cost of Capital (Gas and Electric Distribution)
California Utilities Commission				
San Diego Gas & Electric Company	2019	San Diego Gas & Electric Company	A-19-04-014	Cost of Capital (Gas Distribution)
Connecticut Department of Public Utility Control				
Aquarion Water Company of CT/ Macquarie Securities	2007	Aquarion Water Company of CT	DPUC Docket No. 07-05-19	Return on Equity (Water)
Federal Energy Regulatory Commission				
Atlantic Power Corporation	2007	Atlantic Path 15, LLC	ER08-374-000	Return on Equity (Electric)
Atlantic Power Corporation	2010	Atlantic Path 15, LLC	Docket No. ER11-2909-000	Return on Equity (Electric)
Atlantic Power Corporation	2011	Atlantic Path 15, LLC	Docket Nos. ER11-2909 and EL11-29	Rate of Return (Electric Transmission)
Startrans IO, LLC	2012	Startrans IO, LLC	ER-13-272-000	Cost of Capital (Electric Transmission)
Startrans IO, LLC	2015	Startran IO, LLC	ER-16-194-000 and EL16-25-000	Cost of Capital (Electric Transmission)
Northern States Power Company	2019	Northern States Power Company	ER20-26-000	Cost of Capital (Electric Transmission)

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
PPL Electric Utilities Corp.	2020	PP&l Industrial Customer Alliance v. PPL Electric	EL20-48-000	Answering Testimony in Response to a Section 206 ROE Complaint
Hawaii Public Utility Commission				
The Gas Company	2017	The Gas Company	Docket No. 2017-0105	Cost of Capital (Gas Distribution)
Maine Public Utilities Commission				
Bangor Hydro Electric Company	1998	Bangor Hydro Electric Company	MPUC Docket No. 98-820	Transaction-Related Financial Advisory Services, Valuation
Central Maine Power Company	2007	Central Maine Power Company	MPUC Docket No. 2007-215	Sales Forecast
Enmax Corporation	2019	Enmax Corporation	2019-00097	Regulatory Approval of Emera Maine Acquisition
Maryland State Board of Contract Appeals				
Green Planet Power Solutions	2018	Green Planet Power Solutions and Maryland Bio Eneregy LLC v. Maryland Department of General Services	MSBCA 3061	Contract Litigation, Power Purchase Agreement, Damages Analysis
Massachusetts Superior Court				
Burncoat Pond Watershed District	2010	Central Water District v. Burncoat Pond Watershed District	WDCV 2001-0105	Valuation/Eminent Domain
Minnesota Public Utilities Commission				
Northern States Power Company	2015 2016	Northern States Power Company	E-002-GR-15-826	Cost of Capital (Electric)
Northern States Power Company	2017	Northern States Power Company	E002/M-17-797 G002/M-17-787 E002/M-17-818	Cost of Capital (Electric and Gas Rate Riders for Transmission, Renewable Generation and Gas Distribution)
Newfoundland and Labrador Board of Commissioners of Public Utilities				
Newfoundland Power	2016	Newfoundland Power	2016 GRA	Cost of Capital (Electric)
Newfoundland Power	2018	Newfoundland Power	2018 GRA	Cost of Capital (Electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
New Jersey Board of Public Utilities				
Conectiv	2000-2001	Atlantic City Electric Company	NJBPU Docket No. EM00020106	Transaction-Related Financial Advisory Services
Nova Scotia Utility and Review Board				
Nova Scotia Power Inc.	2012	Nova Scotia Power Inc.	2013 GRA	Return on Equity/Business Risk (Electric)
Ontario Energy Board				
Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	2009	Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	EB-2009-0084	Ontario Energy Board's 2009 Consultative Process on Cost of Capital Review (Gas & Electric)
Enbridge Gas Distribution	2012	Enbridge Gas Distribution	EB-2011-0354	Industry Benchmarking Study and Cost of Capital (Gas Distribution)
Enbridge Gas Distribution	2014	Enbridge Gas Distribution	EB-2012-0459	Incentive Regulation Plan and Industry Productivity Study
Ontario Power Generation	2016	Ontario Power Generation	EB-2016-0152	Cost of Capital (Electric Generation)
Prince Edward Island Regulatory and Appeals Commission				
Maritime Electric Company	2015	Maritime Electric Company	UE20942	Return on Capital (Electric)
Régie de l'énergie du Québec				
Gaz Métro	2012	Gaz Métro	R-3809-2012	Return on Equity/Business Risk/ Capital Structure (Gas Distribution)
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2013	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3842-2013	Return on Equity/Business Risk (Electric)
Hydro-Québec Distribution	2014	Hydro-Québec Distribution	R-3905-2014	Remuneration of Deferral Accounts
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2015-2017	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3897-2014	Performance-Based Ratemaking
South Dakota Public Service Commission				
Northern States Power Company-MN	2012	Northern States Power Company-MN	EL 11-019	Return on Equity
Texas Public Utility Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Texas New Mexico Power Company	2004	Texas New Mexico Power Company	PUC Docket No. 29206	Auction Process and Stranded Cost Recovery
U.S. Department of Commerce				
Government of Québec	2017	Duty Investigation of Uncoated Groundwood Paper from Canada	PUC Docket No. 29206	Contracting for Renewable Resources, Market Analysis, Damages Analysis
Vermont Public Service Board				
Vermont Gas Systems, Inc.	2006	Vermont Gas Systems, Inc.	VPSB Docket No. 7109	Models of Incentive Regulation
Vermont Gas Systems, Inc.	2012	Vermont Gas Systems, Inc.	Docket No. 7803A	Cost of Capital (Gas Distribution)
Green Mountain Power Corporation	2013	Green Mountain Power Corporation	Docket No. 8191	Return on Equity (Electric)
Vermont Gas Systems, Inc.	2016	Vermont Gas Systems, Inc.	Docket No. 8698/8710	Return on Equity (Gas Distribution)
Green Mountain Power Corporation	2017	Green Mountain Power Corporation	Docket No. Tariff-8677	Return on Equity (Electric)
Green Mountain Power Corporation	2018	Green Mountain Power Corporation	18-0974	Return on Equity (Electric)
Wisconsin Public Service Commission				
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-170	Return on Equity (Electric)
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-171	Return on Equity (Electric)
Northern States Power Company	2011	Northern States Power Company	PSCW Docket No. 4220-UR-117	Return on Equity (Electric)
Northern States Power Company	2013	Northern States Power Company	PSCW Docket No. 4220-UR-119	Return on Equity (Gas & Electric)
Northern States Power Company	2015	Northern States Power Company	PSCW Docket No. 4220-UR-121	Return on Equity (Gas & Electric)
Northern States Power Company	2017 2019	Northern States Power Company	PSCW Docket No. 4220-UR-123, 4220-UR-124	Return on Equity (Gas & Electric)
Yukon Utilities Board				
ATCO Electric Yukon	2016	ATCO Electric Yukon	2016-2017 GRA	Return on Equity (Electric)

APPENDIX D:
RESUME OF DANIEL S. DANE

DANIEL S. DANE, CPA
Senior Vice President

Daniel S. Dane has 20 years of experience in the energy, utility, and financial services industries providing advisory services to power companies, natural gas pipelines, and local gas distribution companies in the areas of regulation and ratemaking, litigation support, mergers and acquisitions, valuation, financial statement audits and analysis, and the examination of financial reporting systems and controls. Mr. Dane has also provided expert testimony on regulated ratemaking matters and merger approval applications for investor- and provincially-owned utilities, including on merger impacts, revenue requirements, the cost of capital, capital structure, lead-lag studies/cash working capital, regulatory lag and rate base development. Mr. Dane has an MBA from Boston College in Chestnut Hill, Massachusetts, and a BA in Economics from Colgate University in Hamilton, New York. Mr. Dane is a certified public accountant, and is a licensed securities professional (Series 7, 28, 63, 79, and 99). Mr. Dane also serves as the Financial and Operations Principal of CE Capital Advisors, a FINRA-Member firm and a subsidiary of Concentric.

PROFESSIONAL HISTORY

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

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

ZIA Information Analysis Group (1997 – 2000)

EDUCATION

Boston College
M.B.A., 2003

Colgate University
B.A., Economics, 1996

REPRESENTATIVE PROJECT EXPERIENCE

Ratemaking and Utility Regulation Assignments

Expert Testimony

- Submitted expert testimony on behalf of utilities and other stakeholders in state administrative rate setting and merger approval proceedings regarding merger impacts, revenue requirements, the cost of capital, capital structure, lead-lag studies/cash working capital, regulatory lag and rate base development.

Regulatory Support

- Provided financial modeling, development of expert reports, and preparation of multiple rounds of testimony on behalf of U.S. and Canadian investor-owned electric, natural gas, and water utilities related to multiple aspects of the ratemaking process, including: cost of capital; ring fencing; revenue requirements and lead-lag studies/cash working capital; decoupling; prudence and cost recovery; capital tracker tariff mechanisms; cost allocation and shared services; merger approval; regulatory lag; and ratemaking policy.
- Consulting assignments have included utility clients across the U.S. and Canada.

Financial Advisory Assignments

Competitive Solicitations & Asset Divestitures

- Sell-side support for approximately $2 billion in generating asset transactions, including nuclear, natural gas, and coal generating facilities.
- Buy-side due diligence support for U.S., Canadian, and international investors in electric and natural gas LDC utility operations, wind generation and natural gas pipeline facilities.
- Regulatory policy, ring-fencing, and merger impacts advisory services provided to U.S. and Canadian investor-owned utilities.

Valuation Services

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

Litigation Advisory Assignments

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

Management and Operations Consulting Assignments

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

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Public Accountant, 2004

Massachusetts Society of Certified Public Accountants, 2004

American Institute of Certified Public Accountants, 2011

CERTIFICATIONS

Licensed Securities Professional: NASD Series 7, 28, 63, 79 and 99 Licenses

PRESENTATIONS

"Regulatory Treatment of Timing Differences Related to Pension and OPEB Costs." Presented to the Ontario Energy Board, July 2016 (Docket No. EB-2015-0040).

"Financial Management and Capital Markets." University of Idaho Utility Executive Course, 2018.

"Increasing Shareholder Value through the Capital Markets." University of Idaho Utility Executive Course, 2015, 2016 and 2017.

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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Connecticut Public Utilities Regulatory Authority				
SJW Group and Connecticut Water Service, Inc.	4/19	Application of SJW Group and Connecticut Water Service, Inc. for Approval of Change of Control	Docket No. 19-04-02	Merger Impacts
SJW Group and Connecticut Water Service, Inc.	12/18	Application of SJW Group and Connecticut Water Service, Inc. for Approval of Change of Control	Docket No. 18-07-10	Merger Impacts
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Lead-Lag Study Cash Working Capital
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Lead-Lag Study Cash Working Capital
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Lead-lag Study Cash Working Capital
Illinois Commerce Commission				
The Ameren Illinois Utilities	07/10	Central Illinois Light Company; Central Illinois Public Service Company; Illinois Power Company	Docket Nos. 09-0306 thru 09-0311 (cons.)	Rate Base Adjustments Earnings Attrition
Maine Public Utilities Commission				
The Maine Water Company	07/19	Application for Approval of Reorganization Pursuant to 35-A M.R.S. § 708	Docket No. 2019-00096	Merger Impacts, Customer Benefits, Public Interest
Massachusetts Department of Public Utilities				
National Grid	11/20	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 20-120	Revenue Requirement Lead-lag Study Cash Working Capital
The Berkshire Gas Company	05/18	The Berkshire Gas Company	D.P.U. 18-40	Revenue Requirement
National Grid	04/18	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 17-170	Impact of the Tax Cuts and Jobs Act of 2017; Administrative and General Expense Allocations
National Grid	11/17	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 17-170	Revenue Requirement Lead-lag Study Cash Working Capital
New Hampshire Public Utilities Commission				
Liberty Utilities (EnergyNorth Natural Gas) Corp.	04/17	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Docket No. DG 17-048	Temporary Rates
Liberty Utilities (EnergyNorth Natural Gas) Corp.	04/17	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Docket No. DG 17-048	Revenue Requirement

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
New Mexico Public Regulation Commission				
El Paso Electric Company	05/20	El Paso Electric Company	Case No. 20-00104-UT	Lead-lag Study Cash Working Capital
Public Utility Commission of Texas				
El Paso Electric Company	02/17	El Paso Electric Company	Docket No. 46831	Lead-lag Study Cash Working Capital
South Dakota Public Service Commission				
Northern States Power Company-MN	06/11	Northern States Power Company-MN	EL 11-019	Return on Equity
Vermont Public Utility Commission				
Vermont Department of Public Service	08/17	Joint Petition of NorthStar Decommissioning Holdings, LLC, NorthStar Nuclear Decommissioning Company, LLC, NorthStar Group Services, Inc., LVI Parent Corp., NorthStar Group Holdings, LLC, Entergy Nuclear Vermont Investment Company, LLC, and Entergy Nuclear Operations, Inc., and any other necessary affiliates entities to transfer ownership of Entergy Nuclear Vermont Yankee, LLC, and for certain ancillary approvals, pursuant to 30 V.S.A. §§ 107, 231, and 232	Docket No. 8880	Nuclear Facility Transfer
Ontario Energy Board				
Ontario Power Generation	05/16	Ontario Power Generation	EB 2016-0152	Capital Structure

Concentric Proxy Group Screening Data

Proxy Group Company	Ticker	Regulated Generation Assets in Rate Base?	% of Regulated Generation		Regulated Revenue as a % of Total Revenue	Regulated Income as a % of Total Income	Regulated Electric Revenue as a % of Regulated Revenue	Regulated Electric Income as a % of Regulated Income	Investment Grade Credit Rating?
			Nuclear	Hydro					
		[1]	[1]	[1]	[2]	[2]	[2]	[2]	[1]
ALLETE, Inc.	ALE	Yes	0.00%	7.01%	73.45%	75.04%	97.70%	97.43%	Yes
Ameren Corporation	AEE	Yes	11.15%	7.36%	100.00%	100.00%	86.10%	88.30%	Yes
American Electric Power Company, Inc.	AEP	Yes	9.47%	3.59%	89.15%	95.59%	100.00%	100.00%	Yes
Avista Corporation	AVA	Yes	0.00%	51.45%	98.28%	100.00%	100.00%	100.00%	Yes
Duke Energy Corporation	DUK	Yes	16.39%	6.27%	98.18%	100.00%	93.37%	93.07%	Yes
Edison International	EIX	Yes	19.85%	35.44%	99.59%	94.78%	100.00%	100.00%	Yes
El Paso Electric Company	EE	Yes	29.04%	0.00%	100.00%	100.00%	100.00%	100.00%	Yes
Entergy Corporation	ETR	Yes	18.49%	0.34%	84.88%	100.00%	98.54%	98.85%	Yes
FirstEnergy Corporation	FE	Yes	0.00%	11.11%	100.00%	100.00%	100.00%	100.00%	Yes
Evergy, Inc.	EVRG	Yes	10.02%	0.05%	100.00%	100.00%	100.00%	100.00%	Yes
IDACORP, Inc.	IDA	Yes	0.00%	52.14%	99.71%	98.87%	100.00%	100.00%	Yes
NextEra Energy, Inc.	NEE	Yes	12.21%	0.00%	69.38%	70.04%	100.00%	100.00%	Yes
Pinnacle West Capital Corporation	PNW	Yes	20.04%	0.00%	99.90%	100.00%	100.00%	100.00%	Yes
PNM Resources, Inc.	PNM	Yes	18.54%	0.00%	100.00%	99.96%	100.00%	100.00%	Yes
Portland General Electric Company	POR	Yes	0.00%	12.16%	100.00%	100.00%	100.00%	100.00%	Yes
Southern Company	SO	Yes	11.97%	9.37%	90.47%	95.71%	84.46%	81.27%	Yes
Xcel Energy Inc.	XEL	Yes	9.03%	2.87%	99.32%	100.00%	85.46%	87.45%	Yes
Algonquin Power & Utilities Corp [2]	AQN	Yes	0.00%	1.07%	81.85%	81.58%	49.13%	49.13%	Yes
Emera Inc.	EMA	Yes	N/A	N/A	90.86%	100.00%	84.19%	87.49%	Yes
Fortis Inc.	FTS	Yes	0.00%	0.68%	97.52%	100.00%	75.63%	76.49%	Yes

Notes:
[1] Per S&P Global Market Intelligence
[2] Per company 10-Ks and annual reports

