OPG

EB-2016-0152

OEB Staff Compendium

Panel 5Ai

needed as a consequence of any other findings in this decision, OPG should detail those adjustments in its draft order.

8.2 Capital Structure and Cost of Capital – Introduction

OPG's interim rates are based on a debt/equity ratio of 55/45 and a return on equity (ROE) of 5%. The following table sets out OPG's proposed capital structure and cost of capital for 2008 and 2009.

Table 8-2: Proposed Capital Structure and Cost of Capital

	2008		2009	
	% of Capital Structure	Rate	% of Capital Structure	Rate
Short-Term Debt	2.6%	5.83%	2.6%	5.98%
Existing/Planned Long-Term Debt	29.7%	5.79%	32.1%	5.79%
Other Long-Term Debt Provision	10.3%	5.65%	7.8%	6.47%
Total Debt	**42.5%**	**5.76%**	**42.5%**	**5.92%**
Common Equity	**57.5%**	**10.50%**	**57.5%**	**10.50%**
Total Rate Base	**100%**	**8.48%**	**100%**	**8.56%**

Source: Ex. C1-2-1, Tables 2 and 3.

OPG also proposed that the Board adopt a formula to be used for future adjustments to the ROE.

Ms. McShane provided evidence for OPG. Intervenors also presented expert evidence as follows:

- Board staff sponsored evidence by Mr. Goulding.
- The Pollution Probe Foundation (Pollution Probe) sponsored evidence by Drs. Kryzanowski and Roberts.
- VECC and CCC sponsored evidence by Dr. Booth.
- Energy Probe sponsored evidence by Dr. Schwartz.
- Green Energy Coalition (GEC) sponsored evidence by Mr. Chernick.
- AMPCO sponsored evidence by Dr. Murphy and Mr. Adams.

The following table summarizes the quantitative evidence of the witnesses.

Table 8-3: Summary of Expert Recommendations

Expert	Return on Equity	Capital Structure	
		Debt	Equity
Ms. McShane		42.5%	57.5%
Equity Risk Premium test	9.5-10.25%		
Discounted Cash Flow test	9.5-10.0%		
Comparable Earnings test	12.5%		
Recommendation	10.50%		
Dr. Kryzanowski / Dr. Roberts	7.35% (2008) 7.40% (2009)	53%	47%
Dr. Booth	7.75%	60%	40%
Dr. Schwartz	7.64%	55%	45%

This chapter will address the following issues:

- Capital structure
- Return on equity
- Cost of debt

8.3 Capital Structure

8.3.1 Approach to setting capital structure

CME submitted that the Board should begin with the premise that the debt/equity structure determined by the Province for purposes of setting the payments in the interim period was appropriate and that the structure should only change if there has been a material change in OPG's risks. CME pointed to OPG's testimony that its risks had not changed.

OPG responded that this position would have some merit if the prior capital structure had been set by the Board. OPG submitted that the Province adopted the interim equity ratio "as a transition to full cost of service rates established after an independent review by the OEB."[98] OPG pointed out that the level was set without a thorough cost of capital study and O. Reg. 53/05 clearly makes the Board the authority to set the payments. OPG also argued that if the Province thought the capital structure was appropriate, it could have indicated as such in O. Reg. 53/05. In OPG's view, the fact that the O. Reg. 53/05 does not stipulate the equity ratio supports the conclusion that the Province expected the Board to make its determination of the cost of capital on a commercial basis.

Board Findings

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.

The equity ratio underlying the interim rates is informative, but not determinative for purposes of the Board's decision; rather it is an expression of the Province's expectations at that time and its assessment of what would be reasonable in the circumstances. The Board agrees that an important distinction is that the equity ratio was not set under the auspices of a Board proceeding with evidence, testimony and argument.

The following factors were raised in the context of the risk assessment, each of which will be addressed in turn:

- The stand-alone principle
- Regulatory risk
- Operating risk

8.3.2 The stand-alone principle

Many regulated utilities are part of a broader entity that includes affiliates or non-regulated operations. Under the stand-alone principle, the regulated operations of the utility are treated for regulatory purposes as if they were operating separately from the other activities of the entity. The intent is that the cost of capital borne by customers, in respect of the regulated operations, should not reflect subsidies to or from other activities of the firm and should only reflect the business risks associated with the regulated operations.

[98] OPG Reply Argument, p. 9.

OPG has several characteristics which differentiate it from other utilities regulated by the Board. Both the regulated and unregulated operations are in the business of generating power for sale into the Ontario market; both the regulated and unregulated operations are owned by the Province. It is also the Province that has determined, in certain respects, the Board's current and future approach to setting payment amounts. That is the context in which the Board considers the application of the stand-alone principle to the regulated operations of OPG.

At issue in the hearing was whether in the course of setting an appropriate capital structure, the application of the stand-alone principle excluded a consideration of the significance of the Province's ownership of OPG as part of the assessment of business risks associated with the regulated operations.

OPG's position is that the matter of ownership should not be taken into account, and the cost of capital for the regulated operations should reflect what the cost would be if OPG were raising capital in the public markets on the strength of their own business and financial parameters. OPG noted that Mr. Goulding and Drs. Kryzanowski and Roberts agree that the stand-alone principle is a fundamental principle in determining the cost of capital.

OPG also noted that Mr. Goulding recognized the political risk which OPG faces due to changing power sector policies and that the bond rating agencies have highlighted political risk. Mr. Goulding's evidence was that the prescribed assets face greater political risk than transmission, distribution or merchant generators because these other entities are less likely to be used directly by government for policy purposes. Ms. McShane assessed that "the risk of future political intervention in the market is higher than in other Canadian jurisdictions."[99]

CCC, VECC, AMPCO, and CME all took the position that provincial ownership of OPG should be a factor in assessing OPG's risk and in determining the appropriate capital structure.

