Board Staff Interrogatory #013

Ref: Exh A1-2-2 page 1

Issue Number: 3.1
Issue: What is the appropriate capital structure and rate of return on equity for the currently regulated facilities and newly regulated facilities?

Interrogatory

On page 1, one of the approvals that OPG is seeking is stated as:

> Approval of a deemed capital structure of 53 per cent debt and 47 per cent equity and a combined rate of return on rate base to be determined using data available for the three months prior to the effective date of the payment amounts order, in accordance with the Board's Cost of Capital Report, and currently forecast at 8.98 per cent for 2014 and 2015, as presented in Ex. C1-1-1.

Please confirm that the 8.98% refers to the return on equity ("ROE") as issued by the Board in its letter of February 14, 2013 for rates effective May 1, 2013, and not the "combined rate of return" as stated above. In the alternative, please document the basis for OPG's requested approval.

Response

Confirmed.

Board Staff Interrogatory #014

Ref: Exh C1-1-1 page 1

Issue Number: 3.1
Issue: What is the appropriate capital structure and rate of return on equity for the currently regulated facilities and newly regulated facilities?

Interrogatory

At the bottom of page 1, OPG states:

> OPG is not proposing any changes to its capital structure as there have been no significant changes in the risks faced by OPG's **regulated** asset portfolio that are not otherwise addressed by proposals to establish new variance and/or deferral accounts as described in Ex. H1-3-1. **[Emphasis added]**

Board staff notes that a key aspect of OPG's application is a significant change to OPG's "regulated asset portfolio" through the addition of "newly regulated hydroelectric" facilities, per O.Reg. 312/03,

Please confirm that OPG is of the view that the newly regulated hydroelectric facilities have similar business risks to the existing prescribed nuclear and hydroelectric generation assets. If yes, please provide OPG's reasons for this view.

Response

OPG believes that the business risks associated with the newly regulated hydroelectric assets are lower than the existing nuclear generation assets. This view is consistent with that of the OEB which found in OPG's previous application that "business risks associated with the nuclear business are higher than those of the regulated hydroelectric business[1]". In addition, OPG believes that the business risks associated with the newly regulated hydroelectric assets are higher than the previously regulated hydroelectric assets, as described below. In providing these views, OPG has assumed that its proposal to extend the existing deferral and variance accounts to the newly regulated hydroelectric assets is accepted.

The number of facilities and dams (48 and 175 for the newly regulated versus 6 and 27 for the previously regulated) compared to their production (2014 forecast of 12.4 TWh for the newly regulated versus 20.1 TWh for the previously regulated), their geographic distribution and remoteness of many of the facilities, along with the variability of production associated with inland rivers, combine to contribute to the operational risk of the newly regulated plants. Additionally, owing to the geographic location of the units, the newly regulated units have greater exposure to First Nations' risks than the previously regulated units.

[1] EB-2010-0008 Decision With Reasons, Page 116

Extending the application of the currently approved Hydroelectric Water Conditions Variance Account and the Surplus Baseload Generation ("SBG") Variance Account to include 21 of the 48 newly regulated hydroelectric units addresses some of the higher risk of the newly regulated hydroelectric assets.

Board Staff Interrogatory #015

Ref: Exh C1-1-1 page 2

Issue Number: 3.1
Issue: What is the appropriate capital structure and rate of return on equity for the currently regulated facilities and newly regulated facilities?

Interrogatory

In the application filed on September 27, 2013, OPG proposed that the ROE be updated based on Consensus Forecasts [and other Statistics Canada/Bank of Canada and Bloomberg LLP] data for three months prior to the effective date of the payment rates order, in accordance with the Cost of Capital Report and with the Decisions in its previous payment order EB-2010-0008.

On November 21, 2013, the Board issued the *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379), in which the Board stated that the Cost of Capital parameters would normally be updated once a year.[1] This was repeated in the letter issued November 25, 2013 announcing the Cost of Capital parameters effective for cost of service rates applications effective January 1, 2014.

a) In light of the Board's process to calculate the Cost of Capital parameters only once annually, does OPG intend to change its proposal and adopt the 2014 ROE as announced in the Board's letter of November 25, 2013?
b) If OPG proposes an alternative, including updating the ROE based on data three months prior to the effective date of the payments order, please provide OPG's rationale for doing so, and why it does not consider the 2014 Cost of Capital parameters issued by the Board on November 25, 2013 to be suitable for setting its 2014-2015 payments.

Response

a) No, OPG is not planning on changing its proposal in the Application as OPG is using the cost of capital methodology approved by the Board in its last payments amounts application. This methodology is described at Ex. C1-1-1 page 2, lines 19-29.

   For 2014, OPG is proposing to use data three months prior to the effective date of the payment amounts order, proposed to be January 1, 2014, from the Bank of Canada, *Consensus Forecasts*, and Bloomberg LLP. For 2015, OPG is proposing that the ROE be set at the same time as the first year but using data from Global Insight because *Consensus Forecasts* data is only projected for 12 months and thus would not cover 2015.

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[1] *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379), November 21, 201, page 10

b) In OPG's last payment amounts application (EB-2010-0008), the issue of whether one ROE should be set for both years of OPG's application was specifically addressed by the Board. SEC argued that the ROE for the two years should be set "at the same level, an approach that is consistent with that used under IRM[2]". This is the regulatory approach used to set rates for electricity distributors in the report identified by Board Staff. However, the OEB found that it was "…appropriate to set separate ROEs for each year of the test period. The issue is what data should be used for establishing the 2012 ROE.[3]" OPG's proposal for setting its ROE for 2015 is in accordance with the approach approved by the OEB. No alternative to the Board-approved methodology for OPG is being proposed in this Application.

[2] EB-2010-0008, Decision With Reasons, Page 121
[3] EB-2010-0008, Decision With Reasons, Page 122

Board Staff Interrogatory #016

Ref: Exh C1-1-1 page 2

Issue Number: 3.1
Issue: What is the appropriate capital structure and rate of return on equity for the currently regulated facilities and newly regulated facilities?

Interrogatory

At the bottom of page 2, OPG states:

> For the second year of that test period (2015), the ROE will be set at the same time as the first year but using data from Global Insight instead of the *Consensus Forecasts* used by the OEB because the *Consensus Forecasts* data is only projected for 12 months.

This is the same approach as OPG had proposed, and the Board had approved, in OPG's prior payments application.

a) Has OPG investigated sources other than Global Insights for economic forecasts that extend beyond the one-year horizon provided by *Consensus Forecasts*? If so, which ones (e.g. Conference Board of Canada)? If not, why not?

b) The Board's use of *Consensus Forecasts* is derived, in part, on that publication's use of multiple economic forecasting sources and the use of mean/median/consensus results from the pool of forecasters surveyed. Doing so may reduce the forecasting error or bias of a single forecaster and hence may have a greater likelihood of being close to the future actuality. Please explain why OPG is relying solely on Global Insights for the forecast beyond the first test year.

Response

a) OPG has not investigated other sources of economic forecasts. Use of Global Insights is consistent with the ROE methodology approved by the Board in OPG's last payment amounts application. OPG has used Global Insights economic forecasts for many years, and has not identified a business need to investigate other sources of economic forecasts.

b) OPG is relying on Global Insights for 2015 because it wanted to continue with the methodology approved by the Board in the last payment amounts proceeding.

CME Interrogatory #006

Ref: Exhibit AI-2-2 page 1 and Board Staff IR 3.1-Staff-13

Issue Number: 3.1
What is the appropriate capital structure and rate of return on equity for the currently regulated facilities and newly regulated facilities?

Interrogatory

Board Staff has asked OPG to confirm that the 8.98 percent referred to on page 1 of this Exhibit refers to the return on equity ("ROE") as issued by the Board in its letter of February 14, 2013 for rates effective May 1, 2013 and not the "combined rate of return".

CME wishes the following additional information:

(a) If the 8.98 percent refers to the ROE as issued by the Board, then please set out the ROE that the "combined rate of return" would produce; and

(b) If the 8.98 percent refers to the ROE produced by the "combined rate of return", then please provide the ROE calculated in accordance with the Board's letter of February 14, 2013 instead of the "combined rate of return".

Response

a) As confirmed in Ex L-3.1-1 Staff 13, the 8.98 per cent refers to the ROE issued by the OEB in its letter of February 14, 2013.

b) The combined rate of return is the overall return on rate base. The return on rate base is comprised of the return on equity and the return on debt in proportion to the OEB's approved capital structure (47 per cent common equity, 53 per cent debt). The rate of return on common equity is 8.98 per ent. The combined rate of return on rate base is 6.77 per cent and 6.79 per cent in 2014 and 2015, respectively, as shown in Ex C1-1-1, Table 1, line 6 (2015) and Table 2 line 6 (2014).

SEC Interrogatory #024

Ref: A1-2-2/p.1

Issue Number: 3.1
Issue: What is the appropriate capital structure and rate of return on equity for the currently regulated facilities and newly regulated facilities?

Interrogatory

Please provide all evidence available to the Applicant to show that the 53% debt, 47% equity deemed capital structure continues to be reflective of the Applicant's business risks after the addition to the regulated business of the previously unregulated hydroelectric facilities.

Response

Foster Associates Inc. was engaged by OPG to provide an analysis of, and expert opinion on, whether the currently approved deemed capital structure continues to be an appropriate basis for setting OPG's payment amounts after the completion of the Niagara Tunnel Project and the inclusion of the additional hydroelectric facilities in OPG's regulated rate base. The analysis is Attachment 1.

Report to Ontario Power Generation

Common Equity Ratio for OPG's Regulated Generation

Foster Associates, Inc.

December 2013

I. INTRODUCTION AND CONCLUSIONS

A. INTRODUCTION

In September 2013, Ontario Power Generation ("OPG") filed an application for regulated payments for its prescribed hydroelectric and nuclear generating facilities for test years 2014 and 2015. The prescribed assets include the Niagara Tunnel Project ("NTP") which was completed and placed in service in March 2013. They also include 48 additional hydroelectric generation facilities that are to be regulated effective July 2014 under an expanded Ontario Regulation 53/05. OPG's request for regulated payments includes the application of the cost of capital parameters approved by the Ontario Energy Board ("OEB" or "the Board") in *Decision EB-2008-2010*.[1]

Foster Associates Inc. was engaged by OPG to provide an analysis of and expert opinion on whether the OEB's application of the cost of capital adopted in *Decision EB-2010-0008* continues to be an appropriate basis for setting OPG's regulated hydroelectric and nuclear payments as a result of the completion of the NTP and the inclusion of the additional hydroelectric facilities in OPG's regulated rate base. The results of the analysis and the expert opinion are contained in this report. The qualifications of Ms. Kathleen McShane, the principal author of the report, are attached as Appendix A.

[1] OEB, *In The Matter Of An Application By Ontario Power Generation Inc., Payment Amounts For Prescribed Facilities For 2011 and 2012, Decision With Reasons*, EB-2010-0008, May 11, 2011 (decision hereafter referred to as "*Decision EB-2010-0008*").

B. CONCLUSIONS

Based on the analysis conducted, OPG's deemed common equity should, at a minimum, remain at 47%, based on the following:

1. The business risks specific to OPG's regulated hydroelectric generation operations, including the newly regulated facilities, are somewhat higher than when the Board issued *Decision 2010-0008*, due largely to the higher operating risks of the newly regulated facilities.

2. The fundamental business risks of the nuclear generation operations have not changed materially. The operating leverage has continued to rise as anticipated, leading to higher potential volatility in earnings for the nuclear generation operations. All other things equal, a thicker equity component would be required to dampen the volatility.

3. The lower end of a reasonable range of equity ratios for the regulated hydroelectric generation operations, including the newly regulated generation, consistent with their relative business risks and the fair return standard is, conservatively, 45%. As such, a 47% common equity ratio for OPG's combined hydroelectric and nuclear operations, given the latter's higher operating risks and increased operating leverage, remains reasonable even with the higher proportion of regulated hydroelectric generation rate base during the test period.

4. The Darlington Refurbishment, due to its size, will reverse the relative proportions of the test period hydroelectric and nuclear generation rate base. Capital structure decisions reflect longer-term, not test period, business risks. As the Darlington Refurbishment investment is more than double the combined rate base additions from the NTP and newly regulated hydro facilities, maintaining the approved 47% common equity ratio is, a conservative approach that OPG should revisit once a decision on the Darlington refurbishment has been reached.

5. The Darlington Refurbishment will require significant capital investment, including approximately $1.5 billion during the test period. With no additional cash flows to service the corresponding debt financing, credit metrics will be weaker, putting downward pressure on debt ratings. At a minimum, OPG's allowed common equity ratio should remain at the previously approved 47% to avoid further weakening of credit metrics.

6. The Board is committed to the implementation of incentive regulation for both the regulated hydroelectric and nuclear operations. Although the specifics of the plans have yet to be developed, the characteristics of incentive regulation expose regulated companies to higher risk than cost of service regulation. The higher business risk of the regulated operations under incentive regulation provides support for, at a minimum, maintaining the approved 47% common equity ratio.

II. BACKGROUND

In EB-2007-0905, the OEB undertook its first review of the cost of capital for OPG's regulated hydroelectric and nuclear operations. With respect to capital structure, "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."[2] Based on its assessment of OPG's absolute and relative risks, the OEB adopted a deemed common equity ratio of 47% for the regulated nuclear and hydroelectric operations. The OEB also decided that it would, in the next regulated payments application, examine whether to set separate capital structures for the regulated hydroelectric and nuclear businesses. In *Decision EB-2007-0905*, the Board indicated that it expected that the same ROE would be applicable to both regulated hydroelectric and nuclear generation, consistent with the approach

[2] OEB, *In The Matter Of An Application By Ontario Power Generation Inc., Payment Amounts For Prescribed Facilities, Decision With Reasons*, EB-2007-0905, November 3, 2008, page 136 (decision hereafter referred to as "*Decision EB-2007-0905*").

of setting a benchmark ROE and recognizing business risk differences among utilities in the capital structure.

In *Decision EB-2010-0008*, the Board confirmed utilization of a single common equity ratio for the combined regulated operations, in large part because it found that there was no methodology presented which allowed robust technology-specific estimates to be derived with sufficient precision. While recognizing that the nuclear generation operations were riskier than the regulated hydroelectric operations, the Board also recognized that (1) the weighted average equity ratio had to be the 47% adopted in *Decision EB-2007-0905*; and (2) the equity ratio for each of the two technologies had to be consistent with its relative business risks, i.e., the equity ratio for the regulated hydroelectric operations could not be less than the 40% adopted for electricity transmission and distribution utilities. These two constraints placed the potential technology-specific common equity ratios within a very narrow band.

The Board further expressed concern that, with separate equity ratios, over time, the interaction between the individual equity ratios and the combined equity ratio would create an issue. Specifically, as the relative size of the hydroelectric and nuclear businesses changes, the issue will arise as to whether the overall equity ratio is to remain unchanged or whether the technology-specific equity ratios are to remain unchanged. The Board found:

> "If the overall level of 47% is to remain unchanged, then this could result in ongoing variability in the technology specific levels, which may not be desirable. Likewise, if the technology specific ratios are to remain unchanged, it might result in changes to the overall ratio that are not warranted. The Board concludes that introducing this level of variability and complexity would not be appropriate."[3]

[3] *Decision EB-2010-0008*, page 117.

III. OEB'S CAPITAL STRUCTURE POLICY

In *Decision EB-2010-0008*, the Board followed the capital structure policy described in its *Cost of Capital Report*.[4] The same policy has been applied for the purpose of this analysis.

In its *Cost of Capital Report*, the Board concluded that its capital structure policy, initially set out in its 1997 Draft Guidelines,[5] continued to be appropriate. The policy considers that (1) capital structure for electricity transmitters, electricity generators and natural gas utilities should be determined on a case-by-case basis; (2) the base capital structure will remain relatively constant over time; and (3) a full reassessment of capital structure should be undertaken only in the event of significant changes in the company's business and/or financial risk. In the absence of a significant change in risk, the Board considers that the Fair Return Standard has been met at the utility's existing allowed capital structure and allowed ROE whose determination for all Ontario utilities is prescribed in the *Cost of Capital Report*. Only if there has been a significant change in the business and/or financial risk will the Board conduct a full analysis based on the principles of the Fair Return Standard to determine the appropriate equity ratio.[6]

Further, in determining whether there has been a significant change, the Board will focus on changes since the last time it reviewed the utility's capital structure.[7] For OPG, the Board last reviewed the business risks and common equity ratio in EB-2010-0008, concluding in *Decision EB-2010-0008* (page 116) that "The Board finds 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".

[4] OEB, *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, EB-2009-0084, December 11, 2009 (decision hereafter referred to as "*Cost of Capital Report*").
[5] OEB, *Compendium to Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities, March 1997*, page 2.
[6] *EGD Decision on Equity Ratio*, page 5.
[7] *EGD Decision on Equity Ratio*, page 7.

IV. FAIR RETURN STANDARD

The fair return standard governs the assessment of the reasonableness of OPG's common equity ratio. The standards for a fair return arise from legal precedents which are echoed in numerous regulatory decisions across North America, including the OEB's *Cost of Capital Report.*[8] The *Cost of Capital Report*, citing the National Energy Board, states:

> A fair or reasonable return on capital should:
>
> - be comparable to the return available from the application of 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).[9]

As the OEB recognized in its *Cost of Capital Report*, the fair return reflects the aggregate return on capital, which incorporates the capital structure of the utility and cost rates for each element of the capital structure. With respect to equity, as the OEB stated in its most recent cost of capital determination for Enbridge Gas Distribution:

> The Cost of Capital Report indicates that the Board makes determinations on two elements in establishing the equity component of the cost of capital:
>
> 1) The deemed return on equity ("ROE"). This is a single rate of return set by the Board periodically for all utilities, considering overall market conditions; and
> 2) The deemed equity ratio, which is set by the Board for each utility individually, considering the circumstances of that particular utility.[10]

[8] The principal seminal court cases in Canada and the U.S. establishing the standards include *Northwestern Utilities Ltd.* v. *Edmonton (City)*, [1929] S.C.R. 186; *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia,(262 U.S. 679, 692 (1923))*; and, *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591 (1944))*. Each of these was cited in the *Cost of Capital Report*.

[9] National Energy Board, *Reasons for Decision, TransCanada PipeLines Limited, RH-2-2004 Phase 2, Cost of Capital*, April 2005.

[10] OEB, *In the Matter of an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2013, Decision on Equity Ratio and Order, EB-2011-0354*, February 7, 2013, page 3 (hereafter referred to as "*EGD Decision on Equity Ratio*").

V. STAND-ALONE PRINCIPLE

The continued reasonableness of OPG's 47% common equity ratio has been assessed pursuant to the stand-alone principle. Under the stand-alone principle:

> a utility is regulated as if the provision of the regulated service were the only activity in which the company was engaged. The cost of providing utility service and rates for provision of that service are to reflect only the expenses, capital costs, risks and required returns associated with the provision of regulated service (National Energy Board, *Reasons for Decision, TransCanada PipeLines Limited, RH-R-1-2002, Review of RH-4-2001 Cost of Capital Decision*, February 2003, page 25).

The stand-alone principle encompasses the notion that the cost of capital incurred by a utility should be equivalent to that which would be faced if it was raising capital in the public markets on the strength of its own business and financial parameters; in other words, as if it were operating as an independent entity. The cost of capital for the company should reflect neither subsidies given to, nor taken from, other activities of the firm. Respect for the stand-alone principle is intended to promote efficient allocation of capital resources among the various activities of the firm. Adherence to the stand-alone principle ensures that the focus of the determination of a fair return is on the use of capital, i.e., their opportunity cost, not the source of the capital. The opportunity cost of capital reflects the return that could be earned if that capital were invested in an alternative venture of similar risk.

The stand-alone principle, a cornerstone of Canadian utility regulation with a history dating to at least 1978,[11] has been respected by virtually every Canadian regulator, including the OEB, in setting both regulated capital structures and allowed rates of returns on equity.

As regards OPG specifically, the OEB determined in its first decision setting regulated payments for OPG's prescribed assets that it should not consider the identity of the shareholder, the Province of Ontario, and its ability to direct the activities of OPG as either a source of higher or

[11] Public Utilities Board of Alberta, *In the Matter of The Alberta Gas Trunk Line Company Act*, Decision C78221, December 21, 1978, pages 19-27.

lower risk. "In other words, Provincial ownership will not be a factor to be considered by the Board in establishing capital structure."[12]

VI. RISK AND CAPITAL STRUCTURE

The cost of capital to a firm is determined by the firm's risk. Risk is a prospective concept. From a layman's perspective, risk is the possibility of suffering harm, or loss. The financial economics definition of risk is based on the notion that (1) the outcome of an investment decision is uncertain; i.e., there are various possible outcomes; (2) probabilities of those outcomes can be ascertained; and (3) the financial consequences of the outcomes can be measured. In other words, the probability that investors' future returns will fall short of their expected returns is measurable. However, as both the National Energy Board[13] and the Alberta Energy and Utilities Board (predecessor to the Alberta Utilities Commission) have recognized, the assessment of business risk is qualitative and subjective.[14] The qualitative or subjective nature of business risk reflects, in part, that the uncertainty of future outcomes does not lend itself easily to an objective assignment of probabilities.