Authorized Capital Structure Analysis - Concentric Proxy Group

Company	State	Subsidiary	Service	Case Type	Rate Case Decision Date	Authorized Equity Ratio	Customers Served	Weighted Equity Ratio	Avg. Equity Ratio
ALLETE, Inc.	Minnesota	Minnesota Power	Electric	Vertically Integrated	3/12/2018	53.81%	146,741	78,961	53.81%
Ameren Corporation	Illinois	Ameren Illinois Company	Electric	Distribution	12/16/2019	50.00%	1,220,680	610,340	
Ameren Corporation	Illinois	Ameren Illinois Company	Natural Gas	Distribution	11/1/2018	50.00%	812,267	406,134	
Ameren Corporation	Missouri	Union Electric Company	Electric	Vertically Integrated	3/18/2020	N/A	N/A	N/A	
Ameren Corporation	Missouri	Union Electric Company	Natural Gas	Distribution	8/21/2019	N/A	N/A	N/A	50.00%
American Electric Power Company, Inc.	Arkansas [1]	Southwestern Electric Power Company	Electric	Vertically Integrated	12/20/2019	44.60%	119,644	53,363	
American Electric Power Company, Inc.	Indiana [1]	Indiana Michigan Power Company	Electric	Vertically Integrated	5/30/2018	46.32%	465,774	215,737	
American Electric Power Company, Inc.	Kentucky	Kentucky Power Company	Electric	Vertically Integrated	1/18/2018	41.68%	166,603	69,440	
American Electric Power Company, Inc.	Louisiana	Southwestern Electric Power Co.	Electric	Vertically Integrated	2/27/2013	N/A	N/A	N/A	
American Electric Power Company, Inc.	Michigan [1]	Indiana Michigan Power Co.	Electric	Vertically Integrated	1/23/2020	46.26%	129,418	59,871	
American Electric Power Company, Inc.	Ohio	Columbus Southern Power Company	Electric	Distribution	12/14/2011	50.64%	1,500,000	759,600	
American Electric Power Company, Inc.	Oklahoma	Public Service Co. of OK	Electric	Vertically Integrated	3/14/2019	N/A	N/A	N/A	
American Electric Power Company, Inc.	Tennessee	Kingsport Power Company	Electric	Vertically Integrated	8/9/2016	40.25%	48,032	19,333	
American Electric Power Company, Inc.	Texas	AEP Texas Central Co.	Electric	Distribution	12/13/2007	40.00%	1,029,536	411,814	
American Electric Power Company, Inc.	Texas	AEP Texas North Co.	Electric	Distribution	5/24/2007	N/A	N/A	N/A	
American Electric Power Company, Inc.	Texas	Southwestern Electric Power Co.	Electric	Vertically Integrated	12/14/2017	48.46%	185,508	89,897	46.07%
Avista Corporation	Alaska	Alaska Electric Light & Power	Electric	Vertically Integrated	11/15/2017	58.18%	17,165	9,987	
Avista Corporation	Idaho	Avista Corp.	Electric	Vertically Integrated	11/29/2019	50.00%	133,401	66,701	
Avista Corporation	Idaho	Avista Corp.	Natural Gas	Distribution	12/28/2017	50.00%	88,068	44,034	
Avista Corporation	Oregon	Avista Corp.	Natural Gas	Distribution	10/8/2019	50.00%	102,017	51,009	
Avista Corporation	Washington	Avista Corp.	Electric	Vertically Integrated	3/25/2020	48.50%	254,232	123,303	
Avista Corporation	Washington	Avista Corp.	Natural Gas	Distribution	3/25/2020	48.50%	164,915	79,984	49.36%
Duke Energy Corporation	Florida	Duke Energy Florida LLC	Electric	Vertically Integrated	10/25/2017	N/A	N/A	N/A	
Duke Energy Corporation	Indiana [1]	Duke Energy Indiana, LLC	Electric	Vertically Integrated	6/29/2020	53.91%	830,270	447,619	
Duke Energy Corporation	Kentucky	Duke Energy Kentucky Inc.	Electric	Vertically Integrated	4/27/2020	48.23%	142,393	68,676	
Duke Energy Corporation	Kentucky	Duke Energy Kentucky Inc.	Natural Gas	Distribution	3/27/2019	50.76%	100,040	50,780	
Duke Energy Corporation	North Carolina	Duke Energy Carolinas LLC	Electric	Vertically Integrated	6/22/2018	52.00%	2,005,333	1,042,773	
Duke Energy Corporation	North Carolina	Duke Energy Progress LLC	Electric	Vertically Integrated	2/23/2018	52.00%	1,411,441	733,949	
Duke Energy Corporation	North Carolina	Piedmont Natural Gas Co.	Natural Gas	Distribution	10/31/2019	52.00%	441,656	229,661	
Duke Energy Corporation	Ohio	Duke Energy Ohio Inc.	Electric	Distribution	12/19/2018	50.75%	718,099	364,435	
Duke Energy Corporation	Ohio	Duke Energy Ohio Inc.	Natural Gas	Distribution	11/13/2013	53.30%	431,666	230,078	
Duke Energy Corporation	South Carolina	Duke Energy Carolinas LLC	Electric	Vertically Integrated	5/1/2019	53.00%	591,113	313,290	
Duke Energy Corporation	South Carolina	Duke Energy Progress LLC	Electric	Vertically Integrated	5/8/2019	53.00%	169,208	89,680	
Duke Energy Corporation	South Carolina	Piedmont Natural Gas Co.	Natural Gas	Distribution	9/26/2018	53.00%	441,656	234,078	
Duke Energy Corporation	Tennessee	Piedmont Natural Gas Co.	Natural Gas	Distribution	1/23/2012	52.71%	184,982	97,504	52.26%
Edison International	California	Southern California Edison Co.	Electric	Vertically Integrated	12/19/2019	52.00%	5,111,838	2,658,156	52.00%
El Paso Electric Company	New Mexico	El Paso Electric Co.	Electric	Vertically Integrated	6/8/2016	49.29%	98,984	48,789	
El Paso Electric Company	Texas	El Paso Electric Co.	Electric	Vertically Integrated	12/14/2017	48.35%	323,297	156,314	48.57%
Entergy Corporation	Arkansas [1]	Entergy Arkansas LLC	Electric	Vertically Integrated	12/13/2019	47.04%	711,931	334,902	
Entergy Corporation	Louisiana	Entergy Gulf States LA LLC	Electric	Vertically Integrated	12/16/2013	N/A	N/A	N/A	
Entergy Corporation	Louisiana	Entergy Gulf States LA LLC	Natural Gas	Distribution	7/6/2005	47.52%	99,500	47,282	
Entergy Corporation	Louisiana	Entergy Louisiana LLC	Electric	Vertically Integrated	7/10/2014	N/A	N/A	N/A	
Entergy Corporation	Louisiana	Entergy New Orleans LLC	Electric	Vertically Integrated	11/7/2019	50.00%	202,634	101,317	
Entergy Corporation	Louisiana	Entergy New Orleans LLC	Natural Gas	Distribution	11/7/2019	50.00%	99,500	49,750	
Entergy Corporation	Mississippi	Entergy Mississippi LLC	Electric	Vertically Integrated	12/11/2014	N/A	N/A	N/A	
Entergy Corporation	Texas	Entergy Texas Inc.	Electric	Vertically Integrated	12/20/2018	N/A	N/A	N/A	47.89%

Authorized Capital Structure Analysis - Concentric Proxy Group

Company	State	Subsidiary	Service	Case Type	Rate Case Decision Date	Authorized Equity Ratio	Customers Served	Weighted Equity Ratio	Avg. Equity Ratio
FirstEnergy Corporation	Maryland	Potomac Edison Co.	Electric	Distribution	3/22/2019	52.82%	268,830	141,996	
FirstEnergy Corporation	New Jersey	Jersey Cntrl Power & Light Co.	Electric	Distribution	12/12/2016	45.00%	1,131,190	509,036	
FirstEnergy Corporation	Ohio	Cleveland Elec Illuminating Co	Electric	Distribution	1/21/2009	49.00%	751,979	368,470	
FirstEnergy Corporation	Ohio	Ohio Edison Co.	Electric	Distribution	1/21/2009	49.00%	1,050,129	514,563	
FirstEnergy Corporation	Ohio	Toledo Edison Co.	Electric	Distribution	1/21/2009	49.00%	310,979	152,380	
FirstEnergy Corporation	Pennsylvania	Metropolitan Edison Co.	Electric	Distribution	1/19/2017	N/A	N/A	N/A	
FirstEnergy Corporation	Pennsylvania	Pennsylvania Electric Co.	Electric	Distribution	1/19/2017	N/A	N/A	N/A	
FirstEnergy Corporation	Pennsylvania	Pennsylvania Power Co.	Electric	Distribution	1/19/2017	N/A	N/A	N/A	
FirstEnergy Corporation	Pennsylvania	West Penn Power Co.	Electric	Distribution	1/19/2017	N/A	N/A	N/A	
FirstEnergy Corporation	West Virginia	Monongahela Power Co.	Electric	Vertically Integrated	2/4/2015	N/A	N/A	N/A	48.00%
Evergy, Inc.	Kansas	Evergy Kansas Central Inc.	Electric	Vertically Integrated	9/27/2018	51.24%	381,420	195,440	
Evergy, Inc.	Kansas	Evergy Metro Inc	Electric	Vertically Integrated	12/13/2018	49.09%	259,099	127,192	
Evergy, Inc.	Missouri	Evergy Metro Inc	Electric	Vertically Integrated	10/31/2018	N/A	N/A	N/A	
Evergy, Inc.	Missouri	Evergy Missouri West	Electric	Vertically Integrated	10/31/2018	N/A	N/A	N/A	50.37%
IDACORP, Inc.	Idaho	Idaho Power Co.	Electric	Vertically Integrated	12/30/2011	N/A	N/A	N/A	
IDACORP, Inc.	Oregon	Idaho Power Co.	Electric	Vertically Integrated	2/23/2012	49.90%	19,054	9,508	49.90%
NextEra Energy, Inc.	Florida	Florida Power & Light Co.	Electric	Vertically Integrated	11/29/2016	N/A	N/A	N/A	
NextEra Energy, Inc.	Florida	Gulf Power Co.	Electric	Vertically Integrated	4/4/2017	N/A	N/A	N/A	
NextEra Energy, Inc.	Florida [2]	Pivotal Utility Holdings Inc.	Natural Gas	Distribution	3/26/2018	48.00%	109,674	52,644	48.00%
Pinnacle West Capital Corporation	Arizona	Arizona Public Service Co.	Electric	Vertically Integrated	8/15/2017	55.80%	1,235,451	689,382	55.80%
PNM Resources, Inc.	New Mexico	Public Service Co. of NM	Electric	Vertically Integrated	12/20/2017	49.61%	526,346	261,120	
PNM Resources, Inc.	Texas	Texas-New Mexico Power Co.	Electric	Distribution	12/20/2018	45.00%	253,216	113,947	48.11%
Portland General Electric Company	Oregon	Portland General Electric Co.	Electric	Vertically Integrated	12/14/2018	50.00%	888,123	444,062	50.00%
Southern Company	Alabama	Alabama Power Co.	Electric	Vertically Integrated	10/12/1982	N/A	N/A	N/A	
Southern Company	Georgia	Atlanta Gas Light Co.	Natural Gas	Distribution	12/19/2019	56.00%	1,643,000	920,080	
Southern Company	Georgia	Georgia Power Co.	Electric	Vertically Integrated	12/17/2019	56.00%	2,536,685	1,420,544	
Southern Company	Georgia	Savannah Electric & Power Co.	Electric	Vertically Integrated	5/25/2005	N/A	N/A	N/A	
Southern Company	Illinois	Northern Illinois Gas Co.	Natural Gas	Distribution	10/2/2019	54.20%	2,226,874	1,206,966	
Southern Company	Mississippi	Mississippi Power Co.	Electric	Vertically Integrated	3/17/2020	53.00%	188,000	99,640	
Southern Company	Tennessee	Chattanooga Gas Co.	Natural Gas	Distribution	10/15/2018	49.23%	67,000	32,984	
Southern Company	Virginia	Virginia Natural Gas Inc.	Natural Gas	Distribution	12/21/2017	N/A	N/A	N/A	55.25%
Xcel Energy Inc.	Colorado	Public Service Co. of CO	Electric	Vertically Integrated	2/11/2020	55.61%	1,478,992	822,467	
Xcel Energy Inc.	Colorado	Public Service Co. of CO	Natural Gas	Distribution	12/21/2018	54.60%	1,400,000	764,400	
Xcel Energy Inc.	Minnesota	Northern States Power Co. - MN	Electric	Vertically Integrated	4/7/2020	N/A	N/A	N/A	
Xcel Energy Inc.	Minnesota	Northern States Power Co. - MN	Natural Gas	Distribution	12/6/2010	52.46%	250,000	131,150	
Xcel Energy Inc.	North Dakota	Northern States Power Co. - MN	Electric	Vertically Integrated	2/26/2014	52.56%	94,212	49,518	
Xcel Energy Inc.	North Dakota	Northern States Power Co. - MN	Natural Gas	Distribution	6/13/2007	51.59%	250,000	128,975	
Xcel Energy Inc.	New Mexico	Southwestern Public Service Co	Electric	Vertically Integrated	5/20/2020	54.77%	121,604	66,603	
Xcel Energy Inc.	South Dakota	Northern States Power Co. - MN	Electric	Vertically Integrated	6/15/2015	N/A	N/A	N/A	
Xcel Energy Inc.	Texas	Southwestern Public Service Co	Electric	Vertically Integrated	8/27/2020	54.62%	271,560	148,326	
Xcel Energy Inc.	Wisconsin	Northern States Power Co - WI	Electric	Vertically Integrated	9/4/2019	52.52%	300,000	157,560	
Xcel Energy Inc.	Wisconsin	Northern States Power Co - WI	Natural Gas	Distribution	9/4/2019	52.52%	100,000	52,520	54.41%

Authorized Capital Structure Analysis - Concentric Proxy Group

Company	State	Subsidiary	Service	Case Type	Rate Case Decision Date	Authorized Equity Ratio	Customers Served	Weighted Equity Ratio	Avg. Equity Ratio
Algonquin Power & Utilities Corp	California	Liberty Utilities	Electric	Vertically Integrated	8/27/2020	52.50%	49,000	25,725	
Algonquin Power & Utilities Corp	Kansas	Empire District Electric Co.	Electric	Vertically Integrated	7/30/2019	N/A	N/A	N/A	
Algonquin Power & Utilities Corp	Massachusetts	Liberty Utilities	Natural Gas	Distribution	2/10/2016	50.00%	50,000	25,000	
Algonquin Power & Utilities Corp	Missouri	Empire District Electric Co.	Electric	Vertically Integrated	7/1/2020	46.00%	154,042	70,859	
Algonquin Power & Utilities Corp	Missouri	Empire District Gas Co.	Natural Gas	Distribution	1/20/2010	N/A	N/A	N/A	
Algonquin Power & Utilities Corp	Missouri	Liberty Utilities (Midstates)	Natural Gas	Distribution	6/6/2018	N/A	N/A	N/A	
Algonquin Power & Utilities Corp	New Hampshire	Granite State	Electric	Distribution	6/30/2020	52.00%	44,092	22,928	
Algonquin Power & Utilities Corp	New Hampshire	EnergyNorth	Natural Gas	Distribution	2/28/2020	N/A	N/A	N/A	
Algonquin Power & Utilities Corp	New Brunswick	Enbridge Gas New Brunswick	Natural Gas	Distribution	11/30/2010	45.00%	12,000	5,400	48.49%
Emera Inc.	Florida	Tampa Electric Co.	Electric	Vertically Integrated	11/6/2017	N/A	N/A	N/A	
Emera Inc.	New Mexico	New Mexico Gas Co.	Natural Gas	Distribution	7/17/2019	N/A	N/A	N/A	
Emera Inc.	Nova Scotia	Nova Scotia Power Inc.	Electric	Vertically Integrated	12/21/2012	37.50%	519,000	194,625	37.50%
Fortis Inc.	New York	Central Hudson Gas & Electric	Electric	Distribution	6/14/2018	48.00%	307,025	147,372	
Fortis Inc.	New York	Central Hudson Gas & Electric	Natural Gas	Distribution	6/14/2018	48.00%	82,462	39,582	
Fortis Inc.	Arizona	Tucson Electric Power Co.	Electric	Vertically Integrated	2/24/2017	50.03%	426,451	213,353	
Fortis Inc.	Arizona	UNS Electric Inc.	Electric	Vertically Integrated	8/18/2016	52.83%	97,926	51,734	
Fortis Inc.	Arizona	UNS Gas Inc.	Natural Gas	Distribution	4/24/2012	50.82%	582,074	295,810	
Fortis Inc.	Alberta	FortisAlberta Inc	Electric	Distribution	12/16/16 & 8/2/18	37.00%	564,000	208,680	
Fortis Inc.	British Columbia	FortisBC	Electric	Vertically Integrated	3/25/2014	40.00%	176,000	70,400	
Fortis Inc.	British Columbia	FortisBC Energy	Natural Gas	Distribution	8/10/2016	38.50%	1,030,000	396,550	
Fortis Inc.	Newfoundland & Labrador	Newfoundland Power Inc	Electric	Vertically Integrated	1/24/2019	45.00%	268,000	120,600	
Fortis Inc.	Prince Edward Island	Maritime Electric Company Ltd.	Electric	Vertically Integrated	9/27/2019	40.00%	81,000	32,400	43.61%
					Mean, All Results	**49.52%**			**49.47%**
					Median, All Results	**50.00%**			**49.63%**

Notes:
[1] Authorized equity ratio adjusted to remove zero cost of capital items from the capital structure.
[2] While zero cost of of capital items are typically included in the capital structure for utilities operating in Florida, this case involved a settlement that was silent with respect to most traditional cost of capital parameters. Accordingly, no adjustment was made to remove zero cost of capital items from the capital structure.

Authorized Capital Structure Analysis - Moody's Proxy Group

Company	State	Subsidiary	Docket	Service	Case Type	Rate Case Decision Date	Authorized Equity Ratio	Avg. Equity Ratio
Public Service Enterprise Group, Inc.	New Jersey	Public Service Electric Gas	D-ER18010029	Electric	Distribution	10/29/2018	54.00%	
Public Service Enterprise Group, Inc.	New Jersey	Public Service Electric Gas	D-GR18010030	Natural Gas	Distribution	10/29/2018	54.00%	54.00%
NextEra Energy, Inc.	Florida	Florida Power & Light Co.	D-160021-EI	Electric	Vertically Integrated	11/29/2016	N/A	
NextEra Energy, Inc.	Florida	Gulf Power Co.	D-160186-EI	Electric	Vertically Integrated	4/4/2017	N/A	
NextEra Energy, Inc.	Florida	Pivotal Utility Holdings Inc.	20170179-GU	Natural Gas	Distribution	3/26/2018	48.00%	48.00%
Exelon Corporation	DC	Potomac Electric Power Co.	FC-1150	Electric	Distribution	8/8/2018	50.44%	
Exelon Corporation	Delaware	Delmarva Power & Light Co.	D-17-0977	Electric	Distribution	8/21/2018	50.52%	
Exelon Corporation	Delaware	Delmarva Power & Light Co.	D-17-0978	Natural Gas	Distribution	11/8/2018	50.52%	
Exelon Corporation	Illinois	Commonwealth Edison Co.	D-19-0387	Electric	Distribution	12/4/2019	47.97%	
Exelon Corporation	Maryland	Baltimore Gas and Electric Co.	C-9610 (EL)	Electric	Distribution	12/17/2019	N/A	
Exelon Corporation	Maryland	Baltimore Gas and Electric Co.	C-9610 (GAS)	Natural Gas	Distribution	12/17/2019	N/A	
Exelon Corporation	Maryland	Delmarva Power & Light Co.	C-9455	Electric	Distribution	7/14/2020	50.53%	
Exelon Corporation	Maryland	Potomac Electric Power Co.	C-9602	Electric	Distribution	8/12/2019	50.46%	
Exelon Corporation	New Jersey	Atlantic City Electric Co.	D-ER18080925	Electric	Distribution	3/13/2019	49.94%	
Exelon Corporation	Pennsylvania	PECO Energy Co.	D-R-2018-3000164	Electric	Distribution	12/20/2018	N/A	
Exelon Corporation	Pennsylvania	PECO Energy Co.	D-R-2010-2161592	Natural Gas	Distribution	12/16/2010	N/A	50.05%
						Mean	**50.64%**	**50.68%**
						Median	**50.49%**	**50.05%**

CAPITAL STRUCTURE ANALYSIS - CONCENTRIC PROXY GROUP

EQUITY RATIO [1]

Proxy Group Company	Ticker	2019	2018	2017	2016	2015	Average
ALLETE, Inc.	ALE	59.55%	61.27%	60.15%	57.01%	55.95%	58.79%
Ameren Corporation	AEE	52.85%	53.13%	53.05%	52.99%	52.51%	52.90%
American Electric Power Company, Inc.	AEP	49.44%	49.20%	49.57%	48.29%	48.06%	48.91%
Avista Corporation	AVA	50.83%	49.89%	50.75%	50.93%	50.41%	50.56%
Duke Energy Corporation	DUK	52.56%	52.50%	52.55%	52.14%	55.25%	53.00%
Edison International	EIX	53.79%	51.34%	57.19%	58.20%	56.29%	55.36%
El Paso Electric Company	EE	48.98%	47.88%	49.95%	47.73%	49.86%	48.88%
Entergy Corporation	ETR	48.21%	48.85%	47.79%	48.19%	49.87%	48.58%
FirstEnergy Corporation	FE	56.32%	58.90%	56.97%	54.59%	51.34%	55.63%
Evergy, Inc.	EVRG	54.13%	54.93%	54.22%	55.08%	55.84%	54.84%
IDACORP, Inc.	IDA	55.14%	54.25%	54.22%	53.15%	52.34%	53.82%
NextEra Energy, Inc.	NEE	59.37%	63.95%	59.41%	62.29%	60.61%	61.13%
Pinnacle West Capital Corporation	PNW	52.80%	54.36%	53.14%	54.59%	55.50%	54.08%
PNM Resources, Inc.	PNM	47.68%	48.13%	49.03%	49.23%	48.79%	48.57%
Portland General Electric Company	POR	49.85%	50.19%	49.80%	49.82%	50.61%	50.05%
Southern Company	SO	54.20%	54.72%	49.24%	51.13%	50.58%	51.97%
Xcel Energy Inc.	XEL	54.29%	54.48%	54.23%	54.22%	54.59%	54.36%
Algonquin Power & Utilities Corp	AQN	57.80%	58.92%	55.52%	56.15%	54.58%	56.59%
Emera Inc.	EMA	48.06%	48.44%	49.22%	48.66%	46.92%	48.26%
Fortis Inc.	FTS	49.88%	48.98%	49.50%	50.13%	50.86%	49.87%
MEAN		52.79%	53.22%	52.77%	52.73%	52.54%	52.81%
LOW		47.68%	47.88%	47.79%	47.73%	46.92%	48.26%
HIGH		59.55%	63.95%	60.15%	62.29%	60.61%	61.13%

EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2019	2018	2017	2016	2015	Average
ALLETE (Minnesota Power)	ALE	59.59%	61.39%	60.04%	56.92%	55.86%	58.76%
Superior Water, Light and Power Company	ALE	58.08%	56.86%	64.99%	61.12%	60.23%	60.26%
Ameren Illinois Company	AEE	53.37%	53.27%	53.85%	53.95%	53.96%	53.68%
Union Electric Company	AEE	52.36%	53.00%	52.42%	52.30%	51.53%	52.32%
AEP Texas Central Company	AEP				46.01%	43.63%	44.82%
AEP Texas North Company	AEP				43.29%	42.36%	42.82%
Appalachian Power Company	AEP	48.74%	49.51%	48.72%	46.89%	46.77%	48.13%
Indiana Michigan Power Company	AEP	46.74%	44.62%	46.33%	49.11%	52.65%	47.89%
Kentucky Power Company	AEP	47.34%	45.72%	43.52%	43.45%	43.26%	44.66%
Kingsport Power Company	AEP	54.62%	50.79%	46.53%	65.24%	59.70%	55.38%
Ohio Power Company	AEP	54.50%	57.80%	58.63%	56.51%	50.09%	55.51%
Public Service Company of Oklahoma	AEP	49.69%	49.16%	48.50%	48.47%	46.45%	48.46%
Southwestern Electric Power Company	AEP	48.80%	46.97%	48.52%	45.95%	49.59%	47.97%
Transource Maryland, LLC	AEP	40.18%	41.81%				40.99%
Transource Pennsylvania, LLC	AEP	40.15%	41.92%				41.03%
Wheeling Power Company	AEP	53.51%	54.62%	54.26%	54.12%	53.73%	54.05%
Avista Corporation	AVA	50.83%	49.89%	50.75%	50.93%	50.41%	50.56%
Duke Energy Carolinas, LLC	DUK	52.11%	51.78%	52.98%	52.81%	58.07%	53.55%
Duke Energy Florida, LLC	DUK	49.91%	50.04%	49.25%	50.83%	55.28%	51.06%
Duke Energy Indiana, LLC	DUK	52.84%	53.26%	51.94%	51.59%	50.27%	51.98%
Duke Energy Kentucky, Inc.	DUK	49.37%	51.95%	53.11%	54.74%	56.11%	53.06%
Duke Energy Ohio, Inc.	DUK	65.22%	68.09%	66.24%	66.39%	68.71%	66.93%
Duke Energy Progress, LLC	DUK	51.29%	51.00%	52.27%	51.58%	52.40%	51.71%
Piedmont Natural Gas Company, Inc.	DUK		49.32%	44.79%	38.72%	42.06%	43.72%
Southern California Edison Company	EIX	53.79%	51.34%	57.19%	58.20%	56.29%	55.36%
El Paso Electric Company	EE	48.98%	47.88%	49.95%	47.73%	49.86%	48.88%
Entergy Arkansas, LLC	ETR	47.90%	49.42%	46.27%	46.54%	45.65%	47.16%
Entergy Louisiana, LLC	ETR	47.47%	47.37%	47.43%	47.87%	51.13%	48.25%
Entergy Mississippi, LLC	ETR	48.60%	49.11%	48.28%	49.58%	50.08%	49.13%
Entergy New Orleans, LLC	ETR	49.26%	51.19%	53.16%	54.81%	60.01%	53.69%
Entergy Texas, Inc.	ETR	50.92%	53.46%	50.45%	49.56%	49.96%	50.87%
Cleveland Electric Illuminating Company	FE	55.17%	55.44%	55.27%	50.89%	45.10%	52.37%
Jersey Central Power & Light Company	FE	68.33%	69.46%	65.30%	59.21%	52.32%	62.92%
Metropolitan Edison Company	FE	48.00%	53.21%	52.33%	50.30%	48.43%	50.45%
Monongahela Power Company	FE	46.36%	48.87%	49.15%	49.15%	48.89%	48.48%
Ohio Edison Company	FE	66.77%	69.93%	64.91%	63.66%	63.58%	65.77%
Pennsylvania Electric Company	FE	50.37%	53.89%	52.06%	51.85%	47.70%	51.18%
Pennsylvania Power Company	FE	48.79%	49.03%	53.82%	52.06%	58.16%	52.37%
Potomac Edison Company	FE	54.31%	52.35%	51.59%	50.08%	51.59%	51.98%
Toledo Edison Company	FE	59.74%	60.43%	60.04%	61.98%	60.41%	60.52%
West Penn Power Company	FE	47.69%	53.50%	52.82%	52.62%	49.48%	51.22%
Great Plains Energy Incorporated	EVRG	50.32%	51.05%	50.15%	51.15%	50.80%	50.70%
Westar Energy (KPL)	EVRG	57.97%	59.08%	58.74%	59.68%	62.21%	59.54%
Idaho Power Company	IDA	55.14%	54.25%	54.22%	53.15%	52.34%	53.82%
Florida Power & Light Company	NEE	60.24%	64.37%	59.93%	62.65%	61.41%	61.72%
Gulf Power Company	NEE	50.30%	59.73%	54.19%	58.68%	53.39%	55.26%
Pivotal Utility Holdings, Inc.	NEE						
Arizona Public Service Company	PNW	52.80%	54.36%	53.14%	54.59%	55.50%	54.08%
Public Service Company of New Mexico	PNM	45.42%	45.83%	46.26%	46.22%	45.54%	45.85%
Texas-New Mexico Power Company	PNM	52.74%	53.79%	56.70%	58.27%	59.35%	56.17%
Portland General Electric Company	POR	49.85%	50.19%	49.80%	49.82%	50.61%	50.05%
Alabama Power Company	SO	51.90%	48.74%	48.14%	48.07%	47.66%	48.90%
Atlanta Gas Light Company	SO		58.77%	54.62%	54.31%	54.46%	55.54%
Chattanooga Gas Company	SO		52.54%	52.46%	53.33%	52.34%	52.67%
Georgia Power Company	SO	56.12%	59.02%	50.06%	52.22%	51.70%	53.83%
Mississippi Power Company	SO	50.84%	50.35%	39.92%	49.90%	48.44%	47.89%
Northern Illinois Gas Company	SO		53.19%	53.66%	61.39%	62.31%	57.64%
Virginia Natural Gas, Inc.	SO		52.49%	54.18%	51.42%	50.91%	52.25%
Northern States Power Company - MN	XEL	52.20%	52.81%	52.38%	52.31%	53.26%	52.59%
Northern States Power Company - WI	XEL	54.23%	53.60%	53.36%	54.93%	54.27%	54.08%

EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2019	2018	2017	2016	2015	Average
Public Service Company of Colorado	XEL	56.32%	56.31%	56.50%	56.32%	56.34%	56.36%
Southwestern Public Service Company	XEL	54.14%	54.17%	53.55%	53.93%	53.83%	53.92%
Empire District Electric Company	AQN	53.99%	52.25%	51.49%	51.51%	49.95%	51.84%
Empire District Gas Company	AQN	38.39%	37.28%	35.66%	33.12%	32.33%	35.35%
Liberty Utilities (CalPeco Electric) LLC	AQN		77.00%				77.00%
Liberty Utilities (EnergyNorth Natural Gas) Corp.	AQN	54.12%	52.96%	51.47%	63.06%	61.29%	56.58%
Liberty Utilities (Granite State Electric) Corp.	AQN	77.03%	76.42%	75.52%	74.62%	73.78%	75.47%
Liberty Utilities (Midstates Natural Gas) Corp	AQN	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Liberty Utilities (New England Natural Gas Company) Corp	AQN	73.37%	70.67%	67.74%	59.76%	58.06%	65.92%
St. Lawrence Gas Company, Inc.	AQN		83.65%	82.81%	81.96%	84.74%	83.29%
New Mexico Gas Company, Inc.	EMA		70.77%	70.45%	69.81%	69.82%	70.21%
Peoples Gas System	EMA	61.29%	58.39%	60.09%	57.18%	57.07%	58.80%
Tampa Electric Company	EMA	55.30%	55.63%	57.40%	55.73%	53.12%	55.44%
Nova Scotia Power	EMA	35.17%	30.70%	30.85%	32.38%	31.51%	32.12%
Central Hudson Gas & Electric Corporation	FTS	50.84%	50.84%	51.15%	50.58%	51.44%	50.97%
ITC Interconnection LLC	FTS	59.21%	60.03%	60.60%	58.06%		59.48%
Tucson Electric Power Company	FTS	55.10%	52.80%	53.20%	51.58%	50.20%	52.58%
UNS Electric, Inc.	FTS	57.48%	55.84%	54.59%	53.62%	52.56%	54.82%
UNS Gas, Inc.	FTS						
Fortis Alberta	FTS	41.06%	39.86%	40.26%	41.42%	43.59%	41.24%
Fortis BC	FTS	51.75%	51.59%	51.40%	54.01%	53.20%	52.39%
Fortis BC Energy (Gas)	FTS	51.30%	51.64%	52.85%	54.15%	56.26%	53.24%
Newfoundland Power	FTS	48.08%	45.53%	45.55%	46.26%	45.59%	46.20%
Maritime Electric	FTS						

Notes:
[1] Ratios are weighted by actual common capital and long-term debt of Operating Subsidiaries
[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

CAPITAL STRUCTURE ANALYSIS - CONCENTRIC PROXY GROUP

		LONG-TERM DEBT RATIO [1]					
Proxy Group Company	Ticker	2019	2018	2017	2016	2015	Average
ALLETE, Inc.	ALE	40.45%	38.73%	39.85%	42.99%	44.05%	41.21%
Ameren Corporation	AEE	47.15%	46.87%	46.95%	47.01%	47.49%	47.10%
American Electric Power Company, Inc.	AEP	50.56%	50.80%	50.43%	51.71%	51.94%	51.09%
Avista Corporation	AVA	49.17%	50.11%	49.25%	49.07%	49.59%	49.44%
Duke Energy Corporation	DUK	47.44%	47.50%	47.45%	47.86%	44.75%	47.00%
Edison International	EIX	46.21%	48.66%	42.81%	41.80%	43.71%	44.64%
El Paso Electric Company	EE	51.02%	52.12%	50.05%	52.27%	50.14%	51.12%
Entergy Corporation	ETR	51.79%	51.15%	52.21%	51.81%	50.13%	51.42%
FirstEnergy Corporation	FE	43.68%	41.10%	43.03%	45.41%	48.66%	44.37%
Evergy, Inc.	EVRG	45.87%	45.07%	45.78%	44.92%	44.16%	45.16%
IDACORP, Inc.	IDA	44.86%	45.75%	45.78%	46.85%	47.66%	46.18%
NextEra Energy, Inc.	NEE	40.63%	36.05%	40.59%	37.71%	39.39%	38.87%
Pinnacle West Capital Corporation	PNW	47.20%	45.64%	46.86%	45.41%	44.50%	45.92%
PNM Resources, Inc.	PNM	52.32%	51.87%	50.97%	50.77%	51.21%	51.43%
Portland General Electric Company	POR	50.15%	49.81%	50.20%	50.18%	49.39%	49.95%
Southern Company	SO	45.80%	45.28%	50.76%	48.87%	49.42%	48.03%
Xcel Energy Inc.	XEL	45.71%	45.52%	45.77%	45.78%	45.41%	45.64%
Algonquin Power & Utilities Corp	AQN	42.20%	41.08%	44.48%	43.85%	45.42%	43.41%
Emera Inc.	EMA	51.94%	51.56%	50.78%	51.34%	53.08%	51.74%
Fortis Inc.	FTS	50.12%	51.02%	50.50%	49.87%	49.14%	50.13%
MEAN		47.21%	46.78%	47.23%	47.27%	47.46%	47.19%
LOW		40.45%	36.05%	39.85%	37.71%	39.39%	38.87%
HIGH		52.32%	52.12%	52.21%	52.27%	53.08%	51.74%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2019	2018	2017	2016	2015	Average
ALLETE (Minnesota Power)	ALE	40.41%	38.61%	39.96%	43.08%	44.14%	41.24%
Superior Water, Light and Power Company	ALE	41.92%	43.14%	35.01%	38.88%	39.77%	39.74%
Ameren Illinois Company	AEE	46.63%	46.73%	46.15%	46.05%	46.04%	46.32%
Union Electric Company	AEE	47.64%	47.00%	47.58%	47.70%	48.47%	47.68%
AEP Texas Central Company	AEP				53.99%	56.37%	55.18%
AEP Texas North Company	AEP				56.71%	57.64%	57.18%
Appalachian Power Company	AEP	51.26%	50.49%	51.28%	53.11%	53.23%	51.87%
Indiana Michigan Power Company	AEP	53.26%	55.38%	53.67%	50.89%	47.35%	52.11%
Kentucky Power Company	AEP	52.66%	54.28%	56.48%	56.55%	56.74%	55.34%
Kingsport Power Company	AEP	45.38%	49.21%	53.47%	34.76%	40.30%	44.62%
Ohio Power Company	AEP	45.50%	42.20%	41.37%	43.49%	49.91%	44.49%
Public Service Company of Oklahoma	AEP	50.31%	50.84%	51.50%	51.53%	53.55%	51.54%
Southwestern Electric Power Company	AEP	51.20%	53.03%	51.48%	54.05%	50.41%	52.03%
Transource Maryland, LLC	AEP	59.82%	58.19%				59.01%
Transource Pennsylvania, LLC	AEP	59.85%	58.08%				58.97%
Wheeling Power Company	AEP	46.49%	45.38%	45.74%	45.88%	46.27%	45.95%
Avista Corporation	AVA	49.17%	50.11%	49.25%	49.07%	49.59%	49.44%
Duke Energy Carolinas, LLC	DUK	47.89%	48.22%	47.02%	47.19%	41.93%	46.45%
Duke Energy Florida, LLC	DUK	50.09%	49.96%	50.75%	49.17%	44.72%	48.94%
Duke Energy Indiana, LLC	DUK	47.16%	46.74%	48.06%	48.41%	49.73%	48.02%
Duke Energy Kentucky, Inc.	DUK	50.63%	48.05%	46.89%	45.26%	43.89%	46.94%
Duke Energy Ohio, Inc.	DUK	34.78%	31.91%	33.76%	33.61%	31.29%	33.07%
Duke Energy Progress, LLC	DUK	48.71%	49.00%	47.73%	48.42%	47.60%	48.29%
Piedmont Natural Gas Company, Inc.	DUK		50.68%	55.21%	61.28%	57.94%	56.28%
Southern California Edison Company	EIX	46.21%	48.66%	42.81%	41.80%	43.71%	44.64%
El Paso Electric Company	EE	51.02%	52.12%	50.05%	52.27%	50.14%	51.12%
Entergy Arkansas, LLC	ETR	52.10%	50.58%	53.73%	53.46%	54.35%	52.84%
Entergy Louisiana, LLC	ETR	52.53%	52.63%	52.57%	52.13%	48.87%	51.75%
Entergy Mississippi, LLC	ETR	51.40%	50.89%	51.72%	50.42%	49.92%	50.87%
Entergy New Orleans, LLC	ETR	50.74%	48.81%	46.84%	45.19%	39.99%	46.31%
Entergy Texas, Inc.	ETR	49.08%	46.54%	49.55%	50.44%	50.04%	49.13%
Cleveland Electric Illuminating Company	FE	44.83%	44.56%	44.73%	49.11%	54.90%	47.63%
Jersey Central Power & Light Company	FE	31.67%	30.54%	34.70%	40.79%	47.68%	37.08%
Metropolitan Edison Company	FE	52.00%	46.79%	47.67%	49.70%	51.57%	49.55%
Monongahela Power Company	FE	53.64%	51.13%	50.85%	50.85%	51.11%	51.52%
Ohio Edison Company	FE	33.23%	30.07%	35.09%	36.34%	36.42%	34.23%
Pennsylvania Electric Company	FE	49.63%	46.11%	47.94%	48.15%	52.30%	48.82%
Pennsylvania Power Company	FE	51.21%	50.97%	46.18%	47.94%	41.84%	47.63%
Potomac Edison Company	FE	45.69%	47.65%	48.41%	49.92%	48.41%	48.02%
Toledo Edison Company	FE	40.26%	39.57%	39.96%	38.02%	39.59%	39.48%
West Penn Power Company	FE	52.31%	46.50%	47.18%	47.38%	50.52%	48.78%
Great Plains Energy Incorporated	EVRG	49.68%	48.95%	49.85%	48.85%	49.20%	49.30%
Westar Energy (KPL)	EVRG	42.03%	40.92%	41.26%	40.32%	37.79%	40.46%
Idaho Power Company	IDA	44.86%	45.75%	45.78%	46.85%	47.66%	46.18%
Florida Power & Light Company	NEE	39.76%	35.63%	40.07%	37.35%	38.59%	38.28%
Gulf Power Company	NEE	49.70%	40.27%	45.81%	41.32%	46.61%	44.74%
Pivotal Utility Holdings, Inc.	NEE						
Arizona Public Service Company	PNW	47.20%	45.64%	46.86%	45.41%	44.50%	45.92%
Public Service Company of New Mexico	PNM	54.58%	54.17%	53.74%	53.78%	54.46%	54.15%
Texas-New Mexico Power Company	PNM	47.26%	46.21%	43.30%	41.73%	40.65%	43.83%
Portland General Electric Company	POR	50.15%	49.81%	50.20%	50.18%	49.39%	49.95%
Alabama Power Company	SO	48.10%	51.26%	51.86%	51.93%	52.34%	51.10%
Atlanta Gas Light Company	SO		41.23%	45.38%	45.69%	45.54%	44.46%
Chattanooga Gas Company	SO		47.46%	47.54%	46.67%	47.66%	47.33%
Georgia Power Company	SO	43.88%	40.98%	49.94%	47.78%	48.30%	46.17%
Mississippi Power Company	SO	49.16%	49.65%	60.08%	50.10%	51.56%	52.11%
Northern Illinois Gas Company	SO		46.81%	46.34%	38.61%	37.69%	42.36%
Virginia Natural Gas, Inc.	SO		47.51%	45.82%	48.58%	49.09%	47.75%
Northern States Power Company - MN	XEL	47.80%	47.19%	47.62%	47.69%	46.74%	47.41%
Northern States Power Company - WI	XEL	45.77%	46.40%	46.64%	45.07%	45.73%	45.92%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2019	2018	2017	2016	2015	Average
Public Service Company of Colorado	XEL	43.68%	43.69%	43.50%	43.68%	43.66%	43.64%
Southwestern Public Service Company	XEL	45.86%	45.83%	46.45%	46.07%	46.17%	46.08%
Empire District Electric Company	AQN	46.01%	47.75%	48.51%	48.49%	50.05%	48.16%
Empire District Gas Company	AQN	61.61%	62.72%	64.34%	66.88%	67.67%	64.65%
Liberty Utilities (CalPeco Electric) LLC	AQN		23.00%				23.00%
Liberty Utilities (EnergyNorth Natural Gas) Corp.	AQN	45.88%	47.04%	48.53%	36.94%	38.71%	43.42%
Liberty Utilities (Granite State Electric) Corp.	AQN	22.97%	23.58%	24.48%	25.38%	26.22%	24.53%
Liberty Utilities (Midstates Natural Gas) Corp	AQN	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Liberty Utilities (New England Natural Gas Company) Corp	AQN	26.63%	29.33%	32.26%	40.24%	41.94%	34.08%
St. Lawrence Gas Company, Inc.	AQN		16.35%	17.19%	18.04%	15.26%	16.71%
New Mexico Gas Company, Inc.	EMA		29.23%	29.55%	30.19%	30.18%	29.79%
Peoples Gas System	EMA	38.71%	41.61%	39.91%	42.82%	42.93%	41.20%
Tampa Electric Company	EMA	44.70%	44.37%	42.60%	44.27%	46.88%	44.56%
Nova Scotia Power	EMA	64.83%	69.30%	69.15%	67.62%	68.49%	67.88%
Central Hudson Gas & Electric Corporation	FTS	49.16%	49.16%	48.85%	49.42%	48.56%	49.03%
ITC Interconnection LLC	FTS	40.79%	39.97%	39.40%	41.94%		40.52%
Tucson Electric Power Company	FTS	44.90%	47.20%	46.80%	48.42%	49.80%	47.42%
UNS Electric, Inc.	FTS	42.52%	44.16%	45.41%	46.38%	47.44%	45.18%
UNS Gas, Inc.	FTS						
Fortis Alberta	FTS	58.94%	60.14%	59.74%	58.58%	56.41%	58.76%
Fortis BC	FTS	48.25%	48.41%	48.60%	45.99%	46.80%	47.61%
Fortis BC Energy (Gas)	FTS	48.70%	48.36%	47.15%	45.85%	43.74%	46.76%
Newfoundland Power	FTS	51.92%	54.47%	54.45%	53.74%	54.41%	53.80%
Maritime Electric	FTS						