CCC took the position that the real shareholders are the residents of Ontario, and that the government is acting as their agent or proxy and is responsible for ensuring there is an adequate supply of electricity at reasonable prices:

[99] Ex. C2-1-1, p.64

> The Council submits that the facts require the Board to consider the capital structure and return on equity, not on the basis of what amounts to an artificial concept of a stand-alone entity, but on the basis of the reality that the government, because of its obligations to the residents of the province, has a stake in limiting the risks which OPG faces, and ensuring that OPG does not fail.[100]

CCC noted that the government had directed the OPA to include up to 14,000MW of baseload nuclear generation in its planning, directed OPG to refurbish existing and develop new nuclear capacity, and established a deferral account to recover the costs related to refurbished and new nuclear capacity. In CCC's view, "the government has exercised a power no private sector shareholder has, namely to direct the regulator to ensure risks which are taken in the public interest are protected."[101]

VECC made similar submissions:

> While the identity of any private group of shareholders or owners is not of relevance, ownership of a utility by the same entity that can simultaneously direct utility operations and direct regulatory treatment is of the utmost relevance in this case especially with respect to risk and return.[102]

VECC submitted that three factors reduce OPG's risk in relation to other utilities, especially unregulated generators:

- The requirements imposed on OPG through the MOA to mitigate the Province's financial and operational risk in operating the assets and reducing the Province's risk exposure to its nuclear assets
- The requirements in O. Reg. 53/05 that the Board accept certain amounts from OPG's audited financial statements and provide for recovery of various costs
- The various deferral and variance accounts which increase the probability of recovering unforecast costs

AMPCO submitted that the ownership of OPG affects the risks it bears and should be taken into account by the Board. AMPCO noted that both Standard & Poors' and Dominion Bond Rating Service recognize this in citing ownership of OPG as an important factor in determining OPG's debt rating. AMPCO pointed to the evidence it filed from Mr. Adams and Dr. Murphy, which concluded that the impact of past political

[100] CCC Argument, p. 8

[101] Ibid.

[102] VECC Argument, p. 14.

changes on OPG have been passed on to consumers. AMPCO questioned why, if political uncertainty creates risk for OPG, the shareholder should be compensated for a risk of its own creation. AMPCO concluded that regardless of the Board's findings, if the shareholder is dissatisfied with the risk borne by OPG, it can issue a further Directive to shift the impact to consumers.

CME submitted that Ms. McShane "misapplies the stand-alone principle by ascribing little weight to the risk mitigation effects of the government's ownership of OPG."[103] CME also disagreed with Ms. McShane's assessment of political risk:

> We submit that it is unreasonable to suggest that electricity consumers should pay a higher return because OPG's owner, the Government, might take some action which could harm the shareholder interest the Government holds in OPG. Ratepayers should not be burdened with higher Costs of Capital because the Government might decide to act in a way which causes harm to taxpayers as the ultimate owners of OPG.[104]

In response to CCC, OPG submitted that customers' interests must be kept separate from taxpayers' interest, and that this principle has been recognized by the Board in the past. OPG further submitted that the Province's objective of limiting its risk is no different than any other shareholder's, and that the proposed regulatory framework, including deferral and variance accounts, is a reasonable sharing of those risks and consistent with the approach of other utilities.

OPG argued that Hydro One is as important to the province as OPG and it is permitted to earn a commercial rate of return on a stand-alone basis.

OPG also argued that it was incorrect to claim that the government's legislative power has always been used to benefit or protect OPG. OPG pointed to the price caps of the early 2000s and the original requirement to decontrol a substantial portion of OPG's assets: "It is the very fact that the government can act both in ways to advantage and disadvantage OPG that creates uncertainty – and therefore political risk – in the future."[105]

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[103] CME Argument, p. 50.

[104] CME Argument, p. 51.

[105] OPG Reply Argument, p. 14.

OPG also noted Ms. McShane's testimony that the circumstances suggest that the Province is trying to establish an arm's-length company and concluded as follows:

> To proceed on the assumption that the shareholder will intervene to protect OPG as an argument for ignoring the stand-alone principle directly contradicts the province's decision to place OPG's prescribed assets under the independent jurisdiction of the OEB.[106]

Board Findings

The stand alone principle is a long-established regulatory principle and the Board has considered its application in a variety of circumstances. The unique circumstances of OPG, however, are in many ways without precedent. As noted above:

- Both the regulated and non-regulated operations perform the same function (i.e., generate power).
- The owner is the Province.
- The Board's approach to setting the payments now and in the future have in some respects been determined by the Province (through O. Reg. 53/05).

OPG is also different from the other entities the Board regulates in that it is not a natural monopoly.

Risk, in the regulatory context, can be considered to be the magnitude of the range of potential outcomes, with the focus generally being on the potential for an adverse outcome. In other words, the greater the range of potential outcomes, the greater is the risk. The Board is faced with two questions when considering the appropriate application of the stand-alone principle in the assessment of risk for OPG:

- Should OPG's risk be considered lower than other regulated Ontario energy utilities because the Province as owner has substantial control over OPG's risks – either in creating them or in protecting OPG from them (shifting the risk to consumers)? This is the issue of the shareholder impact on a regulated entity's risk.
- Is the political risk higher for OPG's regulated assets than for other regulated Ontario energy utilities? This is the issue of the impact of electricity policy changes on risk.

[106] OPG Reply Argument, p. 16

The witnesses and the parties generally agreed that deferral and variance accounts affect the level of risk and reduce it from what it would otherwise be. Similarly, where O. Reg. 53/05 mandates the recovery of certain costs, it is agreed that this reduces risk. O. Reg. 53/05, and in particular the establishment of various deferral and variance accounts and the requirement that certain types of cost be recovered, operates to transfer risk from OPG to customers. The Board must consider the precise nature of the accounts and determine the impact on risk; this is discussed in more detail later in this chapter.

In summary, some of these protections relate to expenditures before the period of Board regulation (the PARTS account) or to activities beyond the operation of the prescribed facilities (recovery of Bruce costs and new nuclear costs). These do not affect the level of risk for the prescribed facilities in the test period. Some of the accounts are comparable to the accounts of other regulated entities; they have not been stipulated through O. Reg. 53/05 for the test period, but rather have been approved by the Board (the accounts related to tax changes, water conditions, nuclear fuel expense, and ancillary service revenues). OPG also applied for other accounts, which the Board has decided not to approve (OPEB changes and SMO and WT revenues).

Two significant protections related to the prescribed assets have been established by O. Reg. 53/05 and will be ongoing: changes in nuclear liabilities and refurbishment costs. These are significant additional protections which have been established by the government and exceed the level of protection typically granted to a regulated utility.

The Board's conclusion is that these accounts do reduce risk. The Board notes, however, that under O. Reg. 53/05, amounts placed in the deferral and variance accounts after the Board's first order will be subject to a prudence review. These accounts will operate the same way for OPG as they do for other regulated entities, although the breadth of protection is greater.

While OPG's risk is lower due to these accounts, should OPG be considered of even lower risk because the shareholder can control whether OPG's financial risks are borne by the customers or the shareholder? The Board concludes that it should not. To conclude that OPG is of lower risk would be comparable to assuming that, after the Board's first order, the Province will direct the regulation of the prescribed assets, and regulate the distribution of risks between OPG and its customers, beyond the protections already established and assessed for purposes of setting the capital structure. O. Reg. 53/05 is viewed by the Board as setting the baseline for OPG as it enters into a formal regulatory framework; essentially limiting any review of activities in the period prior to the Board's payment setting mandate and requiring protection against forecast error (subject to a prudence review) for certain significant costs going forward. 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.