Business risk comprises the fundamental characteristics of the business and the political/regulatory operating environment that together determine the probability that future returns (including the return on and of the capital invested) to investors will fall short of their expected and required returns. Business risk thus relates largely to the assets of the firm.

While there is no universal agreement whether a single optimal capital structure for a firm exists, there is widespread agreement that, as a general proposition, companies with lower business risk can safely assume more debt than those with higher business risk without impairing their ability

[12] *Decision EB-2007-0905*, page 142.
[13] National Energy Board, *Reasons for Decision, Cost of Capital, RH-2-94*, March 1995, page 24. "The Board has systematically assessed the various risk factors for each of the pipelines but has not found it possible to express, in any quantitative fashion, specific scores or weights to be given to risk factors. The determination of business risk, in our view, must necessarily involve a high degree of judgement, and the analysis is best expressed qualitatively."
[14] Alberta Energy and Utilities Board, *Generic Cost of Capital, Decision 2004-052*, July 2004, page 35. "In the Board's view, setting an appropriate equity ratio is a subjective exercise that involves the assessment of several factors and the observation of past experience. The assessment of the level of business risk of the utilities is also a subjective concept. Consequently, the Board considers that there is no single accepted mathematical way to make a determination of equity ratio based on a given level of business risk."

to access the capital markets on reasonable terms and conditions. In principle, higher business risk can be "offset" by assuming less financial risk. Thus, two regulated firms with different levels of business risk can face similar costs of debt and equity if the firm facing higher business risk maintains a lower debt ratio than the firm facing lower business risk. That premise is reflected in the OEB's cost of capital policy which, as noted above, sets a single ROE for all utilities and uses capital structure as the "adjusting variable" to recognize differences in business risks among the companies that it regulates.

Business risks have both short-term and longer-term aspects. The capital structure and fair rate of return on equity compensate for both short-term and long-term risks. Long-term risks are important because regulated assets are long-lived. The capital structure in particular needs to compensate for longer-term risks, as the financing of a regulated firm is premised on the longer-term risks as perceived by investors when committing capital to the enterprise. When business risks materialize, the regulated firm may find it more difficult to raise new debt capital. Consequently, the common equity component effectively provides a cushion in the event of deterioration of access to capital. Because regulated firms are generally regulated on the basis of annual revenue requirements, where utilities regularly reset their rates based on updated costs and are allowed to use deferral accounts, there has been a tendency to downplay longer-term risks. The rationale is frequently that, if the long-term risk crystallizes or materializes, the regulator will be able to either compensate the shareholder for the longer-term risk at that time through a higher return or provide another means to protect the shareholder, e.g., accelerated capital recovery. This premise may not hold. First, due to competition with alternatives, the utility may not be able to charge rates that would allow it to recover the higher return or its invested capital.[15] Second, no regulator can bind his successors and thus guarantee that investors will be compensated for longer-term risks when they are incurred in the future.

[15] The circumstances of the TransCanada Mainline are illustrative. Historically, TransCanada was viewed as among the lowest risk regulated entities in Canada. In recent years, with the shale gas revolution, the pipeline has increasingly experienced excess capacity, as shippers have had alternatives to Western Canadian natural gas. In order for the Mainline to recover its prudently incurred costs at the lower volumes, its tolls continually increased, raising the spectre of a "death spiral". Ultimately a restructuring of its services was required. In the NEB's *Reasons for Decision, TransCanada PipeLines Limited, NOVA Gas Transmission Ltd., and Foothills Pipe Lines Ltd., RH-003-2011*, March 2013, TransCanada was awarded an 11.5% ROE (in conjunction with a five-year restructuring of tolls) to compensate for the increased business risk, including the risk that competitive market conditions might ultimately prevent TransCanada from fully recovering the capital investment in the Mainline.

VII. TRENDS IN BUSINESS RISK OF OPG'S REGULATED OPERATIONS

A. CHANGED CIRCUMSTANCES SINCE *DECISION EB-2010-0008*

At the time of *Decision EB-2010-0008*, in which the Board had found that there had been no material change in business risks since EB-2007-0905 and confirmed the previously approved 47% common equity ratio:

1. The approved test period (2012) rate base was comprised of approximately 50% hydroelectric assets and 50% nuclear assets. Because the rate base financed by the OEB approved capital structure removes the Asset Retirement Costs (ARC), the rate base financed by the hypothetical capital structure containing 47% common equity was allocated 61.5% to the regulated hydroelectric rate base and 38.5% to the nuclear rate base (*EB-2010-0008 Payment Amounts Order*, Appendix A, Table 1A).

2. The Niagara Tunnel Project, on which construction began in 2006, was expected to be placed in service in 2013.

3. OPG had announced its intention to proceed with the refurbishment of the Darlington nuclear generation station, expecting to commence construction by 2016, at an estimated cost of \$6 to \$10 billion (2009\$). The Board noted in *Decision EB-2010-0008* that the project was larger than the 2012 nuclear generation rate base of approximately \$4 billion, which was comprised of \$2.4 billion financed by the capital structure and \$1.5 billion of ARC (*EB-2010-0008 Payment Amounts Order*, Appendix A, Table 1A).

4. The Board had declined to allow the inclusion of Construction Work in Progress related to the Darlington Refurbishment in rate base.

5. The passage of the Green Energy and Green Economy Act, which created a Feed-in Tariff program designed to attract investment in renewable energy projects, combined with lower market demand, had raised the potential that OPG would experience surplus baseload generation ("SBG"). In *Decision EB-2010-0008*, the Board directed OPG to create a variance account to capture the impacts of SBG (Hydroelectric Surplus Baseload Generation Variance Account, or SBG Variance Account), rather than forecast its occurrence.

The following changes since *Decision EB-2010-0008* impact OPG's business and financial risk:

1. The scope of Ontario Regulation 53/05 is expected to be expanded, so that all of OPG's hydroelectric generating plants that are not governed by contracts with the Ontario Power Authority will be regulated by the OEB. The 48 newly regulated hydroelectric plants, with an aggregate capacity of approximately 3100 MW, will add approximately $2.5 billion to OPG's regulated rate base.

2. The Niagara Tunnel Project has been placed into service. OPG's current application is requesting an addition to the 2014 rate base of $1.4 billion related to the NTP. The NTP increases the diversion capacity of the existing Sir Adam Beck (SAB) diversion facilities by approximately 500 m^3 per second, increasing the average annual energy production at the SAB generating complex by 1.5 TWh.

3. The definition phase of the Darlington Refurbishment Project has continued. OPG received a decision in early 2013 from the Canadian Nuclear Safety Commission which agreed that the project will not result in any significant adverse environmental effects. In October 2013, the Minister of Energy of Ontario announced that the province would go ahead with the refurbishment of the Darlington nuclear station as part of its revised long-term energy plan, expected to be released before the end of 2013. The Darlington Refurbishment

will require significant capital investment, including approximately $1.5 billion during the test period.

4. In March 2013, the Board issued the *Report of the Board: Incentive Rate-making for Ontario Power Generation's Prescribed Generation Assets, EB-2012-0340* ("*Incentive Rate-making Report*"), in which it reconfirmed its commitment to move to incentive rate-making methodologies for both OPG's hydroelectric and nuclear prescribed assets, with policies for both technologies expected to be issued by the Board in the relatively near term. As discussed below, incentive regulation points to higher risk than the existing cost of service framework.

B. TRENDS IN BUSINESS RISKS OF THE REGULATED HYDROELECTRIC GENERATION OPERATIONS

The combined additions to OPG's rate base from the NTP and the newly regulated hydroelectric units will double OPG's hydroelectric rate base between 2012 and 2014. Approximately 60% of the increase is related to the newly regulated hydroelectric units. The newly regulated hydroelectric units are largely peaking units, individually smaller in scale than the previously regulated units, and widely geographically dispersed. With the significantly larger number of stations and dams than the previously regulated units (48 and 175 versus 6 and 27) compared to their production (2014 forecast 12.4 TWh versus 20.1 TWh), the newly regulated units are subject to relatively higher operating risk than the previously regulated plants. The number of structures and dams, their geographic dispersal and remoteness of many facilities, along with variability of production associated with inland rivers, combine to contribute to the relatively higher operational risk of the newly regulated plants. Additionally, owing to the geographic location of the units, the newly regulated units have greater exposure to First Nations risks than the previously regulated units. The latter are governed by signed agreements; the former are still subject to outstanding past grievances which OPG is working to resolve.

The electricity production of the newly regulated units, largely located on inland rivers, is more variable than that of the previously regulated hydroelectric generation units. OPG is applying in its 2014-2015 regulated payments application to extend the operation of the Hydroelectric Water

Conditions Variance Account that currently applies to the previously regulated plants to include 21 of the 48 newly regulated hydroelectric units. The operation of this account will act to mitigate the cost recovery risks related to a substantial portion of the newly regulated hydroelectric generation facilities.[16] In the absence of the Hydroelectric Water Conditions Variance Account, the risk of those newly regulated hydroelectric generation facilities would be higher.

OPG is also requesting that the Board continue the SBG variance account adopted in *Decision EB-2010-0008* and to extend it to the same 21 of the newly regulated hydroelectric generating plants. Similar to the Hydroelectric Water Conditions Variance Account, if the SBG Variance Account were not available to those newly regulated hydroelectric units, their risk would be higher. The fact that not all of the newly regulated hydroelectric generating plants are covered by the two variance accounts also marginally increases the risk of the regulated hydroelectric operations relative to EB-2010-0008.

With respect to the NTP, it increases the diversion capacity from about 1,800 m^3/s to 2,300 m^3/s. As a result, the addition of the NTP results in available flow being over diversion capacity approximately 15 percent of the time, down from approximately 65% prior to the NTP. While the NTP reduces spill generally, it increases the potential for SBG. At low demand levels, OPG will incur more SBG with additional NTP diversion capacity. There is no increased risk as the continuation of the SBG Variance Account addresses the increased dispatch risk that OPG would otherwise be exposed to as a result of the addition of the NTP diversion capacity.

Further, in the 2014-2015 regulated payments proceeding, OPG is seeking to add the NTP to rate base, as a result of which the incurred costs will be scrutinized for prudency. From an investor perspective, given the relatively large size of the project, i.e., close to 30% of 2014 previously

[16] Twenty-seven of the smaller plants (which account for only 2% of total hydroelectric production) would be excluded from the Hydroelectric Water Conditions Variance Account as OPG does not have computer models to forecast production from these units.

regulated hydroelectric rate base and 15% of total (net of ARC) rate base, the risk of a material cost disallowance is higher than at the time of EB-2010-0008.[17]

On balance, even with the inclusion of 21 of 48 newly regulated hydroelectric facilities in the Hydroelectric Water Conditions Variance Account and the SBG Variance Account, the risks specific to OPG's regulated hydroelectric operations, including the newly regulated facilities, are somewhat higher than when the Board issued *Decision 2010-0008*.

C. TRENDS IN BUSINESS RISKS OF THE REGULATED NUCLEAR GENERATION OPERATIONS

With respect to OPG's regulated nuclear generation operations, there have been no material changes in the market environment, the regulated price setting model or the operating risks since *Decision EB-2010-0008*. The operating leverage has increased since EB-2010-0008 as expected, due to the reduction in the return on equity dollars as a proportion of the revenue requirement with the ongoing depreciation of the nuclear generation rate base. All else equal, lower than forecast nuclear generation revenues or higher than forecast nuclear operating expenses will have a larger negative impact on ROE currently than at the time of EB-2010-0008. The higher operating leverage indicates higher earnings volatility, and, again, all else equal, a higher equity component to dampen the otherwise increased earnings volatility.

In addition, since *Decision EB-2010-0008*, the funded nuclear liabilities as a percent of the prescribed nuclear assets have continued to grow. In 2008, funded nuclear liabilities related to the prescribed nuclear assets were approximately 300% of the associated nuclear generation rate base (net of ARC). By 2015, they are expected to be more than 450% of the nuclear rate base. The higher the proportion of funded nuclear liabilities to nuclear rate base is, the greater the

[17] The potential for cost disallowances, particularly as related to large scale projects such as the NTP, highlights the asymmetrical risk that is inherent in rate regulation: Under rate base/rate of return regulation, rates are generally set to ensure that utilities neither materially over-earn (i.e., the upside opportunities are limited) nor under-earn (downside risk is limited) their allowed returns. With the risk of disallowed investment, the risk becomes skewed to the downside, i.e., there is a greater probability of not earning the allowed return than overearning the allowed return. The downside skewness is not accounted for in the cost of capital, which reflects an expected return, where the expected return comprises a normal distribution of outcomes, i.e., the potential outcomes are symmetrically distributed around an average value.

dependence of the nuclear operations on the fund earnings. The fund earnings, in turn, reflect the volatility of the capital markets.

D. MINIMUM EQUITY RATIO AND FAIR RETURN STANDARD

As had been indicated in EB-2010-0008 in discussing why technology-specific capital structures were not warranted, the bottom end of the range of common equity ratios for the regulated hydroelectric generation operations consistent with their relative risks and the fair return standard was 45%.[18] Specifically, the 45% minimum reflects the higher risks of hydroelectric generation compared to electricity transmission and distribution utility operations, whose allowed common equity ratio in Ontario is 40%.[19] Because, as noted above, the newly regulated hydroelectric generation facilities are exposed to somewhat higher operating risk than the previously regulated hydroelectric generation facilities, the previously identified 45% minimum equity ratio for hydroelectric generation operations should be viewed as conservative. In that context, all other things being equal, a two percentage point higher common equity ratio for OPG's combined hydroelectric and nuclear operations, given the latter's higher risks, remains reasonable even with the higher proportion of regulated hydroelectric generation operations. The higher operating leverage of the nuclear operations during the test period compared to EB-2010-0008 provides further support for that conclusion.

[18] EB-2010-0008, Cross-examination of Kathleen McShane, Tr. Vol. 11, p. 33.

[19] The higher risk of hydroelectric generation compared to electricity transmission and distribution was recognized by DBRS in the context of FortisBC Inc., a vertically integrated utility, whose owned generation assets are 100% hydroelectric. In its most recent report for FortisBC, DBRS stated: "FortisBC generates virtually all of its earnings from its integrated and regulated transmission, distribution and generation operations. Risks associated with the regulated electricity generating assets (which tends to be higher risk than transmission and distribution) are manageable, given that the hydro facilities are low cost, emission free and have no exposure to hydrology risk." (DBRS, *Rating Report: FortisBC Inc*., March 25, 2013)

E. NUCLEAR GENERATION RATE BASE OVER THE LONG TERM

With the Darlington Refurbishment, the increased proportion of hydroelectric assets forecast for the test period will not persist over the longer term. As noted earlier, as of *Decision EB-2010-0008*, the estimated cost was in the range of $6 to $10 billion (2009$), more than double the combined rate base additions from the NTP and newly regulated hydroelectric facilities. As of OPG's 2014-2015 regulated payments application, the estimated cost is still within that range. Thus, the Darlington Refurbishment will mean a shift to a higher proportion of nuclear than hydroelectric generation assets in the rate base. Since capital structure decisions are made with a longer-term, not a test period, perspective, maintaining the approved 47% common equity ratio is a conservative approach that OPG should revisit once a decision on Darlington refurbishment has been reached.

F. INCENTIVE REGULATION AND RISK

The Board's commitment to implement incentive regulation for OPG's prescribed facilities points to higher risk than the existing cost of service framework for both the hydroelectric and nuclear operations. Although the specifics of the plans are not known, the most likely outcome for the regulated hydroelectric operations, based on the *Incentive Rate-making Report* in EB-2012-0340, is a price cap approach. For the nuclear operations, the approach that may be taken is less certain, as a result of the unique circumstances of the nuclear operations, (e.g., as indicated in the *Incentive Rate-making Report*, years of high capital investment and potential reductions in capacity). The *Incentive Rate-making Report* suggests that the unique circumstances of the nuclear operations may be best addressed by a price cap with incremental targeted incentives. Although the specifics of either plan are unknown, there are a number of characteristics of incentive regulation that expose utilities to higher risk than cost of service regulation.

1. Under cost of service regulation utilities typically have had rates set for a relatively short period of time. Under price cap style incentive regulation plans, rates are typically constrained by the rate of inflation net of the productivity factor

offsets for an extended period. Under a cost of service model, if costs increase faster than revenues, the negative impacts on earnings are limited to the test period. Under an incentive regulation plan, the negative impact on earnings can extend over the full term of the plan, which is frequently up to five years.

2. Under cost of service regulation, a utility's revenue requirement is set to allow recovery of the utility's own costs. Under the price cap plans, prices are to a large extent decoupled from the utility's own costs, which raises the uncertainty of cost recovery relative to a cost of service environment. The ability to flow through certain recurring costs (deferral or variance accounts) or seek approval for recovery of exogenous event related costs can mitigate the risk, but does not reduce it to the cost of service model level.

3. With price cap regulation which incorporates productivity offsets, a utility must achieve productivity gains in excess of the specified productivity factor in order to earn its allowed return. Continuing to achieve productivity gains becomes more difficult over time.

The conclusion that PBR exposes utilities to higher risk than cost of service regulation is shared by DBRS. In its May 2012 report, *Assessing Regulatory Risk in the Utilities Sector*, DBRS stated that it views cost of service as lower risk than incentive regulation. That conclusion was reiterated in its *Industry Study, Regulatory Framework for Utilities: Canada vs. the United States, A Rating Agency Perspective*, October 2013. On the criterion of cost of service versus incentive rate mechanism, DBRS rates Ontario "Very Good", a step down from the "Excellent" rating that it affords cost of service regulation.[20]

For OPG specifically, the DBRS rating on that criterion could be lower, as the methodology will likely be untested as applied to regulated generation.[21] In that context, S&P's commentary on the impact of the newly introduced performance-based regulation on the Alberta distribution

[20] In the Industry Study, DBRS evaluated regulatory risk in Canadian provinces and U.S. states according to ten criteria, for which it has five rating categories, Excellent, Very Good, Satisfactory, Below Average and Poor.
[21] For Alberta, which is just initiating performance-based regulation, DBRS has assigned a rating of "Satisfactory".

utilities is germane. S&P "believes that performance-based regulation (PBR) will heighten regulatory risk during its roll-out and over the initial five-year period and could make it more challenging for utilities to continue to earn the allowed generic return on equity (currently set at 8.75%)". Although S&P concluded that regulatory risk may diminish as the Alberta Utilities Commission ("AUC") establishes precedents reducing uncertainty, it also concluded that capital spending and the implementation of the capital tracker within the PBR formula will remain a key area of risk.[22]

With respect to the impact of performance-based regulation on cost of capital, there have been several studies that have concluded that the cost of capital is higher under performance-based regulation than under cost of service regulation. Fernando Camacho and Flavio Menezes "The Impact of Price Regulation on the Cost of Capital", *Annals of Public and Cooperative Economics*, Vol. 84, No. 2, 2013, pages 139-158 briefly summarize the related literature, stating "A more direct test of the impact of the type of regulation on the cost of capital is the subject of a larger literature… Two basic results have emerged from this literature. First, a regulated firm's cost of capital under PC [price cap] regulation depends on the level of the price cap, and a tightening of the regulatory contract increases this cost. Second, the firm's cost of capital under PC regulation is higher than under COS regulation".

One of the studies cited was an empirical study by Ian Alexander, Colin Mayer and Helen Weeds, *Regulatory Structure and Risk: An International Comparison*, prepared for PSD/PPI, World Bank, January 30, 1996. That study, a cross-country study of differences in costs of capital resulting from different types of regulatory regimes, concluded that the difference in asset (business risk) betas between energy utilities operating under cost of service or rate of return regulation (a "low powered" regulatory regime) and price cap or revenue cap regulation ("high powered" regulatory regimes) was close to 0.40, translating into a material difference in the cost of equity. As indicated above, the specifics of incentive regulation as it will apply to either the hydroelectric or nuclear assets have not yet been established. Nevertheless, as the discussion in

[22] The capital trackers are intended to provide a mechanism within the PBR framework for the distributors to recover their capital costs during a period of relatively high capital expenditures. S&P, *Credit FAQ: How The Alberta Utilities Commission's Rate Regulation Initiative Will Affect Alberta Utilities' Credit Quality*, November 30, 2012.

the *Incentive Rate-making Report* indicates that the methodologies for both technologies are likely to have features of price cap regulation (as do the incentive rate-making plans applicable to the Ontario electric and gas distribution utilities), it is reasonable to conclude, based on the study, that the cost of capital for OPG will be higher under incentive regulation, all other things equal, than under cost of service regulation. That conclusion supports, at a minimum, maintaining OPG's existing 47% deemed equity ratio.