Notes:
[1] Ratios are weighted by actual common capital and long-term debt of Operating Subsidiaries
[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

CAPITAL STRUCTURE ANALYSIS - MOODY'S PROXY GROUP

EQUITY RATIO [1]

Proxy Group Company	Ticker	2019	2018	2017	2016	2015	Average
Public Service Enterprise Group, Inc.	PEG	54.72%	54.24%	53.41%	52.74%	52.65%	53.55%
NextEra Energy, Inc.	NEE	59.37%	63.95%	59.41%	62.29%	60.61%	61.13%
Exelon Corporation	EXC	53.13%	53.31%	53.38%	52.99%	52.47%	53.06%
MEAN		55.74%	57.17%	55.40%	56.01%	55.24%	55.91%
LOW		53.13%	53.31%	53.38%	52.74%	52.47%	53.06%
HIGH		59.37%	63.95%	59.41%	62.29%	60.61%	61.13%

EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2019	2018	2017	2016	2015	Average
Public Service Electric and Gas Company	PEG	54.72%	54.24%	53.41%	52.74%	52.65%	53.55%
Florida Power & Light Company	NEE	60.24%	64.37%	59.93%	62.65%	61.41%	61.72%
Gulf Power Company	NEE	50.30%	59.73%	54.19%	58.68%	53.39%	55.26%
Pivotal Utility Holdings, Inc.	NEE						
Atlantic City Electric Company	EXC	49.29%	49.14%	49.19%	48.37%	47.04%	48.61%
Baltimore Gas and Electric Company	EXC	52.80%	53.67%	54.77%	52.54%	57.75%	54.31%
Commonwealth Edison Company	EXC	54.94%	55.06%	54.85%	54.52%	54.99%	54.87%
Delmarva Power & Light Company	EXC	50.12%	49.98%	50.38%	49.43%	49.05%	49.79%
PECO Energy Co.	EXC	53.62%	53.72%	53.54%	55.13%	53.80%	53.96%
Pepco Holdings LLC	EXC					48.56%	48.56%
Potomac Electric Power Company	EXC	50.16%	50.01%	49.89%	49.57%	49.00%	49.72%

Notes:
[1] Ratios are weighted by actual common capital and long-term debt of Operating Subsidiaries
[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

CAPITAL STRUCTURE ANALYSIS - MOODY'S PROXY GROUP

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2019	2018	2017	2016	2015	Average
Public Service Enterprise Group, Inc.	PEG	45.28%	45.76%	46.59%	47.26%	47.35%	46.45%
NextEra Energy, Inc.	NEE	40.63%	36.05%	40.59%	37.71%	39.39%	38.87%
Exelon Corporation	EXC	46.87%	46.69%	46.62%	47.01%	47.53%	46.94%
MEAN		44.26%	42.83%	44.60%	43.99%	44.76%	44.09%
LOW		40.63%	36.05%	40.59%	37.71%	39.39%	38.87%
HIGH		46.87%	46.69%	46.62%	47.26%	47.53%	46.94%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2019	2018	2017	2016	2015	Average
Public Service Electric and Gas Company	PEG	45.28%	45.76%	46.59%	47.26%	47.35%	46.45%
Florida Power & Light Company	NEE	39.76%	35.63%	40.07%	37.35%	38.59%	38.28%
Gulf Power Company	NEE	49.70%	40.27%	45.81%	41.32%	46.61%	44.74%
Pivotal Utility Holdings, Inc.	NEE						
Atlantic City Electric Company	EXC	50.71%	50.86%	50.81%	51.63%	52.96%	51.39%
Baltimore Gas and Electric Company	EXC	47.20%	46.33%	45.23%	47.46%	42.25%	45.69%
Commonwealth Edison Company	EXC	45.06%	44.94%	45.15%	45.48%	45.01%	45.13%
Delmarva Power & Light Company	EXC	49.88%	50.02%	49.62%	50.57%	50.95%	50.21%
PECO Energy Co.	EXC	46.38%	46.28%	46.46%	44.87%	46.20%	46.04%
Pepco Holdings LLC	EXC					51.44%	51.44%
Potomac Electric Power Company	EXC	49.84%	49.99%	50.11%	50.43%	51.00%	50.28%

Notes:
[1] Ratios are weighted by actual common capital and long-term debt of Operating Subsidiaries
[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

CAPITAL STRUCTURE ANALYSIS - CONCENTRIC PROXY GROUP

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2015	2016	2017	2018	2019	Average
ALLETE, Inc.	ALE	53.70%	58.00%	59.00%	60.10%	61.40%	58.44%
Ameren Corporation	AEE	49.70%	51.30%	49.80%	48.80%	47.10%	49.34%
American Electric Power Company, Inc.	AEP	50.20%	50.00%	48.50%	46.80%	43.90%	47.88%
Avista Corporation	AVA	50.00%	48.80%	52.80%	49.50%	50.60%	50.34%
Duke Energy Corporation	DUK	51.40%	47.40%	46.00%	46.20%	44.10%	47.02%
Edison International	EIX	46.70%	49.20%	45.80%	38.30%	39.90%	43.98%
El Paso Electric Company	EE	47.30%	47.30%	48.80%	47.50%	47.60%	47.70%
Entergy Corporation	ETR	40.80%	35.50%	35.50%	35.90%	37.10%	36.96%
FirstEnergy Corporation	FE	39.30%	25.50%	15.70%	27.40%	26.20%	26.82%
Evergy, Inc.	EVRG	N/A	N/A	N/A	60.00%	49.40%	54.70%
IDACORP, Inc.	IDA	54.40%	55.20%	56.30%	56.40%	58.70%	56.20%
NextEra Energy, Inc.	NEE	45.80%	46.70%	47.30%	56.00%	49.60%	49.08%
Pinnacle West Capital Corporation	PNW	57.00%	54.40%	51.10%	53.00%	52.90%	53.68%
PNM Resources, Inc.	PNM	45.50%	44.00%	43.60%	38.60%	39.90%	42.32%
Portland General Electric Company	POR	52.20%	51.60%	49.90%	53.50%	48.70%	51.18%
Southern Company	SO	44.00%	35.70%	35.00%	37.60%	39.50%	38.36%
Xcel Energy Inc.	XEL	45.90%	43.70%	44.10%	43.60%	43.20%	44.10%
Algonquin Power & Utilities Corp [2]	AQN	45.55%	26.72%	39.58%	42.55%	44.26%	39.73%
Emera Inc.	EMA	52.83%	31.97%	35.04%	36.79%	38.51%	39.03%
Fortis Inc.	FTS	38.10%	36.20%	37.10%	37.20%	41.80%	38.08%
MEAN		47.91%	44.17%	44.26%	45.79%	45.22%	45.75%
LOW		38.10%	25.50%	15.70%	27.40%	26.20%	26.82%
HIGH		57.00%	58.00%	59.00%	60.10%	61.40%	58.44%

[1] Data per Value Line Investment Survey
[2] Calculated per Annual Reports, excludes preferred equity & non-controlling interests

CAPITAL STRUCTURE ANALYSIS - CONCENTRIC PROXY GROUP

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2015	2016	2017	2018	2019	Average
ALLETE, Inc.	ALE	46.30%	42.00%	41.00%	39.90%	38.60%	41.56%
Ameren Corporation	AEE	49.30%	47.70%	49.20%	50.30%	52.10%	49.72%
American Electric Power Company, Inc.	AEP	49.80%	50.00%	51.50%	53.20%	56.10%	52.12%
Avista Corporation	AVA	50.00%	51.20%	47.20%	50.50%	49.40%	49.66%
Duke Energy Corporation	DUK	48.60%	52.60%	54.00%	53.80%	54.00%	52.60%
Edison International	EIX	45.00%	41.80%	45.60%	53.60%	53.50%	47.90%
El Paso Electric Company	EE	52.70%	52.70%	51.20%	52.50%	52.40%	52.30%
Entergy Corporation	ETR	57.80%	63.60%	63.60%	63.20%	62.00%	62.04%
FirstEnergy Corporation	FE	60.70%	74.50%	84.30%	72.30%	73.80%	73.12%
Evergy, Inc.	EVRG	N/A	N/A	N/A	40.00%	50.60%	45.30%
IDACORP, Inc.	IDA	45.60%	44.80%	43.70%	43.60%	41.30%	43.80%
NextEra Energy, Inc.	NEE	54.20%	53.30%	52.70%	44.00%	50.40%	50.92%
Pinnacle West Capital Corporation	PNW	43.00%	45.60%	48.90%	47.00%	47.10%	46.32%
PNM Resources, Inc.	PNM	54.10%	55.70%	56.10%	61.10%	59.80%	57.36%
Portland General Electric Company	POR	47.80%	48.40%	50.10%	46.50%	51.30%	48.82%
Southern Company	SO	52.80%	61.50%	64.50%	62.00%	60.10%	60.18%
Xcel Energy Inc.	XEL	54.10%	56.30%	55.90%	56.40%	56.80%	55.90%
Algonquin Power & Utilities Corp [2]	AQN	39.35%	61.15%	48.12%	47.44%	47.15%	48.64%
Emera Inc.	EMA	47.17%	68.03%	64.96%	63.21%	61.49%	60.97%
Fortis Inc.	FTS	53.30%	59.30%	58.40%	58.80%	54.20%	56.80%
MEAN		50.09%	54.22%	54.26%	52.97%	53.61%	52.80%
LOW		39.35%	41.80%	41.00%	39.90%	38.60%	41.56%
HIGH		60.70%	74.50%	84.30%	72.30%	73.80%	73.12%

[1] Data per Value Line Investment Survey
[2] Calculated per Annual Reports

CAPITAL STRUCTURE ANALYSIS - MOODY'S PROXY GROUP

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2015	2016	2017	2018	2019	Average
Public Service Enterprise Group, Inc.	PEG	59.70%	54.70%	53.40%	52.20%	52.30%	54.46%
NextEra Energy, Inc.	NEE	45.80%	46.70%	47.30%	56.00%	49.60%	49.08%
Exelon Corporation	EXC	51.30%	44.50%	47.80%	47.20%	50.40%	48.24%
MEAN		52.27%	48.63%	49.50%	51.80%	50.77%	50.59%
LOW		45.80%	44.50%	47.30%	47.20%	49.60%	48.24%
HIGH		59.70%	54.70%	53.40%	56.00%	52.30%	54.46%

Notes:
[1] Data per Value Line Investment Survey

CAPITAL STRUCTURE ANALYSIS - MOODY'S PROXY GROUP

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2015	2016	2017	2018	2019	Average
Public Service Enterprise Group, Inc.	PEG	40.30%	45.30%	46.60%	47.80%	47.70%	45.54%
NextEra Energy, Inc.	NEE	54.20%	53.30%	52.70%	44.00%	50.40%	50.92%
Exelon Corporation	EXC	48.30%	55.50%	52.20%	52.80%	49.60%	51.68%
MEAN		47.60%	51.37%	50.50%	48.20%	49.23%	49.38%
LOW		40.30%	45.30%	46.60%	44.00%	47.70%	45.54%
HIGH		54.20%	55.50%	52.70%	52.80%	50.40%	51.68%

Notes:
[1] Data per Value Line Investment Survey

RISK ASSESSMENT: Concentric Proxy Group

Proxy Group Company	Ticker	Operating Subsidiary	Type	[1] Credit Rating	[2] Jurisdiction	[3] S&P Regulatory Assessment	[4] Test Year
ALLETE, Inc.	ALE	Minnesota Power	Electric	BBB	Minnesota	Highly Credit Supportive (strong/adequate	Fully Forecast
Ameren Corporation	AEE	Ameren Illinois Co.	Electric	BBB+	Illinois	Very Credit Supportive (strong/adequate)	Historical
	AEE	Ameren Illinois Co.	Gas	BBB+	Illinois	Very Credit Supportive (strong/adequate)	Fully Forecast
	AEE	Union Electric Co.	Electric	BBB+	Missouri	Very Credit Supportive (strong/adequate)	Historical
	AEE	Union Electric Co.	Gas	BBB+	Missouri	Very Credit Supportive (strong/adequate)	Historical
American Electric Power Company, Inc.	AEP	Southwestern Electric Power Co.	Electric	A-	Arkansas	Highly Credit Supportive (strong/adequate	Partially Forecast
	AEP	Indiana Michigan Power Co.	Electric	A-	Indiana	Highly Credit Supportive (strong/adequate	Fully Forecast
	AEP	Kentucky Power Co.	Electric	A-	Kentucky	Most Credit Supportive (strong)	Fully Forecast
	AEP	Southwestern Electric Power Co.	Electric	A-	Louisiana	Highly Credit Supportive (strong/adequate	Historical
	AEP	Indiana Michigan Power Co.	Electric	A-	Michigan	Most Credit Supportive (strong)	Fully Forecast
	AEP	Ohio Power Co.	Electric	A-	Ohio	Very Credit Supportive (strong/adequate)	Partially Forecast
	AEP	Public Service Co. of Oklahoma	Electric	A-	Oklahoma	More Credit Supportive (strong/adequate)	Historical
	AEP	Kingsport Power Co.	Electric	A-	Tennessee	Highly Credit Supportive (strong/adequate	Fully Forecast
	AEP	AEP Texas	Electric	A-	Texas	Very Credit Supportive (strong/adequate)	Historical
	AEP	Southwestern Electric Power Co.	Electric	A-	Texas	Very Credit Supportive (strong/adequate)	Historical
	AEP	Appalachian Power Co.	Electric	A-	Virginia	Highly Credit Supportive (strong/adequate	Historical
	AEP	Appalachian Power Co.	Electric	A-	West Virginia	Very Credit Supportive (strong/adequate)	Historical
Avista Corporation	AVA	Alaska Electric Light & Power	Electric	BBB	Alaska	More Credit Supportive (strong/adequate)	Historical
	AVA	Avista Corp.	Electric	BBB	Idaho	Very Credit Supportive (strong/adequate)	Historical
	AVA	Avista Corp.	Gas	BBB	Idaho	Very Credit Supportive (strong/adequate)	Historical
	AVA	Avista Corp.	Gas	BBB	Oregon	Highly Credit Supportive (strong/adequate	Fully Forecast
	AVA	Avista Corp.	Electric	BBB	Washington	More Credit Supportive (strong/adequate)	Historical
	AVA	Avista Corp.	Gas	BBB	Washington	More Credit Supportive (strong/adequate)	Historical
Duke Energy Corporation	DUK	Duke Energy Florida LLC	Electric	A-	Florida	Most Credit Supportive (strong)	Fully Forecast
	DUK	Duke Energy Indiana LLC	Electric	A-	Indiana	Highly Credit Supportive (strong/adequate	Historical
	DUK	Duke Energy Kentucky Inc.	Electric	A-	Kentucky	Most Credit Supportive (strong)	Fully Forecast
	DUK	Duke Energy Kentucky Inc.	Gas	A-	Kentucky	Most Credit Supportive (strong)	Fully Forecast
	DUK	Duke Energy Carolinas LLC	Electric	A-	North Carolina	Most Credit Supportive (strong)	Historical
	DUK	Duke Energy Progress LLC	Electric	A-	North Carolina	Most Credit Supportive (strong)	Historical
	DUK	Piedmont Natural Gas Co. Inc.	Gas	A-	North Carolina	Most Credit Supportive (strong)	Historical
	DUK	Duke Energy Ohio Inc.	Electric	A-	Ohio	Very Credit Supportive (strong/adequate)	Partially Forecast
	DUK	Duke Energy Ohio Inc.	Gas	A-	Ohio [6]	Very Credit Supportive (strong/adequate)	Partially Forecast
	DUK	Duke Energy Progress LLC	Electric	A-	South Carolina	More Credit Supportive (strong/adequate)	Historical
	DUK	Duke Energy Carolinas LLC	Electric	A-	South Carolina	More Credit Supportive (strong/adequate)	Historical
	DUK	Piedmont Natural Gas Co. Inc.	Gas	A-	South Carolina	More Credit Supportive (strong/adequate)	Historical
	DUK	Piedmont Natural Gas Co. Inc.	Gas	A-	Tennessee	Highly Credit Supportive (strong/adequate	Fully Forecast

RISK ASSESSMENT: Concentric Proxy Group

Proxy Group Company	Ticker	Operating Subsidiary	[5] Electric fuel/gas commodity/purch. power	[5] Conserv. program expense	[5] Full Decoupling	[5] Partial Decoupling	[5] Renewables expense	[5] Environmental compliance	[5] Generation capacity	[5] Generic infrastructure	[5] Transmission expense	[5] Other
ALLETE, Inc.	ALE	Minnesota Power	✓	✓			✓	✓			✓	
Ameren Corporation	AEE	Ameren Illinois Co.	NA	✓			✓	✓			✓	✓
	AEE	Ameren Illinois Co.	✓	✓		✓		✓		✓		✓
	AEE	Union Electric Co.	✓	✓		✓	✓	✓		✓	✓	✓
	AEE	Union Electric Co.	✓			✓				✓		✓
American Electric Power Company, Inc.	AEP	Southwestern Electric Power Co.	✓	✓		✓		✓	✓		✓	✓
	AEP	Indiana Michigan Power Co.	✓	✓		✓	✓	✓		✓	✓	✓
	AEP	Kentucky Power Co.	✓	✓		✓	✓	✓				✓
	AEP	Southwestern Electric Power Co.	✓	✓		✓		✓				✓
	AEP	Indiana Michigan Power Co.	✓	✓			✓					✓
	AEP	Ohio Power Co.	NA	✓		✓	✓			✓	✓	✓
	AEP	Public Service Co. of Oklahoma	✓	✓		✓	✓			✓	✓	✓
	AEP	Kingsport Power Co.	✓									
	AEP	AEP Texas	NA	✓						✓	✓	
	AEP	Southwestern Electric Power Co.	✓	✓						✓	✓	
	AEP	Appalachian Power Co.	✓	✓			✓		✓		✓	✓
	AEP	Appalachian Power Co.	✓	✓			✓					✓
Avista Corporation	AVA	Alaska Electric Light & Power	✓									
	AVA	Avista Corp.	✓	✓	✓							
	AVA	Avista Corp.	✓	✓	✓							
	AVA	Avista Corp.	✓	✓	✓							
	AVA	Avista Corp.	✓	✓		✓	✓					
	AVA	Avista Corp.	✓	✓		✓						
Duke Energy Corporation	DUK	Duke Energy Florida LLC	✓	✓				✓	✓			✓
	DUK	Duke Energy Indiana LLC	✓	✓		✓	✓	✓	✓	✓	✓	✓
	DUK	Duke Energy Kentucky Inc.	✓	✓		✓	✓	✓				✓
	DUK	Duke Energy Kentucky Inc.	✓	✓		✓						✓
	DUK	Duke Energy Carolinas LLC	✓	✓			✓	✓				
	DUK	Duke Energy Progress LLC	✓	✓			✓	✓				
	DUK	Piedmont Natural Gas Co. Inc.	✓	✓	✓					✓		
	DUK	Duke Energy Ohio Inc.	NA	✓		✓	✓			✓	✓	✓
	DUK	Duke Energy Ohio Inc.	✓		✓			✓		✓		✓
	DUK	Duke Energy Progress LLC	✓	✓				✓				
	DUK	Duke Energy Carolinas LLC	✓	✓				✓				
	DUK	Piedmont Natural Gas Co. Inc.	✓	✓		✓						
	DUK	Piedmont Natural Gas Co. Inc.	✓			✓				✓		✓