The Board must also consider how it will address the shareholder's ability to control future risk. If the Province transfers risks from OPG to consumers in future, then the Board would need to assess the resulting level of risk and adjust the risk ranking (and possibly the capital structure) accordingly.

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. All of Ontario's energy utilities are subject to risks arising from changing energy policy. The Province has established cost recovery requirements for utilities in which it has no ownership (for example, the regulations related to smart meter implementation). For example, the Province also required the LDCs to spend the third tranche of their market rates of return on conservation and demand management expenditures. The Board concludes that OPG's exposure to the risks and benefits of Provincial direction regarding expenditures and cost recovery are comparable to that of other regulated utilities.

The Board finds no evidence that OPG's regulated hydroelectric and nuclear facilities will be uniquely exposed. Mr. Goulding's evidence suggests that the risk of political interference is higher for OPG, but precisely because the Province is the owner and may choose to use OPG in a way which would be adverse to OPG's financial interests. It would not be appropriate for the Board to assume that the Province will interfere in the distribution of OPG's risks now that the Board has regulatory authority over OPG; it is consistent therefore to regulate OPG on the basis that the Province will not control OPG's currently regulated facilities in a manner which is adverse to OPG's commercial interests. The stand alone principle leads us to conclude that OPG's financial risks are not lower as a result of Provincial ownership; therefore it is consistent to conclude that political risk is not higher as a result of Provincial ownership.

8.3.3 Regulatory Risk

OPG noted that this is OPG's first application under the Board's regulatory authority. In OPG's view there is no track record of stable or consistent regulation and, therefore, there is regulatory uncertainty about the regulatory end state and OPG's ability to recover its costs. As a result, OPG argued, there is a risk of unintended consequences from specific decisions until there is a track record of consistent, stable regulation.

AMPCO pointed to Ms. McShane's evidence wherein she assumes the Board will regulate OPG the way it regulates other utilities and that the Board will provide OPG with a reasonable opportunity to recover its costs and earn a risk related return. AMPCO concluded that this was inconsistent with the claim that OPG's regulatory risks are higher than for other utilities. AMPCO noted that Dr. Booth and Drs. Kryzanowski and Roberts agreed that OPG did not face higher regulatory risk. Pollution Probe pointed, in particular, to Drs. Kryzanowski and Roberts's testimony that regulatory risk is low in reality because the Board has extensive experience with regulating gas and electric utilities, even if it has not regulated OPG previously. CCC and CME also disagreed that OPG's regulatory risks are higher than for other utilities.

OPG noted that both Ms. McShane and Mr. Goulding recognized the regulatory risk associated with the newness of OPG's regulatory regime. In OPG's view, it is not an issue of the Board's competence or integrity; it is an issue that there is not yet an established track record.

OPG also submitted that it faces operating risk from the fact that it is regulated by the Canadian Nuclear Safety Commission (CNSC) which has powers to make orders, including without a hearing in the event of an emergency, the consequences of which have the potential to impose significant costs on OPG. OPG argued that these powers are a significant factor in the regulatory risk assessment.

Board Findings

The Board finds that there is little evidence to support the conclusion that OPG's regulatory risk is higher than that of other regulated energy utilities because of its new regulatory framework. Hydro One and the electric LDCs were also new to Board determined cost of service regulation, but no evidence was presented that those entities were exposed to higher regulatory risk. It is also important to note that the Board's regulatory process provides ample opportunities to address issues of cost recovery through applications, deferral accounts, and motions to review. These are standard and well established regulatory tools; cost of service is a long established regulatory framework; even incentive regulation is well established.

The Board does accept that there could be some risk associated with the uncertainty of applying cost of service regulation, which is typically applied to natural monopolies, to generation assets in Ontario's hybrid market. However, the Board notes that throughout North America there continues to be rate regulation of generation facilities, and that the traditional models of cost of service or incentive regulation are applied in these circumstances. The Board concludes that the risk is therefore minimal.

The risk with respect to the CNSC is whether OPG would be able to recover the costs arising from CNSC action. The Board does agree that it is a category of costs not faced by other regulated Ontario utilities. However, the Board expects that were such costs to arise, OPG would apply for recovery through an application, as would any other regulated entity faced with a significant cost which it claimed was beyond its control and imposed by a body with the authority to do so. The Board would consider the application in the normal way, including a test of prudence.

The Board concludes that regulatory risk is not a significant factor for OPG and is not materially higher for it than for the other utilities the Board regulates.

8.3.4 Operating Risk

For OPG, operating risk entails outage risk, dispatch risk, non-payment risk and the risk associated with environmental obligations. There was general agreement that electricity generators have greater operational risks than non-generation entities regulated by the Board. It was also generally agreed that OPG's risks were lower than those of merchant generators. Given the proposed continuation of the deferral account covering fluctuations in water availability during the test period for the hydroelectric operations, the focus was largely on OPG's nuclear operations and primarily on the risk related to forced outages and dispatch.

OPG took the position that although much has been made of deferral and variance account protection in this case, most of the accounts are simply reflections of the prohibition against retroactive rate making; i.e., they are designed to ensure the recovery of costs associated with initiatives that were directed, authorized or approved by the government before the introduction of rate regulation by the Board. OPG also noted that operating and production risk is the largest risk it faces as nuclear technology is more complex than other types of generation and is subject to a higher risk of unanticipated costs of repair, and loss of production and revenues.

One of the risks that OPG and Ms. McShane identified is dispatch risk. This is the risk that baseload generation from OPG's regulated assets will not be dispatched because of economic conditions and/or the presence of generators with lower marginal costs. AMPCO submitted that this risk is insignificant and pointed to Ms. McShane's analysis of the Ontario market over the last three years. In AMPCO's view, her analysis shows that even at low levels of demand there is the opportunity for additional baseload capacity to be added without a risk that OPG's regulated assets will not be dispatched. AMPCO also noted the evidence of Dr. Booth and Drs. Kryzanowski and Roberts, both of which concluded that dispatch risk is low. CME supported AMPCO's submissions. In the end, there was limited dispute that dispatch risk for OPG is low.

