EB-2016-0152

Ontario Power Generation Inc.
Application for payment amounts for the period from January 1, 2017 to December 31, 2021

VULNERABLE ENERGY CONSUMERS COALITION

("VECC")
CROSS-
EXAMINATION PANEL
5Ai

April 4, 2017

TAB 1

VECC Interrogatory #5

Issue Number: 3.1
Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:
Reference: C1/T1/S1

In terms of OPG's requested capital structure at EB2016-0152 please provide the following:

a) The actual approved capital structure of OPG for each year since 2005.

b) The applied capital structure for each year in EB2007-0905 and subsequent applications.

c) The percentage rate base assets in nuclear and hydro for each year since 2005.

d) The forecast rate base percentage assets for each year in nuclear and hydro in EB-2007-0905 and subsequent applications.

e) Please restate the Chart 1 data on page 1 to include the periods between 2005 and 2016.

Response

a) See Attachment 1, Table 1

b) See Attachment 1, Table 2

c) See Attachment 1, Table 3

d) See Attachment 1, Table 4

e) See Attachment 1, Table 5

Numbers may not add due to rounding.

Table 1
Approved Capital Structure[1]

Line No.		2008	2009	2011	2012	2014	2015
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Rate Application**	EB-2007-0905[2]	EB-2007-0905[2]	EB-2010-0008[3]	EB-2010-0008[3]	EB-2013-0321[4]	EB-2013-0321[4]
	Approved Capital Structure						
2	**Equity**	47.0%	47.0%	47.0%	47.0%	45.0%	45.0%
3	**Debt**	53.0%	53.0%	53.0%	53.0%	55.0%	55.0%

Notes:
1 The first approved capital structure from the OEB was issued in EB-2007-0905 for 2008
2 2008-2009 from EB-2007-0905 Payment Amounts Order Appendix A, Table 4b, 5b respectively
3 2011-2012 from EB-2010-0008 Payment Amounts Order Appendix A, Table 4b, 5b respectively
4 2014-2015 from EB-2013-0321 Payment Amounts Order Appendix A, Table 5b, 6b respectively

Numbers may not add due to rounding.

Table 2
Proposed Capital Structure[1]

Line No.		2008	2009	2011	2012	2014	2015
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Rate Application**	EB-2007-0905[2]	EB-2007-0905[2]	EB-2010-0008[3]	EB-2010-0008[3]	EB-2013-0321[4]	EB-2013-0321[4]
	Proposed Capital Structure						
2	**Equity**	57.5%	57.5%	47.0%	47.0%	47.0%	47.0%
3	**Debt**	42.5%	42.5%	53.0%	53.0%	53.0%	53.0%

Notes:
1 OPGs first rate application to the OEB was EB-2007-0905 for 2008 and 2009 rates
2 2008-2009 from EB-2007-0905 Ex. C1-2-1 Table 3,2 respectively
3 2011-2012 from EB-2010-0008 Ex. C1-1-1 Table 3,2,1 respectively
4 2014-2015 from EB-2013-0321 Ex. C1-1-1 Table 3,2,1 respectively

Numbers may not add due to rounding.

Table 3
Actual Rate Base

Line No.		2005	2006	2007	2008[3]	2009[3]	2010[3]	2011[3]	2012[3]	2013[3]	2014[3,4]	2015[3,4]
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Actual Rate Base											
1	**Hydro[1]**	4,001.3	3,957.3	3,911.1	3,871.5	3,834.0	3,798.0	3,771.8	3,744.0	4,828.5	7,547.5	7,473.2
2	**Nuclear[2]**	2,865.5	3,005.7	3,500.1	2,501.4	2,261.5	2,377.7	2,368.6	2,281.9	2,309.7	2,325.0	2,346.5
3	**Total Rate Base**	6,866.8	6,963.0	7,411.2	6,372.9	6,095.5	6,175.6	6,140.4	6,025.9	7,138.2	9,872.4	9,819.7
4	**% Hydro**	58.3%	56.8%	52.8%	60.7%	62.9%	61.5%	61.4%	62.1%	67.6%	76.4%	76.1%
5	**% Nuclear**	41.7%	43.2%	47.2%	39.3%	37.1%	38.5%	38.6%	37.9%	32.4%	23.6%	23.9%

Notes:

1 Actual Rate Base: 2005-2007 from EB-2007-0905 Ex. B1-1-1 Table 1
2008-2009 from EB-2010-0008 Ex. B1-1-1 Table 1
2010-2012 from EB-2013-0321 Ex. B1-1-1 Table 1

2 Actual Rate Base: 2005-2007 from EB-2007-0905 Ex. B1-1-1 Table 2
2008-2009 from EB-2010-0008 Ex. B1-1-1 Table 2, less UNL/ARC from Ex. C1-1-1 Tables 5,4 respectively
2010-2012 from EB-2013-0321 Ex. B3-2-1 Table 1 line 1
2013-2015 from EB-2016-0152 Ex. B3-2-1 Table 1 line 1

3 Nuclear amounts do not include the lesser of unamortized asset retirement costs (“ARC”) or unfunded nuclear liabilities (“UNL”). This is consistent with the OEB-approved methodology for determining rate base financed by capital structure, wherein the weighted average cost of capital is applied to OPG’s rate base that does not include the lesser of ARC or UNL.

4 Newly regulated hydroelectric facilities are included for the full year beginning on January 1, 2014, as presented in the EB-2013-0321 Payment Amounts Order.

Numbers may not add due to rounding.

Table 4
OEB Approved Rate Base

Line No.		2008	2009	2011	2012	2014	2015
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Rate Application**	EB-2007-0905	EB-2007-0905	EB-2010-0008	EB-2010-0008	EB-2013-0321	EB-2013-0321
	Approved Rate Base[1]						
2	**Hydro**	3,880.2	3,869.9	3,803.4	3,787.4	7,525.7	7,489.6
3	**Nuclear**[2]	2,448.8	2,470.9	2,392.5	2,354.7	2,317.2	2,350.2
4	**Total Rate Base**	6,329.0	6,340.8	6,195.9	6,142.1	9,843.0	9,839.8
5	**% Hydro**	61.3%	61.0%	61.4%	61.7%	76.5%	76.1%
6	**% Nuclear**	38.7%	39.0%	38.6%	38.3%	23.5%	23.9%

Notes:

1 Approved Rate Base: 2008-2009 from PAO Appendix A, Tables 1-2
2011-2012 from EB-2010-0008 PAO Appendix A, Tables 1-2
2014-2015 from EB-2013-0321 PAO Appendix A, Tables 1-3

2 Nuclear amounts do not include the lesser of unamortized asset retirement costs (“ARC”) or unfunded nuclear liabilities (“UNL”). This is consistent with the OEB-approved methodology for determining rate base financed by capital structure, wherein the weighted average cost of capital is applied to OPG’s rate base that does not include the lesser of ARC or UNL.

Numbers may not add due to rounding.

Table 5
Nuclear Portion of Total Rate Base

Line No.		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Hydro ($B)[1]	4.0	4.0	3.9	3.9	3.8	3.8	3.8	3.7	4.8	7.5	7.5	7.4	7.5	7.5	7.5	7.6	7.7
2	Nuclear ($B)[2,3]	2.9	3.0	3.5	2.5	2.3	2.4	2.4	2.3	2.3	2.3	2.3	2.7	3.3	3.5	3.5	7.5	8.0
3	Total ($B)	6.9	7.0	7.4	6.4	6.1	6.2	6.1	6.0	7.1	9.9	9.8	10.2	10.8	11.0	10.9	15.1	15.6
4	Nuclear Proportion of Total Rate Base (%)	42%	43%	47%	39%	37%	39%	39%	38%	32%	24%	24%	27%	31%	32%	32%	50%	51%

Notes

1 2005-2007 from EB-2007-0905 Ex. B1-1-1 Table 1
2008-2009 from EB-2010-0008 Ex. B1-1-1 Table 1
2010-2012 from EB-2013-0321 Ex. B1-1-1 Table 1

2 2005-2007 from EB-2007-0905 Ex. B1-1-1 Table 2
2008-2009 from EB-2010-0008 Ex. B1-1-1 Table 2, less UNL/ARC from Ex. C1-1-1 Tables 5 and 4 respectively
2010-2012 from EB-2013-0321 Ex. B3-2-1 Table 1 line 1
2013-2021 from EB-2016-0152 Ex. B3-2-1 Table 1 line 1, 4, and 7

3 methodology for determining rate base financed by capital structure, wherein the weighted average cost of capital is applied to OPG's rate base that does not include the lesser of ARC or UNL.

TAB 2

COMMON EQUITY RATIO:

FOR OPG'S REGULATED GENERATION

PREPARED FOR
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GENERATION MIX

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

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

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

OPG'S RATE PROPOSALS[44]

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

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

43 *Ibid*.

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

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

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

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

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

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

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

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

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

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

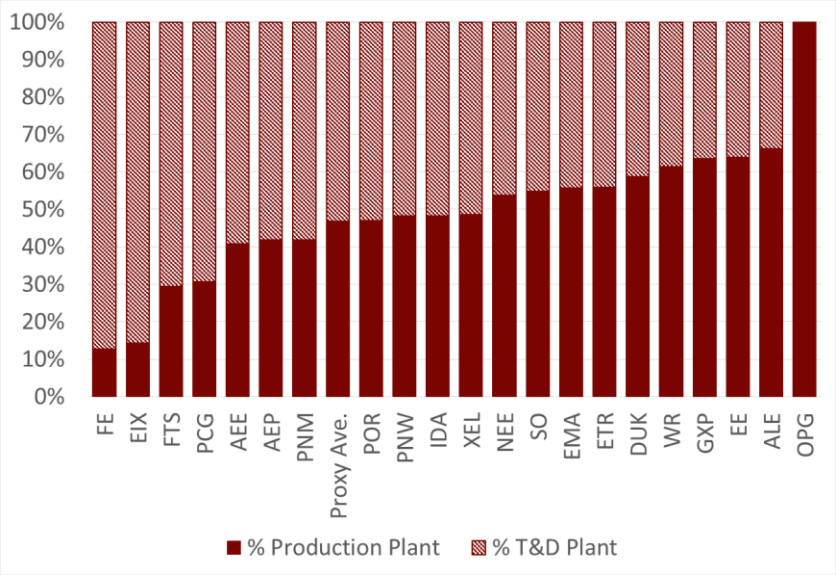
Consistent with DBRS' findings regarding the increased level of risk a utility faces with relatively longer incentive rate plans, discussed above, OPG's planned five-year rate-setting proposals expose the Company to material incremental risk relative to the two-year cost-of-service rate periods established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

FINANCIAL RISK

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

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

Figure 6: Generation versus Transmission and Distribution Assets



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

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

TAB 3

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

Figure 9: Proxy Group Equity Ratios[68]

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

67 *Ibid.*, at 93.