RISK ASSESSMENT: Concentric Proxy Group

[5]

Proxy Group Company	Ticker	Operating Subsidiary	Other: Text
ALLETE, Inc.	ALE	Minnesota Power	
Ameren Corporation	AEE	Ameren Illinois Co.	Certain hazardous materials litigation, bad-debt costs, and taxes recoverable
	AEE	Ameren Illinois Co.	Certain hazardous materials litigation, bad-debt costs, and taxes recoverable
	AEE	Union Electric Co.	Renewable energy standard compliance costs, emission allowance costs, government-mandated investments, and certain taxes recoverable
	AEE	Union Electric Co.	Renewable energy standard compliance costs, emission allowance costs, government-mandated investments, and certain taxes recoverable
American Electric Power Company, Inc.	AEP	Southwestern Electric Power Co.	Certain taxes recoverable
	AEP	Indiana Michigan Power Co.	Regulatory mechanisms allow sharing of off system sales margins
	AEP	Kentucky Power Co.	Regulatory mechanisms allow sharing of off system sales margins; Certain taxes recoverable
	AEP	Southwestern Electric Power Co.	Regulatory mechanisms allow sharing of off system sales margins; Economic development riders
	AEP	Indiana Michigan Power Co.	Economic development rider
	AEP	Ohio Power Co.	Certain bad-debt costs and taxes recoverable
	AEP	Public Service Co. of Oklahoma	Regulatory mechanisms allow sharing of off system sales margins; Certain taxes recoverable
	AEP	Kingsport Power Co.	
	AEP	AEP Texas	
	AEP	Southwestern Electric Power Co.	
	AEP	Appalachian Power Co.	Certain taxes recoverable
	AEP	Appalachian Power Co.	Certain taxes recoverable
Avista Corporation	AVA	Alaska Electric Light & Power	
	AVA	Avista Corp.	
	AVA	Avista Corp.	
	AVA	Avista Corp.	
	AVA	Avista Corp.	
	AVA	Avista Corp.	
Duke Energy Corporation	DUK	Duke Energy Florida LLC	Certain taxes and storm costs recoverable
	DUK	Duke Energy Indiana LLC	Regulatory mechanisms allow sharing of off system sales margins
	DUK	Duke Energy Kentucky Inc.	Regulatory mechanisms allow sharing of off system sales margins; Certain taxes recoverable
	DUK	Duke Energy Kentucky Inc.	Regulatory mechanisms allow sharing of off system sales margins; Certain taxes recoverable
	DUK	Duke Energy Carolinas LLC	
	DUK	Duke Energy Progress LLC	
	DUK	Piedmont Natural Gas Co. Inc.	
	DUK	Duke Energy Ohio Inc.	Incremental vegetation management costs, certain taxes and bad-debt costs recoverable
	DUK	Duke Energy Ohio Inc.	Certain taxes and bad-debt costs recoverable
	DUK	Duke Energy Progress LLC	
	DUK	Duke Energy Carolinas LLC	
	DUK	Piedmont Natural Gas Co. Inc.	
	DUK	Piedmont Natural Gas Co. Inc.	Riders related to capacity management and release, off-system sales, and capacity assignment; Margin losses from bypassable customers recoverable

RISK ASSESSMENT: Concentric Proxy Group

Proxy Group Company	Ticker	Operating Subsidiary	Type	[1] Credit Rating	[2] Jurisdiction	[3] S&P Regulatory Assessment	[4] Test Year
Edison International	EIX	Southern California Edison Co.	Electric	BBB	California	More Credit Supportive (strong/adequate)	Fully Forecast
El Paso	EE	El Paso Electric Co.	Electric	BBB	New Mexico	Credit Supportive (adequate)	Historical
	EE	El Paso Electric Co.	Electric	BBB	Texas	Very Credit Supportive (strong/adequate)	Historical
Entergy Corporation	ETR	Entergy Arkansas LLC	Electric	A-	Arkansas	Highly Credit Supportive (strong/adequate	Fully Forecast
	ETR	Entergy New Orleans LLC	Electric	BBB+	Louisiana NOCC	Highly Credit Supportive (strong/adequate	Historical
	ETR	Entergy New Orleans LLC	Gas	BBB+	Louisiana NOCC	Highly Credit Supportive (strong/adequate	Historical
	ETR	Entergy Louisiana LLC	Electric	A-	Louisiana PSC	Highly Credit Supportive (strong/adequate	Historical
	ETR	Entergy Louisiana LLC	Gas	A-	Louisiana PSC	Highly Credit Supportive (strong/adequate	Historical
	ETR	Entergy Mississippi	Electric	A-	Mississippi	Credit Supportive (adequate)	Fully Forecast
	ETR	Entergy Texas Inc.	Electric	BBB+	Texas	Very Credit Supportive (strong/adequate)	Historical
FirstEnergy Corp.	FE	Potomac Edison Co.	Electric	BBB	Maryland	More Credit Supportive (strong/adequate)	Partially Forecast
	FE	Jersey Central Power & Light Co.	Electric	BBB	New Jersey	More Credit Supportive (strong/adequate)	Partially Forecast
	FE	Cleveland Electric Illuminating	Electric	BBB	Ohio	Very Credit Supportive (strong/adequate)	Partially Forecast
	FE	Metropolitan Edison Co	Electric	BBB	Pennsylvania	Highly Credit Supportive (strong/adequate	Fully Forecast
	FE	Pennsylvania Electric Co.	Electric	BBB	Pennsylvania	Highly Credit Supportive (strong/adequate	Fully Forecast
	FE	Pennsylvania Power Co.	Electric	BBB	Pennsylvania	Highly Credit Supportive (strong/adequate	Fully Forecast
	FE	West Penn Power Co.	Electric	BBB	Pennsylvania	Highly Credit Supportive (strong/adequate	Fully Forecast
	FE	Monongahela Power Co.	Electric	BBB	West Virginia	Very Credit Supportive (strong/adequate)	Historical
	FE	Potomac Edison Co.	Electric	BBB	West Virginia	Very Credit Supportive (strong/adequate)	Historical
Evergy, Inc.	EVRG	Evergy Kansas Central Inc.	Electric	A-	Kansas	Highly Credit Supportive (strong/adequate	Historical
	EVRG	Evergy Kansas South Inc.	Electric	A-	Kansas	Highly Credit Supportive (strong/adequate	Historical
	EVRG	Evergy Metro Inc.	Electric	A	Kansas	Highly Credit Supportive (strong/adequate	Historical
	EVRG	Evergy Metro Inc.	Electric	A	Missouri	Very Credit Supportive (strong/adequate)	Historical
	EVRG	Evergy Missouri West Inc.	Electric	A-	Missouri	Very Credit Supportive (strong/adequate)	Historical
IDACORP, Inc.	IDA	Idaho Power Co.	Electric	BBB	Idaho	Very Credit Supportive (strong/adequate)	Partially Forecast
	IDA	Idaho Power Co.	Electric	BBB	Oregon	Highly Credit Supportive (strong/adequate	Partially Forecast
NextEra Energy, Inc.	NEE	Florida Power & Light Co.	Electric	A	Florida	Most Credit Supportive (strong)	Fully Forecast
	NEE	Gulf Power CO.	Electric	A-	Florida	Most Credit Supportive (strong)	Fully Forecast
	NEE	Pivotal Utility Holdings Inc.	Gas	A-	Florida	Most Credit Supportive (strong)	Fully Forecast
	NEE	Lone Star Transmission LLC	Electric	A-	Texas	Very Credit Supportive (strong/adequate)	Historical
Pinnacle West Capital Corporation	PNW	Arizona Public Service Co.	Electric	A-	Arizona	More Credit Supportive (strong/adequate)	Historical
PNM Resources, Inc.	PNM	Public Service Co. of New Mexico	Electric	BBB	New Mexico	Credit Supportive (adequate)	Fully Forecast
	PNM	Texas-New Mexico Power	Electric	BBB+	Texas	Very Credit Supportive (strong/adequate)	Historical
Portland General Electric Company	POR	Portland General Electric Co.	Electric	BBB+	Oregon	Highly Credit Supportive (strong/adequate	Fully Forecast
Southern Company	SO	Alabama Power Co.	Electric	A	Alabama	Most Credit Supportive (strong)	Fully Forecast
	SO	Georgia Power Co.	Electric	A-	Georgia	Highly Credit Supportive (strong/adequate	Fully Forecast
	SO	Atlanta Gas Light Co.	Gas	A-	Georgia [6]	Highly Credit Supportive (strong/adequate	Fully Forecast
	SO	Northern Illinois Gas Co.	Gas	A	Illinois	Very Credit Supportive (strong/adequate)	Fully Forecast
	SO	Mississippi Power Co.	Electric	A-	Mississippi	Credit Supportive (adequate)	Fully Forecast
	SO	Chattanooga Gas Co.	Gas	A-	Tennessee	Highly Credit Supportive (strong/adequate	Fully Forecast
	SO	Virginia Natural Gas	Gas	A-	Virginia	Highly Credit Supportive (strong/adequate	Historical
Xcel Energy Inc.	XEL	Public Service Co. of Colorado	Electric	A-	Colorado	Most Credit Supportive (strong)	Historical
	XEL	Public Service Co. of Colorado	Gas	A-	Colorado	Most Credit Supportive (strong)	Historical
	XEL	Northern States Power Co - Minnesota	Electric	A-	Minnesota	Highly Credit Supportive (strong/adequate	Fully Forecast
	XEL	Northern States Power Co - Minnesota	Gas	A-	Minnesota	Highly Credit Supportive (strong/adequate	Fully Forecast
	XEL	Southwestern Public Service Co.	Electric	A-	New Mexico	Credit Supportive (adequate)	Historical
	XEL	Northern States Power Co - Minnesota	Electric	A-	North Dakota	Highly Credit Supportive (strong/adequate	Fully Forecast
	XEL	Northern States Power Co - Minnesota	Gas	A-	North Dakota [6]	Highly Credit Supportive (strong/adequate	Fully Forecast
	XEL	Northern States Power Co - Minnesota	Electric	A-	South Dakota	Very Credit Supportive (strong/adequate)	Historical
	XEL	Southwestern Public Service Co.	Electric	A-	Texas	Very Credit Supportive (strong/adequate)	Historical
	XEL	Northern States Power Co - Wisconsin	Electric	A-	Wisconsin	Most Credit Supportive (strong)	Fully Forecast
	XEL	Northern States Power Co - Wisconsin	Gas	A-	Wisconsin	Most Credit Supportive (strong)	Fully Forecast

RISK ASSESSMENT: Concentric Proxy Group

Proxy Group Company	Ticker	Operating Subsidiary	[5] Electric fuel/gas commodity/purch. power	[5] Conserv. program expense	[5] Full Decoupling	[5] Partial Decoupling	[5] Renewables expense	[5] Environmental compliance	[5] Generation capacity	[5] Generic infrastructure	[5] Transmission expense	[5] Other
Edison International	EIX	Southern California Edison Co.	✓		✓							✓
El Paso	EE	El Paso Electric Co.	✓	✓								✓
	EE	El Paso Electric Co.	✓	✓						✓		✓
Entergy Corporation	ETR	Entergy Arkansas LLC	✓	✓		✓	✓		✓	✓	✓	✓
	ETR	Entergy New Orleans LLC	✓	✓		✓		✓	✓		✓	✓
	ETR	Entergy New Orleans LLC	✓									✓
	ETR	Entergy Louisiana LLC	✓	✓		✓		✓	✓	✓	✓	✓
	ETR	Entergy Louisiana LLC	✓			✓				✓		
	ETR	Entergy Mississippi	✓	✓		✓		✓			✓	✓
	ETR	Entergy Texas Inc.	✓	✓						✓		✓
FirstEnergy Corp.	FE	Potomac Edison Co.	NA	✓						✓		✓
	FE	Jersey Central Power & Light Co.	NA	✓			✓	✓		✓		✓
	FE	Cleveland Electric Illuminating	NA	✓		✓	✓			✓	✓	✓
	FE	Metropolitan Edison Co	NA	✓						✓	✓	✓
	FE	Pennsylvania Electric Co.	NA	✓						✓	✓	✓
	FE	Pennsylvania Power Co.	NA	✓						✓		✓
	FE	West Penn Power Co.	NA	✓						✓		✓
	FE	Monongahela Power Co.	✓	✓						✓		✓
	FE	Potomac Edison Co.	✓	✓						✓		✓
Evergy, Inc.	EVRG	Evergy Kansas Central Inc.	✓	✓		✓	✓	✓			✓	✓
	EVRG	Evergy Kansas South Inc.	✓	✓		✓	✓	✓			✓	✓
	EVRG	Evergy Metro Inc.	✓	✓						✓	✓	✓
	EVRG	Evergy Metro Inc.	✓	✓		✓	✓	✓		✓	✓	✓
	EVRG	Evergy Missouri West Inc.	✓	✓		✓	✓	✓		✓	✓	✓
IDACORP, Inc.	IDA	Idaho Power Co.	✓	✓	✓							
	IDA	Idaho Power Co.	✓	✓			✓					
NextEra Energy, Inc.	NEE	Florida Power & Light Co.	✓	✓				✓	✓			✓
	NEE	Gulf Power CO.	✓	✓				✓	✓			✓
	NEE	Pivotal Utility Holdings Inc.	✓	✓				✓		✓		✓
	NEE	Lone Star Transmission LLC	NA							✓		
Pinnacle West Capital Corporation	PNW	Arizona Public Service Co.	✓	✓		✓	✓	✓			✓	✓
PNM Resources, Inc.	PNM	Public Service Co. of New Mexico	✓	✓			✓	✓		✓		✓
	PNM	Texas-New Mexico Power	NA	✓						✓	✓	✓
Portland General Electric Company	POR	Portland General Electric Co.	✓	✓		✓	✓	✓	✓			
Southern Company	SO	Alabama Power Co.	✓				✓	✓	✓			✓
	SO	Georgia Power Co.	✓						✓			
	SO	Atlanta Gas Light Co.	NA		✓			✓		✓		
	SO	Northern Illinois Gas Co.	✓	✓		✓		✓		✓		✓
	SO	Mississippi Power Co.	✓	✓		✓		✓				✓
	SO	Chattanooga Gas Co.	✓		✓							✓
	SO	Virginia Natural Gas	✓			✓				✓		
Xcel Energy Inc.	XEL	Public Service Co. of Colorado	✓	✓			✓	✓	✓	✓		✓
	XEL	Public Service Co. of Colorado	✓	✓		✓				✓		
	XEL	Northern States Power Co - Minnesota	✓	✓		✓	✓	✓			✓	
	XEL	Northern States Power Co - Minnesota	✓	✓						✓		
	XEL	Southwestern Public Service Co.	✓	✓			✓					✓
	XEL	Northern States Power Co - Minnesota	✓							✓		✓
	XEL	Northern States Power Co - Minnesota	✓		✓							
	XEL	Northern States Power Co - Minnesota	✓	✓		✓		✓	✓	✓		✓
	XEL	Southwestern Public Service Co.	✓	✓						✓	✓	✓
	XEL	Northern States Power Co - Wisconsin	✓									✓
	XEL	Northern States Power Co - Wisconsin	✓									✓

RISK ASSESSMENT: Concentric Proxy Group

Proxy Group Company	Ticker	Operating Subsidiary	[5] Other: Text
Edison International	EIX	Southern California Edison Co.	All large electric utilities in California now impose a non-bypassable charge on ratepayers to establish a $21 billion wildfire insurance fund
El Paso	EE	El Paso Electric Co.	Certain taxes and franchise fees recoverable
	EE	El Paso Electric Co.	Riders related to lost revenue associated with discounted service to military bases
Entergy Corporation	ETR	Entergy Arkansas LLC	Storm recovery rider related to securitization bond charges; Certain taxes and franchise fees recoverable
	ETR	Entergy New Orleans LLC	Storm reserve rider
	ETR	Entergy New Orleans LLC	Storm reserve rider
	ETR	Entergy Louisiana LLC	Economic development rider
	ETR	Entergy Louisiana LLC	
	ETR	Entergy Mississippi	Riders for ad valorem tax adjustments and storm reserves
	ETR	Entergy Texas Inc.	Rider for ad valorem tax adjustments
FirstEnergy Corp.	FE	Potomac Edison Co.	Certain taxes and fees recoverable
	FE	Jersey Central Power & Light Co.	Certain taxes and fees, low-income customer assistance programs, and restructuring-related buyout of non-utility generation contracts recoverable
	FE	Cleveland Electric Illuminating	Certain taxes and fees and uncollectible expense recoverable
	FE	Metropolitan Edison Co	Certain taxes and fees, universal service and uncollectible costs recoverable
	FE	Pennsylvania Electric Co.	Certain taxes and fees, universal service and uncollectible costs recoverable
	FE	Pennsylvania Power Co.	Certain taxes and fees, universal service and uncollectible costs recoverable
	FE	West Penn Power Co.	Certain taxes and fees, universal service and uncollectible costs recoverable
	FE	Monongahela Power Co.	Certain taxes and fees recoverable
	FE	Potomac Edison Co.	Certain taxes and fees recoverable
Evergy, Inc.	EVRG	Evergy Kansas Central Inc.	Regulatory mechanisms allow sharing of off system sales margins; Certain taxes recoverable
	EVRG	Evergy Kansas South Inc.	Regulatory mechanisms allow sharing of off system sales margins; Certain taxes recoverable
	EVRG	Evergy Metro Inc.	Regulatory mechanisms allow sharing of off system sales margins; Certain taxes recoverable
	EVRG	Evergy Metro Inc.	Regulatory mechanisms allow sharing of off system sales margins; Certain taxes recoverable
	EVRG	Evergy Missouri West Inc.	Regulatory mechanisms allow sharing of off system sales margins; Certain taxes recoverable
IDACORP, Inc.	IDA	Idaho Power Co.	
	IDA	Idaho Power Co.	
NextEra Energy, Inc.	NEE	Florida Power & Light Co.	Storm costs and certain taxes and fees recoverable; Riders reflect economy energy sales
	NEE	Gulf Power CO.	Storm costs and certain taxes and fees recoverable; Riders reflect economy energy sales
	NEE	Pivotal Utility Holdings Inc.	Certain taxes and fees recoverable
	NEE	Lone Star Transmission LLC	
Pinnacle West Capital Corporation	PNW	Arizona Public Service Co.	Franchise fees recoverable via adjustable line item on monthly bills
PNM Resources, Inc.	PNM	Public Service Co. of New Mexico	Certain taxes and fees recoverable
	PNM	Texas-New Mexico Power	Adjustment clause reflects changes in municipal franchise fees
Portland General Electric Company	POR	Portland General Electric Co.	
Southern Company	SO	Alabama Power Co.	Adjustment provisions reflects changes in income, general, and local taxes
	SO	Georgia Power Co.	
	SO	Atlanta Gas Light Co.	
	SO	Northern Illinois Gas Co.	Riders to recover certain bad-debt costs, taxes and franchise fees
	SO	Mississippi Power Co.	Ad valorem tax adjustment rider
	SO	Chattanooga Gas Co.	Riders related to capacity management and release, off-system sales, and capacity assignment; Riders allow sharing of gross profit margin reduction associated with negotiated contracts that bypass distribution system
	SO	Virginia Natural Gas	
Xcel Energy Inc.	XEL	Public Service Co. of Colorado	Sharing of customer margins from generation-based short-term energy trading and proprietary trading
	XEL	Public Service Co. of Colorado	
	XEL	Northern States Power Co - Minnesota	
	XEL	Northern States Power Co - Minnesota	
	XEL	Southwestern Public Service Co.	Certain taxes and fees recoverable
	XEL	Northern States Power Co - Minnesota	Sharing of non-asset-based wholesale power margins
	XEL	Northern States Power Co - Minnesota	
	XEL	Northern States Power Co - Minnesota	Sharing of wholesale power margins
	XEL	Southwestern Public Service Co.	Rider for lost revenue associated with discounted sales to state universities
	XEL	Northern States Power Co - Wisconsin	Certain taxes and fees recoverable
	XEL	Northern States Power Co - Wisconsin	Certain taxes and fees recoverable