AMPCO submitted that there appears to be a consensus that the major risk facing OPG is related to the operation of the nuclear units. AMPCO submitted that these risks are largely mitigated: ONFA limits OPG's potential liabilities, as changes in the nuclear liability resulting from changes to the decommissioning reference plan are recovered through a variance and deferral account; other deferral and variance accounts cover unexpected costs related to nuclear regulatory costs and technological changes, and the non-capital costs associated with the Pickering A return to service; and new accounts are proposed to cover variances in nuclear fuel costs, pension costs, and taxes.

AMPCO pointed to the evidence of Dr. Booth as supporting the conclusion that the variance and deferral accounts effectively transfer operational risks to consumers. AMPCO submitted that the remaining operational risks are within the control of management and are not risks for which OPG should be compensated.

CCC submitted that while the nuclear assets are undoubtedly riskier than the hydroelectric assets, many of the risks have been covered off with deferral accounts and the only substantive remaining risks are production and operating risks. In CCC's view, "It is inconceivable that the government would allow OPG to be materially adversely affected by production or operating risks."[107] CCC submitted that these risks can be mitigated by increasing the fixed portion for nuclear payments to 50%.

CME submitted that if the proposed additional variance and deferral accounts and the fixed nuclear payment are approved, then the equity ratio should be reduced to 40% in recognition of the reduction in risk from these mechanisms.

OPG replied:

> It was Mr. Goulding's opinion, shared by Drs. Kryzanowski and Roberts, that OPG's nuclear assets are far more exposed to potential loss of revenues due to operational risk than a transmission or distribution network. The operational risk associated with OPG's prescribed assets is, in fact, the principal risk that faces OPG.[108]

OPG submitted that none of OPG's nuclear production risk is mitigated by a deferral or variance account. OPG argued that Dr. Booth's contention that all of OPG's risks are covered by deferral and variance accounts does not recognize that deferral and variance accounts are a common feature of regulated utilities or that OPG does not have an account to cover nuclear production risk. Further, OPG argued that Dr. Booth had not reviewed the ONFA or analyzed the actual extent of the nuclear liabilities and OPG's risk related to residual unfunded liabilities and the limits on the provincial guarantee cap. In OPG's view it still faces significant exposure to this item, even with the related deferral and variance account.

With respect to the deferral and variance accounts generally, OPG characterized them as being designed to prevent "hindsight re-examinations of historical decisions and commitments made long before the OEB acquired jurisdiction to determine payment amounts."[109] In OPG's view, the most recently established accounts reflect the reality that the Board was not the regulator at the time.

All of the experts acknowledged that the use of deferral and variance accounts reduced risk. Ms. McShane testified that her recommendations were based on the assumption that the proposed variance and deferral accounts are implemented. She estimated that if the new proposed accounts (related to nuclear fuel, OPEBs/Pension costs, and tax

[107] CCC Argument, p. 18.

[108] OPG Reply Argument, p. 17.

[109] OPG Reply Argument, p. 22.

changes/assessments) were not implemented, the increased risk would warrant an upward adjustment to either the equity ratio or the ROE.

OPG argued that the evidence is clear that Ms. McShane's recommendations are premised on the approval of the proposed deferral and variance accounts, and that if they are not approved, the equity ratio and/or ROE would need to be adjusted accordingly. OPG submitted that if the scope of the accounts, including, for example, the Nuclear Liabilities Deferral Account, is reduced, then OPG's risk will increase which would need to be reflected in the cost of capital.

Mr. Goulding testified that the fixed payment component would reduce OPG's business risk and pointed out that this payment structure would not be available to merchant generators nor to the generators under contract with the OPA. Ms. McShane estimated that without the fixed payment component, the ROE would need to increase by about half the increase in the variability, approximately 25 basis points, or the equity component should be increased to 60%.

Board Findings

The Board finds that while the dispatch risk for the regulated facilities is low, the operational and productions risks, particularly for the nuclear assets, are significant. Some of these risks are mitigated by the existing and ongoing deferral and variance accounts, but the accounts do not cover all of the risk, particularly not the risk of forced outages and the corresponding impact on costs and production. The accounts fall into four categories: those not related to the prescribed assets; one which provides for recovery of costs which pre-date the Board's regulation of OPG; those that have been specifically approved by the Board in this decision and are typical of utility variance and deferral accounts; and those which provide extended protection against forecast variance. We will review each in turn.

Some of the accounts and cost recovery protection mechanisms contained in O. Reg. 53/05 do not relate to the prescribed assets. The Board is required to ensure that OPG recovers the costs associated with Bruce and the costs associated with new nuclear build. Although these represent significant shifts of costs and risks to customers, they are not related to the regulation of the prescribed facilities. The Board finds that although these requirements may lower OPG's risk as a corporation, they have no impact on the risks of the prescribed facilities.

One of the accounts relates to circumstances and decisions taken before the period in which the Board has regulatory authority. The PARTS account is related to non-capital expenditures related to Pickering A which pre-date the period of the Board's regulatory authority. No new amounts will be added to this account; it is being maintained as the amounts are recovered over the next four years. The Board concludes that this account has no significant impact on OPG's risk in the test period, as the expenditures pre-date the Board's regulatory authority.

Some of the approved accounts going forward are related to protection against forecast error, namely tax changes, nuclear fuel cost, water conditions and ancillary services. The Board concludes that while these accounts each reduce risk, they are not dissimilar to the accounts of other regulated utilities. The electric LDCs have accounts related to tax changes; the ancillary services account ensures customers receive the full benefit of these revenues; and the nuclear fuel and water accounts, while providing protection against inputs over which OPG has little control, are not large relative to the size of OPG's revenue requirement.

The Board is also required to ensure that OPG recovers the revenue requirement implications of changes in the nuclear liabilities Reference Plan and the costs of the refurbishment of the prescribed nuclear facilities. These represent a more extensive risk protection than might typically apply to a regulated utility. Although the nuclear liabilities are unique to OPG, the deferral account ensures that OPG is kept whole and the impact of any change in the Reference Plan is borne by customers. This protects OPG against a significant risk. The refurbishment account provides protection against forecast variance in non-capital costs; this could be significant given the high levels of project OM&A. While the account also provides protection related to capital costs, these costs will not be included in rate base until the assets are in-service in any event and therefore the account does not provide significant additional risk protection. The requirement for a prudence review continues to provide a measure of protection to customers and ensures that OPG retains some risk.

The Board notes that future accounts may be established which further reduce risk; however, that factor is not determinative of the Board's assessment of the current level of risk. The proposed payment structure would also mitigate some of the risk, but as set out in Chapter 9, the Board has determined that it is not appropriate to include a fixed component in the payment structure.