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

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

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

TAB 4

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

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

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

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

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

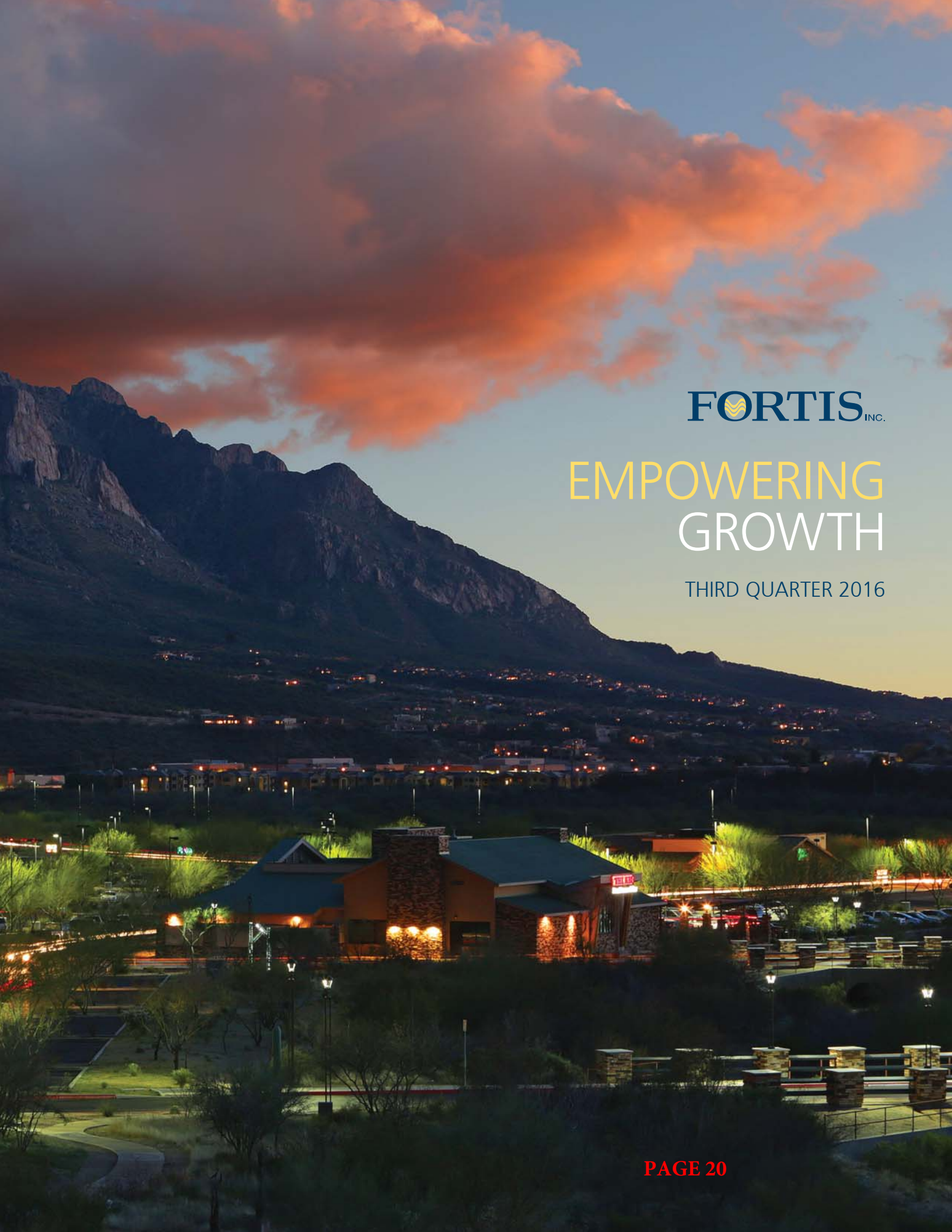
Concentric concludes that, based on the above, OPG's operational risks related to its prescribed hydroelectric facilities have remained relatively the same since EB-2013-0321, but OPG's regulatory risk related to the hydroelectric facilities is expected to change as a result of the movement to a five-year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

NUCLEAR FACILITIES

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

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

TAB 5



FORTIS INC.

EMPOWERING GROWTH

THIRD QUARTER 2016

CAPITAL STRUCTURE

The Corporation's principal businesses of regulated electric and gas utilities require ongoing access to capital to enable the utilities to fund maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. Fortis generally finances a significant portion of acquisitions at the corporate level with proceeds from common share, preference share and long-term debt offerings. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure that will enable it to maintain investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in each of the utility's customer rates.

The consolidated capital structure of Fortis is presented in the following table.

Capital Structure (Unaudited)	**As at**			
	September 30, 2016		December 31, 2015	
	($ millions)	***(%)***	*($ millions)*	*(%)*
Total debt and capital lease and finance obligations (net of cash) [1]	**12,430**	**56.2**	12,022	54.9
Preference shares	**1,623**	**7.4**	1,820	8.3
Common shareholders' equity	**8,045**	**36.4**	8,060	36.8
Total [2]	**22,098**	**100.0**	21,902	100.0

[1] Includes long-term debt, capital lease and finance obligations, including current portion, and short-term borrowings, net of cash. Excludes deferred financing costs.

[2] Excludes amounts related to non-controlling interests

Excluding capital lease and finance obligations, the Corporation's capital structure as at September 30, 2016 was 55.3% debt, 7.5% preference shares and 37.2% common shareholders' equity (December 31, 2015 - 53.8% debt, 8.5% preference shares and 37.7% common shareholders' equity). The change in the Corporation's capital structure was mainly due to an increase in total debt at the Corporation, primarily to finance the acquisition of Aitken Creek and redeem first preference shares, and at the regulated utilities, largely in support of energy infrastructure investment. The acquisition of ITC in October 2016 will significantly increase the Corporation's total capitalization, however, the percentage breakdown of the consolidated capital structure is expected to be comparable with September 30, 2016.

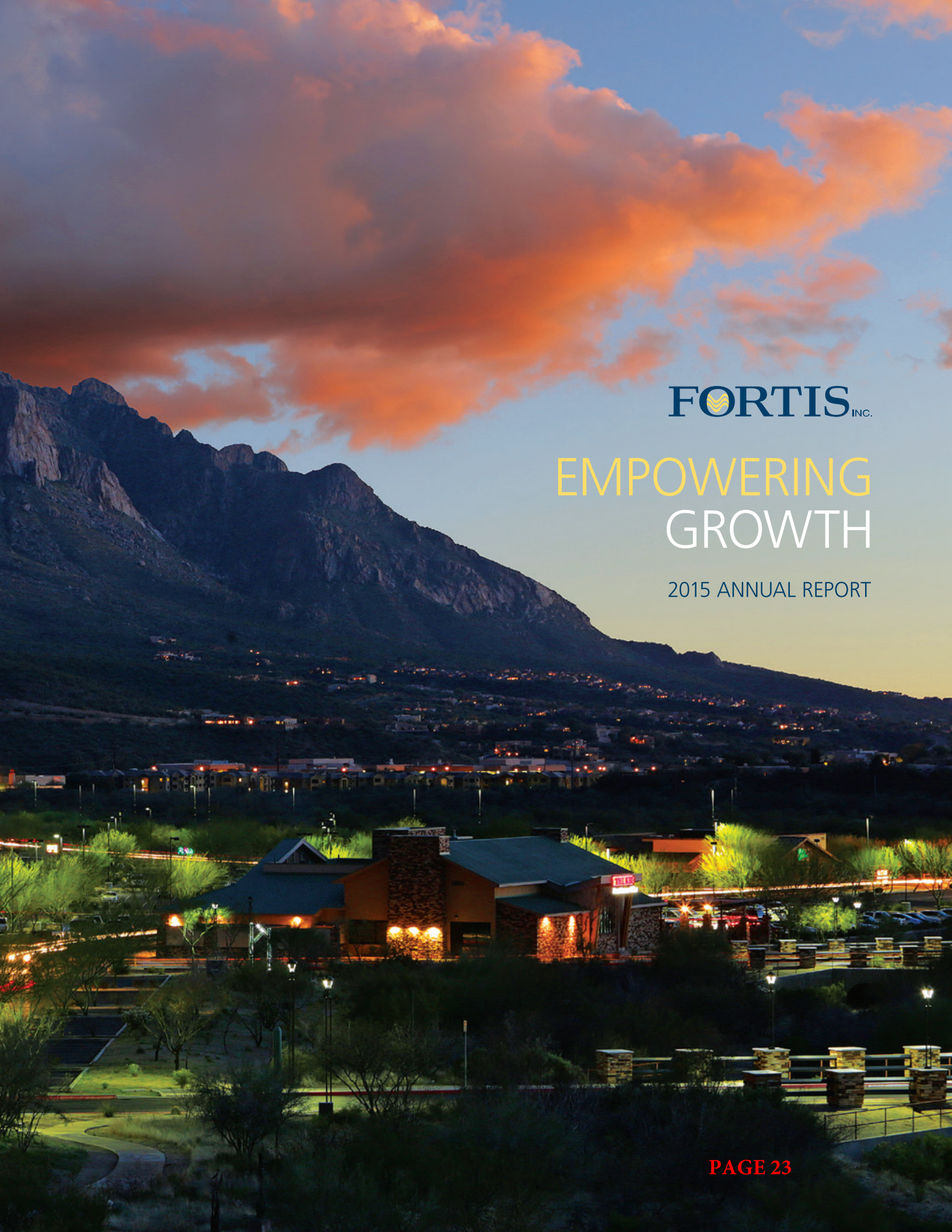
CREDIT RATINGS

The Corporation's credit ratings are as follows:

Rating Agency	**Credit Rating**	**Type of Rating**	**Outlook**
Standard & Poor's ("S&P")	A-	Corporate	Stable
	BBB+	Unsecured debt	Stable
DBRS	BBB (high)	Unsecured debt	Stable
Moody's Investor Service ("Moody's")	Baa3	Issuer	Stable
	Baa3	Unsecured debt	Stable

The above-noted credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, and the level of debt at the holding company. In February 2016, after the announcement by Fortis that it had entered into an agreement to acquire ITC, S&P affirmed the Corporation's long-term corporate credit rating at A-, revised its unsecured debt credit rating to BBB+ from A-, and revised its outlook on the Corporation to negative from stable. Similarly, in February 2016 DBRS placed the Corporation's unsecured debt credit rating under review with negative implications. In September 2016 Moody's commenced rating Fortis and assigned the Corporation an issuer credit rating of Baa3 and an unsecured debt credit rating of Baa3, both with a stable outlook. In October 2016, following the completion of the acquisition of ITC, DBRS revised the Corporation's unsecured debt credit rating to BBB (high) from A (low) and revised its outlook to stable from under review with negative implications, and S&P affirmed the Corporation's long-term corporate and unsecured debt credit ratings, as previously discussed, and revised its outlook to stable from negative.

TAB 6



FORTIS INC.

EMPOWERING GROWTH

2015 ANNUAL REPORT

Other Contractual Obligations

Capital Expenditures: The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems and to meet customer growth. The Corporation's consolidated capital expenditure program, including capital spending at its non-regulated operations, is forecast to be approximately $1.9 billion for 2016. Over the five years 2016 through 2020, the Corporation's consolidated capital expenditure program is expected to be approximately $9 billion, which has not been included in the Contractual Obligations table.