VIII. TRENDS IN FINANCIAL RISK OF OPG'S REGULATED OPERATIONS

As noted earlier, as the OEB recognized in its *Cost of Capital Report*, the fair return reflects the aggregate return on capital, including both the capital structure and ROE. The capital structure plays a key role in assuring that the two requirements of the fair return standard, access to capital on reasonable terms and conditions and maintenance of financial integrity are achieved and maintained.

OPG has begun to undertake significant capital expenditures related to the Darlington Refurbishment. In the 2014-2015 regulated payments application, OPG is forecasting capital expenditures of $765 million and $738 million in 2014 and 2015 respectively, which would bring total refurbishment capital expenditures to approximately $2.4 billion by the end of the test period. To put the approximately $2.4 billion of capital expenditures into perspective, it is equivalent to over 20% of the forecast 2015 total rate base. These capital expenditures must be financed, but will not produce any cash flow until the project is complete and put into rate base. Further, as the OEB's policy is to allow construction work in progress to attract a debt cost, rather than a weighted average cost of capital, implicitly the project is financed with 100% debt until complete. As the refurbishment progresses, the percentage of regulated assets that are producing no cash flow will increase. With no cash flow to support the financing, the capital structure assets that are in rate base needs to support the financing of the construction work in progress.

In the absence of additional cash flow to service the additional financing costs, credit metrics weaken, which puts pressure on debt ratings. This is particularly true when, as in the case of OPG, the project is not only large, but expected to extend over many years, and subject to the risk that all costs incurred may not be recoverable.[23] While debt rating agencies are likely to accommodate some weakening of credit metrics during a period of large capital expenditures, they will downgrade utilities if the credit metrics breach levels viewed to be bare minimums for the ratings.[24]

The AUC has recognized the importance of maintaining strong investment grade credit ratings throughout a "big build" cycle. For the Alberta electricity transmission facility owners which are undertaking major, extended term capital projects, AltaLink and ATCO Electric, the AUC has provided several forms of credit support, including strengthening the allowed common equity ratio, adopting a two percentage point increase during the "big build" cycle.[25]

The AUC explained the issues succinctly:

> 798. Moreover, the Commission considers that the downgrade cannot be characterized simply as a matter of cost. The Commission has considered the UCA's evidence that BBB rated companies are able to issue debt. However, the Commission finds that although that may be true, as a BBB category issuer, a utility may face more significant challenges in accessing debt markets, particularly at a time of adverse market conditions. A list of individual debt transactions provided by AltaLink shows that during the period June 11, 2008 to January 29, 2009, companies with credit rating outside of an A category were not able to issue long-term debt on any terms in the public Canadian debt market. (footnote omitted)

[23] S&P noted in its February 2013 credit report for OPG that the nuclear segment is highly susceptible to cost overruns, which, in their view, heightens regulatory risk.

[24] For example, in the case of AltaLink LP, which is in the midst of constructing and financing large additions to its electricity transmission system, Standard & Poor's has indicated that a downgrade could result if they forecast a funds from operations-to-debt (FFO/Debt) ratio below the 10% threshold that they associate with AltaLink's A-rating. (Standard & Poor's, RatingsDirect, *AltaLink LP*, June 19, 2013)

[25] The other forms of credit support are allowing construction work in progress in the rate base and the collection of future income taxes rather than only income taxes payable, both of which provide additional cash flows to service the incremental financing. The two percentage point increase for the TFOs engaged in major construction projects was in addition to the two percentage point across-the-board increase for the Alberta utilities that the AUC initially adopted in *Generic Cost of Capital Decision 2009-216* (December 2009) and confirmed in *Generic Cost of Capital Decision 2011-474* (November 2011). The allowed increase was partly related to maintaining credit metrics consistent with the AUC's target rating in the A category.

> 799. Finally, the Commission has also considered the risk associated with attempting to reverse a credit metric downgrade, and, based on the evidence provided by AltaLink, and in particular, noting the recent experience of Nova Scotia Power, the Commission considers that it would be difficult to reverse a downgrade even if the Commission took steps to assist AltaLink in restoring its credit metrics after the downgrade.
>
> 800. Consequently, the Commission finds that it is in the public interest to avoid a downgrade from AltaLink's current A- credit rating. The Commission is persuaded that the potential adverse consequences and risk of a downgrade require the Commission to address the potential for a downgrade in this decision.[26]

OPG's regulated operations do not have a separate debt rating; only the consolidated company is rated. Nevertheless, given their growing predominance, due both to the coal plant closures and the change in regulatory status of the newly regulated hydroelectric generation facilities, the regulated operations are the principal determinant of the consolidated company's bond rating. At the time of S&P's most recent credit report, OPG's regulated operations comprised over 75% of the Company's consolidated Earnings before Interest, Taxes, Depreciation and Amortization (EBITDA).[27] S&P rates the consolidated company A-, reflecting its view of the company's stand-alone (i.e., in the absence of provincial government support) credit profile and its assessment that there is a high likelihood that the province as shareholder would provide timely and sufficient extraordinary support in the event of financial distress. As far as the stand-alone credit profile, S&P assigns OPG a BBB- rating. With over three-quarters of OPG's EBITDA attributable to regulated operations, it is reasonable to infer that, if "OPG Regulated" were separately rated, its stand-alone (i.e., in the absence of provincial government support) credit profile would most likely be in the mid-BBB range, two notches below the median A- rating assigned by S&P to Canadian utilities (See Schedule 1).

[26] Alberta Utilities Commission, *AltaLink Management Ltd., 2011-2013 General Tariff Application, Decision 2011-473*, November 18, 2011. The reference to addressing the potential for a downgrade refers to additional credit metric support that might be warranted, e.g., ability to collect future income taxes, construction work in progress in rate base.
[27] S&P, *Ontario Power Generation Inc.*, February 8, 2013. With the newly regulated hydroelectric generation assets added to the prescribed assets, virtually all of OPG's operations will be either regulated by the OEB or under long-term contract with the Ontario Power Authority.

For perspective, OPG's average 2010-2012 FFO/Debt ratio for the regulated operations only calculated using S&P's analytic methodology[28] was 10.2%. The FFO/Debt ratio[29] is considered one of the most critical credit metrics by the rating agencies. Moody's calls it the single most predictive financial measure.[30] The median FFO/Debt ratios for all Canadian electric and gas utilities with rated debt[31] and all investor-owned Canadian electric and gas utilities with rated debt over the same period were 15.4% and 14% respectively (See attached Schedule 1). Not only are the ratios materially stronger than OPG's, they are for utilities that, on average, face lower business risk than OPG's regulated operations. OPG's higher business risk but weaker financial metrics for its regulated operations imply that that they would be assigned lower stand-alone credit ratings than the actual credit ratings assigned, on average, to other Canadian utilities.[32]

Attached Schedule 1 also provides a comparison of two other widely used credit metrics, Earnings before Interest and Taxes (EBIT) Interest Coverage ratios[33] and Funds from Operations (FFO) Interest Coverage ratios.[34] The comparison shows that, despite a higher allowed common equity ratio than average for Canadian electric and gas utilities, OPG's credit metrics have been weaker. OPG's EBIT Interest Coverage ratio for its regulated operations averaged 1.8X from 2010-2012, much lower than the 2.4X for all Canadian electric and gas utilities and all investor-owned Canadian electric and gas utilities with rated debt. Similarly, OPG's FFO Interest Coverage ratio, at an average of 2.8X, was materially weaker than the 3.6X and 3.5X achieved by all and investor-owned Canadian electric and gas utilities with rated debt.

[28]The rating agencies adjust reported values from utilities' financial statements to produce a more economically meaningful assessment of the companies' financial position than accounting values might indicate. S&P adjusts OPG's reported debt and equity balances, for example, for pension and OPEB obligations and its reported interest expense for pension and OPEB expense.
[29] Funds from Operations (FFO) are equal to net income plus non-cash items, largely depreciation and amortization and deferred income taxes. The FFO to Debt ratio is equal to FFO divided by total debt.
[30] Moody's, *Request for Comment: Proposed Refinements to the Regulated Utilities Rating Methodology and our Evolving View of US Utility Regulation*, September 23, 2013, page 3.
[31] Includes provincially and municipally owned utilities whose debt is not guaranteed by the shareholder.
[32] S&P's February 2013 rating report for OPG cites its significant financial risk as one of its weaknesses, to which low allowed returns are one of the main contributors.
[33] EBIT Interest Coverage is equal to earnings before interest and income taxes divided by interest.
[34] FFO Interest Coverage is equal to FFO plus interest divided by interest.

In isolation, the increase in the regulated hydroelectric generation rate base and the associated cash flows would strengthen the credit metrics of the regulated operations. However, the magnitude of the capital expenditures required for the Darlington Refurbishment project with no corresponding cash flows will more than offset any improvement. Any reduction in OPG's regulated common equity ratio would exacerbate the deterioration in credit metrics and put pressure on the debt rating. This consideration provides further support for, at a minimum, maintaining OPG's existing deemed 47% common equity ratio.

IX. CONCLUSIONS

With the expansion of the scope of Ontario Regulation 53/05 to regulate 48 additional hydroelectric units and the addition of the NTP to rate base, for the 2014-2015 test period, hydroelectric generation assets will comprise two-thirds of OPG's rate base (three-quarters financed by the deemed 47% equity), compared to approximately 50% (slightly more than 60% financed by the deemed equity) as of *Decision EB-2010-0008*. In light of the widely accepted recognition[35] that hydroelectric generation is less risky than nuclear generation, it is reasonable to consider whether that shift should lead to a change in OPG's regulated capital structure.

In so doing, the concern noted by the Board in *Decision EB-2010-0008* in rejecting technology-specific capital structures is also germane in this context. That concern, referenced earlier, was that technology-specific equity ratios could introduce a change in OPG's overall ratio that is not warranted. Similarly, a change to OPG's overall equity ratio may not be warranted solely as a result of a higher proportion of hydroelectric than nuclear rate base during the test period.

The analysis conducted supports, at a minimum, maintaining OPG's deemed common equity at 47%, based on the following:

1. The business risks specific to OPG's regulated hydroelectric generation operations, including the newly regulated facilities, are somewhat higher than

[35] OEB, *Decision EB-2010-0008*, page 116.

when the Board issued *Decision 2010-0008*, due largely to the higher operating risks of the newly regulated facilities.

2. The fundamental business risks of the nuclear generation operations have not changed materially. The operating leverage has continued to rise as anticipated, leading to higher potential volatility in earnings for the nuclear generation operations. All other things equal, a thicker equity component would be required to dampen the volatility.

3. The lower end of a reasonable range of equity ratios for the regulated hydroelectric generation operations, including the newly regulated generation, consistent with their relative business risks and the fair return standard is, conservatively, 45%. As such, a 47% common equity ratio for OPG's combined hydroelectric and nuclear operations, given the latter's higher operating risks and increased operating leverage, remains reasonable even with the higher proportion of regulated hydroelectric generation rate base during the test period.

4. The Darlington Refurbishment, due to its size, will reverse the relative proportions of the test period hydroelectric and nuclear generation rate base. Capital structure decisions reflect longer-term, not test period, business risks. As the Darlington Refurbishment investment is more than double the combined rate base additions from the NTP and newly regulated hydro facilities, maintaining the approved 47% common equity ratio is a conservative approach that OPG should revisit once a decision on the Darlington refurbishment has been reached.

5. The Darlington Refurbishment will require significant capital investment, including approximately $1.5 billion during the test period. With no additional cash flows to service the corresponding debt financing, credit metrics will be weaker, putting downward pressure on debt ratings. At a minimum, OPG's allowed common equity ratio should remain at the previously approved 47% to avoid further weakening of credit metrics.

6. The Board is committed to the implementation of incentive regulation for both the regulated hydroelectric and nuclear operations. Although the specifics of the incentive regulation plans have yet to be developed, the characteristics of incentive regulation expose regulated companies to higher risk than cost of service regulation. The higher business risk of the regulated operations under incentive regulation provides support for, at a minimum, maintaining the approved 47% common equity ratio.

APPENDIX A
QUALIFICATIONS OF KATHLEEN C. MCSHANE

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 200 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian electric utilities, gas distributors and pipelines, and telephone companies. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, financial performance measures, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, stand-alone cost of debt, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service.

She has also conducted seminars on cost of capital and related regulatory issues for public utilities, with focus on the Canadian regulatory arena.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

PUBLICATIONS, PAPERS AND PRESENTATIONS:

- *Utility Cost of Capital: Canada vs. U.S.*, presented at the CAMPUT Conference, May 2003.
- *The Effects of Unbundling on a Utility's Risk Profile and Rate of Return*, (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.
- *Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?* presented at the 24th Annual Rate Symposium, Kansas City, Missouri, sponsored by several commissions and universities, April 1998.
- *Incentive Regulation: An Alternative to Assessing LDC Performance*, (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.
- *Alternative Regulatory Incentive Mechanisms*, (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.
- "The Fair Return", (co-authored with Michael Cleland), *Energy Law and Policy*, Gordon Kaiser and Bob Heggie, eds., Toronto: Carswell Legal Publications, 2011.

EXPERT TESTIMONY/OPINIONS

ON

RATE OF RETURN AND CAPITAL STRUCTURE

Alberta Natural Gas
1994

Alberta Utilities
Generic Cost of Capital
2011

AltaGas Utilities
2000

Ameren (Central Illinois Public Service)
2000, 2002, 2005, 2007 (2 cases),
2009 (2 cases)

Ameren (Central Illinois Light Company)
2005, 2007 (2 cases), 2009 (2 cases)

Ameren (Illinois Power)
2004, 2005, 2007 (2 cases), 2009 (2 cases)

Ameren (Union Electric)
2000 (2 cases), 2002 (2 cases), 2003,
2006 (2 cases)

ATCO and AltaGas Utilities
Generic Cost of Capital, Alberta
2003

ATCO Electric
1989, 1991, 1993, 1995
1998, 1999, 2000, 2003

ATCO Gas
2000, 2003, 2007

ATCO Pipelines
2000, 2003, 2007, 2011

ATCO Utilities
Generic Cost of Capital
2008

Bell Canada
1987, 1993

Benchmark Utility Cost of Capital
(British Columbia)
1994, 1999, 2012

Canadian Western Natural Gas
1989, 1996, 1998, 1999

Centra Gas B.C.
1992, 1995, 1996, 2002

Centra Gas Ontario
1990, 1991, 1993, 1994, 1995

Direct Energy Regulated Services
2005

Dow Pool A Joint Venture
1992

Electricity Distributors Association
2009

Enbridge Gas Distribution
1988, 1989, 1991, 1992, 1993, 1994
1995, 1996, 1997, 2001, 2002

Enbridge Gas New Brunswick
2000, 2010

Enbridge Pipelines (Line 9)
2007, 2009

Enbridge Pipelines (Southern Lights)
2007

EPCOR Water Services Inc.
1994, 2000, 2006, 2008, 2011

FortisBC Inc.
1995, 1999, 2001, 2004, 2013

FortisBC Energy Inc.
1992, 2005, 2009, 2011, 2013

FortisBC Energy (Whistler) Inc.
2008, 2013

Gas Company of Hawaii
2000, 2008

Gaz Métro
1988

Gazifère
1993-1998, 2010

Heritage Gas
2004, 2008, 2011

Hydro One
1999, 2001, 2006 (2 cases)

Insurance Bureau of Canada (Newfoundland)
2004

Laclede Gas Company
1998, 1999, 2001, 2002, 2005

Laclede Pipeline
2006

Mackenzie Valley Pipeline
2005

Maritime Electric
2010

Maritime Link
2013

Maritimes NRG (Nova Scotia and New Brunswick)
1999

MidAmerican Energy Company
2009

Multi-Pipeline Cost of Capital Hearing (National Energy Board)
1994

Natural Resource Gas
1994, 1997, 2006, 2010

New Brunswick Power Distribution
2005

Newfoundland & Labrador Hydro
2001, 2003

Newfoundland Power
1998, 2002, 2007, 2009, 2012 (2 cases)

Newfoundland Telephone
1992

Northland Utilities
2008 (2 cases)

Northwestel, Inc.
2000, 2006

Northwestern Utilities
1987, 1990

Northwest Territories Power Corp.
1990, 1992, 1993, 1995, 2001, 2006

Nova Scotia Power Inc.
2001, 2002, 2005
2008, 2011, 2012

Ontario Power Generation
2007, 2010

Ozark Gas Transmission
2000

Pacific Northern Gas
1990, 1991, 1994, 1997
1999, 2001, 2005, 2009, 2013

Plateau Pipe Line Ltd.
2007

Platte Pipeline Co.
2002

St. Lawrence Gas
1997, 2002

Southern Union Gas
1990, 1991, 1993

Stentor
1997

Tecumseh Gas Storage
1989, 1990

Telus Québec
2001

TransCanada PipeLines
1988, 1989, 1991 (2 cases), 1992, 1993

TransGas and SaskEnergy LDC
1995

Trans Québec & Maritimes Pipeline
1987

Union Gas
1988, 1989, 1990, 1992
1994, 1996, 1998, 2001

Westcoast Energy
1989, 1990, 1992 (2 cases), 1993, 2005

Yukon Electrical Company
1991, 1993, 2008

Yukon Energy
1991, 1993

EXPERT TESTIMONY/OPINIONS

ON

OTHER ISSUES

Client	Issue	Date
Greater Toronto Airports Authority	Financial Performance Measures	2012
Heritage Gas	Criteria for a Mature Utility	2011
Alberta Utilities	Management Fee on CIAC	2011
ATCO Electric	Construction Work in Progress (CWIP) Recovery of Future Income Tax (FIT)	2010
Maritimes & Northeast Pipeline	Return on Escrow Account	2010
Nova Scotia Power	Calculation of ROE	2009
Alberta Oilsands Pipeline	Cash Working Capital	2007
New Brunswick Power Distribution	Interest Coverage/Capital Structure	2007
Heritage Gas	Revenue Deficiency Account	2006
Hydro Québec	Cash Working Capital	2005
Nova Scotia Power	Cash Working Capital	2005
Ontario Electricity Distributors	Stand-Alone Income Taxes	2005
Caisse Centrale de Réassurance	Collateral Damages	2004
Hydro Québec	Cost of Debt	2004
Enbridge Gas New Brunswick	AFUDC	2004
Heritage Gas	Deferral Accounts	2004
ATCO Electric	Carrying Costs on Deferral Account	2001
Newfoundland & Labrador Hydro	Rate Base, Cash Working Capital	2001
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Rate Subsidies	2000
Enbridge Gas Distribution	Principles of Cost Allocation	1998
Enbridge Gas Distribution	Unbundling/Regulatory Compact	1998

Maritime Electric	Form of Regulation	1995
Northwest Territories Power	Rate Stabilization Fund	1995
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Gaz Métro/Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984

SEC Interrogatory #025

Ref: A1-2-2/p.1

Issue Number: 3.1
Issue: What is the appropriate capital structure and rate of return on equity for the currently regulated facilities and newly regulated facilities?

Interrogatory

Please provide all studies, analyses, forecasts, presentations or other documents relating in whole or in part to the Applicant's expected, planned or forecast debt/equity ratio over the period 2014-2018.

Response

For regulatory accounting, reporting and ratemaking purposes the expected/planned/forecast debt/equity ratio is the 53/47 debt/equity ratio approved by the OEB. The only document related to OPG's approved debt/equity ratio was provided in Ex. L-03.1-17 SEC-024.

SEP Interrogatory #001

Ref: Exh C-1-1-1

Issue Number: 3.1
Issue: What is the appropriate capital structure and rate of return on equity for the currently regulated facilities and newly regulated facilities?

Interrogatory

(a) The application at page 4, lines 28-31, indicates that there have been no changes to the, `risks faced by OPG's regulated asset portfolio that are not otherwise addressed by proposals to establish new variance and/or deferral accounts.` Please describe the specific risks that require a high percentage of equity, given that OPG is owned by the government of Ontario. Does OPG consider a change in the governing party for Ontario to be a risk?

(b) Please calculate the change in the revenue requirement for OPG`s regulated asset portfolio from the current debt-equity ratio (53:47) to 70:30 (i.e. 70% debt) and 90:10, all other financial parameters kept the same.