The Board concludes that OPG's regulated nuclear business is riskier than regulated distribution and transmission utilities in terms of operational and production risk, but is less risky than merchant generation (for example, given the risk reduction afforded by some of the deferral and variance accounts). The Board also concludes that it is not appropriate for the shareholder to be compensated for all of the operational risks associated with the regulated nuclear facilities. Under cost of service regulation OPG has the opportunity to forecast production and operating costs and to seek recovery of the associated revenue requirement. The Board concludes that it would not be appropriate for shareholders to be fully compensated for the risk that those forecasts are incorrect given that management controls the development of the forecasts and has some considerable control over the achievement of those forecasts.

8.3.5 Capital Structure Conclusion

CCC concluded that OPG was no riskier than any other utility and that Dr. Booth's recommended equity ratio of 40% was appropriate. Similarly, AMPCO took the position that OPG and Ms. McShane have exaggerated the risks facing OPG and concluded that the equity ratio should remain unchanged. SEC submitted that the equity component should be 47%, representing 40% for hydroelectric and 50% for nuclear. OPG replied that those who have recommended lower equity ratios than Ms. McShane have underestimated OPG's business risk.

Board Findings

Union Gas Limited and Enbridge Gas Distribution Inc. both have equity ratios of 36%, and the risk differential between Union and Enbridge is reflected in Union's ROE which is 15 basis points higher. The electric LDCs and Hydro One have equity ratios of 40%, and Great Lakes (transmission) has an equity ratio of 45%. The Board has concluded that OPG is of higher risk than electricity LDCs, gas utilities and electricity transmission utilities and of lower risk than merchant generation. And while the deferral and variance accounts mitigate some aspects of OPG's risk, they do not protect against outage risk.

The Board finds that the proposed equity ratio of 57.5% is excessive. The incremental level of risk does not warrant the additional 12.5% equity over that of the next highest regulated utility. It is also well in excess of the equity levels of merchant generators, who have higher risk than OPG, as pointed out by Mr. Goulding. The Board concludes that the recommendation of Drs. Kryzanowski and Roberts, namely 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. The Board notes that this deemed capital structure will be applied to the rate base which is net of the specific treatment to be applied to the nuclear liabilities related to Pickering and Darlington (which is discussed in Chapter 5).

8.4 Return on Equity

8.4.1 Introduction

Ms. McShane used three tests: the Equity Risk Premium ("ERP") test, the Discounted Cashflow ("DCF") model test and the Comparable Earnings ("CE") test. For the ERP test, she used three approaches:

- Capital Asset Pricing Model ("CAPM")
- Historical utility risk premium test
- Discounted Cash Flow ("DCF") risk premium test

Although Ms. McShane updated her estimates of the various tests in April 2008, the result was no change in the aggregate ROE recommendation: in her view, the lower government interest rate is partially offset by a higher risk premium which is reflected in a higher spread between government bonds and long-term A-rated utility bonds.

Pollution Probe submitted that the Board should prefer and accept the recommendations of Drs. Kryzanowski and Roberts. They used four methods to estimate the market equity risk premium: the Equity Risk Premium (including CAPM) methodology and three other methods to support the "directional conservatism" of the estimate derived from the ERP method. Pollution Probe noted that OPG acknowledged that this was now the dominant methodology used for regulated energy utilities in Canada.

CCC submitted that the Board should prefer the testimony of Dr. Booth to that of Ms. McShane. Dr. Booth estimated that OPG will have sufficient financial flexibility to access capital markets on reasonable terms with an ROE of 7.75% and an equity ratio of 40%. Dr. Booth relied on a CAPM risk premium model and a two-factor model, with the CAPM estimate based on an historic average market risk premium adjusted for the

9 CAPITAL STRUCTURE AND COST OF CAPITAL

This is the second cost of service application to set payment amounts for OPG's prescribed assets. Cost of capital was extensively reviewed in the previous proceeding. OPG's circumstances are different, in a number of respects, from those of other entities that the Board rate regulates. These are reflected in the different treatment that the Board approved for OPG in that proceeding.

Since the previous decision, the Board has conducted a consultation that reviewed cost of capital policies for all of the sectors rate-regulated by the Board, including OPG. The outcome of that process was the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* issued on December 11, 2009 (the "Cost of Capital Report"). OPG and many of the stakeholders participated in that consultation.

OPG has applied for payment amounts based on a deemed capital structure of 53% debt and 47% equity. This was the structure approved in the previous proceeding.

OPG proposed that the ROE for 2011 be set on the basis of the Board's policy (although it used 9.85% as a placeholder) and that the level for 2012 be set using the Board's policy, but that it be determined now based on Global Insight data because Consensus Forecasts only go out 12 months.

For long-term debt, OPG proposed to use the weighted average cost of actual and forecasted debt for actual debt capitalization, and the Board's deemed long-term debt rate for any incremental, unfunded long-term debt capitalization. For short-term debt, OPG used a methodology to forecast the costs of its two main sources of short-term financing, namely its commercial paper program and its accounts receivable securitization program. OPG's proposed cost of capital followed that approved in the previous payments case, EB-2007-0905.

The proposed test period capitalization and cost of capital are summarized in the following tables for each of the years in the test period.

Table 26: Capitalization and Cost of Capital - Calendar Year Ending December 31, 2011

Capitalization	Principal ($million)	Component (%)	Cost Rate (%)	Cost of Capital ($million)
Short-Term Debt	189.5	3.0%	2.64%	7.6
Existing/Planned Long-Term Debt	2,283.1	36.1%	5.53%	126.2
Other Long-Term Debt Provision	877.7	13.9%	5.87%	51.5
Total Debt	3,350.3	53.0%	5.53%	185.3
Common Equity	2,971.1	47.0%	9.85%	292.7
Rate Base Financed by Capital Structure	6,321.4	80.6%	7.56%	477.9
Adjustment for Lesser of UNL or ARC	1,523.3	19.4%	5.58%	85.0
Rate Base	7,844.7	100%	7.18%	562.9

Source: Exh. C1-1-1, Table 2

Table 27: Capitalization and Cost of Capital - Calendar Year Ending December 31, 2012

Capitalization	Principal ($million)	Component (%)	Cost Rate (%)	Cost of Capital ($million)
Short-Term Debt	189.5	2.9%	4.13%	10.4
Existing/Planned Long-Term Debt	2,502.8	38.8%	5.50%	137.6
Other Long-Term Debt Provision	725.2	11.2%	5.87%	42.6
Total Debt	3,417.5	53.0%	5.58%	190.6
Common Equity	3,030.6	47.0%	9.85%	298.5
Rate Base Financed by Capital Structure	6,448.1	81.2%	7.59%	489.1
Adjustment for Lesser of UNL or ARC	1,490.1	18.8%	5.58%	83.1
Rate Base	7,938.2	100%	7.21%	572.2

Source: Exh. C1-1-1, Table 1

The following issues were addressed in the proceeding:

- Technology-specific capital structures;
- Return on equity;
- Cost of short-term debt; and
- Cost of long-term debt.