Other: CH Energy Group is party to an investment to develop, own and operate electric transmission projects in New York State. In December 2014 an application was filed with the U.S. Federal Energy Regulatory Commission ("FERC") for the recovery of the cost of and return on five high-voltage transmission projects totalling US$1.7 billion, of which CH Energy Group's maximum commitment is US$182 million. CH Energy Group issued a parental guarantee to assure the payment of a maximum commitment of US$182 million. As at December 31, 2015, no payment obligation is expected under this guarantee.

FortisBC Energy issued commitment letters to customers, totalling $33 million as at December 31, 2015, to provide Energy Efficiency and Conservation ("EEC") funding under the EEC program approved by the BCUC.

Caribbean Utilities is party to primary and secondary fuel supply contracts and is committed to purchasing approximately 60% and 40%, respectively, of the Company's diesel fuel requirements under the contracts for the operation of its diesel-powered generating plant. The approximate combined quantity under the contracts for 2016 is 20 million imperial gallons. Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

The Corporation's long-term regulatory liabilities of $1,340 million as at December 31, 2015 have been excluded from the Contractual Obligations table, as the final timing of settlement of many of the liabilities is subject to further regulatory determination or the settlement periods are not currently known. The nature and amount of the long-term regulatory liabilities are detailed in Note 8 to the Corporation's 2015 Audited Consolidated Financial Statements.

Capital Structure

The Corporation's principal businesses of regulated electric and gas utilities require ongoing access to capital to enable the utilities to fund maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. Fortis generally finances a significant portion of acquisitions at the corporate level with proceeds from common share, preference share and long-term debt offerings. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 35% common equity, 65% debt and preferred equity, as well as investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in each of the utility's customer rates.

The consolidated capital structure of Fortis is presented in the following table.

Capital Structure

	2015		2014	
As at December 31	*($ millions)*	*(%)*	*($ millions)*	*(%)*
Total debt and capital lease and finance obligations (net of cash) [1]	**11,950**	**54.8**	11,239	56.4
Preference shares	**1,820**	**8.3**	1,820	9.1
Common shareholders' equity	**8,060**	**36.9**	6,871	34.5
Total [2]	**21,830**	**100.0**	19,930	100.0

[1] Includes long-term debt and capital lease and finance obligations, including current portions, and short-term borrowings, net of cash

[2] Excludes amounts related to non-controlling interests

Excluding capital lease and finance obligations, the Corporation's capital structure as at December 31, 2015 was 53.7% debt, 8.5% preference shares and 37.8% common shareholders' equity (December 31, 2014 – 54.8% debt, 9.5% preference shares and 35.7% common shareholders' equity).

PAGE 24

TAB 7

AUC
Alberta Utilities Commission

Energy and Public Utility Trends and Issues

What happens if customers “cut the wire”?

2014 CAMPUT Energy Regulation Course
Bob Heggie, Chief Executive, Alberta Utilities Commission

Used and useful (1)

Facilities that are “used” (actually operating in the course of providing service to the customer) and “useful” (necessary to provide service in an economic fashion) remain in rate base. A utility receives return of and on capital employed related to those facility investments. (In Alberta the test is used or required to be used.)

“The words “used or required to be used” are intended to identify assets that are presently used, are reasonably used, and are likely to be used in the future to provide services. Specifically, the past or historical use of assets will not permit their inclusion in rate base unless they continue to be used in the system.”

See: ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board) 2008 ABCA 200, at paras. 23 and 25

ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission), 2009 ABCA 246, para. 56

‘Prudence’ seeks to evaluate management’s performance, while ‘used and useful’ is largely an economic concept used to reflect market conditions or the continuing need for the facility to provide utility service.

TAB 8

A: Universally across all segments of the construction industry, it is difficult to successfully complete a mega-project or mega-program. Because the vast majority of mega-projects are not completed on time and within budget, researchers have called the "'iron law of mega-projects': *over budget, over time, over and over again*".[62] Mega-projects and mega-programs are inherently risky due to the long duration and complex interfaces. Under-staffing, inexperienced project planners or managers, and manager turnover during the life cycle of the project weaken leadership and threaten the consistent application of processes and procedures. Project scope will typically change over time. The occurrence of low probability-high impact events is possible, and the budget and time contingencies included in the original planning frequently prove to be inadequate. Successes in delivering mega-projects and mega-programs are rare. For example, a non-exhaustive list of mega-projects that have experienced 50% or more cost overruns is provided in Appendix 2.[63]

It is difficult to make comparisons of two or more nuclear projects. The two most important metrics for after-the-fact comparison are cost and schedule. Each construction project is unique and publicly available information will omit commercially sensitive and confidential details necessary for a full and complete understanding of the basis for the outcome of the project or program. Accordingly, publicly available information does not tell the complete story regarding the overall cost and schedule outcome. Even seemingly similar projects can vary regarding the following non-exhaustive list of factors: type of technology; size and scope; project

[62] Bent Flyvbjerg, 2014, "What You Should Know about Megaprojects and Why: An Overview," *Project Management Journal*, vol. 45, no. 2, April-May, pp. 11.

[63] Most of the information in the chart in Appendix 2 is from Table 2 from Bent Flyvbjerg, 2014, "What You Should Know about Megaprojects and Why: An Overview," *Project Management Journal*, vol. 45, no. 2.

TAB 9

Ontario Cutting Electricity Bills by 25 Per Cent

System Restructuring Delivers Lasting Relief to Households Across Province

March 2, 2017 9:40 A.M.

Office of the Premier

Ontario is lowering electricity bills by 25 per cent on average for all residential customers as part of a significant system restructuring that will address long-standing policy challenges and ensure greater fairness.

Starting this summer, Ontario's Fair Hydro Plan would provide households with this 25 per cent break. Many small businesses and farms would also benefit from the initiative. People with low incomes and those living in eligible rural communities would receive even greater reductions to their electricity bills. As part of this plan, rate increases over the next four years would be held to the rate of inflation for everyone.

These measures include the eight per cent rebate introduced in January and build on previously announced initiatives to deliver broad-based rate relief on all electricity bills.

Taken together, these changes will deliver the single-largest reduction to electricity rates in Ontario's history.

Recently, electricity rates have risen for two key reasons:

- Decades of under-investment in the electricity system by governments of all stripes resulted in the need to invest more than $50 billion in generation, transmission and distribution assets to ensure the system is clean and reliable
- The decision to eliminate Ontario's use of coal and produce clean, renewable power, as well as policies put in place to provide targeted support to rural and low-income customers, have created additional costs.

The burden of financing these system improvements and funding key programs has unfairly fallen almost entirely on the shoulders of today's ratepayers. To relieve that burden and share costs more fairly, two system fixes are being undertaken.

Recognizing that the electricity infrastructure that has been built will last for many decades to come, the province would refinance those capital investments to ensure that system costs are more equitably distributed over time. In addition, a number of important programs, such as the Ontario Electricity Support Program (OESP), will now be funded by the government instead of by ratepayers.

The province will also launch a new Affordability Fund, enhance the existing OESP and Rural or Remote Rate Protection (RRRP) program and provide on-reserve First Nations households with

a delivery credit. These new measures will cost the government up to $2.5 billion over the next three years.

Notwithstanding that hydro rate relief costs will add significant pressure on the fiscal framework, the province continues to project a balanced budget for 2017-18, and will provide a full update on its fiscal plan in the spring budget.

Reducing electricity costs is part of Ontario's plan to create jobs, grow our economy and help people in their everyday lives.

Quick Facts

- Ontario's Fair Hydro Plan would improve sector efficiency and modernize the province's electricity market, working in collaboration with the Independent Electricity System Operator (IESO) and the Ontario Energy Board (OEB).
- The Province will expand the RRRP to provide distribution charge relief to additional customers served by LDCs with the highest rates. About 800,000 customers would benefit from the enhanced RRRP program.
- The Affordability Fund would be accessible to Local Distribution Companies (LDCs) for customers who do not qualify for low-income conservation programs and who are unable to undertake energy efficiency improvements without financial assistance.
- On-reserve First Nations customers will receive a 100 per cent credit of the delivery line on their monthly electricity bills.
- The expanded OESP will provide an additional $180 to $276 per year for households of eligible size and combined income.
- Ontario is expanding the Industrial Conservation Initiative (ICI) program by reducing the threshold from 1 mW to 500 kW and targeting more small manufacturing and industrial consumers.

Background Information

- Energy Sector Efficiencies
- Refinancing the Global Adjustment
- Previous Actions to Reduce Energy Costs
- Enhancing Electricity Support and Conservation Programs

Additional Resources

- Learn how Ontario is developing the next Long-Term Energy Plan

Quotes

“I have heard from people around the province who are worried about the price they are asked to pay for electricity and the impact it has on their household budget. Electricity is a necessity. By fixing problems in the system, we will be able to provide every residential customer in Ontario with an average 25 per cent off their bills now and make rates fairer in the future.”

Kathleen Wynne

Premier of Ontario

“Ratepayers across Ontario have been loud and clear — we need to do more to help reduce costs. The government has listened and Ontario’s Fair Hydro Plan would reduce costs now and ensure an affordable and reliable electricity system. These new measures would have a significant impact on your monthly hydro bill and would help the most vulnerable.”

Glenn Thibeault

Minister of Energy

TAB 10

VECC Interrogatory #8

Issue Number: 3.1
Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:
Reference: C1/T1/S1/Attachment 1 - Concentric Energy Report

a) Please confirm that in April 19, 2013 Concentric Energy provided a report to the Regie authored by Mr. Coyne and Mr. Trogonoski with a recommended fair ROE and common equity ratio for Hydro Quebec Transmission (HQT) and Hydro Quebec Distribution (HQD).

b) Please provide a copy of that testimony and confirm that:
   i. the recommended and allowed common equity ratio was 30% for HQT and 35% for HQD;
   ii. the recommendations were based on the stand-alone principle; and,
   iii. that on page 9 of the summary Concentric stated:

"the only important difference is that a percentage of electric companies in the US Proxy group (and in Canada) own some regulated generation, which suggests that these companies have somewhat more business risk than HQD and HQT."

   iv. that on page 53 of that report Concentric stated:

"as discussed in the following section of this testimony the incremental ROE required to offset the increased operating risk of regulated generation is approximately 41 basis points."

In the context of an incremental ROE of 0.41% please indicate how much this would translate to in terms of common equity ratio if the ROE were not adjusted for the differential generating risk.

   v. that the Regie allowed HQT and HQD an ROE of 8.2% while at the same time the Ontario formula ROE allowed Ontario's electric distributors an ROE of 9.30% and Concentric recommended the same 9.22% ROE for HQT and HQD.

c) Please confirm that S&P has a policy of not rating debt issued by subsidiaries higher than that of its parent unless it is "ring fenced" and that OPG was downgraded to BBB+ because S&P downgraded its parent, the Province of Ontario. In addition:
   i. Please indicate whether the actions of S&P in its rating policy is consistent with the stand alone principle of regulation
   ii. Please provide copies of both the S&P OPG rating and the current DBRS rating and report.

iii. Please explain in detail why the selection criteria used to form proxy samples for OPG are different from those used for HQT and HQD.

iv. Please confirm that none of the utilities in the proxy group on Page 34 are 100% provincially or state owned and that Concentric's recommendation would not change if OPG were still a Crown corporation, rather than an OBCA company.

v. Please confirm that OPG is included in the Provincial budget as income from government business enterprises.