Response

a) The OEB determined OPG's deemed capital structure in EB-2007-0905 based on its assessment of the risks facing OPG. The OEB's approach and assessment of risk is discussed at pages 135 - 150 of that decision. In summary, the OEB concluded that "OPG is of higher risk than electricity LDCs, gas utilities and electricity transmission utilities and of lower risk than merchant generation … an equity ratio of 47%, is appropriate in the circumstances. This ratio is higher than the equity ratio of any other regulated Ontario energy utility, thereby recognizing the higher risk of OPG (pp. 149 - 150). In reaching this conclusion, the OEB addressed a number of risks including those raised in the question:

> "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." (page 142)

> "OPG suggests that its regulated assets are subject to greater political risk than other energy utilities in the province. The Board does not agree that this is a risk that should be reflected in OPG's cost of capital." (page 142).

b) Attachment 1, Table 1 (2015) and Table 2 (2014) shows the change in the cost of capital using a 70:30 debt/equity ratio. The impact on revenue requirement is provided below:

Impact on revenue requirement of 70:30 debt/equity ratio

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
$M		Pre-filed	Pre-filed	Pre-filed	IR Request	IR Request	IR Request	Change	Change
Line	Descrip-tion	Reference	2015 ($M)	2014 ($M)	Reference	2015 ($M)	2014 ($M)	2015 ($M)	2014 ($M)
1	Interest Expense	C1-1-1 Table 1 and Table 2 line 4, col d)	256.2	253.6	Attachment 1 Table 1 and Table 2 line 4, col d)	338.5	335.7	82.3	82.1
2	ROE	C1-1-1 Table 1 and Table 2 line 5, col d)	420.5	420.2	Attachment 1 Table 1 and Table 2 line 5, col d)	268.4	268.2	-152.1	-152.0
3	Income tax	(line 2 / (1-25%) – line 2	140.2	140.1	(line 2 / (1-25%) – line 2	89.5	89.4	-50.7	-50.7
4	Revenue Require-ment Impact	Line 1 + 2 + 3	816.9	813.9	Line 1 + 2 + 3	694.6	693.4	**-120.4**	**-120.5**

Attachment 1, Table 3 (2015) and Table 4 (2014) shows the change in the cost of capital using a 90:10 debt/equity ratio. The impact on revenue requirement is provided below:

Impact on revenue requirement of 90:10 debt/equity ratio

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
$M		Pre-filed	Pre-filed	Pre-filed	IR Request	IR Request	IR Request	Change	Change
Line	Descrip-tion	Reference	2015 ($M)	2014 ($M)	Reference	2015 ($M)	2014 ($M)	2015 ($M)	2014 ($M)
1	Interest Expense	C1-1-1 Table 1 and Table 2 line 4, col d)	256.2	253.6	Attachment 1 Table 3 and Table 4 line 4, col d)	435.4	432.3	179.2	178.7
2	ROE	C1-1-1 Table 1 and Table 2 line 5, col d)	420.5	420.2	Attachment 1 Table 3 and Table 4 line 5, col d)	89.5	89.4	-331.0	-330.8
3	Income tax	(line 2 / (1-25%) – line 2	140.2	140.1	(line 2 / (1-25%) – line 2	29.8	29.8	-110.3	-110.3
4	Revenue Require-ment Impact	Line 1 + 2 + 3	816.9	813.9	Line 1 + 2 + 3	554.7	551.5	-262.2	-262.4

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, 2015

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	192.2	1.9%	2.89%	9.0
2	**Existing/Planned Long-Term Debt**	2	3,481.6	34.9%	4.86%	169.2
3	**Other Long-Term Debt Provision**	3	3,300.3	33.1%	4.86%	160.4
4	**Total Debt**	4	6,974.1	70.0%	4.85%	338.5
5	**Common Equity**	4	2,988.9	30.0%	8.98%	268.4
6	**Rate Base Financed by Capital Structure**	5	9,963.0	88.4%	6.09%	607.0
7	**Adjustment for Lesser of UNL or ARC**	5, 6	1,308.8	11.6%	5.37%	70.3
8	**Rate Base**	7	11,271.8	100%	6.01%	677.2

Notes:
1 Ex. C1-1-3 Table 2: Principal (line 13), Cost Rate (line 8), Cost of Capital (line 14).
2 Ex. C1-1-2 Table 7, line 47.
3 Debt required to balance capital structure requested in Interrogatory with proposed rate base. See Ex. C1-1-2, Section 5.0. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2) per EB-2010-0008 Decision with Reasons.
4 Capital Structure requested in this Interrogatory
Return on Equity reflects the last Cost of Capital Parameter Update reported by the OEB (Feb. 14, 2013).
5 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded 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 32. Weighted average accretion rate from Ex. C2-1-1, section 3.0.
7 Ex. B1-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro) and Ex. B1-1-1 Table 2 (Nuclear).

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, 2014

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	192.2	1.9%	1.87%	7.0
2	**Existing/Planned Long-Term Debt**	2	3,372.7	33.9%	4.85%	163.6
3	**Other Long-Term Debt Provision**	3	3,404.8	34.2%	4.85%	165.1
4	**Total Debt**	4	6,969.7	70.0%	4.82%	335.7
5	**Common Equity**	4	2,987.0	30.0%	8.98%	268.2
6	**Rate Base Financed by Capital Structure**	5	9,956.7	87.8%	6.07%	603.9
7	**Adjustment for Lesser of UNL or ARC**	5, 6	1,389.5	12.2%	5.37%	74.6
8	**Rate Base**	7	11,346.1	100%	5.98%	678.6

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 13), Cost Rate (line 8), Cost of Capital (line 14).

2 Ex. C1-1-2 Table 6, line 45.

3 Debt required to balance capital structure requested in Interrogatory with proposed rate base. See Ex. C1-1-2, Section 5.0. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2) per EB-2010-0008 Decision with Reasons.

4 Capital Structure requested in this Interrogatory
Return on Equity reflects the last Cost of Capital Parameter Update reported by the OEB (Feb. 14, 2013).

5 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded 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 32. Weighted average accretion rate from Ex. C2-1-1, section 3.0.

7 Ex. B1-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro) and Ex. B1-1-1 Table 2 (Nuclear).

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, 2015

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	192.2	1.9%	2.89%	9.0
2	**Existing/Planned Long-Term Debt**	2	3,481.6	34.9%	4.86%	169.2
3	**Other Long-Term Debt Provision**	3	5,292.9	53.1%	4.86%	257.2
4	**Total Debt**	4	8,966.7	90.0%	4.86%	435.4
5	**Common Equity**	4	996.3	10.0%	8.98%	89.5
6	**Rate Base Financed by Capital Structure**	5	9,963.0	88.4%	5.27%	524.9
7	**Adjustment for Lesser of UNL or ARC**	5, 6	1,308.8	11.6%	5.37%	70.3
8	**Rate Base**	7	11,271.8	100%	5.28%	595.1

Notes:
1. Ex. C1-1-3 Table 2: Principal (line 13), Cost Rate (line 8), Cost of Capital (line 14).
2. Ex. C1-1-2 Table 7, line 47.
3. Debt required to balance capital structure requested in Interrogatory with proposed rate base.
   See Ex. C1-1-2, Section 5.0. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2) per EB-2010-0008 Decision with Reasons.
4. Capital Structure requested in this Interrogatory
   Return on Equity reflects the last Cost of Capital Parameter Update reported by the OEB (Feb. 14, 2013).
5. The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded 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 32. Weighted average accretion rate from Ex. C2-1-1, section 3.0.
7. Ex. B1-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro) and Ex. B1-1-1 Table 2 (Nuclear).

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, 2014

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	192.2	1.9%	1.87%	7.0
2	**Existing/Planned Long-Term Debt**	2	3,372.7	33.9%	4.85%	163.6
3	**Other Long-Term Debt Provision**	3	5,396.1	54.2%	4.85%	261.7
4	**Total Debt**	4	8,961.0	90.0%	4.82%	432.3
5	**Common Equity**	4	995.7	10.0%	8.98%	89.4
6	**Rate Base Financed by Capital Structure**	5	9,956.7	87.8%	5.24%	521.7
7	**Adjustment for Lesser of UNL or ARC**	5, 6	1,389.5	12.2%	5.37%	74.6
8	**Rate Base**	7	11,346.1	100%	5.26%	596.3

Notes:
1 Ex. C1-1-3 Table 2: Principal (line 13), Cost Rate (line 8), Cost of Capital (line 14).
2 Ex. C1-1-2 Table 6, line 45.
3 Debt required to balance capital structure requested in Interrogatory with proposed rate base.
See Ex. C1-1-2, Section 5.0. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2) per EB-2010-0008 Decision with Reasons.
4 Capital Structure requested in this Interrogatory
Return on Equity reflects the last Cost of Capital Parameter Update reported by the OEB (Feb. 14, 2013).
5 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded 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 32. Weighted average accretion rate from Ex. C2-1-1, section 3.0.
7 Ex. B1-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro) and Ex. B1-1-1 Table 2 (Nuclear).

Board Staff Interrogatory #017

Ref: Exh C1-1-2 pages 4-5

Issue Number: 3.2
Issue: Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

Interrogatory

At the bottom of page 4 and continuing on page 5, OPG documents the following:

> The cost of planned new and refinanced corporate debt and project-related debt for 2013, 2014 and 2015 is based on a forecast of 10-year Long Canada Bond[s] as published in April 2013 by Global Insight, a third party independent market source.

Year	Q1	Q2	Q3	Q4
2013	1.87	2.10	2.38	2.39
2014	2.50	2.65	2.76	2.80
2015	2.87	3.05	3.22	3.44

> The long-term interest rates forecast for the 10-year Government of Canada bonds are provided in Chart 1. As discussed below, a credit risk spread for OPG of 132 basis points is added to the Global Insight rates notes in Chart 1 to determine the forecast rate for OPG's OEFC debt in 2013, 2014 and 2015.

Chart 1
Forecast 10-year Long Canada Bond Rates

Year	Q1	Q2	Q3	Q4
2013	1.87	1.95	2.08	2.26
2014	2.40	2.54	2.64	2.67
2015	2.71	2.85	3.15	3.37

* Annual forecast

OPG's credit spread at the end of 2012 was 132 basis points and this spread has been used for 2013, 2014 and 2015.

a) The table at the top of page 5 contains different numbers than are shown in Chart 1. Please identify this first table, and explain what purpose it serves with respect to OPG's evidence on its long-term debt.
b) What does the footnote "* Annual forecast" below Chart 1 refer to?
c) What is OPG's actual weighted average debt rate for its corporate and project-related debt for 2013?
d) What is OPG's credit spread as of December 31, 2013?
e) Please provide a copy of the April 2013 Global Insight document referenced at the bottom of page 4.

f) If OPG has a more recent copy of the Global Insight publication, please provide a copy of the most recent publication.

Response

a) Chart 1 reflects the April 2013 Global Insight forecast of 10-year Government of Canada Bond Rates. The rates provided in this table support OPG's forecast cost of long-term debt in Ex C1-1-2, Tables 5, 5a, 6, 6a, 7 and 7a. The unlabelled chart is the August 2013 update of the Global Insight forecast. The August update information was inadvertently included. It was not used to calculate OPG's long term debt costs in the Application.

b) "Annual forecast" means the rates listed in Chart 1 are annualized forecast rates.

c) Refer to Attachment 1.

d) OPG's credit spread as of December 31, 2013 was 126 bps.

e) The Global Insight forecast referenced at the bottom of page 4 is provided in Attachment 2, which is an extract from its April 2013 Canadian Forecast Summary.

f) The Global Insight forecast, which is an extract from the February 2014 Canadian Forecast Summary, is provided in Attachment 3.

Numbers may not add due to rounding.

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

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Coupon Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 and 2 Redeemed During 2007							
	Issues 3 and 4 Redeemed During 2008							
	Issues 5 and 6 Redeemed During 2009							
	Issues 7, 8, 11, 12, 13, 14, 15 Redeemed During 2010							
	Issues 9 and 10 Redeemed During 2011							
	Issue 16 Redeemed During 2012						**(Note 4)**	
1	**Issue 17**		100.0	6/22/2007	10.0	6/22/2017	5.44%	5.4
2	**Issue 18**		200.0	9/24/2007	10.0	9/22/2017	5.53%	11.1
3	**Issue 19**		400.0	12/21/2007	9.8	9/22/2017	5.31%	21.2
4	**Issue 20**		200.0	3/22/2008	10.0	3/22/2018	5.35%	10.7
5	**Issue 21**		100.0	3/22/2009	10.0	3/22/2019	5.65%	5.7
6	**Issue 22**		300.0	3/22/2010	5.0	3/22/2015	3.56%	10.7
7	**Issue 23**		230.0	3/22/2010	10.0	3/22/2020	4.68%	10.8
8	**Issue 24**		200.0	9/22/2010	5.0	9/22/2015	3.24%	6.5
9	**Issue 25**		230.0	9/22/2010	10.0	9/22/2020	4.39%	10.1
10	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
11	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
12	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
13	**Total**		**2,460.0**				**4.72%**	**116.0**
	Regulated Portion of Company-Wide Borrowing							
14	**Allocation**	3	**1,279.0**				**4.72%**	**60.3**
	Project Financing - Regulated Projects							
15	**Niagara 1**		160.0	10/22/2006	10.0	10/22/2016	5.23%	8.4
16	**Niagara 2**		50.0	1/22/2007	10.0	1/22/2017	5.10%	2.5
17	**Niagara 3**		30.0	4/23/2007	10.0	4/22/2017	5.09%	1.5
18	**Niagara 4**		40.0	1/22/2008	10.0	1/22/2018	5.53%	2.2
19	**Niagara 5**		30.0	4/22/2008	10.0	4/22/2018	5.90%	1.8
20	**Niagara 6**		30.0	7/22/2008	10.0	7/22/2018	5.87%	1.8
21	**Niagara 7**		30.0	1/22/2009	10.0	1/22/2019	8.41%	2.5
22	**Niagara 8**		35.0	4/22/2009	10.0	4/22/2019	7.71%	2.7
23	**Niagara 9**		35.0	7/22/2009	10.0	7/22/2019	6.41%	2.2
24	**Niagara 10**		50.0	10/22/2009	10.0	10/22/2019	5.63%	2.8
25	**Niagara 11**		50.0	1/22/2010	10.0	1/22/2020	5.44%	2.7
26	**Niagara 12**		65.0	4/22/2010	10.0	4/22/2020	5.73%	3.7
27	**Niagara 13**		35.0	7/22/2010	10.0	7/22/2020	5.57%	1.9
28	**Niagara 14**		50.0	10/22/2010	10.0	10/22/2020	4.87%	2.4
29	**Niagara 15**		40.0	1/24/2011	10.0	1/22/2021	5.18%	2.1
30	**Niagara 16**		35.0	4/26/2011	10.0	4/22/2021	5.34%	1.9
31	**Niagara 17**		50.0	7/22/2011	10.0	7/22/2021	5.24%	2.6
32	**Niagara 18**		60.0	10/24/2011	10.0	10/22/2021	5.74%	3.4
33	**Niagara 19**		40.0	1/22/2012	10.0	1/22/2022	5.50%	2.2
34	**Niagara 20**		35.0	4/22/2012	10.0	4/22/2022	5.36%	1.9
35	**Niagara 21**		45.0	7/22/2012	10.0	7/22/2022	5.51%	2.5
36	**Niagara 22**		30.0	10/22/2012	10.0	10/22/2022	5.52%	1.7
37	**Niagara 23**	1,5	18.8	1/22/2013	10.0	1/22/2023	5.35%	1.0
38	**Niagara 24**	2,5	13.9	4/22/2013	10.0	4/22/2023	5.37%	0.7
39	**Total**		**1,057.7**				**5.60%**	**59.3**
	Total Regulated Funded Long-Term Debt							
40	Line 14+39		**2,336.7**				**5.12%**	**119.6**

See Ex. L-3.2-1 Staff-17, Table 1a) for notes

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

Numbers may not add due to rounding.

Table 1a
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2013
Notes to Ex. L-3.2-1 Staff 17 Table 1

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

Note 3 Allocation ratio for 2013 described in Ex. L-3.2-1 Staff-17, Table 1, line 14 (excludes Newly Regulated Hydroelectric net fixed assets). The 2012 allocation ratio is used as it reflects OPG's most recent available financing results (i.e., not all information was available to determine a 2013 ratio).

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

Note 5 Realized effective rate on 2013 debt

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

Note 6 Issue 29, Niagara 25 and Niagara 26 were not issued due to lower than expected financing requirement during Q3-Q4 2013

IHS Global Insight

Canadian Forecast Executive Summary

April 2013

ihs.com

Canadian short-term economic outlook

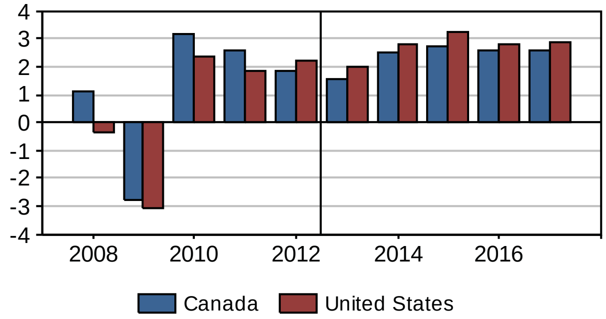
It's not the same

Just a year ago, the title of the update to our short-term forecast was "Stronger Employment, Solid Housing". We can no longer say that today. Canada's economy is in flux. We continue to see marked weakness across several industries, while other areas of the economy are set in a holding pattern. Meanwhile, momentum in the US economy has mainly improved, despite issues surrounding the sequester that will dampen the outlook for 2013, shaving 0.4 percentage point off growth.

Fourth-quarter US real GDP growth was revised up from 0.1% last month to 0.4%. The first-quarter outlook was also revised up, from 2.3% to a solid 3.8% pace. The huge sway in inventories from a negative contribution in the fourth quarter to a positive contribution will help push the first-quarter growth rate up higher than previously expected. Unfortunately, another adjustment to inventories will also contribute to growth slowing back down to only 0.4% in the second quarter. The sequester, which is now expected to remain in place until the end of the third quarter, will also dampen growth. Furthermore, slowing global demand will hold back the pace of US export growth. Despite these many headwinds, the recovering US housing market continues to hold ground, adding to growth this year and next. The US economy is on track to expand 2.0% this year and 2.8% in 2014, close to last month's expectations.

Canadian and US Real GDP Growth

(Percent change)



Canada's economic outlook was also subject to revisions this month. We are more downbeat on the near-term outlook, specifically in a few areas. Looking at leading indicators such as consumer confidence levels, there has also been a general downward trend. Likewise, business activity indicators point to sluggish growth, especially as the RBC manufacturing purchasing managers' index dipped into contraction mode in March after hovering just above the expansion mark for six consecutive months. In terms of small business activity, the CFIB small business barometer declined in March, erasing the gains it made since the start of the year. Contrasting both of these indicators was the massive jump in the Ivey PMI in March, hitting a seven-month high.

The 0.2% rebound in real GDP by industry output in January merely made up for the equivalent decline in the month before. The good news in January was that there were sizable gains across some industries. Even so, output declined in 7 of the 20 industries, with some of the largest drops in transportation and warehousing, professional services, finance and insurance, and construction. We expect output in the construction industry to continue to decline, particularly residential construction, which has been one of the worst performers in the industry over the past three months. Therefore, combined with a steadily dimming view on housing and worsening leading indicators, we have lowered our first-quarter outlook from 1.9% to 1.6%.

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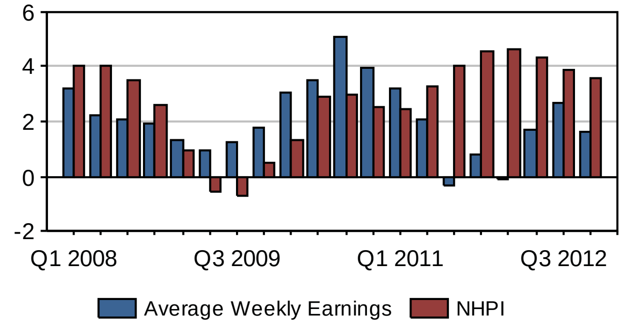
The second quarter will likely post a 2.1% rise in real GDP output as some of the loss output in the first quarter will trickle into the second quarter. We were expecting a 2.0% increase in last month's forecast. We have left our real GDP outlook during of the last half of this year unchanged, growing at a 2.3% in both the third and final quarters. For the year as a whole, the Canadian economy is expected to expand at a slow 1.6% pace this year, which is about 0.4 percentage point below the US economy. The Canadian economy is expected to come back to life with a healthy 2.5% boost in 2014 and then an even stronger 2.7% takeoff in 2015, mostly on the strength of the US economy, which will grow rowing 2.8% in 2014 and 3.2% in 2015.

Ontario

(Percent change from a year ago)



What's up (and down) with housing?

Canada's housing market has begun to cool off from last year's elevated levels. Housing starts activity is typically slower in the first few months of any year before spring fever pushes building activity into high gear during the second quarter. Last year, housing starts were churning out levels above 200,000 throughout the second quarter. This year, we expect housing starts to take a back seat, as those levels are unsustainable. Pent-up demand for homes is being satisfied as there is an ample supply of multifamily homes already in existence or soon to become available, particularly in the larger housing markets (such as Toronto). After peaking at 161,261 units in April 2012, the multifamily segment of the housing market is down 40% as of February 2013. Total housing starts will remain in the 180,000–185,000 unit range over the near term as the dominant multifamily segment of the market pulls back from its very high levels over the past couple of years.