Each issue is addressed in turn.

9.1 Technology-Specific Capital Structures

As noted above, OPG has used a deemed capital structure of 53% debt and 47% equity in its application. The deemed capital structure is applied to the rate base net of the Adjustment for the Lesser of Unfunded Nuclear Liabilities ("UNL") or Asset Retirement

Costs ("ARC"), which is applicable only to the nuclear business. OPG's proposal is consistent with the Board's decision in the previous proceeding.

In the previous proceeding, the Board set one overall capital structure for both regulated hydroelectric and nuclear businesses, but concluded that separate capital structures for the regulated hydroelectric business and the nuclear business was an approach worthy of further investigation at the next proceeding. This is the only issue related to capital structure examined during the proceeding.

In response to the Board's direction in the prior decision, OPG retained Ms. Kathleen McShane of Foster Associates Inc. to determine whether there was a basis on which to establish separate capital structures. Ms. McShane analysed five different quantitative methodologies and one non-quantitative method in her report. Ms McShane also appeared as a witness in the hearing. Ms. McShane concluded that none of the methodologies provided sufficiently robust information to serve as a basis for separate costs of capital and capital structure. Accordingly, OPG concluded that it was appropriate to continue to use a single capital structure for its prescribed facilities.

Pollution Probe filed a report prepared by Drs. Lawrence Kryzanowski and Gordon Roberts. They also appeared as witnesses. Their analysis is based on a heuristic methodology comparing the relative risk of electricity transmission and distribution-only utilities and an integrated (i.e. generation and transmission/distribution) utility versus solely hydroelectric and nuclear generation businesses. They concluded that the capital structure for the hydroelectric business should consist of 43% equity and the capital structure for the nuclear business should consist of 53% equity, subject to OPG's prescribed facilities retaining an equity thickness of 47% in aggregate, as determined in the previous proceeding.

GEC's witness, Mr. Paul Chernick, did not undertake an updated analysis specifically on the issue of technology-specific capital structures, but he did express the opinion that there was a difference in the business risks of hydroelectric and nuclear generation businesses. He testified that the Board could and should make a judgmental determination of the difference.

All consultants agreed that, as the ROE is to remain constant under the Board's Cost of Capital guidelines, the only way to reflect differences in business risk is by adjusting the equity thickness of one division relative to the other.

Pollution Probe maintained that there is no dispute that the nuclear division has a higher business risk than the hydroelectric division. Pollution Probe noted that the capital structure recommended by Drs. Kryzanowski and Roberts was consistent with credit metrics needed to obtain, on a "stand alone" basis, reasonable bond ratings in the "A" credit range. Pollution Probe commented that the methodologies used by Ms. McShane in her analysis are usually used to determine the rate of return, and not the capital structure.

Energy Probe submitted that the Board should deem a higher equity ratio for the nuclear business than the hydroelectric business, setting the nuclear business equity ratio at 50% and the regulated hydroelectric business equity ratio at 40%.

GEC submitted that setting a higher cost of capital for the nuclear business would be more accurate than applying the current combined value to both businesses. GEC submitted that OPG should develop project specific discount rates for large projects to capture business risk more fully in the analysis.

AMPCO, CME, CCC, PWU, SEC and VECC supported retaining a single capital structure for the regulated business. Among the reasons cited were the unnecessary complexity of maintaining two structures and the fact that OPG borrows as a company not by business unit. CCC also commented that the analysis conducted by Drs. Kryzanowski and Roberts was largely a qualitative approach.

Board staff argued that if the Board was inclined to approve technology-specific capital structures, then the Board should also apply the cost of debt on a technology-specific basis. Board staff noted that the nuclear liabilities are treated as a form of debt financing within the capital structure but are only incorporated, appropriately, into the rate base for OPG's regulated nuclear assets.

OPG argued that technology-specific capital structures add unnecessary complications to future applications. OPG noted that consumers do not buy power from particular producers, let alone based on generation type, and that the difference in equity ratios and resulting returns is small. OPG also argued that there is no compelling reason to accept the recommendations of Drs. Kryzanowski and Roberts. In OPG's view, the evidence did not extend the analysis beyond that provided in the previous proceeding and therefore the conclusion of the previous proceeding should be maintained.

If the Board is inclined to approve separate capital structures, OPG submitted that the only reasonable ratios would be 45% for the regulated hydroelectric business and 50% for nuclear. OPG also argued that Board staff is incorrect in concluding that cost of debt is specific to projects, noting that the cost of debt for the projects identified in the staff submission reflect OPG's corporate borrowing costs.

Board Findings

OPG has applied the same capital structure as was approved on a combined basis for its regulated hydroelectric and nuclear generation assets in the previous payments case. 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.

The Board accepts that the business risks associated with the nuclear business are higher than those of the regulated hydroelectric business, and this is not contested by parties in this hearing. However, the Board finds that the evidence in this proceeding does not provide a sufficiently robust basis to set technology-specific costs of capital, by way of division-specific capital structures. In short, the Board finds an inadequate body of evidence to support a change from the conclusions reached by the Board in the previous proceeding.

The evidence of Drs. Kryzanowski and Roberts is a heuristic approach and is qualitative as much as quantitative in nature. Their evidence also largely employed the same techniques as contained in their evidence in the previous case. The difficulty for the Board is the dependence on qualitative assumptions and analysis. Their qualitative assessments of various forms of risk give rise to quantitative scorings that they then have translated into different capital structures corresponding to a cost of capital related to the risks of each business division and constrained by two conditions:

1) the weighted aggregate cost of capital for the two divisions should correspond with the 47% equity thickness set by the Board on an aggregate basis; and
2) the cost of capital and hence the deemed capital structure for the hydroelectric division should be commensurate with a business risk no less risky than that for electricity distributors and transmitters, for which the Board has deemed a 40% equity thickness.

As was discussed during oral cross-examination, these conditions restrict the allowable technology-specific capital structures to a very narrow band. The Board is concerned that different qualitative scorings might result in some different results from their analysis, even while adhering to the relative riskiness (in terms of ranking) of transmission and distribution utilities versus generation technologies. In other words, as was found in the previous case, the Board considers that the heuristic approach of Drs. Kryzanowski and Roberts is not robust enough to set technology-specific costs of capital and capital structures.