Response

The following response was prepared by Concentric Energy Advisors:

a) Concentric did provide a report to the Regie de L'Energie on April 19, 2013, in which Concentric recommended a fair return on equity for Hydro Quebec TransEnergie ("HQT") and Hydro Quebec Distribution ("HQD").

b) Please see 3.1 VECC-8, Attachment 1 for a copy of the report.

i. Concentric's report for HQT and HQD focused on the authorized ROE. Concentric did not recommend any change to the deemed equity ratio for either HQT or HQD. However, page 52 of Concentric's report for HQT and HQD states:

> *HQD and HQT are proposing to maintain their current deemed equity ratios of 35.0 percent and 30.0 percent, respectively. As discussed in Appendix B, the equity ratios for HQD and HQT are somewhat lower than the deemed equity ratios for the operating divisions of the Canadian proxy group, and are substantially lower than the authorized equity ratios of the U.S. electric utility proxy group. In order for HQD and HQT to have the opportunity to earn weighted compensatory equity return at their respective equity ratios as the U.S. electric utility proxy group at an average equity ratio of 50.2 percent, significant increases in the authorized ROE would be required to compensate for the difference in authorized capital structure. Using commonly-accepted methodologies, Concentric estimates that an adjustment to ROE of between approximately 1.50 percent and 3.00 percent would be warranted to compensate for a 15 to 20 percent decline in the common equity ratio from the U.S. proxy group average.*

The Regie's Order did not modify the 30% deemed equity ratio for HQT or the 35% deemed equity ratio for HQD.

ii. The ROE recommendations were made based on the stand-alone principle.

iii. Confirmed. In addition, the following bullet point on page 9 of Concentric's report for HQT and HQD states:

Financial Risk – HQD and HQT have somewhat more financial leverage in their capital structures than the Canadian utilities and substantially more financial leverage and weaker credit metrics than the U.S. electric utility proxy group companies. Credit rating agencies may be satisfied with the degree of regulatory protection and cash flow protection for debt investors, but these metrics expose equity investors to greater risk than their U.S. counterparts. As such, HQD and HQT have greater financial risk than the U.S. electric utility proxy group, which more than offsets the ownership of regulated generation described above.

iv. Confirmed. The complete response on page 53 of Concentric's report for HQT and HQD states:

As discussed in the following section of this testimony, the incremental ROE required to offset the increased operating risk of regulated generation is approximately 41 basis points. Although Concentric does not propose an adjustment in this proceeding for the difference in capital structure between HQD and HQT and the U.S. electric utility proxy group, Concentric views the financial risk of a more highly-leveraged capital structure as more than offsetting any potential difference in the required ROE of the U.S. electric utility proxy group companies that own regulated generation.

The cited passage from the HQT and HQD evidence states that there has been a 41 basis point ROE differential between vertically-integrated electric utilities and transmission and distribution only utilities. However, OPG is a generation only utility. Concentric does not believe it is appropriate (or even possible) to try to translate the 41 basis point ROE differential for integrated electric utilities and T&D utilities to an equity ratio differential for a generation-only utility like OPG.

v. Concentric confirms that the Regie allowed HQT and HQD to increase their authorized ROE to 8.20% from the previous level of 6.41% for HQT and 6.19% for HQD, which had been set under the Regie's automatic adjustment formula. Concentric's understanding is that the formula ROE in Ontario was 9.36% in 2014, which is when the 8.20% ROE became effective for HQT and HQD. Concentric confirms that our recommendation for HQT and HQD in the 2013 report was 9.22%.

c) Concentric confirms that S&P's ratings methodology for electric and gas utilities is based on a consolidated profile, and that subsidiaries are not rated higher than the parent unless there is ring-fencing in place. Concentric also confirms that OPG was downgraded by S&P in July 2015 because S&P downgraded the Province of Ontario.

i. As stated in response to VECC-009, part a), the stand-alone principle is a "long-established regulatory principle." In performing its credit rating analysis, Standard and Poor's is not applying a regulatory principle, but rather is assessing the creditworthiness and likelihood of default for an issuer based on S&P's stated ratings methodology. Concentric notes that while S&P links the rating of OPG to the Province of Ontario, it rates the Company three notches below the Province (i.e., BBB+ for OPG as compared to A+ for the Province of Ontario). S&P has further indicated that on a stand-alone basis (i.e., without provincial support) OPG would have a BBB- rating, or two notches lower. By comparison, as indicated in Footnote 29 to the Concentric report for HQT and HQD that was provided in response to 3-1-VECC-8(a), Moody's Investors Service indicated in an August 2012 report that its Baseline Credit Assessment for Hydro-Quebec would be Baa1 (S&P equivalent BBB+) absent the government debt guarantee of the Province of Quebec. This rating for Hydro-Quebec is two notches higher than OPG's stand-alone credit profile, suggesting that OPG is viewed as riskier from a credit perspective than Hydro-Quebec.

ii. Please see 3.1-VECC-8, Attachments 2 and 3 for S&P reports and Attachment 4 for the DBRS report.

iii. Concentric agrees that the screening criteria used to select the comparator group for OPG are different than the screening criteria used to estimate the cost of equity for HDT and HQD. These differences are primarily driven by two factors: 1) the specific utilities involved; and 2) the purpose of the analysis. As discussed on page 29 of Concentric's report, OPG is unique in that its regulated operations consist of 100% generating assets; therefore, it is not possible to find proxy companies that are perfectly comparable from a risk perspective. With regard to the specific utilities involved, OPG is a generation utility that owns significant regulated nuclear and hydroelectric assets, whereas HDT and HQD are regulated transmission and distribution utilities. The Board has found that OPG is of higher risk transmission and distribution utilities, stating, in EB-2007-0905, page 149: "[t]he Board has concluded that OPG is of higher risk than electricity LDCs, gas utilities and electricity transmission utilities and of lower risk than merchant generation." In developing the comparator group for OPG, Concentric determined it was appropriate to screen for companies that own regulated generation assets that are included in rate base, and companies that own regulated nuclear and/or hydroelectric generation. These screens were not used for selecting companies

comparable to HQT and HQD because HQT and HQD do not own regulated generation.

In terms of the purpose of the analysis, Concentric's report for OPG is recommending a deemed equity ratio, while for HQT and HQD Concentric was recommending the authorized return on equity. Certain screens that are typically used to develop a proxy group for purposes of estimating the cost of equity were not applied to develop a proxy group for the purpose of establishing a capital structure. For example, in the report for HQT and HQD, Concentric excluded companies that 1) did not pay dividends, 2) did not have earnings growth rates from at least two utility industry analysts, 3) were considered a small capitalization company, and 4) were involved in a merger or other transformative transaction. Those criteria were not used for purposes of developing a comparator group in order to determine an appropriate equity ratio for OPG. Rather, these screens are relevant for purposes of ensuring that sufficient data are available in order to estimate the cost of equity using the DCF and CAPM methods, which were not applied in this case.

iv. Concentric confirms that none of the utilities in the proxy group are provincially or state owned. Further, Concentric confirms that our recommendation would not change if OPG were still a crown corporation.

v. Concentric's assessment of OPG's risk profile was performed on a stand-alone basis, consistent with the Board's application of the stand-alone principle in prior OPG payment amount application proceedings. Specifically, the Board has previously found (EB-2007-0905, page 142):

The Board concludes that if OPG is operated at arm's length, then it should be examined in the same way as Hydro One, another energy utility owned by the Province. In other words, Provincial ownership will not be a factor to be considered by the Board in establishing capital structure.

As such, Concentric did not evaluate whether OPG is included in the Provincial budget as income from government business enterprises.

Témoignage de
MM. James M. Coyne et John P. Trogonoski
de Concentric Energy Advisors
sur le taux de rendement et l'analyse de risque

PAGE 41

Q. Why has Concentric developed three proxy groups?

A. Since the purpose of this proceeding is to establish the allowed ROE for the regulated electric distribution and transmission operations of HQD and HQT, respectively, and because there are very few publicly-traded, pure-play electric utilities in Canada, Concentric has selected a sample of Canadian utilities to provide a benchmark for the resulting cost of equity of Canadian utilities in general. Then, in order to gain additional perspective on the cost of equity and risks specific to electric distribution and transmission utilities, we have developed a sample of U.S. companies that are primarily engaged in the provision of electric utility service. Finally, to provide additional perspective, Concentric has compared the authorized returns of HQD and HQT against a group of Canadian government-owned electric utilities.

Q. Please describe how Concentric selected the Canadian proxy group.

A. Concentric developed a group of publicly-traded regulated Canadian electric and natural gas utility companies. Because there are relatively few companies in that sector in the Canadian public market, no specific screening criteria were used to derive the proxy group. The following six companies comprise the Canadian Utility Proxy Group:

- Canadian Utilities Limited
- Emera, Inc.
- Enbridge, Inc.
- Fortis, Inc.

PAGE 42

- TransCanada Corporation
- Valener, Inc.

Q. How did you select the group of U.S. electric utility proxy companies that are risk appropriate for HQD and HQT?

A. To establish the group of U.S. electric utility proxy companies that are risk appropriate for HQD and HQT, Concentric relied on screening criteria to narrow the list of potential proxy companies. As HQD's and HQT's business operations are 100 percent electric, an evaluation of the potential proxy companies' business units was conducted to identify a group of comparable risk companies to HQD and HQT.

As a starting point, Concentric utilized the 48 companies that Value Line classifies as Electric Utility Companies to ensure that the company is considered to be primarily engaged in electric utility operations. From that group, Concentric screened for companies that:

- Have credit ratings of at least A- from S&P;
- Pay dividends;
- Have earnings growth rates from at least two utility industry analysts;
- Derived at least 60 percent of their revenue from regulated operations in the period from 2009-2011;
- Derived at least 60 percent of their regulated revenue from electric utility operations in the period from 2009-2011;
- Are not considered a small capitalization company; and

PAGE 43

- Are not involved in a merger or other transformative transaction that had a material effect on the company's stock price during the evaluation period.

Q. What companies met those screening criteria?

A. The following six companies met those criteria:

- Consolidated Edison Inc.
- NextEra Energy, Inc.
- Northeast Utilities
- Southern Company
- Wisconsin Energy Corp.
- Xcel Energy Inc.