For months, Canadians have heard reports that the housing market is on the verge of a US-style collapse due to skyrocketing real estate prices outpacing incomes, and elevated levels of residential construction. As affordability diminishes, it is reasonable to expect demand to suffer. In conjunction with rising levels of supply, prices should be expected to decline. The problem with these arguments is that they do not necessarily point to the kind of widespread collapse seen in the United States. Although we may see prices moderating at the national level, it will likely only reflect regional declines rather than a larger national trend. If we examine markets at the provincial or municipal level, it becomes apparent that there really is no consistent story in terms of the health of Canadian real estate.

Policymakers expressed growing concern last year as residential construction activity spiked. Many parts of the country saw double-digit housing starts growth rates. Ontario led the pack, as housing starts rose more than 13.0% from the year before, with Toronto leading with a 36% jump. This has helped push Toronto into the top spot in North America with the most skyscrapers in development, according to the Council on Tall Buildings and Urban Habitat. Real estate prices were also on a tear. The MLS average existing home price in the Greater Toronto area advanced 6.5%, while the new housing price index (NHPI) for the city, which excludes condominiums, jumped 5.1%. At the provincial level, Ontario's NHPI growth was second only to Manitoba. As the year went on, it became increasingly unlikely that these trends were sustainable. Burdened by sluggish US growth, Ontario's economy has struggled to regain traction since the onset of the recession. The unemployment rate remains stubbornly high as critical sectors such as manufacturing continue to flag amid a tenuous global economic environment. Consequently, inflated housing costs have not been met with similar wage gains. The result is an increasingly unaffordable market that is not amenable to any further run-up in property values. Existing home sales have begun to plunge, and there have been several reports of cancelled condominium developments. Going forward, we expect new home construction to wane even further, and it is doubtful that we will see any more meaningful increases in real estate prices.

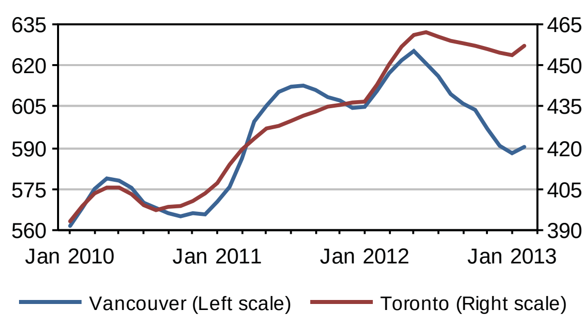
As one of the world's least affordable markets, it is hardly a surprise that residential real estate prices in Vancouver, British Columbia have begun to topple. After sliding to as low as $490,100 in the spring of 2009, the MLS average existing home price measure for the Greater Vancouver area surged nearly 30% in a little over three years. Since reaching its peak of $625,100 in May 2012, the index has subsequently fallen by more than 5.5%. Even so, prices remain high relative to the rest of the country. Despite the weakened state of residential real estate on the west coast, a relatively strong economy, continually low interest rates, and a low unemployment rate will help keep the market from falling apart completely. Furthermore, anecdotal evident suggests that ample foreign investment in property has done its part to keep values afloat, and recent changes to the Chinese capital gains tax structure is apt to keep money flowing into Canada.

In British Columbia's neighbouring province of Alberta, we see a completely different story. Following a massive correction in real estate prices at the onset of the recession, real estate prices in the oil-producing province have been slowly gaining steam. Alberta's largest city, Calgary, has been no exception. In a span of less than two years, prices toppled 19.4% from their summer 2007 peak. Although shaky at first, the market has slowly begun to gain momentum since that trough. Prices have yet to reach their record highs of five years ago, but with its robust economy and one of the country's lowest unemployment rates, Alberta's real estate markets is apt to continue to grow in a sustainable fashion. Rising incomes have only lent further support to an already highly affordable market. Furthermore, an elevated rate of population growth will also continue to prop up residential construction activity.

Even with property prices in Regina, Saskatchewan that have shot up by more than 40% since hitting their recession lows late 2008, the prairie province's real estate market is likely to continue thriving. Saskatchewan currently has the lowest unemployment rate in the country, and substantial increases in income have continually outpaced property prices. Gone are the days of negative population growth; Saskatchewan is expected to continue to experience elevated rates of migration. Unlike

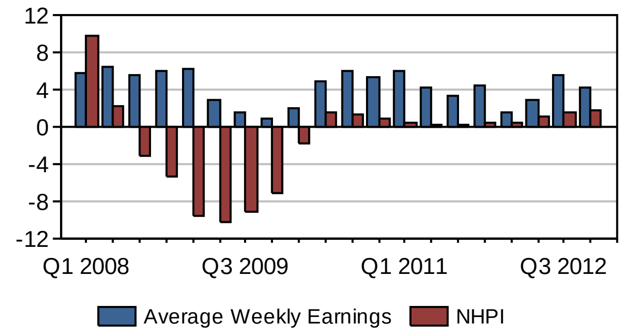
MLS Average Existing Home Prices

(Thousands of dollars)



Alberta

(Percent change from a year ago)



the current state of Toronto's condominium market, price gains in Saskatchewan are likely here to stay.

The bottom line is that in spite of pockets of questionable real estate market health, we do not foresee any precipitous US-style contraction. Canadian mortgage rates remain at historical lows, and government policies aimed at tightening mortgage regulations will keep buyers from biting off more than they can chew. We continue to anticipate a modest cooling in national home price measures in addition to a slowdown in residential construction, but overall the Canadian real estate market is expected to continue to hold its own.

Non-residential investments remain afloat

Remaining somewhat active—and therefore providing some lift to growth—is non-residential capital formation. Compared with recent residential building activity, the non-residential side remains downright robust. However, taking a closer look at the numbers, combined with recent survey results, a slowdown in non-residential capital formation is expected for the year, compared with an outright decline in residential construction capital formation. During the last two months of 2012, non-residential building, repair construction, and engineering and other construction activity grew at a solid pace. Although there was no decline at the start of this year, there was a definite deceleration in output. This was likely caused by the uncertainty that still existed in the global economy given the reduction in demand, especially in the United States. This is why we still have non-residential capital formation pegged to advance a soft 1.3% in the first quarter and remain soft throughout the rest of the year.

Further cementing our view was the recent spring Bank of Canada Business Outlook Survey, which indicated that the degree of uncertainty regarding the global economy is resulting in businesses rethinking their investment decisions, vying for options that include delaying projects, focusing on investment opportunities with a quick turnaround, decreasing capital outlays and risk, or changing altogether to new demand opportunities. Therefore, our views on residential and non-residential capital formation have not changed since our March forecast.

We did lower our first-quarter growth forecast for household spending by 0.2 percentage point in the first quarter, to 1.8%. This was done for a few reasons. Real retail sales activity in January was reported as unchanged in the month, while sales, including the impact of prices, jumped 1.0%. Obviously, the drop in consumer confidence throughout March will impact buying patterns, which have yet to be reported. Moreover, the dismal job growth in the first quarter of only 0.8%, with two out of three months recording job declines, will also likely cause consumers to limit their spending. Household consumption will grow 2.1% this year, a slight dip from the 2.2% expected last month.

Unbalanced job recovery

Statistics Canada recently released a report analyzing Canada's employment market's recovery since the recession, and how not all recoveries across industries are deemed equal. Specifically, some industries have not recouped the job losses since the downturn (for example, manufacturing) while other industries, such as the "other" services category—which typically consists of small business owners—actually expanded during the downturn and pulled back during the recovery.

Our analysis here expands on this concept and focuses on regional job markets and tries to explain why sometimes employment growth and GDP growth numbers just do not jibe, and the resultant impact on productivity.

For Canada as a whole, employment peaked in October 2008. On a regional basis, however, employment across provinces peaked at different times, spanning a period of 26 months. Four provinces' employment level peaked prior to October 2008, while four peaked after. Alberta and Quebec were the only provinces that matched the national date.

As of March 2013, all provinces with the exception of New Brunswick and Nova Scotia have more than recouped the jobs lost during each province's individual downturn and surpassed their previous peaks, ranging from 1.2% higher employment in British Columbia to 5.3% in Saskatchewan. Nova Scotia and New Brunswick are trailing far behind, even with nearly three years for Nova Scotia and over four years for New Brunswick since the downturn began.

Provincial Job Performance Prior to and During the Recession

(Percent)

Province	Peak Employment	Job Growth Since Peak Employment Month	Wage Gains Since Peak Employment Month
Manitoba	April 2008	4.3%	12.8%
Newfoundland	May 2008	5.1%	28.7%
British Columbia	July 2008	1.2%	13.5%
Ontario	September 2008	2.0%	9.1%
Canada	October 2008	2.7%	11.7%
Quebec	October 2008	3.2%	11.2%
Alberta	October 2008	3.9%	15.2%
New Brunswick	January 2009	-2.9%	11.6%
Prince Edward Island	April 2010	4.5%	8.1%
Nova Scotia	May 2010	-0.2%	7.7%
Saskatchewan	June 2010	5.3%	9.0%

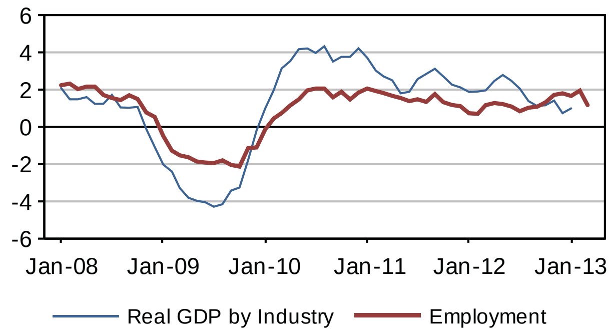
There is also no uniformity as to how wages have responded to the job recovery. Even though job growth was the strongest in Saskatchewan, wages have grown at a relatively low rate. In New Brunswick, although not all jobs have been recovered, wages have grown 11.6%, which is at the national average. Therefore, if wage growth is deemed a proxy for the demand for jobs, the slower advances in wages tell an interesting story. In Nova Scotia, wages grew the weakest, at 7.7% since its job downturn. The province's share of total employment relative to its level in October 2008, when the national level peaked, is down 0.1%. Likewise, Ontario wages grew a bit better at 9.1%, but Ontario's employment share of total employment is now down nearly one-quarter of a percentage point, the largest decline among the provinces. Meanwhile, the gains in Quebec's and Alberta's share make up for Ontario's job loss.

Jobs and GDP growth don't jibe, resulting in productivity swings

Since bottoming out in July 2009, job losses were recorded in only seven months through the end of 2012. Indeed, only one month of job loss was recorded in 2010, and only one month in 2012. For the year as a whole, the number of jobs added was the greatest in 2012 at 310,300 (the largest since 2007), but in terms of growth, jobs advanced only 1.2%. Meanwhile, Canada's economy advanced below potential at 1.8% in 2012, and in the last half of the year, we saw two quarters of dismal growth averaging 0.7%.

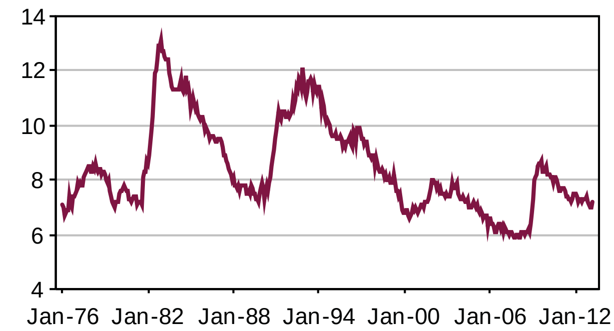
Job Growth Outpaces Economic Growth

(Percent change)



Unemployment Rate: The Seven Year Itch

(Percent)



During the economic recovery, real GDP growth exceeded job growth, resulting in gains in productivity. Over the past several months, however, the rate of employment growth has outpaced that of real GDP by industry. Therefore, productivity growth slowed and then dipped 1.8% at the end of 2012. A small rebound is expected in the first quarter, but for 2013 we expect productivity will likely struggle yet again to eke out a gain with slow annual real GDP growth.

Even with the healthy job gains we have seen until recently, the unemployment rate has been stuck in the low-7% range for the past couple of years. We expect this trend to continue this year and next. The unemployment rate will not edge lower for a couple more years if we look at the typical historical pattern. Since the early 1980s, after hitting a peak, it takes about seven years on average before the unemployment rate bottoms out. If history is to repeat itself, we are just past the mid-point of the cycle. The jobless rate will hit the mid-6% range by 2015–16.

Trade is on track with expectations

We did not change our outlook on Canadian exports and imports, which are advancing as expected, given the data to date. After increasing at decent rates in January, both real exports and imports fell in February. Other economic data for March for the most part was downbeat, so odds are low that March's merchandise trade data will be very positive. Therefore, we maintain our outlook of a small increase in real exports and real imports with export activity edging a bit higher than imports, making a small contribution to first-quarter real GDP growth.

No change in monetary policy

Given this somewhat jumbled backdrop, we have not changed our timing of when the Bank of Canada will raise interest rates. The low 1% overnight rate will hold throughout this year and most of 2014. An increase is expected in the last quarter of 2014.

by Arlene Kish and Jillian Kohut

High-Frequency Indicators

(As of April 5)

	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Dec-13
Real GDP by Industry (M/M, percent)	**0.2**	0.1	0.2	0.2	0.2	0.2	0.3
Employment (Thous.)	**-22**	**51**	**-55**	22	29	25	25
Unemployment Rate (Percent)	**7.0**	**7.0**	**7.2**	7.1	7.1	7.1	7.0
Consumer Price Index (Y/Y, percent)	**0.5**	**1.2**	1.3	1.1	1.3	1.7	2.4
Exchange Rate, Month-End (US cents)	**100.27**	**96.96**	**98.43**	98.17	97.77	97.37	96.57
Exchange Rate, Average (US cents)	**100.79**	**99.02**	**97.59**	98.33	98.00	97.53	96.31
3-Month T-Bill Rate, Month-End	**0.93**	**0.95**	**0.98**	0.98	0.98	0.98	0.98
Overnight Rate, Month-End	**1.00**	**1.00**	**1.00**	1.00	1.00	1.00	1.00

Note: Bolded numbers indicate historical data.

TABLE 2

Canadian Short-term Forecast Update

	12Q4	13Q1	13Q2	13Q3	13Q4	14Q1	2012	2013	2014	2015	2016	2017	2018
Real GDP (Bil. chained 2007 $)	1663.6	1670.2	1679.0	1688.7	1698.1	1708.7	1658.2	1684.0	1726.1	1773.0	1819.0	1865.9	1912.8
Annual Percent Change	0.6	1.6	2.1	2.3	2.3	2.5	1.8	1.6	2.5	2.7	2.6	2.6	2.5
Household	931.2	935.4	940.0	945.0	950.8	956.6	923.1	942.8	965.8	989.9	1012.7	1035.8	1059.7
Annual Percent Change	2.7	1.8	2.0	2.2	2.5	2.5	1.9	2.1	2.4	2.5	2.3	2.3	2.3
Government	413.8	415.8	417.7	419.7	421.1	422.7	412.2	418.5	425.7	433.2	440.5	448.9	457.2
Annual Percent Change	2.4	1.9	1.9	1.9	1.4	1.5	-0.6	1.5	1.7	1.8	1.7	1.9	1.9
Bus. Res. Investment	112.5	110.4	110.7	110.9	111.1	111.2	112.7	110.8	111.5	112.8	113.5	114.5	115.5
Annual Percent Change	0.8	-7.3	1.1	0.7	0.7	0.1	5.8	-1.7	0.7	1.1	0.6	0.9	0.9
Bus. Non-Res. Inv.	184.6	185.2	186.2	187.2	188.6	190.3	182.3	186.8	193.2	200.6	207.1	213.1	218.4
Annual Percent Change	4.4	1.3	2.0	2.3	2.9	3.8	6.2	2.4	3.4	3.8	3.2	2.9	2.5
Exports	503.5	506.5	511.5	516.6	522.2	528.0	506.8	514.2	537.6	566.9	599.8	631.1	661.5
Annual Percent Change	1.2	2.4	4.0	4.1	4.4	4.5	1.6	1.5	4.5	5.5	5.8	5.2	4.8
Imports	552.3	555.0	559.8	563.9	568.8	573.9	551.2	561.9	582.7	609.0	637.1	664.4	690.6
Annual Percent Change	-1.0	1.9	3.5	3.0	3.5	3.6	2.9	2.0	3.7	4.5	4.6	4.3	4.0
Business Inventory Ch.	2.8	4.3	4.7	4.5	3.7	3.5	5.5	4.3	3.4	3.1	3.2	3.1	3.0
Statistical error	1.1	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0
Nominal GDP (Bil. $)	1833.4	1848.4	1871.5	1891.4	1911.8	1932.2	1817.6	1880.8	1965.9	2055.8	2150.0	2252.1	2357.8
Annual Percent Change	1.9	3.3	5.1	4.3	4.4	4.3	3.1	3.5	4.5	4.6	4.6	4.8	4.7
Raw Mat. Price Index	162.0	164.5	163.1	162.2	162.2	161.5	164.4	163.0	161.3	162.1	163.1	163.4	164.1
Percent Change Year Ago	-6.7	-3.9	0.8	-0.1	0.1	-1.9	-6.3	-0.8	-1.0	0.5	0.6	0.2	0.4
Industry Price Index	115.0	116.1	116.4	117.0	117.5	118.0	115.3	116.8	118.5	120.1	121.9	123.6	125.1
Percent Change Year Ago	-0.1	0.6	0.7	1.8	2.2	1.6	0.6	1.3	1.5	1.3	1.6	1.4	1.2
GDP Deflator	110.2	110.7	111.5	112.0	112.6	113.1	109.6	111.7	113.9	115.9	118.2	120.7	123.3
Annual Percent Change	1.3	1.7	2.9	1.9	2.1	1.8	1.3	1.9	2.0	1.8	1.9	2.1	2.1
CPI	121.8	122.4	123.7	123.9	124.2	124.9	121.7	123.5	125.9	128.5	131.0	133.6	136.3
Percent Change Year Ago	0.9	1.0	1.4	1.7	2.0	2.0	1.5	1.5	2.0	2.0	2.0	2.0	2.0
Employment (Thousands)	17628	17661	17700	17752	17814	17921	17510	17732	18009	18345	18625	18818	18973
Annual Percent Change	2.4	0.8	0.9	1.2	1.4	2.4	1.2	1.3	1.6	1.9	1.5	1.0	0.8
Unemployment Rate (%)	7.2	7.1	7.1	7.1	7.1	7.0	7.3	7.1	7.0	6.7	6.5	6.4	6.4
Productivity (Annual Percent Change)	-1.8	0.9	1.2	1.2	0.8	0.1	0.7	0.3	0.9	0.8	1.1	1.5	1.7
Average Hourly Earnings	22.49	22.57	22.67	22.82	22.98	23.14	22.28	22.76	23.36	23.93	24.46	25.03	25.67
Annual Percent Change	0.7	1.3	1.8	2.7	2.8	2.8	2.4	2.1	2.7	2.4	2.2	2.3	2.6
3-Month T-Bill Rate (%)	0.99	0.96	0.98	0.99	0.99	0.99	0.97	0.98	1.07	2.08	3.33	4.31	4.50
US 3-Month T-Bill Rate (%)	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.19	1.69	3.42	3.74
Canada-US Differential (% pts.)	0.90	0.87	0.89	0.90	0.90	0.89	0.89	0.89	0.98	1.88	1.64	0.89	0.76
Prime Rate (%)	3.00	2.96	2.99	2.99	2.99	2.99	3.00	2.98	3.07	4.08	5.33	6.31	6.50
Overnight Rate (%)	1.00	0.96	0.98	0.99	0.99	0.99	1.00	0.98	1.07	2.08	3.33	4.31	4.50
Bank Rate (%)	1.25	1.21	1.24	1.24	1.24	1.24	1.25	1.23	1.32	2.33	3.58	4.56	4.75
GOC Bond Rate (1-3 yrs.) (%)	1.10	1.07	1.08	1.10	1.12	1.13	1.12	1.09	1.22	2.17	3.39	4.35	4.54
GOC Bond Rate (3-5 yrs.) (%)	1.28	1.30	1.27	1.31	1.36	1.40	1.30	1.31	1.51	2.35	3.50	4.43	4.61
GOC Ten-Year Bond Rate (%)	1.77	1.87	1.95	2.08	2.26	2.40	1.85	2.04	2.56	3.02	3.90	4.71	4.87
US Ten-Year T-Note Rate (%)	1.71	1.95	1.93	2.06	2.24	2.38	1.80	2.05	2.54	3.00	3.88	4.69	4.85
US Real GDP (Bil. 2005 $)	13665.4	13793.3	13807.1	13868.6	13982.5	14080.4	13593.2	13862.9	14249.2	14705.9	15122.3	15555.2	15965.9
Annual Percent Change	0.4	3.8	0.4	1.8	3.3	2.8	2.2	2.0	2.8	3.2	2.8	2.9	2.6
Household Credit (Billion $)	1664.3	1684.2	1706.2	1729.8	1754.8	1781.2	1635.9	1718.7	1823.6	1946.2	2076.6	2202.6	2321.5
Annual Percent Change	4.2	4.9	5.3	5.7	5.9	6.1	5.4	5.1	6.1	6.7	6.7	6.1	5.4
Standard of Living Canada/US (Nominal GDP per Capita at PPP Can/US)							0.856	0.850	0.845	0.839	0.834	0.829	0.826
ExCh. Rate (US-Can.)	100.9	99.1	98.0	96.9	96.4	96.7	100.1	97.6	95.8	92.9	91.4	91.1	91.3
Curr. Acct. Bal. (Billion $)	-69.0	-57.8	-52.0	-49.4	-47.0	-43.2	-66.9	-51.5	-41.6	-36.1	-28.9	-18.3	-8.3
Fed. Gov't. NA Bal.(Billion $)	-19.4	-19.4	-15.3	-11.9	-8.6	-5.9	-18.9	-13.8	-3.1	3.3	5.8	4.6	3.1
% GNP	-1.1	-1.1	-0.8	-0.6	-0.5	-0.3	-1.1	-0.7	-0.2	0.2	0.3	0.2	0.1
Corp Net Oper Surplus (Billion $)	255.3	248.0	253.8	257.3	259.6	260.4	259.5	254.7	263.8	272.5	281.2	290.4	299.6
Annual Percent Change	-4.1	-10.9	9.6	5.7	3.6	1.3	-2.7	-1.8	3.6	3.3	3.2	3.3	3.1
Housing Starts (Thousands)	204	171	174	181	185	185	215	178	185	184	183	182	181
Auto Sales (Thous. SAAR)	1693.9	1696.8	1717.5	1737.8	1768.4	1784.3	1716.8	1730.1	1800.1	1825.3	1818.2	1804.0	1787.5
Nominal Exports (Billion $)	541.9	547.3	558.3	568.2	577.6	586.0	545.8	562.8	599.6	640.5	688.5	735.1	781.5
Nominal Imports (Billion $)	577.6	580.8	585.3	592.3	598.5	605.6	582.3	589.2	616.9	654.0	694.1	730.8	768.5
Nominal Trade Balance (Billion $)	-35.7	-33.6	-27.1	-24.0	-21.0	-19.7	-36.4	-26.4	-17.4	-13.5	-5.6	4.3	13.0
Household Saving Rate (%)	3.8	3.1	3.3	3.4	3.3	3.3	4.0	3.3	3.3	3.1	2.9	2.6	2.5
Real Disp. Inc. - Annual Percent Change	0.9	-0.9	2.8	2.6	2.2	2.6	2.1	1.3	2.5	2.3	2.1	1.9	2.2
Industrial Production - Annual Percent Change	-0.6	-1.6	2.4	2.5	2.3	2.7	1.1	0.2	2.6	3.0	3.1	3.0	3.0

IHS **Economics**

Canadian Forecast Executive Summary

February 2014 ihs.com

Canadian short-term economic outlook

Upbeat momentum flows into 2014

Just as we had hoped, the rash of bleak economic data that reared its ugly head a mere month ago did not translate into a trend. Instead, there were some positive data readings that helped lift the fog off of a potentially weak Canadian economy.