RISK ASSESSMENT: Concentric Proxy Group

				[1]	[2]	[3]	[4]
Proxy Group Company	**Ticker**	**Operating Subsidiary**	**Type**	**Credit Rating**	**Jurisdiction**	**S&P Regulatory Assessment**	**Test Year**
Algonquin Power & Utilities Corp.	AQN	Liberty Utilities (Peach State Nat. Gas) Corp.	Gas	BBB	Georgia	Highly credit supportive (strong/adequate)	Partially Forecast
	AQN	Liberty Utilities (Midstates Natural Gas) Corp.	Gas	BBB	Illinois	Very credit supportive (strong/adequate)	Fully Forecast
	AQN	Empire District Electric Co.	Electric	BBB	Kansas	Highly credit supportive (strong/adequate)	Historical
	AQN	Liberty Utilities (NE Nat Gas)	Gas	BBB	Massachusetts	Highly credit supportive (strong/adequate)	Historical
	AQN	Empire District Electric Co.	Electric	BBB	Missouri	Very credit supportive (strong/adequate)	Partially Forecast
	AQN	Empire District Gas Co.	Gas	BBB	Missouri	Very credit supportive (strong/adequate)	Partially Forecast
	AQN	Liberty Utilities (Midstates)	Gas	BBB	Missouri	Very credit supportive (strong/adequate)	Partially Forecast
	AQN	Liberty Utilities EnergyNorth	Gas	BBB	New Hampshire	Highly credit supportive (strong/adequate)	Historical
	AQN	Liberty Utilities Granite St	Electric	BBB	New Hampshire	Highly credit supportive (strong/adequate)	Historical
	AQN	Enbridge Gas New Brunswick	Gas	BBB	New Brunswick	Not ranked	Fully Forecast
Emera Incorporated	EMA	Tampa Electric Co.	Electric	BBB+	Florida	Most Credit Supportive (strong)	Fully Forecast
	EMA	New Mexico Gas Co.	Gas	BBB	New Mexico	Credit Supportive (adequate)	Historical
	EMA	Nova Scotia Power Inc.	Electric	BBB+	Nova Scotia	Most Credit Supportive (strong)	Fully Forecast
Fortis Inc.	FTS	Central Hudson Gas & Electric	Electric	A-	New York	Very Credit Supportive (strong/adequate)	Fully Forecast
	FTS	Central Hudson Gas & Electric	Gas	A-	New York	Very Credit Supportive (strong/adequate)	Fully Forecast
	FTS	Tucson Electric Power Co.	Electric	A-	Arizona	More Credit Supportive (strong/adequate)	Historical
	FTS	UNS Electric Inc.	Electric	A-	Arizona	More Credit Supportive (strong/adequate)	Historical
	FTS	UNS Gas Inc.	Gas	A-	Arizona	More Credit Supportive (strong/adequate)	Historical
	FTS	FortisAlberta Inc	Electric	A-	Alberta	Most Credit Supportive (strong)	Historical
	FTS	FortisBC	Electric	A-	British Columbia	Most Credit Supportive (strong)	Fully Forecast
	FTS	FortisBC Energy	Gas	A-	British Columbia	Most Credit Supportive (strong)	Fully Forecast
	FTS	Newfoundland Power Inc	Electric	A-	Newfoundland & Labrador	Highly Credit Supportive (strong/adequate	Fully Forecast
	FTS	Maritime Electric Company Ltd.	Electric	BBB+	Prince Edward Island	Credit Supportive (adequate)	Fully Forecast
Proxy Group Results				Average	Total	Average	Fully Forecast = 41%
				BBB+	111	Very Credit Supportive (strong/adequate)	Partially Forecast = 12%
							Historical = 48%

RISK ASSESSMENT: Concentric Proxy Group

Proxy Group Company	Ticker	Operating Subsidiary	Electric fuel/gas commodity/purch. power	Conserv. program expense	Full Decoupling	Partial Decoupling	Renewables expense	Environmental compliance	Generation capacity	Generic infrastructure	Transmission expense	Other
			[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]
Algonquin Power & Utilities Corp.	AQN	Liberty Utilities (Peach State Nat. Gas) Corp.	✓		✓							
	AQN	Liberty Utilities (Midstates Natural Gas) Corp.	✓	✓		✓						✓
	AQN	Empire District Electric Co.	✓	✓				✓			✓	✓
	AQN	Liberty Utilities (NE Nat Gas)	✓	✓	✓			✓		✓		✓
	AQN	Empire District Electric Co.	✓					✓			✓	✓
	AQN	Empire District Gas Co.	✓									✓
	AQN	Liberty Utilities (Midstates)	✓			✓				✓		✓
	AQN	Liberty Utilities EnergyNorth	✓		✓					✓		
	AQN	Liberty Utilities Granite St	NA			✓				✓		
	AQN	Enbridge Gas New Brunswick	NA							✓		✓
Emera Incorporated	EMA	Tampa Electric Co.	✓	✓				✓	✓			✓
	EMA	New Mexico Gas Co.	✓	✓								✓
	EMA	Nova Scotia Power Inc.	✓	✓		✓			✓	✓		
Fortis Inc.	FTS	Central Hudson Gas & Electric	NA		✓		✓					✓
	FTS	Central Hudson Gas & Electric	✓		✓			✓		✓		✓
	FTS	Tucson Electric Power Co.	✓	✓		✓	✓	✓				✓
	FTS	UNS Electric Inc.	✓	✓		✓	✓				✓	✓
	FTS	UNS Gas Inc.	✓			✓						✓
	FTS	FortisAlberta Inc	NA							✓	✓	✓
	FTS	FortisBC	✓	✓	✓					✓		✓
	FTS	FortisBC Energy	✓	✓	✓					✓		✓
	FTS	Newfoundland Power Inc	✓	✓		✓			✓	✓		✓
	FTS	Maritime Electric Company Ltd.	✓	✓		✓			✓	✓		✓
Proxy Group Results			Adjustment Clauses Count and Percentage of Total Proxy Group									
			111	91	28	54	46	53	33	66	45	82
			100%	82%	25%	49%	41%	48%	30%	59%	41%	74%

RISK ASSESSMENT: Concentric Proxy Group

Proxy Group Company	Ticker	Operating Subsidiary	[5] Other: Text
Algonquin Power & Utilities Corp.	AQN	Liberty Utilities (Peach State Nat. Gas) Corp.	
	AQN	Liberty Utilities (Midstates Natural Gas) Corp.	Bad-debt costs recovered via riders; certain taxes and franchise fees recovered via other
	AQN	Empire District Electric Co.	Abbreviated rate cases allowed; off-system sales margins, recover variations in certain taxes and franchise fees
	AQN	Liberty Utilities (NE Nat Gas)	Pension and post-employment benefits recoverable
	AQN	Empire District Electric Co.	Off-system sales margins flow through; certain taxes and franchise fees recoverable
	AQN	Empire District Gas Co.	Off-system sales margins flow through; certain taxes and franchise fees recoverable
	AQN	Liberty Utilities (Midstates)	Certain taxes and franchise fees recoverable
	AQN	Liberty Utilities EnergyNorth	
	AQN	Liberty Utilities Granite St	
	AQN	Enbridge Gas New Brunswick	Regulatory deferral account for system buildout, earnings sharing, franchise fees, development O&M capitalized costs, intangible software, carbon tax pass through
Emera Incorporated	EMA	Tampa Electric Co.	Franchise fees, gross receipts taxes, recoverable via line items on customer bills. Storm cost recovery.
	EMA	New Mexico Gas Co.	Certain local taxes and franchise fees recoverable
	EMA	Nova Scotia Power Inc.	
Fortis Inc.	FTS	Central Hudson Gas & Electric	Rate adjustment mechanisms in place to return/collect eligible deferrals and costs, including for pension and OPEB, property taxes, major storm, gas leak-prone pipe, and certain REV costs and
	FTS	Central Hudson Gas & Electric	Rate adjustment mechanisms in place to return/collect eligible deferrals and costs, including for pension and OPEB, property taxes, major storm, gas leak-prone pipe, and certain REV costs and
	FTS	Tucson Electric Power Co.	Franchise fees recoverable via adjustable line items on monthly bills
	FTS	UNS Electric Inc.	Franchise fees recoverable via adjustable line items on monthly bills
	FTS	UNS Gas Inc.	Franchise fees recoverable via adjustable line items on monthly bills
	FTS	FortisAlberta Inc	AUC assessment fees, hearing costs for interveners, property and business taxes, farm transmission credit, efficiency carry over mechanism, legal cost claims, carrying costs, capital trackers, AESO contributions
	FTS	FortisBC	earnings sharing mechanism, Income tax recoverable on OPEB plans, deferred lease costs, deferred net losses on utility capital assets and intangible assets, customer care enhancement, customer and community benefits obligation
	FTS	FortisBC Energy	earnings sharing mechanism, Income tax recoverable on OPEB plans, deferred net losses on utility capital assets and intangible assets, natural gas for transportation incentive, customer care enhancement, customer and community benefits obligation
	FTS	Newfoundland Power Inc	OPEB costs
	FTS	Maritime Electric Company Ltd.	OPEB costs

Proxy Group Results

RISK ASSESSMENT: Concentric Proxy Group

				[1]	[2]	[3]	[4]
Proxy Group Company	**Ticker**	**Operating Subsidiary**	**Type**	**Credit Rating**	**Jurisdiction**	**S&P Regulatory Assessment**	**Test Year**

Notes:
[1] Source: S&P Global Market Intelligence, S&P Long-Term Issuer Rating. If the operating subsidiary is not rated by S&P, then this column reflects the parent company's Long-Term Issuer Rating.
[2] Source: S&P Global Market Intelligence
[3] S&P Global Ratings, Ratings Direct, U.S. And Canadian Regulatory Jurisdiction Updates And Insights: (November 2019)
[4] Source: Source: Regulatory Research Associates; The Test Year refers to the State Commissions' standard practice, regulatory filings and orders, annual reports, annual information forms, when not covered by SNL
[5] Source: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated November 12, 2019. Operating subsidiaries not covered in this report were excluded from this exhibit.
[6] Operations classified as full revenue decoupling since the company operates under a straight fixed-variable rate design.

RISK ASSESSMENT: Moody's Proxy Group

Proxy Group Company	Ticker	Operating Subsidiary	Type	[1] Credit Rating	[2] Jurisdiction	[3] S&P Regulatory Assessment	[4] Test Year
Public Service Enterprise Group, Inc.	PEG	Public Severice Electric & Gas Co.	Electric	A-	New Jersey	More Credit Supportive (strong/adequate)	Partially Forecast
	PEG	Public Severice Electric & Gas Co.	Gas	A-	New Jersey	More Credit Supportive (strong/adequate)	Partially Forecast
NextEra Energy, Inc.	NEE	Florida Power & Light Co.	Electric	A	Florida	Most Credit Supportive (strong)	Fully Forecast
	NEE	Gulf Power CO.	Electric	A	Florida	Most Credit Supportive (strong)	Fully Forecast
	NEE	Pivotal Utility Holdings Inc.	Gas	A-	Florida	Most Credit Supportive (strong)	Fully Forecast
	NEE	Lone Star Transmission LLC	Electric	A-	Texas	Very Credit Supportive (strong/adequate)	Historical
Exelon Corporation	EXC	Delmarva Power & Light Co.	Electric	A-	Delaware	Very Credit Supportive (strong/adequate)	Partially Forecast
	EXC	Delmarva Power & Light Co.	Gas	A-	Delaware	Very Credit Supportive (strong/adequate)	Partially Forecast
	EXC	Potomac Electric Power Co.	Electric	A-	District of Columbia	More Credit Supportive (strong/adequate)	Historical
	EXC	Commonwealth Edison Co.	Electric	BBB+	Illinois	Very Credit Supportive (strong/adequate)	Historical
	EXC	Baltimore Gas & Electric Co.	Electric	A	Maryland	More Credit Supportive (strong/adequate)	Partially Forecast
	EXC	Baltimore Gas & Electric Co.	Gas	A	Maryland	More Credit Supportive (strong/adequate)	Partially Forecast
	EXC	Delmarva Power & Light Co.	Electric	A-	Maryland	More Credit Supportive (strong/adequate)	Partially Forecast
	EXC	Potomac Electric Power Co.	Electric	A-	Maryland	More Credit Supportive (strong/adequate)	Partially Forecast
	EXC	Atlantic City Electric Co.	Electric	A-	New Jersey	More Credit Supportive (strong/adequate)	Partially Forecast
	EXC	PECO Energy Co.	Electric	BBB+	Pennsylvania	Highly Credit Supportive (strong/adequate)	Fully Forecast
	EXC	PECO Energy Co.	Gas	BBB+	Pennsylvania	Highly Credit Supportive (strong/adequate)	Fully Forecast
Proxy Group Results				Average	Total	Average	Fully Forecast = 29%
				A-	17	Very Credit Supportive (strong/adequate)	Partially Forecast = 53%
							Historical = 18%

RISK ASSESSMENT: Moody's Proxy Group

Proxy Group Company	Ticker	Operating Subsidiary	Electric fuel/gas commodity/purch. power	Conserv. program expense	Full Decoupling	Partial Decoupling	Renewables expense	Environmental compliance	Generation capacity	Generic infrastructure	Transmission expense	Other
			[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]
Public Service Enterprise Group, Inc.	PEG	Public Severice Electric & Gas Co.	NA	✓			✓			✓		✓
	PEG	Public Severice Electric & Gas Co.	✓	✓		✓		✓		✓		✓
NextEra Energy, Inc.	NEE	Florida Power & Light Co.	✓	✓				✓	✓			✓
	NEE	Gulf Power CO.	✓	✓				✓	✓			✓
	NEE	Pivotal Utility Holdings Inc.	✓	✓				✓		✓		✓
	NEE	Lone Star Transmission LLC	NA							✓		
Exelon Corporation	EXC	Delmarva Power & Light Co.	NA							✓	✓	✓
	EXC	Delmarva Power & Light Co.	✓					✓		✓		✓
	EXC	Potomac Electric Power Co.	NA			✓	✓			✓		✓
	EXC	Commonwealth Edison Co.	NA	✓			✓	✓		✓	✓	✓
	EXC	Baltimore Gas & Electric Co.	NA	✓	✓							✓
	EXC	Baltimore Gas & Electric Co.	✓	✓	✓					✓		✓
	EXC	Delmarva Power & Light Co.	NA	✓	✓							
	EXC	Potomac Electric Power Co.	NA	✓	✓							✓
	EXC	Atlantic City Electric Co.	NA	✓			✓			✓		✓
	EXC	PECO Energy Co.	NA	✓						✓		✓
	EXC	PECO Energy Co.	✓	✓						✓		✓
Proxy Group Results			Adjustment Clauses Count and Percentage of Total Proxy Group									
			17	13	4	2	4	6	2	12	2	15
			100%	76%	24%	12%	24%	35%	12%	71%	12%	88%

RISK ASSESSMENT: Moody's Proxy Group

[5]

Proxy Group Company	Ticker	Operating Subsidiary	Other: Text
Public Service Enterprise Group, Inc.	PEG	Public Severice Electric & Gas Co.	Certain taxes and fees, low-income customer assistance programs, and restructuring-related buyout of non-utility generation contracts recoverable
	PEG	Public Severice Electric & Gas Co.	Certain taxes and fees recoverable
NextEra Energy, Inc.	NEE	Florida Power & Light Co.	Storm costs and certain taxes and fees recoverable; Riders reflect economy energy sales
	NEE	Gulf Power CO.	Storm costs and certain taxes and fees recoverable; Riders reflect economy energy sales
	NEE	Pivotal Utility Holdings Inc.	Certain taxes and fees recoverable
	NEE	Lone Star Transmission LLC	
Exelon Corporation	EXC	Delmarva Power & Light Co.	Relocation costs of ariel and underground facilities required by government agency projects recoverable
	EXC	Delmarva Power & Light Co.	Relocation costs of ariel and underground facilities required by government agency projects recoverable
	EXC	Potomac Electric Power Co.	Certain taxes and fees recoverable
	EXC	Commonwealth Edison Co.	Certain taxes, fees, and bad-debt costs recoverable
	EXC	Baltimore Gas & Electric Co.	Certain taxes and fees recoverable
	EXC	Baltimore Gas & Electric Co.	Certain taxes and fees recoverable
	EXC	Delmarva Power & Light Co.	
	EXC	Potomac Electric Power Co.	Certain taxes and fees recoverable
	EXC	Atlantic City Electric Co.	Certain taxes and fees, low-income customer assistance programs, and restructuring-related buyout of non-utility generation contracts recoverable
	EXC	PECO Energy Co.	Certain taxes, fees, and nuclear deommissioning costs recoverable
	EXC	PECO Energy Co.	Certain taxes and fees recoverable

Proxy Group Results

RISK ASSESSMENT: Moody's Proxy Group

				[1]	[2]	[3]	[4]
Proxy Group Company	**Ticker**	**Operating Subsidiary**	**Type**	**Credit Rating**	**Jurisdiction**	**S&P Regulatory Assessment**	**Test Year**

Notes:
[1] Source: S&P Global Market Intelligence, S&P Long-Term Issuer Rating. If the operating subsidiary is not rated by S&P, then this column reflects the parent company's Long-Term Issuer Rating.
[2] Source: S&P Global Market Intelligence
[3] S&P Global Ratings, Ratings Direct, U.S. And Canadian Regulatory Jurisdiction Updates And Insights: (November 2019)
[4] Source: Source: Regulatory Research Associates; The Test Year refers to the State Commissions' standard practice, regulatory filings and orders, annual reports, annual information forms, when not covered by SNL
[5] Source: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated November 12, 2019. Operating subsidiaries not covered in this report were excluded from this exhibit.
[6] Operations classified as full revenue decoupling since the company operates under a straight fixed-variable rate design.

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BY EMAIL

CONFIDENTIAL — PRIVILEGED

December 19, 2019

Concentric Energy Advisors, Inc.
293 Boston Post Road West, Suite 500
Marlborough, MA 01752

Attention: Jim Coyne, Senior Vice President

Re: Retainer Letter Agreement – Ontario Power Generation

Dear Sirs/Mesdames,

We represent Ontario Power Generation ("OPG") in connection with payment amounts proceedings and other payment amounts-related proceedings (collectively, the "Proceedings") before the Ontario Energy Board (the "Board").

We confirm that, on behalf of and to assist us in providing legal advice to OPG in connection with the Proceedings, Torys LLP ("Torys" or "we") hereby retains Concentric Energy Advisors, Inc. (the "Consultant" or "you"), effective as of the date first written above ("Effective Date"), to provide consulting services as described in this letter (the "Engagement"). By signing back a copy of this letter, the Consultant agrees that this letter contains the agreed-upon terms and conditions of its retainer with Torys effective on the Effective Date, subject to amendment by written agreement between the parties (the "Retainer Agreement").

1. **No Conflict**

The Consultant does not have any conflict of interest or other constraints on its ability to provide expert advice in connection with this Retainer Agreement. You confirm that you are free to provide your services to Torys in connection with Torys' representation of OPG in the Proceedings. You agree that during this Engagement you will not provide, directly or indirectly, any services to the Board or any other party in connection with the matters at issue in the Proceedings.

2. **Consultant Expertise**

The Consultant has been selected to provide Services (as defined below) to Torys in connection with the Proceedings. The sponsors of the work of the Consultant and the persons who have the relevant expertise will be:

- Dan Dane;

- Jim Coyne; and
- Other experienced professionals from the Consultant, as may be required and agreed to by the parties in advance.