Q. Did you also consider a third proxy group of government-owned electric utilities in Canada?

A. Yes. Since HQD and HQT are divisions of a government-owned crown corporation, Concentric also selected a group of municipal and provincial government-owned Canadian electric distribution and transmission utilities for purposes of comparing the authorized ROE of HQD and HQT to those entities. That group consists of the following six companies:

- British Columbia Hydro
- ENMAX Corp.
- EPCOR Utilities, Inc.
- Hydro One Networks

PAGE 44

Company Name	Ticker		Debt to Capital Ratio	EBIT to Interest Coverage	FFO to Interest Coverage	FFO / Debt Ratio	Debt to EBITDA
Hydro Quebec Distribution			65%	1.88	3.46	0.24	3.98
Hydro Quebec TransEnergie			70%	1.62	2.66	0.19	5.20
		U.S. Proxy Group					
Consolidated Edison	ED		48%	3.80	5.10	0.28	3.40
NextEra Energy	NEE		61%	3.37	5.17	0.24	4.11
Northeast Utilities	NU		57%	3.28	4.58	0.22	4.69
Southern Co.	SO		53%	5.07	7.38	0.30	3.28
Wisconsin Energy Corp	WEC		57%	4.29	6.43	0.29	3.85
Xcel Energy Inc.	XEL		54%	3.33	5.11	0.29	3.45
U.S. Proxy Group			55%	3.86	5.63	0.27	3.80
		Canadian Proxy Group					
Canadian Utilities Limited	CU		53%	4.07	5.23	0.29	3.14
Emera Incorporated	EMA		66%	2.23	4.03	0.22	5.04
Enbridge Inc.	ENB		64%	3.19	4.22	0.20	4.80
Fortis Inc.	FTS		56%	2.24	3.34	0.19	5.22
TransCanada Corporation	TRP		54%	3.30	4.63	0.21	4.59
Valener, Inc.	VNR	[1]	63%	2.67	3.83	0.22	4.42
Canadian Proxy Group			60%	2.95	4.21	0.22	4.54

Notes & Sources:

Unless otherwise noted, all values are based on holding-company financial data downloaded from SNL Financial.

[1] Credit metrics shown are those for Gaz Métro Limited Partnership.

180-DAY MULTI-STAGE DCF -- CANADIAN PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
Canadian Utilities Limited	CU	$1.94	$69.35	7.75%	7.13%	6.51%	5.90%	5.28%	4.66%	4.04%	7.72%
Emera Inc.	EMA	$1.40	$34.69	7.48%	6.90%	6.33%	5.76%	5.19%	4.61%	4.04%	9.22%
Enbridge Inc.	ENB	$1.26	$40.87	10.61%	9.52%	8.42%	7.33%	6.23%	5.14%	4.04%	8.84%
Fortis Inc.	FTS	$1.24	$33.46	4.44%	4.37%	4.30%	4.24%	4.17%	4.11%	4.04%	7.99%
TransCanada Corporation	TRP	$1.76	$45.46	8.99%	8.16%	7.34%	6.51%	5.69%	4.86%	4.04%	9.47%
Valener Inc.	VNR	$1.00	$15.91	7.00%	6.51%	6.01%	5.52%	5.03%	4.53%	4.04%	11.78%
MEAN		$1.43	$39.96	7.71%	7.10%	6.49%	5.87%	5.26%	4.65%	4.04%	9.17%
MEDIAN		$1.33	$37.78	7.61%	7.02%	6.42%	5.83%	5.23%	4.64%	4.04%	9.03%

Notes:

[1] Source: Bloomberg Professional

[2] Source: Bloomberg Professional, 180-day average as of January 18, 2013

[3] Source: Constant Growth DCF

[4] Equals [3] − ([3] − [9]) / 6

[5] Equals [4] − ([3] − [9]) / 6

[6] Equals [5] − ([3] − [9]) / 6

[7] Equals [6] − ([3] − [9]) / 6

[8] Equals [7] − ([3] − [9]) / 6

[9] Consensus Economics Inc., Consensus Forecasts, October 8, 2012

[10] Internal rate of return

TAB 11

VECC Interrogatory #9

Issue Number: 3.1
Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory

Reference:
Reference: C1/T1/S1

Pre-amble: In the 2016 Ontario budget announcement found at http://www.fin.gov.on.ca/en/budget/ontariobudgets/2016/bk9.html, the province stated:
The Province remains committed to building a cleaner and more sustainable energy system for all Ontarians while reducing electricity system cost pressures. Since 2003, more than $34 billion has been invested in cleaner energy generation in Ontario, with Hydro One investing about $15 billion in modern transmission and distribution infrastructure. Other initiatives include:

- Pursuing the continued operation of the Pickering Nuclear Generating Station beyond 2020 up to 2024. By doing this, Ontario Power Generation (OPG) would protect 4,500 jobs across the Durham region, avoid eight million tonnes of GHG emissions, and save Ontario electricity consumers up to $600 million.
- Moving forward with OPG's refurbishment of the four units at the Darlington Nuclear Generating Station. The Independent Electricity System Operator has updated its contract with Bruce Power to refurbish six nuclear units, in addition to two already refurbished units at the Bruce nuclear site. Together, this secures over 9,800 megawatts (MW) of affordable, reliable and emission-free power.

a) Please confirm that in the Ontario Government's infrastructure programme it includes the costs of the Darlington refurbishment programme as provincial government expenditures.

b) Please indicate whether any of the generating plants in the proxy sample are instructed by their owners to follow non-financial objectives such as preserving 4,500 jobs and if their owners put out a release with titles similar to that of Ontario's "Jobs for today and tomorrow". In Concentric's judgement is such an attitude by the shareholder consistent with the stand alone principle.

c) Please indicate the capital structure and allowed ROE for the following 100% provincially owned Canadian electric utilities: New Brunswick Power, Manitoba Hydro Electric System, Saskatchewan Power and BC Hydro.

d) Please explain in detail why the equivalent 100% owned Canadian electric companies are not a better reference point for a fair capital structure than the US

private non-government owned entities, particularly since S&P rates the two entities (electric company and province) the same.

e) Is Concentric aware that NB Power also has a CANDU nuclear reactor at Point LePreau?

Response

The following response was provided by Concentric Energy Advisors:

a) Concentric's assessment of OPG's risk profile was performed on a stand-alone basis, consistent with the Board's application of the stand-alone principle in prior OPG payment amount application proceedings. Specifically, as noted in Concentric's report (page 8), the Board stated in EB-2007-0905 that "[t]he stand-alone principle is a long-established regulatory principle," and that "Provincial ownership will not be a factor to be considered by the Board in establishing capital structure." As such, Concentric did not evaluate how the Ontario Government accounts for the Darlington refurbishment program as such an evaluation was not relevant to the analysis.

b) It is not Concentric's understanding that OPG has been instructed to follow non-financial objectives. Concentric is not aware of any specific examples of generating plants in the proxy sample being instructed by their owners to follow objectives such as preserving 4,500 jobs or if their owners have put out releases with titles similar to that of Ontario's "Jobs for today and tomorrow." Many of the generating plants in the proxy group, however, operate in states or regions in which their owners must comply with legislative or regulatory policies such as renewable energy portfolio standards that may be based on objectives that are not related directly to the profitability of the plants. In addition, job preservation and creation is a common benefit cited for large energy-related construction projects.

As stated in response to part a), the stand-alone principle is a "long-established regulatory principle," not a reflection of an owner's "attitude." Therefore, Concentric finds the shareholder's statements in its press release to be neither consistent nor inconsistent with that regulatory principle.

c) Please see the table below. As noted in the table, and unlike OPG, the rates of New Brunswick Power, Manitoba Hydro and Saskatchewan Power are not set based on traditional authorized cost of capital parameters, nor were they as of the time that OPG's initial cost of service payment amounts proceeding was decided (e.g., EB-2007-0905 in November, 2008).

Utility	Capital Structure (Debt/Equity)	Allowed ROE (%)
New Brunswick Power[1]	N.A.	N.A.
Manitoba Hydro Electric System[2]	N.A.	N.A.
Saskatchewan Power[3]	N.A.	N.A.
BC Hydro	70/30[4]	11.84%[5]

[1] New Brunswick Power Corporation's ("NB Power's") rates are not set based on traditional authorized cost of capital parameters. Rather, the New Brunswick Energy and Utilities Board authorizes a revenue requirement that includes a forecasted amount of net income. In addition, NB Power has a goal of achieving a 20% debt-to-capital ratio. For example, per the New Brunswick Energy and Utilities Board, "[f]or the fiscal year 2016/17, the Board approves the amount of $92.4 million for Net Income and is satisfied that this permits NB Power to continue to move towards its target of a 20% equity ratio." *See*, New Brunswick Energy and Utilities Board Decision in the Matter of an Application by New Brunswick Power Corporation Pursuant to Subsection 103(1) of the *Electricity Act*, S.N.B. 2013, c.7, for approval of the schedules of the rates for the fiscal year commencing April 1, 2016, July 21, 2016, at 14. In NB Power's previous rate case, which was decided in 1993, the New Brunswick Energy and Utilities Board applied a "return on equity test," using the embedded cost of debt as an appropriate rate of return on NB Power's equity. Specifically, the New Brunswick Energy and Utilities Board evaluated whether the approved amount of net income for NB Power would exceed the amount required to satisfy the Board's return on equity test, interest coverage test, and debt to equity ratio test. *See*, New Brunswick Energy and Utilities Board Decision in the Matter of an Application by New Brunswick Power Corporation for Approval of Changes in its Charges, Rates and Tolls, April 23, 1993, at 8 and 45.

[2] Manitoba Hydro-Electric Board's ("Manitoba Hydro's") rates are not set based on traditional authorized cost of capital parameters. Manitoba Hydro sets rates based on the objectives of recovering its cost of service and achieving a target capital structure of 75/25 debt/equity. *See*, *e.g.*, Manitoba Public Utilities Board Order 90/08, June 30, 2008, at 17, and Manitoba Public Utilities Board Order 73/15, July 24, 2015, at 51..

[3] Saskatchewan Power's ("SaskPower's") rates are not set based on traditional authorized cost of capital parameters. SaskPower does, however, have a target debt level of 60-75% and a target ROE of 8.5%. Per SaskPower, "[i]n recent years, SaskPower has attempted to cap its rate increases at 5% per year. The result has been that the Corporation has absorbed some of the required rate adjustments through increased debt rather than passing costs on immediately to [its] customers. These constraints on rate inceases combined with SaskPower's capital program have resulted in SaskPower's debt level reaching the upper limit of [its] 60-75% target," and, "SaskPower's long-term ROE target is 8.5%..." SaskPower Rate Application 2016 and 2017, June 2, 2016, at 14.

[4] Equal to BC Hydro's "deemed equity" from its 2015 to 2016 revenue requirements application. *See*, BC Hydro F2015 to F2016 Revenue Requirements Rate Application (F15-F16 RRRA), March 7, 2014, Appendix C, at 40.