First, Canada's real GDP by industry output jumped 0.2% in November and has generally given a very strong performance over the past year. Output has declined only once on a monthly basis during 2013, a feat that has not been achieved since 2005. The boost in economic growth can be partially attributed to the solid performance in industrial production, which has advanced for five consecutive months. This record growth string has not been matched since 2003.

As a result, we have raised our fourth-quarter real GDP growth outlook from 2.4% to 2.8%. We have boosted our household spending outlook given the recent increase in retail trade activity. In November, retail sales volumes advanced 0.8% for their fifth consecutive monthly increase. Moreover, sales of items related to the cold winter weather were solid, so general merchandise and clothing and accessories store sales in December and January should also be fairly robust. Therefore, household spending is forecast to expand 2.3% in the final quarter of the year, which is a nice lift from the 1.9% pace we were expecting in January.

We are also more upbeat regarding business investment. Housing starts activity was able to maintain the same level of activity recorded in the third quarter. As well, renovations and engineering and other construction activity advanced in the final quarter.

Inventory accumulation also ramped up in the quarter, lifting the fourth-quarter real GDP growth rate.

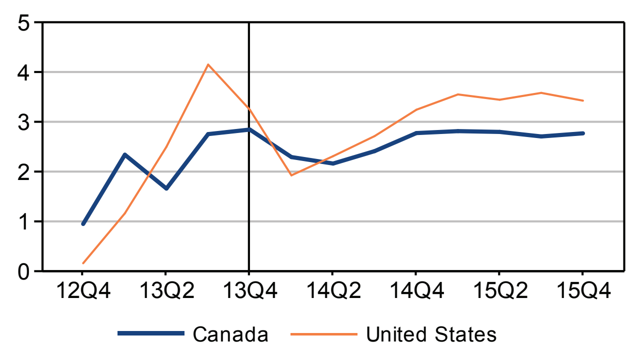
Keeping a lid on growth in the fourth quarter is net trade. Export volumes were down in the third quarter, according to the latest merchandise trade data. However, import volumes were up. Therefore, the negative net trade impact will take away growth in the fourth quarter. Real exports will decline 0.1% and real imports will climb 1.6%.

The latest changes to the outlook have bumped up the 2013 annual growth rate to 1.8% from 1.7%. Looking beyond 2013, we anticipate growth in the first half of 2014 to slow. The economy is still on track to grow 2.4% this year with the strongest performance given in the second half of the year. Canadian real GDP will grow 2.7% in 2015. Both rates are slower than those expected for the United States (2.7% in 2014 and 3.3% in 2015).

All sectors of Canada's economy are forecast to positively contribute going forward. With inflation coming in around 2% in the near term, nominal GDP will expand in the mid-4% range through the end of the decade. This

Canadian and US real GDP growth

(Percent change, annualized)



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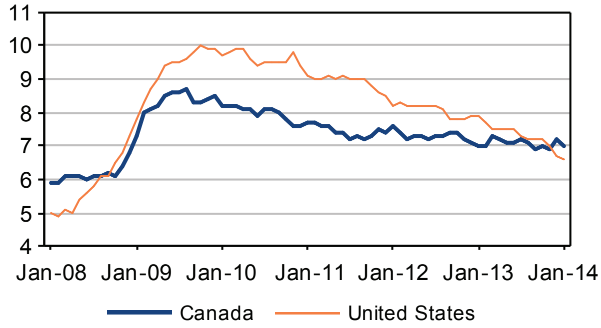
Unemployment rate

(Percent)



will help grow the general tax base which, in turn, will help the government reach a fiscal surplus.

Business indicators were on the rise in January and this helps support our call of 2.3% growth in the first quarter. The CFIB small business barometer rebounded in January after hitting a six-month low in December. There was increased optimism in some key industries, namely construction; manufacturing; retail; finance, insurance, and real estate; and professional and business services. Also riding the positive wave in the first quarter was the significant 10.5-point leap in January's Ivey PMI. The rebound is welcome, given that the index contracted in the previous two months.

The employment components of the CFIB and Ivey PMI indexes told a rather different story. The CFIB was pointing to an expansion of payrolls, but the Ivey PMI showed a strong decline in payrolls. Despite the mixed message, net employment expanded by 29,400 positions. Even if we look past the varied monthly employment data and instead look at the six-month moving average, net employment was consistently positive last year. We anticipate this trend to continue this year. The unemployment rate will still gradually edge lower and average 6.9% this year, which is only 0.2 percentage point lower than the average for 2013. This stands in stark contrast to what is unfolding in the United States, where the unemployment rate has been trending lower for years. The American unemployment rate, although not directly comparable, is firmly below Canada's unemployment rate, something that has not been achieved since September 2008.

We maintain our view that Canada's housing market is still holding up. We made a slight downward adjustment to our near-term housing starts forecast, but nothing that changes the underlying story of what we believe is occurring in the market, which is still deemed relatively healthy. Existing home prices in December are up 4.3% from a year ago. One sign that the market remains solid is that sales of luxury homes hit new records last year for most of the country. Plus, the increase in the number of luxury homes up for sale last year is an indication that sellers are confident that they will be able to get a good price for their homes given the renewed spark in demand. Therefore, housing starts should average around 185,000 units over the next couple of years and home prices should rise around 2.5% through 2016.

In terms of monetary policy, we do not expect the Bank to raise rates until late next year. Retail competition is on the Bank's radar as inflation remains low. As a result, the Bank's 2% target for core inflation will not be reached until 2016.

The Canadian dollar forecast is lower given the dollar reached a four and a half year low at the end of January. The loonie will average 92.2 US cents this year and 94.2 US cents in 2015.

Arlene Kish

High-frequency indicators

(As of February 7)

	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	Dec-14
Real GDP by Industry (M/M, percent)	**0.2**	-0.2	0.2	0.2	0.1	0.2	0.2
Employment (Thous.)	**25**	**-44**	**29**	34	32	24	36
Unemployment Rate (Percent)	**6.9**	**7.2**	**7.0**	7.0	7.1	7.0	6.7
Consumer Price Index (Y/Y, percent)	**0.9**	**1.2**	1.5	1.0	0.9	1.0	1.7
Exchange Rate, Month-End (US cents)	**94.16**	**94.02**	**89.78**	90.44	90.99	91.32	93.81
Exchange Rate, Average (US cents)	**95.31**	**93.99**	**91.39**	90.04	90.85	91.14	93.78
3-Month T-Bill Rate, Month-End	**0.94**	**0.91**	**0.89**	0.90	0.92	0.93	1.00
Overnight Rate, Month-End	**1.00**	**1.00**	**1.00**	1.00	1.00	1.00	1.00

Note: Bolded numbers indicate historical data.

Highlights of the long-term outlook

Household spending, business investment and net trade support growth

There is no new information that will alter our long-term view on the Canadian economy. Moreover, there are no major headwinds that are at risk of throwing the economy off track in the near term, unlike other periods when there were problems with a lingering recession in Europe or a large degree of uncertainty with US policy-makers. Therefore, the economic outlook looks steady, without any major bumps in the road. After five years of real GDP growth forecast at 2.5% or above, the long-term outlook is forecast to come in a bit more subdued, around 2.3%, starting in 2015.

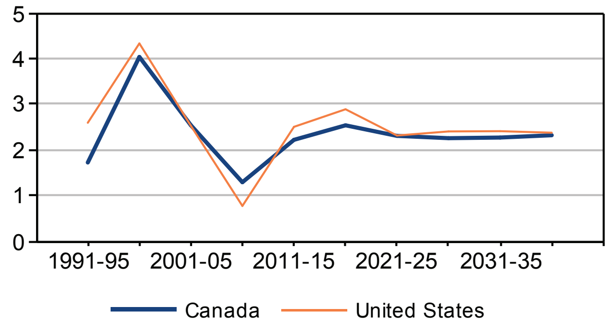
The US real GDP growth profile will match Canada's in the first half of the 2020s, but then just surpass it through the end of the forecast to 2044 with 2.4% growth. Regardless of which country is leading the other, we maintain that the two countries' economic outlooks are tied closely together.

For most of the past 13 years, Canada's economy has been performing well thanks to robust employment growth. This also means that productivity has been underperforming, averaging a mere 0.6%. Historically we know that productivity can outperform; we saw productivity growth average 1.9% in the late 1990s. We are forecasting productivity growth to accelerate in the last half of this decade and onwards to average around 1.7% as the investment in machinery and equipment boosts growth.

Focusing on household spending, a slower growing population will cause total household spending to ease a bit, averaging 2% towards the end of our forecast horizon. We expect that the robust domestic and foreign economies will help boost household spending over the next

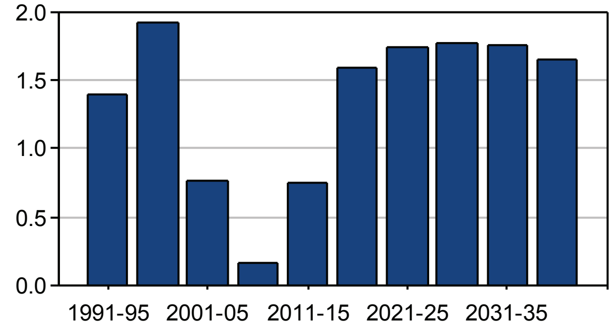
Canada and United States: Always together

(Percent change, real GDP growth)



Productivity gains

(Percent change)



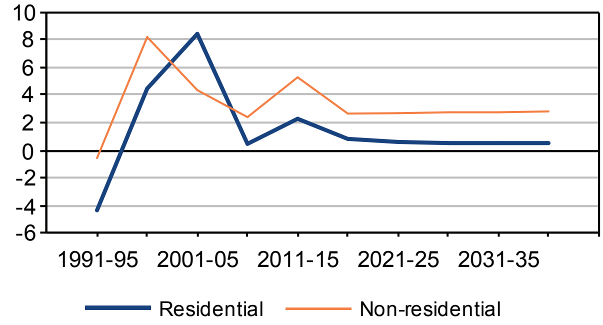
few years to around 2.5%, but growth will eventually slide down to the low 2% range. This will have a noticeable impact on spending on durable goods, or big-ticket items. Durable goods spending growth is forecast to peak this year, after four years of solid increases. Growth will decelerate by the end of the decade and then average 1.5% through to 2044. As a share of total household spending, real durable goods spending will shrink from 14% to about 12% in the face of waning demand for autos. Picking up some of the slack will be purchases of semi-durables, which will be growing around 3% throughout the forecast period. Purchases of non-durable goods will advance 1.4%, but as a share of total household spending, this segment will fall to about 20.0% from its 23.5% share today. Spending on services will continue to dominate the household spending landscape and, as a result, a greater share of spending will flow through this category.

Government spending will be soft until fiscal deficits have been slashed, so we expect only 0.9% average growth through 2015. The federal government recently announced that it will balance the books at this time and perhaps even earlier. Some of the provincial government balances, however, are faring worse. Government spending will accelerate to the 1.9% mark until the end of the forecast horizon, and return to providing a greater level of support to total real GDP, barring any future shocks or recessions.

Historically, growth in non-residential capital formation has outpaced that of residential capital formation, with the exception of during the early 2000s. This trend is on track for future growth. Looking towards the end of this decade, residential investment growth will track below 1% due to slowing new home construction thanks to weaker population growth over the longer term. However, near-term weakness is due to an already ample supply of homes in the multiple units segment. Housing

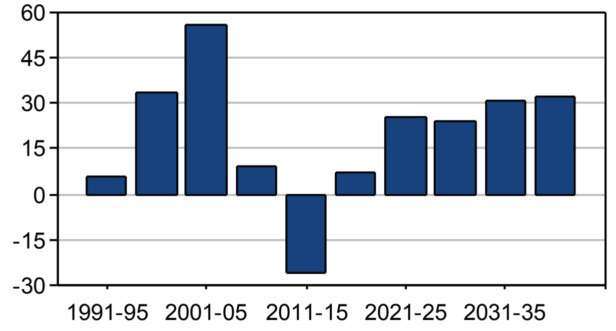
Business gross fixed capital formation

(Percent change)



Nominal trade balance recovers

(Billions of dollars)



starts will gradually slow, easing to about 158,000 units in the last 10 years of our forecast.

Non-residential construction growth, at 2.7%, will always be an important part of business capital formation as long as Canada remains a major source for energy. Investment in machinery and equipment will also be important as we expect businesses to invest in new technologies, which will ultimately increase productivity. Machinery and equipment is expected to take a larger share of total real business capital formation than residential construction beginning in 2030.

After taking a sharp hit from the recession, Canada's nominal trade balance will return to a surplus before this decade is through, on the strength of Canadian exports. We believe that a long-term 4.2% average pace will be sustained given the overall demand for Canada's commodity exports. We maintain a positive outlook for each exported good category. In addition, a greater number of free trade agreements, like the one with Europe that was announced last year, will provide greater opportunity for Canadian exporters to expand their outreach.

Coming in a bit slower, imports will advance in the mid-3–4% range throughout the forecast period to help support domestic demand. This time, imports of goods will likely outpace the imports of services two to one. However, the good news is that net trade will be a positive contributor to growth.

Helping Canada return to surplus by 2017 will be the expected increase in oil and natural gas prices as well as other non-energy commodity prices. The current-account balance will return to surplus two years later, in 2019.

Long-term inflation will be a non-issue as long as the Bank of Canada maintains its mandate of keeping inflation at the 2% target. There are no indications of the Bank straying from this course. We believe the Bank of Canada will keep its tightening bias as the economy "normalizes," and with our projected future path of growth, it shall. Our long-term forecast for all-items and core inflation is still 2%.

Arlene Kish

TABLE 2

Canadian Long-term Forecast Update

	1991-95	1996-00	2001-05	2006-10	2011-15	2016-20	2021-25	2026-30	2031-44
Real GDP (Percent Change)	1.7	4.0	2.5	1.3	2.2	2.5	2.3	2.3	2.3
Household	1.4	3.6	3.2	3.0	2.3	2.3	2.1	2.0	2.0
Government	0.4	1.1	3.0	3.9	0.9	1.9	1.9	1.9	1.9
Business Residential Investment	-4.3	4.5	8.4	0.5	2.3	0.8	0.6	0.5	0.5
Business Non-Residential Investment	-0.6	8.2	4.4	2.4	5.3	2.7	2.7	2.7	2.8
Exports	8.3	8.7	0.8	-1.7	3.1	5.0	4.5	4.5	4.1
Imports	5.9	8.3	3.4	2.6	3.2	4.1	4.0	4.0	3.6
Domestic Demand	0.7	3.6	3.5	2.8	2.2	2.3	2.1	2.0	2.1
Nominal GDP (Percent Change)	3.7	5.9	5.1	3.4	4.2	4.6	4.3	4.0	4.0
Wages, Salaries & Supplementary Labour (Percent Change)	2.6	5.5	4.9	3.9	4.2	4.1	4.0	3.8	3.8
Raw Mat. Price Index (Percent Change)	3.5	3.9	5.2	4.7	3.3	0.7	0.8	1.0	1.2
Industry Price Index (Percent Change)	3.3	1.5	0.9	1.2	2.1	1.4	1.7	1.8	1.8
GDP Deflator (Percent Change)	1.9	1.8	2.5	2.1	2.0	2.0	1.9	1.8	1.7
CPI (Percent Change)	2.3	1.7	2.3	1.7	1.7	2.0	2.0	2.0	2.0
Employment (Percent Change)	0.3	2.1	1.8	1.1	1.5	0.9	0.6	0.5	0.6
Unemployment Rate (Percent)	10.6	8.3	7.3	7.0	7.1	6.4	6.4	6.4	6.4
Labour Force (Percent Change)	0.6	1.5	1.8	1.4	1.2	0.9	0.6	0.5	0.6
Population (Percent Change)	1.2	0.9	1.0	1.1	1.1	1.1	1.0	1.0	0.8
Productivity (Percent change)	1.4	1.9	0.8	0.2	0.8	1.6	1.7	1.8	1.7
Average Hourly Earnings (Percent Change)	2.7	1.8	2.1	2.8	2.8	3.2	3.4	3.4	3.3
3-Month T-Bill Rate (Percent)	6.52	4.48	2.83	2.30	0.99	4.24	4.50	4.50	4.49
US 3-Month T-Bill Rate (Percent)	4.31	5.06	2.10	2.15	0.13	3.40	3.74	3.74	3.74
Canada-US Differential	2.21	-0.58	0.73	0.16	0.85	0.83	0.76	0.76	0.74
Prime Rate (Percent)	7.78	6.27	4.63	4.33	3.03	6.23	6.50	6.50	6.50
Overnight Rate (Percent)	6.44	4.54	2.88	2.46	1.03	4.23	4.50	4.50	4.50
US Federal Funds Rate	4.45	5.46	2.25	2.45	0.16	3.60	4.00	4.00	4.00
Bank Rate (Percent)	6.80	4.77	3.13	2.73	1.28	4.48	4.75	4.75	4.75
GOC Bond Rate (1-3 yrs.) (Percent)	7.26	5.28	3.43	2.73	1.22	4.26	4.51	4.51	4.50
GOC Bond Rate (3-5 yrs.) (Percent)	7.70	5.64	4.07	3.13	1.59	4.30	4.53	4.53	4.52
GOC 10-Year Bond Rate (Percent)	8.24	6.01	4.84	3.71	2.64	4.46	4.62	4.62	4.62
US 10-Year T-Note Rate (Percent)	6.88	5.94	4.44	3.91	2.64	4.44	4.60	4.60	4.60
US Real GDP (Percent Change)	2.6	4.3	2.5	0.8	2.5	2.9	2.3	2.4	2.4
Household Credit (Percent Change)	6.1	6.0	8.3	9.5	5.5	5.6	4.8	4.7	4.4
Standard of Living Canada/US (Nominal GDP per capita at PPP Can/US)	0.809	0.798	0.810	0.826	0.818	0.788	0.773	0.758	0.732
Exchange Rate (US-Can.)	78.7	69.5	71.9	92.2	96.9	92.1	90.8	89.6	88.4
Other Exchange Rates (C$/LCU)									
British Pound	2.07	2.30	2.29	1.91	1.64	1.85	1.94	2.00	2.08
Euro	1.58	1.58	1.52	1.48	1.37	1.48	1.55	1.60	1.67
Japanese Yen	0.0115	0.0124	0.0121	0.0106	0.0114	0.0107	0.0107	0.0108	0.0109
Curr. Acct. Bal. (Billions of dollars)	-21.4	1.3	22.9	-13.9	-50.9	-8.1	15.8	17.5	26.4
Fed. Gov't. NA Bal. (Billion dollars)	-35.6	5.6	8.0	-8.8	-9.9	5.9	5.0	6.2	10.1
Percent GNP	-4.9	0.5	0.7	-0.5	-0.6	0.3	0.2	0.2	0.2
Corp Net Oper Surplus (Percent Change)	4.4	4.0	4.1	3.9	4.3	4.1	4.1	4.1	4.1
Housing Starts (Thousands)	148.9	141.9	208.7	201.4	193.1	179.1	165.0	155.7	156.6
MLS House Price (Percent Change)	0.9	0.8	7.1	6.7	3.1	2.3	2.1	2.1	2.0
Auto Sales (Thous. SAAR)	1226.9	1437.5	1632.7	1620.1	1724.8	1758.9	1717.2	1739.8	1831.9
Nominal Exports (Billion dollars)	226.5	389.3	486.8	512.2	576.8	779.1	1031.3	1369.6	2393.2
Nominal Imports (Billion dollars)	220.8	356.0	431.3	502.8	602.8	771.8	1005.8	1345.5	2361.4
Nominal Trade Balance (Billion dollars)	5.8	33.3	55.5	9.4	-26.1	7.3	25.5	24.1	31.8
Household Saving Rate (Percent)	10.4	3.9	2.3	4.0	4.3	2.6	1.6	1.7	1.7
Real Disposable Income Growth (Percent)	0.6	2.5	2.8	3.6	2.0	2.1	2.1	2.0	2.0
Industrial Production - Percent Change			0.4	-1.7	1.8	2.7	2.7	2.6	2.6
WTI Oil Price (US dollars/barrel)	19.2	21.3	36.2	75.8	94.4	93.5	106.2	117.3	140.0
Natural Gas Price (HH spot, US$/mmBtu)	1.8	2.8	5.5	6.2	3.7	4.1	4.7	5.4	7.3