With respect to Ms. McShane's evidence, the Board acknowledges its more quantitative approach, but also acknowledges some of the concerns raised by parties. For the most part, the analytical approaches used by Ms. McShane are based on the CAPM model, and thus share the strengths and limitations. The CAPM is one of several techniques routinely used by this Board and other regulators in setting the Cost of Capital. However, as was acknowledged by OPG,[44] the CAPM is not used to set the capital structure, which must be derived indirectly. However, the Board considers that the paucity of comparator firms to be more telling in Ms. McShane's analysis not being able to derive a robust estimate of technology-specific capital structures.

There may thus be a lack of major hydroelectric and nuclear generators comparable to OPG's divisions and for which market data is available to apply the methods that Ms. McShane has used. It is not to say that there is not a real difference, but that the approaches put on the record in this proceeding, as in the previous case, are not sufficient to allow for robust estimates with sufficient precision to be derived, at least at this time.

The Board is also concerned that over time a further issue will arise in relation to the interaction between the individual equity ratios and the combined equity ratio. As the relative size of the hydroelectric and nuclear businesses changes (through major additions to rate base, for example) the issue will arise as to whether the overall ratio of 47% is to remain unchanged or whether the technology specific ratios are to remain unchanged. 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.

[44] Exh. L-10-23 and Exh. L-6-7

The Board also accepts that implementing separate capital structures may not lead to any significant ratepayer benefits in the long term.

The primary argument put forward by those who support a separate capital structure is related to the assessment of large capital projects. The Board concludes that this difference in risk can and should be adequately accommodated in the direct valuation of the projects. OPG maintained that it already does so; other parties dispute this. This issue can be pursued further by the parties in subsequent proceedings.

Another argument advanced in favour of separate capital structures is greater transparency for consumers. The Board has some sympathy with this view, but has nonetheless concluded that the benefits from this greater transparency are not sufficient to warrant the complications involved with this approach based on the evidence advanced in this or the previous payments case.

9.2 Return on Equity

Two issues were raised in respect of the return on equity: whether the Board should adjust the ROE below the level established through the operation of the Board's policy, and how the ROE should be set for 2012.

9.2.1 Should the ROE be reduced?

OPG proposed that the ROE be determined according to the formula in the Cost of Capital Report, using data from *Consensus Forecasts*, the Bank of Canada and Bloomberg LLP three months in advance of the March 1, 2011 effective date for rates.

CME maintained that unregulated industries would forego full equity return on investment if external circumstances called for price constraint. CME argued that the Board is not required to award ROE at a specific level as this is not an objective or requirement in the Act, and could award a lower rate than applied for by OPG in order to protect consumers from rising electricity prices. CME pointed out that it would be inconsistent for the ROE to be fixed at a specific rate, when the Board, in some cases, can award a higher ROE, as, for example, contemplated by the *Report of the Board on The Regulatory Treatment of Infrastructure Investment in Connection with the Rate Regulated Activities of Distributors and Transmitters in Ontario*. Also, CME suggested plan. The variance account would enable the tracking of any additional cash contributions made by OPG to be considered in the future for recovery.

OPG submitted that the determination of pension and OPEB expense was not an issue on the issues list and that OPG did not file expert evidence on the matter, nor did any other party. In OPG's view, the matter is very complex and best suited to a generic proceeding.

Fund or Irrevocable Trust for OPEB

While OPG makes contributions to a registered pension plan, there is no equivalent plan for OPEB. The accrual amounts are determined by OPG's actuary and used in OPG's corporate financial statements as required under USGAAP. OPG's actuary also determines the minimum cash requirements for its pension and OPEB plans based on legislation and regulations.

Board staff submitted the Board could approve the accrual method for OPEB on the condition that OPG establishes a set-aside mechanism, such as an irrevocable trust or fund for OPEB, similar to what was referred to the in the Federal Energy Regulatory Commission's Statement of Policy report PL93-1-000.[92] Board staff also submitted that if the Board had any reservations about a fund or trust, the Board could limit recovery of OPEB expense as determined by the cash method, or OPG's out-of-pocket test period costs. OPG submitted that the Board has no jurisdiction to order OPG to set up an irrevocable trust or fund. OPG argued that the matter is complex and submitted that a segregated fund could be considered as part of a generic proceeding.

Board Findings

The Board will only allow OPG to recover its cash requirements for pensions and OPEBs in 2014 and 2015, approving a revenue requirement of $836.9M for pension and OPEB.

The Board will reduce the total proposed amount to be recovered in rates by $457.1M, which is a reduction of $225.1M in proposed pensions and $232.0M in proposed other

[92] Exh K13.2, FERC PL63-1-000, Post-Employment Benefits Other Than Pensions, Statement of Policy, December 17, 1992

post-employment benefit amounts.[93] OPG's most recent actuarial valuation as at January 1, 2014 by AON Hewitt was filed in evidence.[94] The Board relies on the AON Hewitt valuations of the cash requirements in 2014 and 2015 and sets OPG's payment amounts accordingly.

In addition, the Board approves the establishment of a new deferral account to record the differential between the accrual and cash valuations for pension and OPEB expenses. The Board's reasons follow in the sections below.

OPG and some parties suggested that the Board hold a generic hearing to review pension and OPEB costs. The Board agrees and believes that a generic proceeding on the regulatory treatment and recovery of pension and OPEB costs would be beneficial. A generic proceeding could enhance understanding of the different rate making options, establish policy and decide on how best to apply that policy to OPG and other Board-regulated entities. Transition to a different accounting treatment of pensions and OPEBs for OPG, if required, would be addressed by the Board in OPG's next cost of service proceeding, having been informed by the outcomes of the generic proceeding.

The Board is not necessarily permanently moving from an accrual to a cash basis for setting OPG's payment amounts. The Board is providing OPG with sufficient revenue to fund its cash needs for 2014 and 2015 until a comprehensive review of pensions and OPEB is undertaken through a generic proceeding. The Board is concerned that any money collected from ratepayers today, in excess of the cash requirements, is not being used to fund future pension and OPEB cash requirements. The Board has considered both OPG's needs and those of ratepayers. In the absence of a Board policy, the Board will not allow the collection of funds from ratepayers in 2014 and 2015, of an amount higher than OPG's cash needs, when OPG's use of the excess funds is not understood, and the benefit to ratepayers is uncertain.

Until Board policy is established, the Board approves a new deferral account to record the differential between the accrual and cash valuations for pension and OPEB expenses. Based on the policy outcome of the generic proceeding, a future panel will decide on the appropriate disposition (if any) of the deferral account balance.