[5] British Columbia Utilities Commission, Order No. G-48-14 in the matter of the Utilities Commission Act, R.S.B.C. 1996, Chapter 473 and British Columbia Hydro and Power Authority Application Regarding its Rates for F2014, F2015 and F2016, Expenditures on Demand Side Measures in F2014, F2015 and F2016 and Retail Access, March 24, 2014, at 6. Note, in 2016 the Province of British Columbia changed the rate regulation of BC Hydro such that starting in fiscal 2018 the company will no longer earn a set ROE as part of its revenue requirement, but rather will have rates designed to earn a specific distributable surplus (*see*, Project No. 3698869, British Columbia Utilities Commission British Columbia Hydro and Power Authority Fiscal 2017 to Fiscal 2019 Revenue Requirements Application Evidentiary Update, August 17, 2016, at 1-15.)

d) S&P does not rate OPG and the Province of Ontario the same. S&P assigns an A+ rating to the Province of Ontario and a BBB+ rating to OPG (i.e., a three notch difference). In addition, S&P states that its stand-alone credit profile for OPG is BBB-.

New Brunswick Power, Manitoba Hydro Electric System, Saskatchewan Power and BC Hydro, in contrast, are either not separately rated from their Provinces (i.e., New Brunswick Power) or receive a "flow-through" of the Province's rating. The reason for this is each of those companies' debt obligations are either direct obligations of the Province or are wholly guaranteed by the Province. The following are excerpts from DBRS regarding each company's credit rating (except New Brunswick Power, which is not separately rated from the Province of New Brunswick):

- BC Hydro: "The ratings assigned to the Long- and Short-Term Obligations of BC Hydro are a flow-through of the ratings of the Province of British Columbia (the Province; rated AA (high) and R-1 (high) with Stable trends; see DBRS's report dated April 28, 2016). Pursuant to the B.C. Hydro and Power Authority Act, the Long- and Short-Term Obligations of BC Hydro are either direct obligations of, or are guaranteed by, the Province." (DBRS Rating Report, British Columbia Hydro and Power Authority, September 30, 2016, at 1.)
- Manitoba Hydro: "The ratings assigned to the Utility's Long-Term Obligations and Short-Term Obligations are a flow-through of the ratings of the Province of Manitoba (the Province; rated A (high) and R-1 (middle) with Stable trends by DBRS). Pursuant to The Manitoba Hydro Act, the Province unconditionally guarantees almost all of Manitoba Hydro's outstanding third-party debt." (DBRS Rating Report, The Manitoba Hydro-Electric Board, November 26, 2015, at 1.)
- Saskatchewan Power: "The ratings assigned to the Company's Long- and Short-Term Obligations are a flow-through of the ratings of the Province of Saskatchewan (the Province; rated AA and R-1 (high) with Stable trends by DBRS; see DBRS's report on the Province dated September 12, 2016). Pursuant to The Power Corporation Act (the Act), SaskPower does not issue debt directly in the capital markets, but obtains funding from the Government of Saskatchewan Ministry of Finance." (DBRS Rating Report, Saskatchewan Power Corporation, September 29, 2016, at 1.)

New Brunswick Power, Manitoba Hydro Electric System, Saskatchewan Power and BC Hydro are not a better reference point for OPG's capital structure because, as described above and in part (c) to this response, rates are set for those utilities on a different basis than they are set for OPG, and the risks for those utilities, as viewed by DBRS, are indistinguishable from their provinces. That is clearly not the case with OPG. In fact, those companies are rated by DBRS to be between three and six notches higher than OPG (or five to eight notches when OPG's stand-alone credit profile is considered). In contrast, the publicly-traded proxy companies analyzed by Concentric were screened to have risk characteristics similar to OPG, consistent with the fair return standard. In addition, precedent in Ontario and other Canadian provinces for considering U.S. data for

cost of capital evaluations is set out in Appendix A to Exhibit C1-1-1, Attachment 1. For those reasons, Concentric considers the proxy group to be a better reference point for OPG's capital structure.

In addition, it is important to note that New Brunswick Power, Manitoba Hydro Electric System and Saskatchewan Power are not authorized deemed equity ratios through the ratemaking process, but rather the capital structures referenced in the footnotes in response to VECC-9(c) represent target *actual* capital structures. OPG is significantly underleveraged relative to its deemed capital structure. Reflecting the actual capital structure in OPG's rates would result in an equity ratio of over 70%.[6]

e) Yes.

[6] Calculated by setting the portion of rate base financed by deemed debt in Ex. C1-1-1 Tables 1-5 to the sum of short-term debt (line 1) and existing/planned long-term debt (line 2).

TAB 12

AUS MONTHLY REPORT

AUGUST 2016

REPORT PAGES

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)

ELECTRIC COMPANIES

			PER SHARE DATA ($)				PERCENT (2)														% RETURN ON BOOK VALUE		REGULATION	
COMPANY	LATEST 12 MONTHS EARNINGS AVAILABLE	EARNINGS	CURRENT ANNUAL DIVIDEND	BOOK VALUE (1)	STOCK PRICE 7/15/2016	COMMON SHARES O/S MILL	DIV PAYOUT	DIV YIELD	MKT/ BOOK	DIV/ BOOK (2)	PRICE EARN MULT			TOTAL REV $MILL (1)	% REG ELEC REV	% REG GAS REV	NET PLANT $ MILL	NET PLANT PER$ REV (1)	S&P BOND RATING	MOODY'S BOND RATING	COMMON EQUITY RATIO (3)	COMMON EQUITY (4)	TOTAL CAPITAL	ALLOWED ROE	ORDER DATE
1 ALLETE, Inc. (NYSE-ALE)	3/16	2.99	2.08	37.52	63.74	49.3	70	3.3	169.9	5.5	21.3			1,500.2	65	3,642.3	2.43	A-	A3	54.1	8.1	6.5	10.64	1/1/2013
2 Ameren Electric Power Co. (NYSE-AEP)	3/16	3.91	2.24	36.90	69.64	491.2	57	3.2	188.7	6.1	17.8			16,032.9	81	46,832.9	2.92	BBB/BBB-	Baa1	46.3	10.9	6.6	10.12	10/3/2013
3 Edison International (NYSE-EIX)	3/16	3.01	1.92	35.11	77.18	325.8	64	2.5	219.8	5.5	25.6			11,452.0	100	35,323.0	3.08	BBB+	A2/A3	44.8	8.8	6.3	10.82	5/9/2013
4 El Paso Electric Company (NYSE-EE)	3/16	1.80	1.24	24.79	47.52	40.3	69	2.6	191.7	5.0	26.4			843.9	100	2,726.5	3.23	BBB	Baa1	42.3	7.4	6.0	11.25	12/8/2001
5 FirstEnergy Corporation (ASE-FE)	3/16	1.61	1.44	29.35	36.19	424.7	89	4.0	123.3	4.9	22.5			14,998.0	71	37,644.0	2.51	BBB	Baa2	35.8	5.5	5.2	10.45	3/2/2010
6 Great Plains Energy Incorporated (NYSE-GXP)	3/16	1.42	1.04	23.60	30.21	154.7	73	3.4	128.0	4.4	21.3			2,525.2	100	8,694.6	3.44	BBB	Baa2	47.2	6.1	5.5	9.50	7/1/2014
7 Hawaiian Electric Industries, Inc. (NYSE-HE)	3/16	1.49	1.24	18.00	32.48	107.9	83	3.8	180.4	6.9	21.8			2,516.1	89	4,423.6	1.76	BBB-	Baa2	48.8	8.4	6.2	9.67	5/31/2013
8 IDACORP, Inc. (NYSE-IDA)	3/16	3.91	2.04	40.81	80.49	50.4	52	2.5	197.2	5.0	20.6			1,271.8	100	4,009.7	3.15	A-	A3	52.4	9.8	7.4	NM	3/1/2012
9 Nextera Energy (NYSE-NEE)	3/16	5.98	3.48	49.70	24.94	461.0	58	14.0	50.2	7.0	4.2			17,216.0	66	62,894.0	3.65	A-/BBB+	A2/A3	40.9	12.7	7.8	10.50	1/1/2013
10 OGE Energy Corp. (NYSE-OGE)	3/16	1.27	1.12	16.52	32.06	199.7	88	3.5	194.1	6.8	25.2			2,149.9	100	7,387.5	3.44	BBB+	A3	53.9	7.7	6.6	9.98	6/17/2011
11 Otter Tail Corporation (NDQ-OTTR)	3/16	1.48	1.24	16.12	33.90	38.1	84	3.7	210.3	7.7	22.9			783.2	52	1,402.1	1.79	BBB-	Baa2	51.0	9.3	7.8	10.75	4/25/2011
12 Pinnacle West Capital Corp. (NYSE-PNW)	3/16	3.81	2.48	41.39	79.53	111.1	65	3.1	192.1	6.0	20.9			3,501.4	100	11,907.9	3.40	BBB	A3/Baa1	52.1	9.5	7.3	10.00	5/15/2012
13 PNM Resources, Inc. (NYSE-PNM)	3/16	0.15	0.88	20.59	34.26	79.7	NM	2.6	166.4	4.3	NM			1,417.2	100	4,746.7	3.35	BBB	Baa2	37.7	0.7	3.1	10.21	8/8/2011
14 Portland General Electric Company (NYSE-POR)	3/16	2.09	1.28	25.77	43.80	88.9	61	2.9	170.0	5.0	21.0			1,912.0	100	6,160.0	3.22	A-	A3	51.0	8.7	6.6	9.60	1/1/2016
15 PPL Corporation (NYSE-PPL)	3/16	2.26	1.52	14.43	37.15	676.4	67	4.1	257.4	10.5	16.4			7,450.0	60	29,832.0	4.00	A-	Baa1/Baa2	33.0	4.3	7.4	10.35	12/5/2012
16 Southern Company (NYSE-SO)	3/16	2.56	2.24	23.30	53.63	918.6	88	4.2	230.2	9.6	20.9			17,271.0	94	62,552.0	3.62	A	A3/Baa1	42.6	11.1	6.9	11.46	2/13/2013
17 Westar Energy, Inc. (NYSE-WR)	3/16	2.16	1.52	25.92	56.22	141.6	70	2.7	216.9	5.9	26.0			2,437.8	100	8,675.9	3.56	A-	A3/Baa1	50.2	8.8	6.7	10.15	3/1/2016
AVERAGE							71	3.9	181.6	6.2	20.9									46.1	8.1	6.5	10.34	