TABLE 3

Canadian Short-term Forecast Update

	13Q3	13Q4	14Q1	14Q2	14Q3	14Q4	2012	2013	2014	2015	2016	2017
Real GDP (Bil. chained 2007 $)	1695.5	1707.4	1717.0	1726.2	1736.5	1748.3	1661.6	1691.1	1732.0	1778.5	1826.5	1873.8
Annual Percent Change	2.7	2.8	2.3	2.1	2.4	2.8	1.7	1.8	2.4	2.7	2.7	2.6
Household	947.7	953.0	959.3	965.3	971.3	977.5	924.2	944.3	968.3	992.9	1016.7	1040.2
Annual Percent Change	2.2	2.3	2.6	2.5	2.5	2.6	1.9	2.2	2.5	2.5	2.4	2.3
Government	418.3	421.0	422.1	424.1	426.2	428.2	415.2	418.4	425.2	433.4	441.8	450.3
Annual Percent Change	0.8	2.6	1.1	1.9	1.9	1.9	1.0	0.8	1.6	1.9	1.9	1.9
Bus. Res. Investment	113.9	115.2	115.5	115.8	116.0	116.3	112.8	113.4	115.9	116.9	117.6	118.7
Annual Percent Change	2.4	4.7	1.1	0.9	0.8	1.0	6.1	0.6	2.2	0.9	0.6	0.9
Bus. Non-Res. Inv.	185.2	186.9	188.7	190.6	192.5	194.3	181.8	185.3	191.5	198.8	205.2	211.2
Annual Percent Change	2.2	3.8	3.8	4.1	4.0	3.9	6.2	1.9	3.4	3.8	3.2	2.9
Exports	512.2	512.0	518.0	524.0	530.4	537.1	506.5	512.4	527.4	556.2	588.4	619.1
Annual Percent Change	-2.0	-0.1	4.8	4.7	5.0	5.1	1.5	1.2	2.9	5.5	5.8	5.2
Imports	555.3	557.5	561.1	565.3	570.7	576.7	551.6	556.3	568.5	593.4	620.8	647.4
Annual Percent Change	-1.4	1.6	2.6	3.0	3.9	4.3	3.1	0.9	2.2	4.4	4.6	4.3
Business Inventory Ch.	10.2	13.0	9.8	5.5	3.3	3.2	6.8	9.7	5.5	3.1	3.2	3.1
Statistical error	-1.2	0.0	0.0	0.0	0.0	0.0	0.5	-0.5	0.0	0.0	0.0	0.0
Nominal GDP (Bil. $)	1887.8	1909.6	1928.4	1947.2	1967.2	1990.6	1820.0	1879.6	1958.3	2046.6	2140.9	2242.0
Annual Percent Change	5.6	4.7	4.0	4.0	4.2	4.8	3.4	3.3	4.2	4.5	4.6	4.7
Raw Mat. Price Index	120.0	113.9	114.5	114.9	115.0	114.9	114.7	116.0	114.8	116.1	116.9	117.3
Percent Change Year Ago	6.1	0.7	-1.6	1.0	-4.2	0.8	-4.1	1.2	-1.0	1.1	0.7	0.4
Industry Price Index	108.7	108.5	108.9	109.3	109.7	110.0	108.1	108.6	109.5	110.9	112.6	114.1
Percent Change Year Ago	0.9	0.5	-0.0	1.0	0.9	1.4	1.1	0.4	0.8	1.3	1.5	1.4
GDP Deflator	111.3	111.8	112.3	112.8	113.3	113.9	109.5	111.1	113.1	115.1	117.2	119.6
Annual Percent Change	2.8	1.8	1.7	1.8	1.7	2.0	1.7	1.5	1.7	1.8	1.9	2.1
CPI	123.2	122.9	123.7	124.1	124.4	124.6	121.7	122.8	124.2	126.4	128.9	131.5
Percent Change Year Ago	1.1	0.9	1.2	1.0	1.0	1.3	1.5	0.9	1.1	1.8	2.0	2.0
Employment (Thousands)	17750	17788	17831	17912	18023	18142	17509	17729	17977	18332	18643	18857
Annual Percent Change	0.8	0.8	1.0	1.8	2.5	2.7	1.2	1.3	1.4	2.0	1.7	1.2
Unemployment Rate (%)	7.1	7.0	7.0	7.0	6.9	6.8	7.3	7.1	6.9	6.7	6.5	6.4
Productivity (Annual Percent Change)	2.0	2.0	1.3	0.3	-0.1	0.1	0.5	0.5	1.0	0.7	1.0	1.4
Average Hourly Earnings	22.92	23.09	23.20	23.35	23.50	23.65	22.28	22.89	23.42	24.06	24.78	25.56
Annual Percent Change	1.2	3.0	1.9	2.6	2.6	2.6	2.4	2.7	2.3	2.7	3.0	3.1
3-Month T-Bill Rate (%)	1.00	0.91	0.90	0.93	0.96	0.99	0.97	0.97	0.95	1.12	2.84	4.41
US 3-Month T-Bill Rate (%)	0.03	0.06	0.05	0.06	0.06	0.06	0.09	0.06	0.06	0.40	2.18	3.62
Canada-US Differential (% pts.)	0.96	0.85	0.86	0.88	0.90	0.93	0.89	0.91	0.89	0.72	0.67	0.78
Prime Rate (%)	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.17	4.83	6.40
Overnight Rate (%)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.17	2.83	4.40
Bank Rate (%)	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.42	3.08	4.65
GOC Bond Rate (1-3 yrs.) (%)	1.21	1.09	1.09	1.13	1.17	1.20	1.12	1.12	1.15	1.34	2.95	4.42
GOC Bond Rate (3-5 yrs.) (%)	1.67	1.55	1.47	1.52	1.57	1.61	1.30	1.48	1.54	1.77	3.16	4.44
GOC Ten-Year Bond Rate (%)	2.55	2.56	2.81	2.93	3.05	3.12	1.85	2.27	2.98	3.33	3.91	4.51
US Ten-Year T-Note Rate (%)	2.71	2.75	2.79	2.91	3.03	3.10	1.80	2.35	2.96	3.31	3.89	4.49
US Real GDP (Bil. 2009 $)	15839.3	15965.6	16041.2	16132.5	16240.3	16369.8	15470.7	15767.1	16195.9	16726.0	17293.1	17833.4
Annual Percent Change	4.1	3.2	1.9	2.3	2.7	3.2	2.8	1.9	2.7	3.3	3.4	3.1
Household Credit (Billion $)	1712.1	1731.1	1753.0	1777.2	1803.1	1830.4	1634.8	1705.3	1790.9	1904.7	2031.7	2156.3
Annual Percent Change	3.6	4.5	5.2	5.6	5.9	6.2	5.7	4.3	5.0	6.4	6.7	6.1
Standard of Living Canada/US												
(Nominal GDP per Capita at PPP Can/US)							0.820	0.819	0.813	0.806	0.798	0.791
ExCh. Rate (US-Can.)	96.3	95.3	90.8	91.6	92.7	93.7	100.1	97.1	92.2	94.2	93.9	92.2
Curr. Acct. Bal. (Billion $)	-61.9	-61.8	-56.0	-48.3	-42.6	-40.2	-62.2	-61.6	-46.8	-35.4	-27.1	-15.9
Fed. Gov't. NA Bal.(Billion $)	-7.5	-6.3	-3.0	0.6	2.9	5.4	-17.3	-13.0	1.5	9.3	11.1	7.0
% GNP	-0.4	-0.3	-0.2	0.0	0.2	0.3	-1.0	-0.7	0.1	0.5	0.5	0.3
Corp Net Oper Surplus (Billion $)	236.9	259.6	260.4	262.4	264.9	267.4	245.8	239.6	263.8	272.5	281.2	290.4
Annual Percent Change	23.2	44.1	1.3	3.1	3.8	3.9	-4.9	-2.5	10.1	3.3	3.2	3.3
Housing Starts (Thousands)	192	197	188	184	183	183	215	188	185	184	183	182
Auto Sales (Thous. SAAR)	1800.5	1723.2	1738.2	1749.0	1757.9	1767.4	1716.8	1754.3	1753.1	1779.4	1782.4	1775.5
Nominal Exports (Billion $)	566.2	569.1	579.3	589.5	600.0	610.5	546.6	563.3	594.8	638.5	686.3	732.7
Nominal Imports (Billion $)	598.6	602.1	607.8	613.7	621.2	629.2	582.8	596.2	618.0	654.7	694.8	731.5
Nominal Trade Balance (Billion $)	-32.4	-33.0	-28.5	-24.2	-21.2	-18.7	-36.2	-32.9	-23.1	-16.2	-8.5	1.2
Household Saving Rate (%)	5.4	4.6	3.9	3.6	3.4	3.4	5.0	5.3	3.6	3.1	3.2	3.0
Real Disp. Inc. - Annual Percent Change	2.7	-1.2	-0.1	1.1	2.0	2.3	2.5	2.5	0.7	2.1	2.4	2.2
Industrial Production - Annual Percent Change	2.8	-0.2	1.1	1.3	1.8	2.3	0.9	0.9	1.0	2.4	2.8	2.8

Board Staff Interrogatory #018

Ref: Exh C1-1-3 pages 1-3, Exh C1-1-3 Table 2

Issue Number: 3.2
Issue: Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

Interrogatory

a) Please provide the source data and the calculations for the bankers' acceptances interest rate forecast after adjusting for the spread differential between bankers' acceptances and the yield on treasury securities of 1.22% for 2014 and 2.23% for 2015.
b) Please provide any more recent estimates for short term interest rate forecasts for 2014 and 2015 that OPG has.
c) Canadian, U.S. and other major central banks have tended to stay the course on overnight and other central bank rates as they balance inflationary and national and global economy stimulus and growth per governmental policies. Please explain why an increase of about 1 percentage point in 2015 is still to be expected.
d) On pages 1-2 of Exh C1-1-3, OPG explains the purpose of the accounts receivable securitization. In Table 2, OPG shows that it made little use of this program in 2012, with an average principal of $8.3M. OPG explains that it intends to use the A/R securitization program beginning in 2013 Q4 with an average monthly principal balance of $195M and that this will continue for the 2014-2015 test period.
   i. Did OPG use the securitization program in 2013 Q4 as forecasted?
   ii. Please explain why OPG has decided to borrow under the A/R securitization program, when it did not need to avail itself to this short-term funding mechanism in 2012 or most of 2013 to any great extent.

Response

a) The Global Insight forecast used to derive the bankers' acceptance rate forecast is contained in Ex L-3.2-1 Staff 17, Attachment 2, which is an extract from its April 2013 Canadian Forecast Summary.

   The bankers' acceptance rate forecast consists of the Global Insight forecast for the 3-Month T-Bill Rate plus a historical spread of bankers' acceptance over T-Bills of approximately 15 basis points.

b) The most recent estimate for short term interest rate forecast for 2014 and 2015 is contained in Ex L-3.2-1 Staff 17 Attachment 3, which is an extract from the Global Insight February 2014 Canadian Forecast Summary.

c) The increase in the bankers' acceptance rate in 2015 is based on Global Insight's forecast for the 3-Month T-Bill Rate in this period, as shown in Ex L-3.2-1 Staff 17, Attachment 2.

d) (i) The securitization program was not used as due to OPG's lower cash requirement during Q4 2013.

(ii) OPG did not use much of the A/R securitization program for 2012 and 2013 due to OPG's lower cash requirement during that period. However, OPG expects its cash requirements will be higher during the period of 2014 and 2015; hence the A/R securitization program will be utilized to a larger degree, as has happened in prior years.

CCC Interrogatory #012

Ref: Ex. C1/T1/S2/p. 1

Issue Number: 3.2
Issue: Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

Interrogatory

OPG assigns all existing and planned project-related financing to regulated or unregulated operations based on whether the project is related to its regulated assets. Please explain to what extent, if any, there is a differential between the cost of debt for OPG's regulated and unregulated operations. If so, what is the reason for the differential?

Response

For debt allocated to regulated and unregulated operations, there is no differential in the cost of debt. As indicated in Ex. C1-1-2 Table 1, assets using project financing which have different debt costs, are excluded in the allocation.

EP Interrogatory #002

Ref: Exh. C1/T1/Sch. 2, p.3

Issue Number: 3.2
Issue: Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

Interrogatory

OPG states that the average remaining term of its outstanding long-term debt is approximately 8.4 years.

a) Is this a simple average of the remaining terms on outstanding long-term debt or a weighted-average?

b) If a weighted average, please explain briefly the weights used in the calculation.

Response

a) This is a weighted average of the terms remaining on OPG's outstanding long-term debt.

The weighting used in the calculation is based on the face value of each debt note outstanding.

For example: Debts outstanding are composed of a $100M note with term to maturity of 3 years and a $1,000M note with term to maturity of 10 years. The weighted average term of the outstanding debt is:

b) ($100 * 3years + $1,000 * 10years) / ($100 + $1,000) = 9.4 years

EP Interrogatory #003

Ref: Exh. C1/T1/Sch. 2, p.3

Issue Number: 3.2
Issue: Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

Interrogatory

OPG states that its agreements with OEFC contain call provisions that make it more expensive to redeem the debt compared to the potential benefit of refinancing in a lower interest-rate environment.

a) Does "refinancing" mean purchasing an outstanding bond at its market price and financing that purchase by issuing a new bond at a lower interest rate?

b) Do the call provisions in the OEFC agreements allow OPG to redeem an outstanding bond at its face value (rather than its market value) plus accrued interest?

c) Please briefly describe the other portions of the relevant agreements with the OEFC that make redemption more expensive.

d) If the answer to c) is yes, and considering that lower interest rates would raise the market price of the outstanding bond above its face value, why would it be more expensive to redeem than to finance the purchase of the bond on the market at a lower interest rate?

Response

a) No. Refinance in this context means:
   (i) to prepay the outstanding OEFC debt prior to its maturity date, at a price calculated as per the applicable OEFC agreement.
   (ii) to issue new debt at the then market price under a new financing agreement. The coupon rate of the new bond could be higher or lower than the rate on the old debt, depending on market conditions, as well as the term of the new bond.

b) No. OPG's existing debts were issued under various agreements with the OEFC. The debts can be classified into three groups based on the call provisions in the agreements.
   (i) approximately 50% of OPG's debts outstanding were issued with call provisions under which debts can be redeemed at mark-to-market value plus a yield penalty.
   (ii) approximately 35% of OPG's debts outstanding were issued with call provisions under which debt can be redeemed at mark-to-market value.
   (iii) approximately 15% of OPG's debts outstanding were issued with call provisions under which debt may be redeemed at face value plus accrued interest. However, OEFC's consent is required for any early redemption under these agreements.

c) Please see part b)

d) Please see part b)

EP Interrogatory #004

Ref: Exh. C1/T1/Sch. 2, p.4

Issue Number: 3.2
Issue: Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

Interrogatory

OPG states that it is matching the term of its debt portfolio "to better match" the term of its underlying assets thereby reducing refinancing risk.

a) Please explain briefly how the matching of terms reduces refinancing risk.

b) Does OPG agree that longer-term debt is generally more interest-rate sensitive than short-term debt?

c) Does "matching" the term of the debt portfolio with the underlying assets indicate that OPG believes its long-term assets are similarly interest-rate sensitive?

Response

a) Refinancing risk is the uncertainty of the availability and the cost of a new source of funds that are being used to finance long-term fixed assets. This risk occurs when a company holds assets with service life greater than the maturities of its debts, which results in uncertainty of funds being available from lenders at maturity and/or uncertainty of the cost of refinancing on a long-term basis. Therefore matching terms reduces refinancing risk.

b) OPG believes that as a borrower whose intention is to hold its debt to maturity, refinancing risk as addressed in a) is a more relevant factor than interest-rate sensitivity in deciding on the term of maturity of its debt portfolio. Interest-rate sensitivity of bond portfolio, however, is more relevant from an investor's perspective since the movement in interest rate will lead to changes in the fair value of the bond portfolio, as such longer-term debt, with longer duration, would generally be more interest-rate sensitive than short-term debt.

c) No. Given the fact that OPG's underlying assets are primarily hard physical assets, they are not as interest rate sensitive as OPG's debt portfolio. The rationale for OPG's effort to lengthen the term of its debt portfolio to better match the term of its underlying assets is to reduce refinancing risk as addressed in a).

EP Interrogatory #005

Ref: Exh. C1/T1/Sch. 2, p.4

Issue Number: 3.2
Issue: Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

Interrogatory

OPG indicates that the credit margin on its corporate debt will be the same as on its project debt because the credit margin "evaluates OPG as a borrowing entity rather than the project".

a) Do project lenders to OPG have the same degree and extent of recourse to OPG assets as its corporate lenders in the event of default?

b) If project lenders evaluate OPG as a whole as the borrowing entity and require the same credit margin, what is the benefit to OPG of issuing project debt?

Response

a) Yes. The project referenced in Ex. C1-1-2, page 4 is the Niagara Tunnel Project. The OEFC is the sole lender for OPG's company-wide debt and Niagara Tunnel Project debt, so the project lender and corporate lender is the same entity. In any event, all OEFC debt has the same degree and extent of recourse to OPG's assets, whether it is project-related debt or company-wide debt.

b) The benefit of having a specific OEFC project financing agreement was that it secured committed funding for the whole project at the start of the project.

EP Interrogatory #006

Ref: Exh. C1/T1/Sch. 2, p.5

Issue Number: 3.2
Issue: Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

Interrogatory

Please explain the following statement at the bottom of p.5:

> "To the extent that a forecast debt issue is hedged and OPG does not ultimately require the underlying debt issue, the impact of the hedge transaction is charged to unregulated operations."

Response

As noted in Ex C1-1-2, page 5, lines 17 - 18, hedging was undertaken to mitigate OPG's exposure to interest rate fluctuations on debt that is required to finance OPG's rate base. If a debt issue is ultimately not required to finance regulated assets, the hedging cost on that debt is similarly not required to finance regulated assets. The cost of closing out the hedge is therefore excluded from OPG's revenue requirement.

EP Interrogatory #007

Ref: Exh. C1/T1/Sch.3, p.1

Issue Number: 3.2
Issue: Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

Interrogatory

What is the stamping fee that OPG pays for borrowing by way of issuing bankers' acceptances?

Response

The stamping fee that OPG pays for borrowing by way of issuing bankers' acceptances is 100 basis points as per OPG's latest bank credit facility.