(together, the "Sponsors")

3. **Scope of Services and Work Product**

The Consultant will:

(a) carry out an independent study as to whether the application of the cost of capital approved by the Board in the EB-2016-0152 proceeding is an appropriate basis for setting OPG's nuclear and regulated hydroelectric payment amounts in OPG's next payment amounts application, as detailed in **Schedule 1** hereto (the "Cost of Capital Study");

(b) if requested by Torys: (i) an independent study regarding the impact on OPG due to the merchant risk created under the current market renewal proposal, as detailed in **Schedule 1** hereto (the "Merchant Risk Study"), and/or (ii) any other studies as may be required in support of the Engagement (the "Supporting Studies" and, together with the Cost of Capital Study and the Merchant Risk Study, the "Studies");

(c) if requested by Torys, produce a draft and/or final report(s) detailing the applicable Study's methodology, review performed and the Consultant's findings and recommendations (the "Report(s)"), which may be filed with the Board in the Proceedings; and

(d) if requested by Torys, provide support during the hearing of the Proceedings and testify before the Board in the Proceedings, in connection with the scope of the services provided hereunder ("Application Support" and, together with the Studies and the Report(s), the "Services").

4. **Fees and Invoices**

(a) The Consultant acknowledges that the fees for the Consultant to perform the Cost of Capital Study and to deliver the associated written Report(s), if requested, shall (i) be determined based on the hourly rates set forth in paragraph (c) below and (ii) in no event exceed [redacted] net of HST, without prior written approval from Torys.

(b) The Consultant's fees for completing the Merchant Risk Study and/or Supporting Studies (including the delivery of the associated written Report(s)), if requested, shall be determined based on the hourly rates set forth in paragraph (c) below, subject to a forecast maximum level of efforts which is (i) to be estimated by the Consultant and agreed to by Torys prior to the initiation of any such Studies by the Consultant and (ii) not to be exceeded by the Consultant in carrying out any such Studies without prior written approval from Torys.

(c) The Consultant's fees for providing Application Support, if requested, shall be charged at the following hourly rates:

Title	Hourly Rate (USD)
Chairman and Chief Executive Officer	[redacted]
Senior Vice President	[redacted]
Vice President	[redacted]
Assistant Vice President	[redacted]
Senior Project Manager	[redacted]
Project Manager	[redacted]
Senior Consultant	[redacted]
Consultant	[redacted]
Senior Analyst	[redacted]
Analyst	[redacted]
Associate	[redacted]
Project Assistant	[redacted]

(d) The Consultant shall direct all invoices relating to Services performed by it under this Retainer Agreement to OPG, to the attention of:

Aimee Collier
Assistant General Counsel, Law Division
Ontario Power Generation
700 University Avenue
Toronto, ON M5G 1X6
aimee.collier@opg.com

with a copy to Torys, to the attention of:

Charles Keizer
Torys LLP
79 Wellington St. W., 30th Floor
Box 270, TD South Tower
Toronto, Ontario M5K 1N2
ckeizer@torys.com

(e) Due to the confidential nature of this assignment, the Consultant agrees to submit:

(i) a summary sheet only of each account, showing the fee, expenses, all applicable taxes, a subtotal (excluding taxes), and the grand total;

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

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

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

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

(f) The Consultant will be reimbursed for reasonable travel expenses (billed at cost with no mark-up) related to this Retainer Agreement only in accordance with OPG's Standard Form Business Expense Schedule, a copy of which is attached as **Schedule 2** hereto. Any disbursements for additional incidentals incurred by the Consultant in relation to this Retainer Agreement must be pre-approved by OPG or Torys in writing. In the event of conflict between any provisions of **Schedule 2** and any policies or fee schedules of the Consultant relating to the charging of travel expenses or other incidentals, the relevant provisions of **Schedule 2** shall prevail.

(g) Consultant will be reimbursed for reasonable report production, printing, and reproduction charges at Consultant's standard charges for such materials for services.

(h) OPG reserves the right to deduct any applicable non-resident withholding taxes from any amounts owing to the Consultant under this Retainer Agreement and remit such amounts to the applicable taxation authority.

5. **Confidentiality**

All work performed by the Consultant in connection with this Retainer Agreement, including all findings, opinions and conclusions the Consultant reaches in relation to this Retainer Agreement, and any communications relating thereto, are strictly privileged and confidential and shall not be disclosed to any other person or party without the prior written consent of Torys or OPG. The Consultant agrees to designate all written communications and material accordingly. The Consultant further agrees to notify Torys in the event that the Consultant receives a request to disclose information relating to this matter, and agrees to cooperate with Torys, to the fullest extent permitted by law, to prevent or limit the disclosure of such material or otherwise preserve the privileged and confidential status of such material.

The Consultant agrees to hold in confidence: (a) the fact and existence of this Retainer Agreement, (b) all information provided to the Consultant, and (c) the Consultant's opinions to Torys and to OPG as they relate to the information, whether the information or opinions are

documentary or oral (collectively, the "Confidential Information"). The Consultant will not disclose the Confidential Information to any person unless Torys or OPG authorizes you in writing to do so, or as may be required for purposes of providing testimony before the Board in which case the Consultant shall identify and only disclose Confidential Information in accordance with the Board's protocols for the treatment of confidential information. All documents given to the Consultant in connection with this Retainer Agreement remain the property of Torys or of OPG, and are held in trust by the Consultant as agent. The Consultant agrees to return these documents on request. During the Engagement, the Confidential Information shall be segregated from other Consultant or OPG data (including on electronic information systems) and shall not be accessible to individuals other than the Consultant, Torys, and OPG employees requiring access.

The Consultant will not refer to Torys or to OPG, directly or indirectly, in connection with the promotion of its services, without obtaining the prior written consent of Torys or OPG, as the case may be. Notwithstanding the foregoing, Concentric may refer to OPG and the following information in materials used to promote its services: (i) the Board's file number for the Proceeding, (ii) a general description of the nature and scope of the Services performed, and (iii) the time period of the Engagement; *provided* that (a) Concentric has provided testimony before the Board in connection with this Engagement and (b) such information shall in no way include, reflect or reveal, directly or indirectly, any Confidential Information nor any information that is not available on the public record in the Proceeding.

6. **Intellectual Property**

Nothing in this Retainer Agreement shall be deemed to transfer, license, assign, permit the use of, or otherwise convey an interest in whole or in part to the Consultant of any intellectual property belonging to OPG or any of its representatives or any third party whose intellectual property is in OPG's custody or control, and the use by the Consultant of any such intellectual property shall be subject to the prior written approval of OPG.

Torys and OPG shall at all times have full rights and title to all works prepared, generated or created by the Consultant pursuant to this Retainer Agreement, including without limitation any reports, presentations, status updates, or other documents created by the Consultant, and any related works, modifications or additions thereto, but excluding any parts of Consultant's oral testimony and/or final Report that are provided before the Board on the public record in the Proceeding (the "Work Product"), and may at all times take possession of or use any completed or partially completed Work Product, notwithstanding any provision, express or implied, to the contrary. Without limiting the generality of the foregoing, OPG shall own all intellectual property rights in all Work Product, and the Consultant hereby waives and assigns to OPG any such rights, and agrees to give OPG and its representatives all assistance as may be reasonably required to perfect such rights including, without limitation, obtaining waiver of moral rights from any of the Consultant's employees, partners or other representatives.

Anything contained in this agreement to the contrary notwithstanding, nothing in this Retainer Agreement shall prevent Consultant from utilizing any general know-how, ideas, techniques, concepts, methods, processes, proprietary computer software, methodology, procedures, or other proprietary information applied in performing the Services, on behalf of itself or its future customers, or give Torys or OPG any rights with respect to such proprietary information. Subject to Section 1 above, Consultant may (i) perform the same or similar services for others, and (ii) retain one copy of deliverables produced in connection with the Services hereunder for the sole

purpose of documenting the conduct of its work and its exercise of due professional care in connection with the Services, provided that any of OPG's Confidential Information is treated in accordance with the confidentiality requirements of this Retainer Agreement.

7. Controlled Nuclear Information

The Consultant has been made aware of certain Canadian federal requirements relating to the import and export of controlled nuclear information, and recognizes that it is an offence for any person to export controlled nuclear information from Canada without an export permit issued for the purpose by the Canadian Nuclear Safety Commission. The Consultant agrees not to remove or cause to be removed from Canada any controlled nuclear information during the performance of the Services, and will promptly raise the issue with OPG where the Consultant is in doubt as to whether information to be removed from Canada as part of the Services may be – or contain – controlled nuclear information.

8. Termination

Torys may terminate this Retainer Agreement at any time on written notice to the Consultant. Torys will pay, or will cause OPG to pay, for work performed up to the date of the notice of termination. Upon the termination or expiration of this Retainer Agreement, the Consultant shall return to Torys and delete any and all electronic copies the Consultant may have of all documents and materials in its possession relating to the Services or this Retainer Agreement, including all Confidential Information and Work Product, whether completed or not.

9. Liability and Indemnification

The Consultant shall be liable for and shall indemnify and hold harmless OPG and Torys from all claims, demands, actions, penalties, damages, losses, judgments and settlements, liabilities, costs, expenses, including legal fees and other related costs and expenses arising out of, related to, or incident to, the Consultant or any of its representatives' performance of the Services under this Retainer Agreement, including, subject to section 11 (Limitation of Liability) below:

a) any breach, violation or non-performance by the Consultant or any of its representatives of any terms, conditions, warranties, obligations or covenants contained in this Retainer Agreement;

b) any breach or violation by the Consultant or any of its representatives of any applicable laws; and

c) any actions, omissions, negligence or wilful misconduct of the Consultant or any of its representatives.

10. Intellectual Property Protection

The Consultant expressly warrants that the manufacture, delivery, sale or use of the Consultant's Services will not infringe any Canadian or foreign patents, trademarks, copyrights, industrial design or other intellectual property rights and the Consultant shall indemnify and save OPG harmless from all claims, judgments and decrees that may be entered against OPG or its representatives and against all damage, liability, costs and expenses (including legal fees and other attendant costs and expenses) OPG incurs by reason of any infringement or claim thereof.

11. Limitation of Liability

Except for breach of confidentiality obligations, gross negligence, willful misconduct, fraud, breach of applicable laws, breach of privacy laws, and the Consultant's obligation to indemnify under section 10 (Intellectual Property Protection), the Consultant's total liability for any claim arising out of the performance of the Services, regardless of the form of claim, will in no event exceed total fees paid to Consultant hereunder and under no circumstances will either party be liable for any damages in respect of any incidental, punitive, special, indirect or consequential loss, even if that party had been advised of the possibility of such damages including, but not limited to, loss of profits, loss of revenues, failure to realize expected savings, loss of data, loss of business opportunity, or similar losses of any kind.

12. Insurance

(a) Unless otherwise specified in this Retainer Agreement, the Consultant shall, during the term of this Retainer Agreement, and at its own expense, maintain and keep in full force and effect:

i. commercial general liability insurance on an occurrence basis having a minimum inclusive coverage limit, including personal injury and property damage, of not less than one million dollars ($1,000,000.00) per occurrence, which shall be extended to cover contractual liability, products and completed operations liability, owners/contractors protective liability and must also contain a cross liability clause and a severability of interest clause, and must name OPG and its affiliates as additional insureds; and

ii. errors and omissions insurance (professional liability) in the amount of not less than two million dollars ($2,000,000.00).

(b) All insurance coverages and limits required to be maintained by the Consultant shall be primary to any insurance maintained by OPG, which shall be excess and non-contributory. Prior to the commencement of the delivery of the Services, the Consultant shall deliver to OPG a certificate of insurance which evidences the Consultant's compliance with this Section, including the provision of a thirty (30) day prior written notice of cancellation, non-renewal or adverse material change, to OPG. The Consultant agrees that the insurance described herein does in no way limit the Consultant's liability pursuant to the indemnity provisions of this Retainer Agreement.

13. Independence

By entering into this Retainer Agreement, the Consultant acknowledges and agrees that the Sponsors have received a copy of Rule 13A of the Board's *Rules of Practice and Procedure* concerning expert evidence and agree to accept the responsibilities that are or may be imposed on them by that rule with respect to testimony before the Board. A copy of the rule and the relevant form are attached as **Schedules 3 and 4** hereto.

14. Entire Agreement

This Retainer Agreement, together with all Schedules attached hereto and any agreements and other documents to be delivered pursuant to this Retainer Agreement, constitute the complete agreement between Torys and the Consultant or their respective agents with respect to the subject

matter hereof and supersedes any and all prior agreements and understandings. This Retainer Agreement may be amended only in writing with reference to this Retainer Agreement and signed by both parties.

15. **Governing Law**

This Retainer Agreement shall be construed and otherwise governed pursuant to the laws of the Province of Ontario and the federal laws of Canada applicable therein.

Sincerely,

TORYS LLP

Charles Keizer
Partner

Agreed and Accepted by:

Concentric Energy Advisors, Inc.

By: _____
Name: Jim Coyne
Title: Senior Vice President

SCHEDULE 1

Scope of Work

Objective:

To provide independent expert opinion and support to Torys in assistance of its legal advice to OPG with respect to cost of capital-related issues in OPG's next payment amounts application, as further detailed below and pursuant to the terms and conditions of the Retainer Agreement.

Scope:

The Consultant will undertake the following scope of work to support Torys' legal advice to OPG in obtaining the OEB's approval of payment amounts established pursuant to the OEB's new rate-making methodologies for hydroelectric and nuclear operations:

a) The Consultant will carry out an independent study as to whether the application of the cost of capital approved by the OEB in the EB-2016-0152 proceeding is an appropriate basis for setting OPG's nuclear and regulated hydroelectric payment amounts in OPG's next payment amounts application (the "Capital Cost Study").

   In carrying out the Capital Cost Study, the Consultant will select the appropriate peer group against which OPG should be compared, including establishing the appropriate selection criteria for inclusion in the peer group.

   The Capital Cost Study shall build upon the OEB's findings in EB-2007-0905, EB-2010-0008, EB-2013-0321, and EB-2016-0152 in respect of OPG's cost of capital. Specifically:

   i. OPG's cost of capital shall be established based on the stand-alone principle.
   ii. OPG's ROE shall be set in accordance with a formula-based approach provided in the OEB's Cost of Capital Report issued December 11, 2009, which adopts the Fair Return Standard.
   iii. The 45% common equity ratio approved in EB-2013-0321 reflects the OEB's view that the business risks associated with OPG's nuclear business are higher than those of the regulated hydroelectric business.
   iv. The 45% common equity ratio approved in EB-2016-0152 is counter to the position advanced by OPG, the positions advanced by the OEB's independent experts, and the positions advanced by OEB staff.
   v. The Capital Cost Study will address whether the 45% common equity ratio is reasonable, given Pickering End of Commercial Operations, the Darlington Refurbishment Project, and market renewal, among other factors.

   Initial draft of the Cost of Capital Study report, if requested, must be submitted by the Consultant to Torys and OPG by February 28, 2020. The final report of the Cost of Capital Study, if requested, shall be delivered to Torys and OPG by March 27, 2020.

b) If requested, the Consultant will conduct an independent assessment of the impact to OPG's risk due to the merchant risk created under the current market renewal proposal,

including an assessment of the equity thickness required to reflect this risk (the "Merchant Risk Study").

c) If requested, the Consultant will conduct other studies as may be required to support the Cost of Capital Study ("Supporting Studies").

With respect to the Merchant Risk Study and/or Supporting Study (if requested), OPG or Torys will provide specific instructions to the Consultant regarding required scope, activities and timeline, and Consultant shall provide a forecast maximum level of efforts required to complete the work for approval by Torys prior to the initiation of such Study. For clarity, the decision to proceed with the Merchant Risk Study and/or Supporting Study will be determined by OPG and communicated to the Consultant in writing.

d) If requested, the Consultant will prepare for and participate in OPG's payment amounts applications in support of Torys' legal advice to OPG in the Proceedings, including: preparing evidence, responding to interrogatories, providing oral testimony, responding to undertakings and supporting the preparation of argument and other submissions, all as directed by Torys and OPG.

SCHEDULE 2

OPG's Standard Form Business Expense Schedule

(attached)

Schedule C -
Business Expenses.p

STANDARD FORM BUSINESS EXPENSE SCHEDULE FOR CONTRACTORS

Effective June 17, 2009

ONTARIO POWER GENERATION INC.

Updated December 10, 2014

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BUSINESS EXPENSE SCHEDULE

RECITALS

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

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

SECTION 1 – INTERPRETATION

1.1 Three Types of Reimbursement

OPG will reimburse the Contractor for expenses that are eligible for reimbursement in accordance with the Schedule. OPG will make the reimbursements in 1 of 3 ways respecting each Eligible Employee in respect of whom reimbursements are payable. The 3 ways of reimbursements are:

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

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

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

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

1.2 Definitions

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

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

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

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

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

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

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

(g) **Reporting Location** means the normal work location or base office for Eligible Employee. For all work at Darlington Nuclear (DN) and Pickering Nuclear (PN) sites, this is further defined as an area consisting of a 100km radius around the midpoint between DN and PN site. Bruce Nuclear (BN) is also considered a reporting location.

(h) **OPG Representative** is defined in Section 2.1 (d).

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

(j) **Work Site** means a location at which the Eligible Employee may be required to provide service that is different from the Eligible Employee's normal reporting location.

1.3 Headings

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

1.4 Expanded Definitions

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

1.5 Business Day

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

1.6 Payment Currency

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

1.7 Conflict

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

1.8 Notice

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

SECTION 2 – REIMBURSEMENT OF ALLOWABLE EXPENSES

2.1 Allowable Expenses

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

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

(b) vehicle expenses permitted under section 4;

(c) lodging expenses permitted under section 5; and

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

2.2 Expenses Minimised

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

2.3 Excluded Items

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

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

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

(c) gratuities;

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

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

(f) laundry, dry cleaning or valet expenses;

(g) hotel telephone charges or internet access;

(h) personal telephone calls;

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

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

(k) headsets or other in-flight expenses;

(l) dependent care expenses;

(m) pet care expenses;

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

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

(p) automobile washes;

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

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

2.4 Method of Reimbursement

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

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

to OPG for an expense within six months of the expenses being incurred, OPG will not be obliged to reimburse the Contractor for such expense.

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

(c) **GST/HST Deducted.** The Contractor will deduct all Canadian goods and services tax/harmonized sales tax levied under the *Excise Tax Act* (Canada) recovered or recoverable by the Contractor on the payment of expenses before submitting any invoice to OPG covering any allowable expenses. The Goods and Services Tax/Harmonized Sales Tax levied under the *Excise Tax Act* (Canada) and reimbursable by OPG under this Schedule.

(d) **Reimbursement.** OPG will reimburse the Contractor for Allowable Expenses which meet all of the requirements of this Schedule, received and approved by OPG before the 25th of each month on the 25th of the following month. The Contractor will ensure that all Eligible Employees initially pay for expenses using their own payment methods. OPG will not provide any advances respecting allowable expenses. The Contractor is exclusively responsible for the reimbursement of expenses to all Eligible Employees. Failure by the Contractor to comply with the requirements of this Schedule and the rest of the Agreement may result in delay of reimbursement of expenses or rejection of any invoice in whole or in part.