COMBINATION ELECTRIC & GAS COMPANIES

			PER SHARE DATA ($)				PERCENT (2)														% RETURN ON BOOK VALUE		REGULATION	
COMPANY	LATEST 12 MONTHS EARNINGS AVAILABLE	EARNINGS	CURRENT ANNUAL DIVIDEND	BOOK VALUE (1)	STOCK PRICE 7/15/2016	COMMON SHARES O/S MILL	DIV PAYOUT	DIV YIELD	MKT/ BOOK	DIV/ BOOK (2)	PRICE EARN MULT			TOTAL REV $MILL (1)	% REG ELEC REV	% REG GAS REV	NET PLANT $ MILL	NET PLANT PER$ REV (1)	S&P BOND RATING	MOODY'S BOND RATING	COMMON EQUITY RATIO (3)	COMMON EQUITY (4)	TOTAL CAPITAL	ALLOWED ROE	ORDER DATE
1 Alliant Energy Corporation (NYSE-LNT)	3/16	3.34	1.16	34.91	39.41	113.6	35	2.9	112.9	3.3	11.8			3,200.0	87	10	9,626.6	3.01	A-	A2/A3	48.3	9.7	7.2	10.31	6/6/2014
2 Ameren Corporation (NYSE-AEE)	3/16	2.53	1.72	28.31	52.51	242.6	68	3.3	185.5	6.1	20.8			5,976.0	86	19	19,000.0	3.18	BBB+/BBB	Baa1	47.0	9.3	6.6	9.42	12/1/2015
3 Avista Corporation (NYSE-AVA)	3/16	2.11	1.36	25.15	43.44	63.2	64	3.1	172.7	5.4	20.6			1,456.5	68	34	3,927.6	2.70	A-	Baa1	50.3	8.6	6.6	10.19	1/11/2016
4 Black Hills Corporation (NYSE-BKH)	3/16	-0.70	1.68	28.78	62.82	51.4	NM	2.7	218.3	5.8	NM			1,312.6	53	41	4,321.9	3.29	BBB	A3/Baa1	30.5	NM	1.8	10.60	1/1/2015
5 CenterPoint Energy (NYSE-CNP)	3/16	-1.55	1.04	8.14	24.06	430.6	NM	4.3	295.6	12.8	NM			6,937.0	41	37	11,718.0	1.69	A-/BBB+	A3/Baa1	29.3	NM	NM	9.96	4/18/2011
6 Chesapeake Utilities Corporation (NYSE-CPK)	3/16	2.63	1.24	24.45	66.67	15.3	47	1.9	272.7	5.1	25.3			435.5	17	54	881.2	2.02	NR	NR	53.1	11.7	8.1	10.46	11/1/2014
7 CMS Energy Corporation (NYSE-CMS)	3/16	1.75	1.24	14.72	44.82	279.2	71	2.8	304.5	8.4	25.6			6,146.0	69	27	14,907.0	2.43	BBB+/BBB	A3/Baa1	30.7	12.3	6.8	10.50	11/1/2015
8 Consolidated Edison, Inc. (NYSE-ED)	3/16	3.83	2.68	44.87	79.15	294.0	70	3.4	176.4	6.0	20.7			12,094.0	71	14	32,112.0	2.66	A-/BBB+	A3	48.2	8.7	6.8	9.70	4/20/2015
9 Dominion Resources, Inc. (NYSE-D)	3/16	3.18	2.80	21.57	77.53	597.0	88	3.6	359.4	13.0	24.4			11,195.0	64	1	42,623.0	3.81	A-	A3/Baa1	30.0	15.2	6.8	9.88	7/1/2015
10 DTE Energy Company (NYSE-DTE)	3/16	3.89	3.08	49.53	97.66	179.4	79	3.2	197.2	6.2	25.1			9,919.0	49	13	18,127.0	1.83	A-/BBB+	A2/A3	48.1	8.0	6.4	10.65	10/20/2011
11 Duke Energy Corporation (NYSE-DUK)	3/16	3.83	3.44	57.90	84.92	689.0	90	4.1	146.7	5.9	22.2			23,016.0	91	2	76,432.0	3.32	BBB+	A3	47.6	6.5	5.3	10.17	5/1/2013
12 Empire District Electric Co. (NYSE-EDE)	3/16	1.27	1.04	18.41	34.03	43.9	82	3.1	184.8	5.6	26.8			592.3	92	6	2,036.3	3.44	A-	Baa1	48.1	7.0	6.0	NM	8/19/2008
13 Entergy Corporation (NYSE-ETR)	3/16	-1.38	3.40	52.38	80.28	178.7	NM	4.2	153.3	6.5	NM			11,203.0	82	1	28,982.0	2.59	BBB+/BBB	Baa2/Baa3	37.8	NM	1.8	10.25	9/13/2012
14 Eversource Energy (NYSE-ES)	3/16	2.73	1.76	32.91	57.87	317.2	64	3.0	175.8	5.3	21.2			7,497.0	89	11	20,096.7	2.68	A-	A3/Baa1	50.4	8.5	6.1	9.32	6/12/2010
15 Exelon Corporation (NYSE-EXC)	3/16	1.75	1.28	29.21	36.49	887.0	73	3.5	124.9	4.4	20.9			28,189.0	39	4	69,406.0	2.46	BBB+/BBB	Baa1	41.1	7.1	4.9	9.53	12/10/2014
16 MDU Resources Group, Inc. (NYSE-MDU)	3/16	-1.50	0.76	12.12	24.13	195.3	NM	3.1	199.1	6.3	NM			4,234.4	7	20	4,334.7	1.02	BBB+	NR	52.8	NM	5.2	10.75	12/30/2013
17 MGE Energy, Inc. (NYSE-MGEE)	3/16	2.03	1.16	20.11	56.30	34.7	57	2.1	280.0	5.8	27.7			541.4	75	24	1,251.5	2.31	AA-	Aa2	64.1	10.3	8.4	10.30	7/26/2013
18 NiSource Inc. (NYSE-NI)	3/16	0.63	0.68	12.05	26.10	321.4	108	2.6	216.6	5.6	41.4			4,520.6	35	53	12,267.2	2.71	BBB-	Baa1/Baa2	35.6	3.8	4.6	10.61	2/28/2014
19 NorthWestern Corporation (NYSE-NWE)	3/16	2.87	2.00	31.08	61.23	52.0	70	3.3	197.0	6.4	21.3			1,200.8	79	21	4,069.1	3.39	NR	A3	45.2	8.8	6.6	10.00	12/1/2015
20 PG&E Corporation (NYSE-PCG)	3/16	1.94	1.96	33.52	64.62	495.6	101	3.0	192.8	5.8	33.3			16,908.0	81	18	48,044.0	2.84	BBB/BBB-	A3/Baa1	48.5	5.9	5.3	10.40	12/20/2012
21 Public Service Enterprise Group (NYSE-PEG)	3/16	3.08	1.64	26.37	45.87	505.0	53	3.6	173.9	6.2	14.9			9,896.0	44	20	27,274.0	2.76	A-/BBB+	A2	56.5	12.1	8.7	10.30	6/18/2010
22 SCANA Corporation (NYSE-SCG)	3/16	3.65	2.28	38.76	73.49	142.9	62	3.1	189.6	5.9	20.1			4,164.0	60	18	13,365.0	3.21	BBB+	Baa1/Baa2	44.5	9.6	7.1	10.49	10/15/2014
23 Unitil Corporation (ASE-UTL)	3/16	1.69	1.40	20.64	43.84	14.0	83	3.2	212.4	6.8	25.9			380.4	52	46	813.1	2.14	NR	NR	43.2	8.2	6.8	9.52	5/30/2014
24 Vectren Corporation (NYSE-VVC)	3/16	2.28	1.60	20.54	51.78	82.8	70	3.1	252.1	7.8	22.7			2,313.3	25	31	3,718.1	1.61	A/A-	A2	49.6	11.3	8.3	10.34	4/27/2011
25 Wisconsin Energy Corporation (NYSE-WEC)	3/16	2.58	2.00	28.03	63.96	315.6	78	3.1	228.2	7.1	24.8			6,733.0	64	25	19,259.0	2.86	A-/BBB+	A1/A2	46.9	11.8	8.1	9.93	1/21/2015
26 Xcel Energy Inc. (NYSE-XEL)	3/16	2.11	1.36	21.01	43.75	508.0	64	3.1	208.2	6.5	20.7			10,834.5	85	14	31,433.4	2.90	A-	A3	43.3	10.3	7.1	9.46	12/3/2015
AVERAGE							72	3.2	208.9	6.5	23.6									45.0	9.3	6.3	10.12	

NATURAL GAS DISTRIBUTION, TRANSMISSION AND INTEGRATED NATURAL GAS COMPANIES

			PER SHARE DATA ($)				PERCENT (2)														% RETURN ON BOOK VALUE		REGULATION	
COMPANY	LATEST 12 MONTHS EARNINGS AVAILABLE	EARNINGS	CURRENT ANNUAL DIVIDEND	BOOK VALUE (1)	STOCK PRICE 7/15/2016	COMMON SHARES O/S MILL	DIV PAYOUT	DIV YIELD	MKT/ BOOK	DIV/ BOOK (2)	PRICE EARN MULT			TOTAL REV $MILL (1)	% REG GAS REV	NET PLANT $ MILL	NET PLANT PER$ REV (1)	S&P BOND RATING	MOODY'S BOND RATING	COMMON EQUITY RATIO (3)	COMMON EQUITY (4)	TOTAL CAPITAL	ALLOWED ROE	ORDER DATE
1 Atmos Energy Corporation (NYSE-ATO)	3/16	3.16	1.68	32.72	80.06	102.2	53	2.1	244.7	5.1	25.3			3,381.8	71	7,839.4	2.32	A-	A2	52.0	10.0	7.2	9.81	9/9/2014
2 Delta Natural Gas Company (NDQ-DGAS)	3/16	0.73	0.80	11.11	26.40	7.1	110	3.0	237.6	7.2	36.2			65.2	63	137.8	2.11	NR	NR	60.2	6.7	5.9	10.40	10/1/2010
3 Gas Natural, Inc. (NDQ-EGAS)	3/16	0.24	0.32	9.35	7.18	10.5	133	4.5	76.8	3.4	29.9			96.9	91	140.7	1.45	NR	NR	63.0	2.5	1.8	12.63	NA
4 National Fuel Gas Company (NYSE-NFG)	3/16	-9.66	1.64	19.11	56.44	84.9	NM	2.9	295.3	8.6	NM			1,465.2	49	4,572.2	3.12	BBB	Baa1	43.8	NM	NM	9.50	12/12/2007
5 New Jersey Resources Corp. (NYSE-NJR)	3/16	1.36	0.96	14.05	37.65	86.0	71	2.5	268.0	6.8	27.7			1,915.2	31	2,242.7	1.17	A+	Aa2	54.5	10.1	6.9	10.30	10/1/2008
6 Northwest Natural Gas Co. (NYSE-NWN)	3/16	2.25	1.88	29.35	64.94	27.5	84	2.9	221.3	6.4	28.9			717.7	97	2,196.7	3.06	AA-	A1	51.5	7.8	6.5	9.80	11/1/2012
7 Piedmont Natural Gas Co., Inc. (NYSE-PNY)	4/16	1.70	1.36	19.11	59.88	81.2	80	2.3	313.3	7.1	35.2			1,151.0	91	4,535.4	3.94	A	A2	44.3	9.3	6.6	10.33	11/1/2015
8 Questar Corporation (NYSE-STR)	3/16	1.15	0.88	7.76	25.18	175.4	77	3.5	324.5	11.3	21.9			1,162.6	98	3,860.5	3.32	A/A-	A2	48.4	15.2	10.0	9.68	3/1/2015
9 RGC Resources, Inc. (NDQ-RGCO)	3/16	1.13	0.80	11.87	24.83	4.8	71	3.2	209.2	6.7	22.0			58.3	99	124.4	2.13	NR	NR	63.8	9.7	7.9	9.75	5/9/2014
10 South Jersey Industries, Inc. (NYSE-SJI)	3/16	1.73	1.04	15.35	31.35	71.2	60	3.3	204.2	6.8	18.1			909.7	50	2,478.2	2.72	A	A2	43.6	11.6	6.4	9.75	10/1/2014
11 Southwest Gas Corporation (NYSE-SWX)	3/16	2.97	1.80	34.81	78.08	47.5	61	2.3	224.3	5.2	26.3			2,460.7	58	3,929.0	1.60	A-	A3	53.5	8.8	6.9	9.75	6/12/2014
12 Spire, Inc. (NYSE-SR)	3/16	2.31	1.96	39.10	67.95	43.0	85	2.9	173.8	5.0	29.4			609.3	100	2,985.2	4.90	NR	NR	44.4	12.0	6.3	0.00	-
13 UGI Corporation (NYSE-UGI)	3/16	1.98	0.96	16.91	45.02	173.8	48	2.1	266.2	5.7	22.7			5,809.6	12	5,083.1	0.87	NR	A2	37.7	12.1	7.7	11.60	8/11/2011
14 WGL Holdings, Inc. (NYSE-WGL)	3/16	3.18	1.96	2.99	71.26	466.5	62	2.8	2,383.3	65.6	22.4			2,357.9	45	3,832.5	1.63	A+	A1	53.3	11.9	8.3	9.58	11/22/2013
AVERAGE							76	2.9	388.8	10.8	26.6									51.0	9.8	6.8	9.49	