LPMA Interrogatory #003

Ref: Exhibit C1, Tab 1, Schedule 2

Issue Number: 3.2
Issue: Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

Interrogatory

Please update Tables 5, 6 and 7 to reflect actual borrowings in 2013 Issue 29, Niagara 25 and Niagara 26 and any other actual borrowings that were in place at the end of 2013.

Response

Refer to Ex L-03.2-1 Staff-017c) for the 2013 actual debt. Issue 29, Niagara 25 and Niagara 26 were not issued as OPG had lower cash requirements during Q4, 2013. In 2014 and 2015 lower existing long-term debt is directly offset by an increase in OPG's other long-term debt provision to maintain the 47 per cent debt ratio approved by the OEB.

OPG is not updating its 2014 or 2015 test period proposal to reflect 2013 actual information. Such an update would increase the proposed revenue requirement as the interest rate applicable to the other long term debt provision is higher (4.86% in 2015 per Ex. C1-1-1, Table 1, line 3 and 4.85% in 2014 per Ex. C1-1-1, Table 2, line 3) than the interest rates for 2013 forecast debt that did not occur (Issue 29 and Niagara 25 were forecast to cost 3.4%, while Niagara 26 was forecast to cost 3.58%).

LPMA Interrogatory #004

Ref: Exhibit C1, Tab 1, Schedule 2

Issue Number: 3.2
Issue: Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

Interrogatory

Please update Tables 6a and 7a to reflect the most recent Global Insight forecast available and the most recent estimate available for the OPG Spread.

Response

OPG filed an Impact Statement (Ex. N1-1-1) to show the impact of certain material changes contained in its 2014 - 2016 Business Plan. OPG did not update its Application for the most recent Global Insight forecast in that Impact Statement.

The most recent Global Insight Forecast (February 2014) and the 2013 year-end OPG spread is provided in Ex. L-3.2-1 Staff 17 d) and f).

SEP Interrogatory #002

Ref: Exh C-1-1-1,

Issue Number: 3.2
Issue: Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

Interrogatory

Please calculate, using *ceteris paribus* assumptions, the change in the revenue requirement for OPG`s regulated asset portfolio for ROEs of 8% and 7%. Please calculate the corresponding changes in the revenue requirement for these ROEs under the debt-equity ratios in 3.1-SEP-1b (i.e. 70:30 and 90:10).

Response

Attachment 1, Table 1 (2015) and Table 2 (2014) show the change in the cost of capital using a 70:30 debt/equity ratio and an ROE of 8 per cent. The impact on revenue requirement is provided below:

Impact on revenue requirement of 70:30 debt/equity ratio and 8% ROE

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Pre-filed	Pre-filed	Pre-filed	IR Request	IR Request	IR Request	Change	Change
Line	Descrip-tion	Reference	2015 ($M)	2014 ($M)	Reference	2015 ($M)	2014 ($M)	2015 ($M)	2014 ($M)
1	Interest Expense	C1-1-1 Table 1 and Table 2 line 4, col d)	256.2	253.6	Attachment 1 Table 1 and Table 2 line 4, col d)	338.5	335.7	82.3	82.1
2	ROE	C1-1-1 Table 1 and Table 2 line 5, col d)	420.5	420.2	Attachment 1 Table 1 and Table 2 line 5, col d)	239.1	239.0	-181.4	-181.2
3	Income tax	(line 2 / (1-25%) – line 2	140.2	140.1	(line 2 / (1-25%) – line 2	79.7	79.7	-60.5	-60.4
4	Revenue Require-ment Impact	Line 1 + 2 + 3	816.9	813.9	Line 1 + 2 + 3	657.4	654.3	-159.5	-159.5

Attachment 1, Table 3 (2015) and Table 4 (2014) show the change in the cost of capital using a 70:30 debt/equity ratio and an ROE of 7 per cent. The impact on revenue requirement is provided below:

Impact on revenue requirement of 70:30 debt/equity ratio and 7% ROE

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
$M		**Pre-filed**	**Pre-filed**	**Pre-filed**	**IR Request**	**IR Request**	**IR Request**	**Change**	**Change**
Line	**Descrip-tion**	**Reference**	**2015 ($M)**	**2014 ($M)**	**Reference**	**2015 ($M)**	**2014 ($M)**	**2015 ($M)**	**2014 ($M)**
1	Interest Expense	C1-1-1 Table 1 and Table 2 line 4, col d)	256.2	253.6	Attachment 1 Table 3 and Table 4 line 4, col d)	338.5	335.7	82.3	82.1
2	ROE	C1-1-1 Table 1 and Table 2 line 5, col d)	420.5	420.2	Attachment 1 Table 3 and Table 4 line 5, col d)	209.2	209.1	-211.3	-211.1
3	Income tax	(line 2 / (1-25%) – line 2	140.2	140.1	(line 2 / (1-25%) – line 2	69.7	69.7	-70.4	-70.4
4	Revenue Require-ment Impact	Line 1 + 2 + 3	816.9	813.9	Line 1 + 2 + 3	617.5	614.5	**-199.4**	**-199.4**

Attachment 1 Table 5 (2015) and Table 6 (2014) show the change in the cost of capital using a 90:10 debt/equity ratio and an ROE of 8 per cent. The impact on revenue requirement is provided below:

Impact on revenue requirement of 90:10 debt/equity ratio and 8% ROE

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
$M		Pre-filed	Pre-filed	Pre-filed	IR Request	IR Request	IR Request	Change	Change
Line	Descrip-tion	Reference	2015 ($M)	2014 ($M)	Reference	2015 ($M)	2014 ($M)	2015 ($M)	2014 ($M)
1	Interest Expense	C1-1-1 Table 1 and Table 2 line 4, col d)	256.2	253.6	Attachment 1 Table 5 and Table 6 line 4, col d)	435.4	432.3	179.2	178.7
2	ROE	C1-1-1 Table 1 and Table 2 line 5, col d)	420.5	420.2	Attachment 1 Table 5 and Table 6 line 5, col d)	79.7	79.7	-340.8	-340.5
3	Income tax	(line 2 / (1-25%) – line 2	140.2	140.1	(line 2 / (1-25%) – line 2	26.6	26.6	-113.6	-113.5
4	Revenue Require-ment Impact	Line 1 + 2 + 3	816.9	813.9	Line 1 + 2 + 3	541.7	538.5	**-275.2**	**-275.4**

Attachment 1, Table 7 (2015) and Table 8 (2014) show the change in the cost of capital using a 90:10 debt/equity ratio and an ROE of 7 per cent. The impact on revenue requirement is provided below:

Impact on revenue requirement of 90:10 debt/equity ratio and 7% ROE

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
$M		Pre-filed	Pre-filed	Pre-filed	IR Request	IR Request	IR Request	Change	Change
Line	Descrip-tion	Reference	2015 ($M)	2014 ($M)	Reference	2015 ($M)	2014 ($M)	2015 ($M)	2014 ($M)
1	Interest Expense	C1-1-1 Table 1 and Table 2 line 4, col d)	256.2	253.6	Attachment 1 Table 7 and Table 8 line 4, col d)	435.4	432.3	179.2	178.7
2	ROE	C1-1-1 Table 1 and Table 2 line 5, col d)	420.5	420.2	Attachment 1 Table 7 and Table 8 line 5, col d)	69.7	69.7	-350.8	-350.5
3	Income tax	(line 2 / (1-25%) – line 2	140.2	140.1	(line 2 / (1-25%) – line 2	23.2	23.2	-116.9	-116.8
4	Revenue Require-ment Impact	Line 1 + 2 + 3	816.9	813.9	Line 1 + 2 + 3	528.4	525.2	**-288.5**	**-288.6**

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, 2015

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	192.2	1.9%	2.89%	9.0
2	**Existing/Planned Long-Term Debt**	2	3,481.6	34.9%	4.86%	169.2
3	**Other Long-Term Debt Provision**	3	3,300.3	33.1%	4.86%	160.4
4	**Total Debt**	4	6,974.1	70.0%	4.85%	338.5
5	**Common Equity**	4	2,988.9	30.0%	8.00%	239.1
6	**Rate Base Financed by Capital Structure**	5	9,963.0	88.4%	5.80%	577.7
7	**Adjustment for Lesser of UNL or ARC**	5, 6	1,308.8	11.6%	5.37%	70.3
8	**Rate Base**	7	11,271.8	100%	5.75%	647.9

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 13), Cost Rate (line 8), Cost of Capital (line 14).

2 Ex. C1-1-2 Table 7, line 47.

3 Debt required to balance capital structure requested in Interrogatory with proposed rate base. See Ex. C1-1-2, Section 5.0. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2) per EB-2010-0008 Decision with Reasons.

4 Capital Structure requested in this Interrogatory
Return on Equity set at 8 percent requested in this interrogatory.

5 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded 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 32. Weighted average accretion rate from Ex. C2-1-1, section 3.0.

7 Ex. B1-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro) and Ex. B1-1-1 Table 2 (Nuclear).

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, 2014

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	192.2	1.9%	1.87%	7.0
2	**Existing/Planned Long-Term Debt**	2	3,372.7	33.9%	4.85%	163.6
3	**Other Long-Term Debt Provision**	3	3,404.8	34.2%	4.85%	165.1
4	**Total Debt**	4	6,969.7	70.0%	4.82%	335.7
5	**Common Equity**	4	2,987.0	30.0%	8.00%	239.0
6	**Rate Base Financed by Capital Structure**	5	9,956.7	87.8%	5.77%	574.7
7	**Adjustment for Lesser of UNL or ARC**	5, 6	1,389.5	12.2%	5.37%	74.6
8	**Rate Base**	7	11,346.1	100%	5.72%	649.3

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 13), Cost Rate (line 8), Cost of Capital (line 14).

2 Ex. C1-1-2 Table 6, line 45.

3 Debt required to balance capital structure requested in Interrogatory with proposed rate base. See Ex. C1-1-2, Section 5.0. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2) per EB-2010-0008 Decision with Reasons.

4 Capital Structure requested in this Interrogatory
Return on Equity set at 8 percent requested in this interrogatory.

5 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded 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 32. Weighted average accretion rate from Ex. C2-1-1, section 3.0.

7 Ex. B1-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro) and Ex. B1-1-1 Table 2 (Nuclear).

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, 2015

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	192.2	1.9%	2.89%	9.0
2	**Existing/Planned Long-Term Debt**	2	3,481.6	34.9%	4.86%	169.2
3	**Other Long-Term Debt Provision**	3	3,300.3	33.1%	4.86%	160.4
4	**Total Debt**	4	6,974.1	70.0%	4.85%	338.5
5	**Common Equity**	4	2,988.9	30.0%	7.00%	209.2
6	**Rate Base Financed by Capital Structure**	5	9,963.0	88.4%	5.50%	547.8
7	**Adjustment for Lesser of UNL or ARC**	5, 6	1,308.8	11.6%	5.37%	70.3
8	**Rate Base**	7	11,271.8	100%	5.48%	618.1

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 13), Cost Rate (line 8), Cost of Capital (line 14).

2 Ex. C1-1-2 Table 7, line 47.

3 Debt required to balance capital structure requested in Interrogatory with proposed rate base.
See Ex. C1-1-2, Section 5.0. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2) per EB-2010-0008 Decision with Reasons.

4 Capital Structure requested in this Interrogatory
Return on Equity set at 7 percent requested in this interrogatory.

5 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded 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 32. Weighted average accretion rate from Ex. C2-1-1, section 3.0.

7 Ex. B1-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro) and Ex. B1-1-1 Table 2 (Nuclear).

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, 2014

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	192.2	1.9%	1.87%	7.0
2	**Existing/Planned Long-Term Debt**	2	3,372.7	33.9%	4.85%	163.6
3	**Other Long-Term Debt Provision**	3	3,404.8	34.2%	4.85%	165.1
4	**Total Debt**	4	6,969.7	70.0%	4.82%	335.7
5	**Common Equity**	4	2,987.0	30.0%	7.00%	209.1
6	**Rate Base Financed by Capital Structure**	5	9,956.7	87.8%	5.47%	544.8
7	**Adjustment for Lesser of UNL or ARC**	5, 6	1,389.5	12.2%	5.37%	74.6
8	**Rate Base**	7	11,346.1	100%	5.46%	619.4

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 13), Cost Rate (line 8), Cost of Capital (line 14).
2 Ex. C1-1-2 Table 6, line 45.
3 Debt required to balance capital structure requested in Interrogatory with proposed rate base. See Ex. C1-1-2, Section 5.0. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2) per EB-2010-0008 Decision with Reasons.
4 Capital Structure requested in this Interrogatory. Return on Equity set at 7 percent requested in this interrogatory.
5 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded 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 32. Weighted average accretion rate from Ex. C2-1-1, section 3.0.
7 Ex. B1-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro) and Ex. B1-1-1 Table 2 (Nuclear).

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, 2015

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	192.2	1.9%	2.89%	9.0
2	**Existing/Planned Long-Term Debt**	2	3,481.6	34.9%	4.86%	169.2
3	**Other Long-Term Debt Provision**	3	5,292.9	53.1%	4.86%	257.2
4	**Total Debt**	4	8,966.7	90.0%	4.86%	435.4
5	**Common Equity**	4	996.3	10.0%	8.00%	79.7
6	**Rate Base Financed by Capital Structure**	5	9,963.0	88.4%	5.17%	515.1
7	**Adjustment for Lesser of UNL or ARC**	5, 6	1,308.8	11.6%	5.37%	70.3
8	**Rate Base**	7	11,271.8	100%	5.19%	585.4

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 13), Cost Rate (line 8), Cost of Capital (line 14).

2 Ex. C1-1-2 Table 7, line 47.

3 Debt required to balance capital structure requested in Interrogatory with proposed rate base.
See Ex. C1-1-2, Section 5.0. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2) per EB-2010-0008 Decision with Reasons.

4 Capital Structure requested in this Interrogatory
Return on Equity set at 8 percent requested in this interrogatory.

5 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded 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 32. Weighted average accretion rate from Ex. C2-1-1, section 3.0.

7 Ex. B1-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro) and Ex. B1-1-1 Table 2 (Nuclear).

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, 2014

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	192.2	1.9%	1.87%	7.0
2	**Existing/Planned Long-Term Debt**	2	3,372.7	33.9%	4.85%	163.6
3	**Other Long-Term Debt Provision**	3	5,396.1	54.2%	4.85%	261.7
4	**Total Debt**	4	8,961.0	90.0%	4.82%	432.3
5	**Common Equity**	4	995.7	10.0%	8.00%	79.7
6	**Rate Base Financed by Capital Structure**	5	9,956.7	87.8%	5.14%	512.0
7	**Adjustment for Lesser of UNL or ARC**	5, 6	1,389.5	12.2%	5.37%	74.6
8	**Rate Base**	7	11,346.1	100%	5.17%	586.6

Notes:
1 Ex. C1-1-3 Table 2: Principal (line 13), Cost Rate (line 8), Cost of Capital (line 14).
2 Ex. C1-1-2 Table 6, line 45.
3 Debt required to balance capital structure requested in Interrogatory with proposed rate base.
See Ex. C1-1-2, Section 5.0. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2) per EB-2010-0008 Decision with Reasons.
4 Capital Structure requested in this Interrogatory
Return on Equity set at 8 percent requested in this interrogatory.
5 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded 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 32. Weighted average accretion rate from Ex. C2-1-1, section 3.0.
7 Ex. B1-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro) and Ex. B1-1-1 Table 2 (Nuclear).

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, 2015

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	192.2	1.9%	2.89%	9.0
2	**Existing/Planned Long-Term Debt**	2	3,481.6	34.9%	4.86%	169.2
3	**Other Long-Term Debt Provision**	3	5,292.9	53.1%	4.86%	257.2
4	**Total Debt**	4	8,966.7	90.0%	4.86%	435.4
5	**Common Equity**	4	996.3	10.0%	7.00%	69.7
6	**Rate Base Financed by Capital Structure**	5	9,963.0	88.4%	5.07%	505.1
7	**Adjustment for Lesser of UNL or ARC**	5, 6	1,308.8	11.6%	5.37%	70.3
8	**Rate Base**	7	11,271.8	100%	5.10%	575.4

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 13), Cost Rate (line 8), Cost of Capital (line 14).

2 Ex. C1-1-2 Table 7, line 47.

3 Debt required to balance capital structure requested in Interrogatory with proposed rate base. See Ex. C1-1-2, Section 5.0. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2) per EB-2010-0008 Decision with Reasons.

4 Capital Structure requested in this Interrogatory
Return on Equity set at 7 percent requested in this interrogatory.

5 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded 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 32. Weighted average accretion rate from Ex. C2-1-1, section 3.0.

7 Ex. B1-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro) and Ex. B1-1-1 Table 2 (Nuclear).

Numbers may not add due to rounding.

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

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	192.2	1.9%	1.87%	7.0
2	**Existing/Planned Long-Term Debt**	2	3,372.7	33.9%	4.85%	163.6
3	**Other Long-Term Debt Provision**	3	5,396.1	54.2%	4.85%	261.7
4	**Total Debt**	4	8,961.0	90.0%	4.82%	432.3
5	**Common Equity**	4	995.7	10.0%	7.00%	69.7
6	**Rate Base Financed by Capital Structure**	5	9,956.7	87.8%	5.04%	502.0
7	**Adjustment for Lesser of UNL or ARC**	5, 6	1,389.5	12.2%	5.37%	74.6
8	**Rate Base**	7	11,346.1	100%	5.08%	576.6

Notes:

1. Ex. C1-1-3 Table 2: Principal (line 13), Cost Rate (line 8), Cost of Capital (line 14).
2. Ex. C1-1-2 Table 6, line 45.
3. Debt required to balance capital structure requested in Interrogatory with proposed rate base.
   See Ex. C1-1-2, Section 5.0. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2) per EB-2010-0008 Decision with Reasons.
4. Capital Structure requested in this Interrogatory
   Return on Equity set at 7 percent requested in this interrogatory.
5. The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded 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 32. Weighted average accretion rate from Ex. C2-1-1, section 3.0.
7. Ex. B1-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro) and Ex. B1-1-1 Table 2 (Nuclear).

SEP Interrogatory #003

Ref: EB-2009-0084 **Report of the Board on the Cost of Capital for Ontario`s Regulated Utilities**

Issue Number: 3.2
Issue: Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

Interrogatory

On page iii of the Executive Summary to the Board report, the Board says, `If the application of these methods produces numerical results that, in the view of the Board, raise doubt that the Fair Return Standard is met, the Board may then use its discretion to begin a consultative process.`

The Board`s Report was issued in the aftermath of the 2008 financial crisis and the subsequent 2009 economic recession. Are there any considerations that OPG could identify that would justify the Board Panel, in the current proceeding, examining the basis on which the ROE is set?

Response

In the referenced Board Report, the OEB stated that it would annually calculate the cost of capital parameters and, "If the application of these methods produces numerical results that, in the view of the Board, raise doubt that the Fair Return Standard is met, the Board may then use its discretion to begin a consultative process."

On November 25, 2013 the OEB issued cost of capital parameters for utility rates effective January 1, 2014. As the OEB did not indicate that it would initiate a review as a result of the parameter values, the implication is that the OEB is of the view that the current cost of capital approach meets the fair return standard. OPG expects that the Panel in this Application would proceed accordingly.

VECC Interrogatory #001

Ref: C1-1-2, Tables 6 and 7

Issue Number: 3.2
Issue: Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

Interrogatory

a) Please provide the ratio of actual debt (debt that has actually been issued to the end of 2013 and will be outstanding within each test year) to forecast debt for each of the test years.

Response

Attachment 1 provides the ratio of actual to forecast debt reflected in Ex. C1-1-2 ,Table 6 and 7 for the 2008 - 2013 period

		2008	2009	2010	2011	2012	2013
Row #	$M (unless noted)	(a)	(b)	(c)	(d)	(e)	(f)
1	Actual debt[a]	2052.5	2019.8	2128.4	2300.0	2287.6	2336.7
2	Forecast debt[b]	2197.2	2362.7	n/a	2283.1	2502.8	n/a
3	Ratio of actual debt to forecast debt	0.93	0.85	n/a	1.01	0.91	n/a

Note (a): Source of actual debt amounts
2008: EB-2010-0008 Ex C1-1-2 Table 3 line 28
2009: EB-2010-0008 Ex C1-1-2 Table 4 line 31
2010: EB-2013-0321 Ex C1-1-2 Table 2 line 37
2011: EB-2013-0321 Ex C1-1-2 Table 3 line 37
2012: EB-2013-0321 Ex C1-1-2 Table 4 line 39
2013: EB-2013-0321 Ex L-3.2-1 Staff 17 Attachment 1 line 40

Note (b): Source of forecast debt amounts
2008: EB-2007-0905 Payment Amounts Order Appendix A Table 4a line 2
2009: EB-2007-0905 Payment Amounts Order Appendix A Table 5a line 2
2010: n/a
2011: EB-2010-0008 Payment Amounts Order Appendix A Table 4a line 2
2012: EB-2010-0008 Payment Amounts Order Appendix A Table 5a line 2
2013: n/a