2.5 Travel Agency

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

2.6 Confirming Rates

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

2.7 Home Base and Work Site

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

2.8 Non EPSCA Eligible Employees and Extended Staff

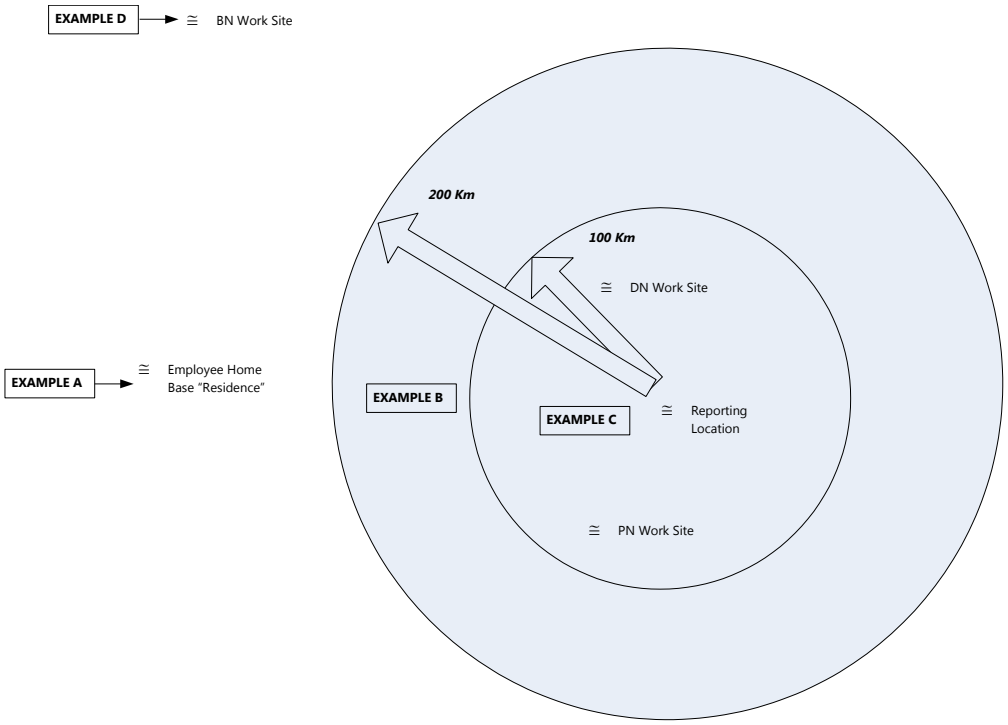
OPG will only reimburse the Contractor's Eligible Employees and extended staff, not subscribed to an EPSCA Agreement, expenses incurred from their Home Base to the designated reporting location as per the illustration below and detailed examples provided:

Example A: Home Base is outside the 200 kilometers ring from the reporting location. Prior approval from an OPG Representative is required and depending on the duration of the assignment, either section 6 or section 7 applies. If the duration is greater than one month, section 7 applies and the Eligible Employee will be paid an "all inclusive" monthly rate (or prorated portion of the month). If the assignment is less than one month, section 6 applies and the Eligible Employee will be paid an "all inclusive" daily rate.

Example B: Home Base is outside the 100 km ring but inside the 200 kilometers ring from the reporting location. Prior approval from an OPG Representative is required and OPG will pay the less of a daily "all inclusive" rate per section 6 or rates in accordance with sections 2 through 5. If sections 2 through 5 apply, the Eligible Employee will only be entitled to one round trip per week, from Home Base to the reporting location.

Example C: Home Base is within a 100 kilometers radius of the reporting location. In this scenario, the Eligible Employee is not entitled to any expenses whatsoever. This would include any and all trips to the Work Site within the 100 kilometers radius.

Example D: In this example, the reporting location and Work Site is one and the same. Prior approval from an OPG Representative is required and the preceding examples A, B and C apply.


EXAMPLE D
≅ BN Work Site
200 Km
100 Km
≅ DN Work Site
EXAMPLE A
≅ Employee Home Base "Residence"
EXAMPLE B
EXAMPLE C
≅ Reporting Location
≅ PN Work Site

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SECTION 3 – AIR, RAIL OR BUS TRAVEL

3.1 Air, Rail or Bus Travel

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

(a) the expense of the taxi fare or other similar out of pocket charge to travel to or from the airport, railway station or bus terminal; and
(b) if applicable, parking charges at the airport, railway station or bus terminal.

3.2 Economy Class

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

3.3 Vehicle Instead of Air, Rail or Bus Travel

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

(a) the expense of the airfare, rail fare or bus fare that would have been reimbursed by OPG to the Contractor under section 3; and
(b) the amount that would otherwise be reimbursable by OPG to the Contractor for vehicle travel pursuant to section 4. OPG will not reimburse the Contractor for any lodging that would not have been incurred had the trip been made by air, rail or bus.

3.4 Visits Home

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

3.5 Minimising Expenses

The Contractor will, to the extent possible, cause all air travel, to be by "lowest logical airfare", to take advantage of weekend specials and other discount fares and to reduce overall expenses and plan ahead (booking at least 2 weeks before the departure date is expected).

SECTION 4 – VEHICLES

4.1 Reimbursable Vehicle Expenses

The expense of rental vehicles or personal vehicles (the lesser of) used by Eligible Employees will be and allowable expense to the extent that:

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

(b) the one way distance between the Eligible Employee's reporting location and the Work Site is greater than 100 kilometers;

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

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

4.2 Personal Vehicle

If the Eligible Employee is required to provide services at a location other than the Eligible Employee's reporting location, OPG will reimburse the Contractor as an allowable expense for all personal vehicle travel by an Eligible Employee in excess of 200 kilometers (round trip), at the published rates per kilometre on the date of invoice, for vehicle expenses for Ontario set on the Canada Revenue Agency website (www.cra-arc.gc.ca/tx/llrts/menu-eng.html). This Canada Revenue Agency amount covers all vehicle related expenses, except parking.

4.3 Reducing Expenses

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

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

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

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

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

4.4 Multiple Users

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

SECTION 5 – LODGING

5.1 Overnight Accommodation

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

(a) the presence of the Eligible Employee is required at a Work Site which is more that 200 km (one way) from that Eligible Employee's reporting locations or;

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

(c) the Contractor will include a written explanation for all overnight accommodation with the invoice.

SECTION 6 – DAILY RATES

6.1 Daily Rates Instead of Allowable Expenses

To the extent this section 6 applies to any Eligible Employee, none of the terms of section 2 to section 5 apply, except for any Allowable Expenses for air, rail or bus travel between an Eligible Employee's reporting location and a Work Site that is reimbursable in accordance with section 3. Notwithstanding the previous sentence, the temporary residence (where the Eligible Employee resides while working on the OPG project), or in some instances the Home Base will be

considered the reporting location for the purpose of calculating Allowable Expenses in the event the Eligible Employee is required to travel to a location other than the reporting location.

6.2 Daily Rates

Before the commencement of, or at any time during, a work assignment for any Eligible Employee, OPG may elect based on the remaining duration of the work assignment, the distance between the Eligible Employee's reporting location and the work site or for other reasons to pay the Contractor a daily rate in respect of that Eligible Employee rather than to reimburse the Contractor for allowable expenses.

6.3 All Inclusive

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

6.4 Rates

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

(a) City of Toronto, $150 and;

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

6.5 Application of Rate

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

6.6 Method of Reimbursement

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

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

(b) Evidence of Expenses. The Contractor will provide OPG with original or electronic photocopies itemised receipts and time sheets evidencing that the Eligible Employee attended the Work Site and made use of temporary accommodation on each day for which the daily rate is being requested. Debit card and credit card receipts are not acceptable without the itemised receipt. Failure by the Contractor to comply with the requirements of this Schedule and the rest of the Agreement may result in delay of reimbursement of expenses or rejection of any invoice whole or in part.

6.7 Absences

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

Section 7 – MONTHLTY RATES

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

SCHEDULE 3

Rule 13A of the Board's Rules of Practice and Procedure

13A. Expert Evidence

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

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

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

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

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

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

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

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

(f) an acknowledgement of the expert's duty to the Board in **Form A** to these Rules, signed by the expert.

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

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

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

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

(a) scope and timing;

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

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

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

(e) any issues in relation to confidentiality.

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

SCHEDULE 4

FORM A

Proceeding: .....

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is James Coyne (*name)*. I live at Lincoln (*city)*, in the Massachusetts (*province/state*) of United States

2. I have been engaged by or on behalf of Ontario Power Generation (*name of party/parties)* 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 January 10, 2020

Signature

SCHEDULE 4

FORM A

Proceeding: .....

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Daniel Dane .....(*name)*. I live at Northborough..... (*city)*, in the Massachusetts..... (*province/state*) of United States.....

2. I have been engaged by or on behalf of Ontario Power Generation (*name of party/parties)* 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 January 10, 2020.....

Daniel Dane

Signature

Numbers may not add due to rounding.

Table 1
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital
Calendar Year Ending December 31, 2026

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	97.4	0.4%	2.23%	7.2
2	**Existing/Planned Long-Term Debt**	2	3,680.9	16.6%	3.65%	134.5
3	**Other Long-Term Debt Provision**	3	7,316.5	33.0%	3.65%	267.4
4	**Total Debt**	4	11,094.8	50.0%	3.69%	409.1
5	**Common Equity**	4	11,094.8	50.0%	8.34%	925.3
6	**Rate Base Financed by Capital Structure**	5	22,189.6	100.0%	6.01%	1,334.4
7	**Adjustment for Lesser of UNL or ARC**	5, 6	0.0	0.0%	4.89%	0.0
8	**Rate Base**		22,189.6	100%	6.01%	1,334.4

Notes:

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

2 Ex. C1-1-2 Table 12, line 26.

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

4 Capital Structure proposed in Ex. C1-1-1, Attch 1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (November 9, 2020).

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

6 Principal from C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

Numbers may not add due to rounding.

Table 2
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital
Calendar Year Ending December 31, 2025

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	97.4	0.5%	1.66%	6.7
2	**Existing/Planned Long-Term Debt**	2	3,686.2	17.6%	3.65%	134.7
3	**Other Long-Term Debt Provision**	3	6,706.9	32.0%	3.65%	245.0
4	**Total Debt**	4	10,490.5	50.0%	3.68%	386.4
5	**Common Equity**	4	10,490.5	50.0%	8.34%	874.9
6	**Rate Base Financed by Capital Structure**	5	20,980.9	100.0%	6.01%	1,261.3
7	**Adjustment for Lesser of UNL or ARC**	5, 6	0.0	0.0%	4.89%	0.0
8	**Rate Base**		20,980.9	100%	6.01%	1,261.3

Notes:

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

2 Ex. C1-1-2 Table 11, line 26.

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

4 Capital Structure proposed in Ex. C1-1-1, Attch 1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (November 9, 2020).

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

6 Principal from C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

Numbers may not add due to rounding.

Table 3
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital
Calendar Year Ending December 31, 2024

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	97.4	0.5%	1.16%	6.2
2	**Existing/Planned Long-Term Debt**	2	3,764.6	19.4%	3.61%	136.0
3	**Other Long-Term Debt Provision**	3	5,859.5	30.1%	3.61%	211.7
4	**Total Debt**	4	9,721.5	50.0%	3.64%	354.0
5	**Common Equity**	4	9,721.5	50.0%	8.34%	810.8
6	**Rate Base Financed by Capital Structure**	5	19,443.0	100.0%	5.99%	1,164.8
7	**Adjustment for Lesser of UNL or ARC**	5, 6	0.0	0.0%	4.89%	0.0
8	**Rate Base**		19,443.0	100%	5.99%	1,164.8

Notes:

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

2 Ex. C1-1-2 Table 10, line 27.

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

4 Capital Structure proposed in Ex. C1-1-1, Attch 1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (November 9, 2020).

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

6 Principal from C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

Numbers may not add due to rounding.

Table 4
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital
Calendar Year Ending December 31, 2023

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	97.4	0.6%	0.78%	5.8
2	**Existing/Planned Long-Term Debt**	2	4,039.6	24.0%	3.49%	140.8
3	**Other Long-Term Debt Provision**	3	4,276.4	25.4%	3.49%	149.0
4	**Total Debt**	4	8,413.4	50.0%	3.51%	295.7
5	**Common Equity**	4	8,413.4	50.0%	8.34%	701.7
6	**Rate Base Financed by Capital Structure**	5	16,826.8	100.0%	5.93%	997.3
7	**Adjustment for Lesser of UNL or ARC**	5, 6	0.0	0.0%	4.89%	0.0
8	**Rate Base**		16,826.8	100%	5.93%	997.3

Notes:

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

2 Ex. C1-1-2 Table 9, line 29.

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

4 Capital Structure proposed in Ex. C1-1-1, Attch 1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (November 9, 2020).

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

6 Principal from C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

Numbers may not add due to rounding.

Table 5
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital
Calendar Year Ending December 31, 2022

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	97.4	0.6%	0.47%	5.5
2	**Existing/Planned Long-Term Debt**	2	3,837.8	23.3%	3.61%	138.4
3	**Other Long-Term Debt Provision**	3	4,305.9	26.1%	3.61%	155.2
4	**Total Debt**	4	8,241.0	50.0%	3.63%	299.1
5	**Common Equity**	4	8,241.0	50.0%	8.34%	687.3
6	**Rate Base Financed by Capital Structure**	5	16,482.0	99.6%	5.98%	986.4
7	**Adjustment for Lesser of UNL or ARC**	5, 6	73.6	0.4%	4.89%	3.6
8	**Rate Base**		16,555.6	100%	5.98%	990.0

Notes:

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

2 Ex. C1-1-2 Table 8, line 35.

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

4 Capital Structure proposed in Ex. C1-1-1, Attch 1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (November 9, 2020).

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

6 Principal from C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

Numbers may not add due to rounding.

Table 6
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital
Calendar Year Ending December 31, 2021

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	97.4	0.6%	0.44%	5.6
2	**Existing/Planned Long-Term Debt**	2	3,676.7	22.7%	3.83%	140.8
3	**Other Long-Term Debt Provision**	3	5,137.5	31.7%	3.83%	196.8
4	**Total Debt**	4	8,911.6	55.0%	3.85%	343.2
5	**Common Equity**	4	7,291.3	45.0%	10.24%	746.3
6	**Rate Base Financed by Capital Structure**	5	16,202.9	98.0%	6.72%	1,089.5
7	**Adjustment for Lesser of UNL or ARC**	5, 6	324.1	2.0%	4.89%	15.9
8	**Rate Base**		16,527.1	100%	6.69%	1,105.4

Notes:

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

2 Ex. C1-1-2 Table 7, line 36.

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

4 Capital Structure as approved by the OEB in EB-2016-0152. Return on Equity as calculated in Ex. I1-1-1, Table 5.

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

6 Principal from C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

Numbers may not add due to rounding.

Table 7
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital
Calendar Year Ending December 31, 2020

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	97.4	0.7%	0.70%	4.2
2	**Existing/Planned Long-Term Debt**	2	3,889.3	27.6%	4.01%	156.1
3	**Other Long-Term Debt Provision**	3	3,771.2	26.7%	4.01%	151.4
4	**Total Debt**	4	7,757.9	55.0%	4.02%	311.7
5	**Common Equity**	4	6,347.3	45.0%	12.67%	804.4
6	**Rate Base Financed by Capital Structure**	5	14,105.2	97.2%	7.91%	1,116.0
7	**Adjustment for Lesser of UNL or ARC**	5, 6	406.3	2.8%	4.89%	19.9
8	**Rate Base**		14,511.5	100%	7.83%	1,135.9

Notes:

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

2 Ex. C1-1-2 Table 6, line 40.

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

4 Capital Structure as approved by the OEB in EB-2016-0152. Return on Equity as calculated in Ex. I1-1-1 Table 4.

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

6 Principal from C2-1-1, Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

Numbers may not add due to rounding.

Table 8
Capitalization and Cost of Capital
Summary of Capitalization and Actual Cost of Capital
Calendar Year Ending December 31, 2019

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	139.9	1.3%	1.96%	5.1
2	**Existing/Planned Long-Term Debt**	2	3,962.3	36.0%	4.33%	171.4
3	**Other Long-Term Debt Provision**	3	1,946.0	17.7%	4.33%	84.2
4	**Total Debt**	4	6,048.2	55.0%	4.31%	260.7
5	**Common Equity**	4	4,948.5	45.0%	15.72%	778.1
6	**Rate Base Financed by Capital Structure**	5	10,996.7	95.7%	9.45%	1,038.8
7	**Adjustment for Lesser of UNL or ARC**	5, 6	488.5	4.3%	4.90%	23.9
8	**Rate Base**		11,485.1	100%	9.25%	1,062.7

Notes:

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

2 Ex. C1-1-2 Table 5, line 44.

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

4 Capital Structure as approved in EB-2016-0152. Return on Equity in col. (d) determined using the reconciliation approach discussed in EB-2013-0321 Ex. C1-1-1 Section 4.2, starting with the financial results for OPG's prescribed assets calculated in accordance with US GAAP.

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

6 Principal from C2-1-1, Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

Numbers may not add due to rounding.

Table 9
Capitalization and Cost of Capital
Summary of Capitalization and Actual Cost of Capital
Calendar Year Ending December 31, 2018

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	86.2	0.8%	1.67%	3.7
2	**Existing/Planned Long-Term Debt**	2	3,783.4	35.1%	4.48%	169.5
3	**Other Long-Term Debt Provision**	3	2,056.6	19.1%	4.48%	92.1
4	**Total Debt**	4	5,926.2	55.0%	4.48%	265.3
5	**Common Equity**	4	4,848.7	45.0%	10.74%	520.8
6	**Rate Base Financed by Capital Structure**	5	10,775.0	95.0%	7.30%	786.1
7	**Adjustment for Lesser of UNL or ARC**	5, 6	570.6	5.0%	4.93%	28.1
8	**Rate Base**		11,345.6	100%	7.18%	814.3

Notes:

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

2 Ex. C1-1-2 Table 4, line 45.

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

4 Capital Structure as approved in EB-2016-0152. Return on Equity in col. (d) determined using the reconciliation approach discussed in EB-2013-0321 Ex. C1-1-1 Section 4.2, starting with the financial results for OPG's prescribed assets calculated in accordance with US GAAP.

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

6 Principal from C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

Numbers may not add due to rounding.

Table 10
Capitalization and Cost of Capital
Summary of Capitalization and Actual Cost of Capital
Calendar Year Ending December 31, 2017

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	38.8	0.4%	1.10%	2.8
2	**Existing/Planned Long-Term Debt**	2	3,016.0	28.8%	4.99%	150.4
3	**Other Long-Term Debt Provision**	3	2,705.4	25.8%	4.99%	134.9
4	**Total Debt**	4	5,760.3	55.0%	5.00%	288.1
5	**Common Equity**	4	4,712.9	45.0%	6.02%	283.7
6	**Rate Base Financed by Capital Structure**	5	10,473.2	95.4%	5.46%	571.8
7	**Adjustment for Lesser of UNL or ARC**	5, 6	505.1	4.6%	4.95%	25.0
8	**Rate Base**		10,978.3	100%	5.44%	596.8

Notes:

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

2 Ex. C1-1-2 Table 3, line 46.

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

4 Capital Structure as approved in EB-2016-0152 and EB-2013-0321. Return on Equity in col. (d) determined using the reconciliation approach discussed in EB-2013-0321 Ex. C1-1-1 Section 4.2, starting with the financial results for OPG's prescribed assets calculated in accordance with US GAAP.

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

6 Principal from C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

Numbers may not add due to rounding.

Table 11
Capitalization and Cost of Capital
Summary of Capitalization and Actual Cost of Capital
Calendar Year Ending December 31, 2016

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	8.0	0.1%	0.79%	2.4
2	**Existing/Planned Long-Term Debt**	2	3,005.8	30.1%	5.23%	157.3
3	**Other Long-Term Debt Provision**	3	2,487.0	24.9%	5.23%	130.2
4	**Total Debt**	4	5,500.9	55.0%	5.27%	290.0
5	**Common Equity**	4	4,500.7	45.0%	3.81%	171.5
6	**Rate Base Financed by Capital Structure**	5	10,001.6	92.4%	4.61%	461.4
7	**Adjustment for Lesser of UNL or ARC**	5, 6	825.7	7.6%	5.11%	42.2
8	**Rate Base**		10,827.2	100%	4.65%	503.6

Notes:

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

2 Ex. C1-1-2 Table 2, line 41.

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

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

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

6 Principal from C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.