WATER COMPANIES

			PER SHARE DATA ($)				PERCENT (2)														% RETURN ON BOOK VALUE		REGULATION	
COMPANY	LATEST 12 MONTHS EARNINGS AVAILABLE	EARNINGS	CURRENT ANNUAL DIVIDEND	BOOK VALUE (1)	STOCK PRICE 7/15/2016	COMMON SHARES O/S MILL	DIV PAYOUT	DIV YIELD	MKT/ BOOK	DIV/ BOOK (2)	PRICE EARN MULT			TOTAL REV $MILL (1)	% REG WATER REV	NET PLANT $ MILL	NET PLANT PER$ REV (1)	S&P BOND RATING	MOODY'S BOND RATING	COMMON EQUITY RATIO (3)	COMMON EQUITY (4)	TOTAL CAPITAL	ALLOWED ROE	ORDER DATE
1 American States Water Co. (NYSE-AWR)	3/16	1.56	0.88	12.79	43.42	36.6	56	2.0	339.5	6.9	27.8			451.2	72	1,079.3	2.39	A+	A2	56.2	12.1	9.7	9.43	1/1/2013
2 American Water Works Co., Inc. (NYSE-AWK)	3/16	2.65	1.52	28.01	81.59	181.4	57	1.9	291.3	5.4	30.8			3,204.3	86	14,098.0	4.40	A+/A	A3/Baa1	42.9	9.5	6.9	9.75	12/12/2012
3 Aqua America, Inc. (NYSE-WTR)	3/16	1.15	0.72	9.93	34.03	177.3	63	2.1	342.7	7.3	29.6			816.5	96	4,752.9	5.82	AA-	NR	49.4	11.9	8.2	9.79	5/2/2014
4 Artesian Resources Corp. (NDQ-ARTNA)	3/16	1.28	0.88	16.30	32.67	8.2	69	2.7	200.4	5.4	25.5			77.5	94	407.2	5.25	NR	NR	54.4	9.0	7.6	10.00	5/2/2014
5 California Water Service Group (NYSE-CWT)	3/16	0.89	0.68	13.19	33.01	48.0	76	2.1	250.3	5.2	37.1			588.1	99	1,739.7	2.96	AA-	NR	51.4	6.8	5.9	9.43	1/1/2013
6 Connecticut Water Service, Inc. (NDQ-CTWS)	3/16	2.04	1.12	20.20	51.98	11.2	55	2.2	257.3	5.5	25.5			102.9	96	554.5	5.39	A/A-	NR	52.6	10.4	7.2	9.63	3/25/2014
7 Middlesex Water Company (NDQ-MSEX)	3/16	1.28	0.80	12.86	41.58	16.2	63	1.9	323.3	6.2	32.5			127.8	87	486.5	3.81	A	NR	59.6	10.3	7.5	9.75	8/19/2014
8 SJW Corporation (NYSE-SJW)	3/16	1.77	0.80	18.81	39.34	20.4	45	2.0	209.1	4.3	22.2			304.1	103	1,042.5	3.43	A	NR	47.8	9.8	7.5	9.43	1/1/2013
9 York Water Company (NDQ-YORW)	3/16	0.96	0.64	8.59	31.26	12.8	67	2.0	363.9	7.5	32.6			47.2	100	261.9	5.55	A-	NR	56.6	11.5	9.1	NM	2/28/2014
AVERAGE							61	2.1	286.4	6.0	29.3									52.3	10.2	7.7	9.65	

TAB 13

August 2016 AUS Utility Report – Equity Ratio Comparisons

	Coyne 2013	AUS 2016
Consolidated Edison, Inc. (NYSE-ED)	52	48.2
Nextera Energy (NYSE-NEE)	39	40.9
Eversource Energy (NYSE-ES)	43	50.4
Southern Company (NYSE-SO)	47	42.6
Wisconsin Energy Corporation (NYSE-WEC)	43	46.9
Xcel Energy Inc. (NYSE-XEL)	46	43.3
Average	45	45.4

North East Utilities rebranded itself Eversource in February 2015
Mr. Coyne's page 161 has the debt ratio rather than the equity ratio

	Common Equity Ratios	
	Coyne P39	AUS
ALLETE, Inc. (NYSE-ALE)	54.29	54.1
American Electric Power Co. (NYSE-AEP)	50.87	46.3
Edison International (NYSE-EIX)	48	44.8
El Paso Electric Company (NYSE-EE)		42.3
FirstEnergy Corporation (ASE-FE)	49.22	35.8
Great Plains Energy Incorporated (NYSE-GXP)	51.04	47.2
IDACORP, Inc. (NYSE-IDA)	49.9	52.4
Nextera Energy (NYSE-NEE)		40.9
Pinnacle West Capital Corp. (NYSE-PNW)	53.94	52.1
PNM Resources, Inc. (NYSE-PNM)	45	37.7
Portland General Electric Company (NYSE-POR)	50	51.0
Southern Company (NYSE-SO)	49.09	42.6
Westar Energy, Inc. (NYSE-WR)	50.13	50.2
Ameren Corporation (NYSE-AEE)	50.87	47.0
Duke Energy Corporation (NYSE-DUK)	50.14	47.6
Entergy Corporation (NYSE-ETR)	46.27	37.8
PG&E Corporation (NYSE-PCG)	52	48.5
Xcel Energy Inc. (NYSE-XEL)	53.89	43.3
Average	**50.29**	**45.6**
Median	**50.14**	**46.7**

TAB 14

Ontario Energy Board
Commission de l'énergie de l'Ontario

OEB Staff Report

EB-2009-0084

Review of the Cost of Capital for Ontario's Regulated Utilities

January 14, 2016

Appendix A: Review of Ontario Utilities (2010-2014)

In addition to reviewing the updated parameters over the 2010-2014 period, OEB staff also reviewed the actual results achieved by the rate regulated utilities.[8] To ensure comparability between utilities and what was approved in cost of service applications, the reviews were based on the deemed capital structure. The results are presented in Appendix A.

Natural Gas Distributors

Natural Gas Distributors have generally achieved returns above the OEB-issued ROE in most years. The earnings sharing mechanisms in the IRM plans of Union Gas and Enbridge have acted to limit overearnings. It is worth noting that, with exception of NRG in 2011, and Enbridge and Union Gas in 2013, natural gas distributors were either under IRM or had no rate changes. For the most part, their ability to achieve and exceed the allowed ROE was independent of the new cost of capital methodology.

Electricity Transmitters

With the exception of one small transmitter (Niagara West Transformation Corporation), Ontario's three electricity transmitters were able to achieve ROEs on a deemed capital structure basis above the allowed ROE for 2013 and 2014. The achieved ROEs on a deemed capital structure basis indicate that these utilities are generally able to meet or exceed a market-based rate of return.

Ontario Power Generation

Ontario Power Generation (OPG) has had payment amounts for prescribed generation assets subject to OEB oversight since 2008. A review of OPG's ROE results, as filed and updated in 2015 for the period 2010-2014, is anomalous in OEB staff's view.

The ROE results in 2010-2012 show achieved ROEs in the high 4% to low 5% range, significantly lower than the approved ROEs. The achieved ROE is 0.46% for 2013 and 6.31% for 2014. OPG rebased its rates for 2011-2012, and again for 2014-2015, but

[8] Due to changes in reporting requirements, consistent data is not available for all years. For electricity transmitters, reporting to the OEB only commenced in 2013.

TAB 15

VECC Interrogatory #6

Issue Number: 3.1
Issue: Are OPG's proposed capital structure and rate of return on equity appropriate?

Interrogatory:

Reference: Exhibit M3 Equity Ratios

Please review the Concentric document published by the Canadian Gas Association May 27, 2016 titled Authorized Return on Equity for Canadian and U.S. Gas and Electric Utilities, a copy of which is attached. The following conclusion appears on the first page:

> **EQUITY RATIOS**
> The median authorized common equity ratio has declined slightly over the past few years in both Canada and the U.S. The gas distribution ratio is now 39.25% in Canada, vs. 50% in the U.S. The median electric distribution equity ratio is now 40% in Canada, and 50% in the U.S.1 Electric transmission equity ratios remain at 36% in Canada.
> The differences between allowed equity ratios in Canada and the U.S. seem attributable to a few factors. Regulators in both countries rely on peer group analysis, which reinforces prevailing levels of allowed equity ratios. Regulators also look for material differences in risk or financial metrics before changing the allowed equity ratio, so they tend to remain relatively stable. While credit rating agencies notice the greater leverage of Canadian companies, and rank some of these utility companies as "Aggressive" in terms of financial risk, most companies have been able to maintain A or A- level credit ratings, so the regulatory response has been muted.

b) Would Dr. Villadsen agree or disagree with Concentric's assessment?

Response:

The following response was provided by The Brattle Group:

a) [Sub-question does not appear in request]

b) Dr. Villadsen is not certain which part of the statement she is asked to agree or disagree with. However, she agrees with the factual statement on allowed **median** equity ratios and that most companies are in the A to A- range. As for the reasons that equity ratios differ, she agrees that regulators tend to maintain relatively stable equity

ratios and use peer analysis so that changes tend to occur slowly. Certainly, some regulators view the ability to maintain an A to A- credit rating as important, but Dr. Villadsen has not studied all jurisdictions and cannot speak to the reasons why regulators in jurisdictions she is not familiar with have maintained the equity ratios they have. Dr. Villadsen further notes that while many Canadian regulators deem an equity ratio, many U.S. regulators use the regulated entity's actual book capital structure.