[93] Undertaking J9.6 states that the 2015 pension requirement on a cash basis is $329.6M. Correcting the 2015 pension requirement on a cash basis in Chart 1 of undertaking J13.7 results in a, accrual vs cash difference of $457.1M.
[94] Undertaking J9.6

At this time, the scope of the generic proceeding is unknown. For clarification, the Board is not setting aside the difference between the cash and accrual amounts for this test period, for purposes of another future prudence review of these costs. The 2014 and 2015 payment amounts will be final in that respect. Any future treatment regarding the deferral account would be limited to the outcomes of the generic proceeding as they relate to the accounting or mechanics of recovery, as applicable.

The application indicated a differential amount of $457.1M based on the 24-month period in 2014 and 2015. However, the $457.1M will be subject to change given the approved effective dates of the payment amounts and OPG's final actuarial evaluations at the end of 2014 and 2015.

OPG indicated that the determination of pension and OPEB expenses for ratemaking was not an issue on the issues list. The Board agrees that the exact words "accounting methods for ratemaking" were not on the issues list. However, the issue was raised in numerous interrogatories and extensively during the pre-hearing technical conference and the oral phase of the hearing. In addition, every proposed expense, particularly material expenses of $1,294M, must be reviewed by the Board to order to determine OPG's payment amounts.

OPEB Costs

Board staff submitted that historical over collection of OPEB expenses should be used to offset the regulatory liability for the future. OPG submitted that Board staff's proposal amounts to a "claw back". The Board does not agree with OPG's characterization and the use of the term "claw back". The amount and use of any excess collected to date from ratepayers must be clearly understood and resolved before the Board allows any further collection in excess of requirements in 2014 and 2015.

On a prospective basis, Board staff estimated that maintaining accrual accounting for ratemaking would result in an over-collection in OPEB revenue of $1.2 billion every 10 years. OPG took issue with Board staff's $1.2 billion estimate. OPG's witnesses indicated a cash flow analysis had been completed, yet were unable to provide any specifics, stating it would be "likely in the next 10 years"[95] before actual OPEB cash payments would exceed the accrual expense. The Board does not find OPG's answer sufficient. The Board has little evidence by which to understand the magnitude or

[95] Tr Vol 13 page 134

duration of the potential over collection of OPEB costs from ratepayers, but the prospective numbers are alarming.

The Board is not confident OPG has undertaken the level of cash flow analysis required to ensure it will have sufficient cash available as a corporation, when its cash needs exceed accrued expenses. It would be inappropriate to collect revenues today in excess of cash requirements and then turn to ratepayers in the future, when cash requirements exceed accrued expenses. The Board must ensure ratepayer interests over time are fully considered.

Pension Costs

From 2008-2013 cash funding requirements for pensions exceeded accrued expenses by $111.4M; the opposite of OPEB costs. However, in 2014 and 2015 accrued pension expenses exceed cash funding requirements by $149.4M in 2014 and $75.7M[96] in 2015.

With accrued pension expenses exceeding cash requirements in 2014 and 2015, the Board's concerns relating to OPEB costs regarding the magnitude and duration of over collection and the associated cash flow analysis apply equally to pension costs.

Prior Board Decisions

The Board is directing the use of the cash basis of recovery for 2014 and 2015. This is different from prior OPG decisions. In OPG's last cost of service proceeding, EB-2010-0008, the Board found no compelling reason to change OPG's approach of using the accrual method. The Board noted that consistency in accounting treatment which allows comparison of year-over-year results to be advantageous for assessing reasonable cost levels.

This panel agrees with the EB-2010-0008 decision as consistency is desirable in order to compare these costs. However, in this case the benefits of consistency are outweighed by the concern regarding the significant increase in payment amounts to recover accrued expenses. In 2011 and 2012, the accrued expenses for pensions were $195.0M and $286.1M respectively. In 2014 and 2015, the forecast accrued expenses are almost double at $471.3M and $405.3M.

[96] After adjusting the cash contribution number in 2015 to the amount shown in J9.6 of $329.6M.

In reply submission, OPG indicated that while the figures may be different from its last cost of service proceeding in EB-2010-0008, “the circumstances have not changed”. The Board disagrees. The circumstances have changed as the accrued expenses are increasing and volatile, dependent upon the assumptions adopted by OPG’s management, such as the appropriate discount rate. Volatility in the test years was evident when OPG filed its Exhibit N1 impact statement in December 2013, months after filing its Application. After updating the discount rate and mortality rate assumptions applied to its pension plan, accrued expenses in 2014 and 2015 increased, exceeding OPG’s materiality threshold and increasing the proposed revenue requirement by $142.3M. This was followed by the Exhibit N2 impact statement filed in May 2014, which based on higher discount rates for the pension plan, decreased the revenue requirement by $278.7M.

Implications of Cash Method

OPG submitted that the cash basis would ultimately require OPG to increase its borrowings and ratepayers would have to pay for that debt. In addition, the cash basis would affect financial ratios. The Board has approved OPG’s capital expenditures and rate base for 2014 and 2015. The payment amounts include a weighted average cost of capital. In addition, every cost that OPG requires to recover to run its business and the opportunity to realize its regulated rate of return, underpins the payment amounts. The Board does not understand what additional borrowing would be required to fund the regulated side of OPG’s business.

OPG prepares its financial statements in accordance with USGAAP, which requires pensions and OPEB costs to be determined on the accrual method. In reply argument, OPG identified corporate financial reporting issues such as qualified audit opinions and the recognition of existing regulatory assets if the Board were to utilize the cash basis for ratemaking while its corporate financial statements were based on the accrual method. The issue of cash versus accrual is one of timing. This Board does not regulate financial reporting requirements, but is confident OPG’s management, its Audit Committee and external auditors will reflect the outcomes of this Decision in its financial statements.

Given the Board’s position on these matters, the additional information provided by OPG in its reply argument regarding its discussions with Ernst & Young LLP was not helpful to the Board. As an aside, however, the Board also notes that it is not generally appropriate to file "new evidence" following the closing of the evidentiary portion of the proceeding.

Pension and OPEB Cost Variance Accounts

OPG has the ability to contribute additional funds to its pension plan in excess of the minimum cash requirements to reduce its unfunded liability. The Board recognizes this opportunity and does not want to dissuade OPG from contributing more than the cash amounts approved in its payment amounts. The total unfunded liability on OPG's <u>corporate</u> balance sheet was $5,469M as of December 31, 2013: a pension deficit of $2,461M; a supplementary pension plan deficit of $289M; and OPEB deficit of $2,719M. In addition, AON Hewitt determined the pension plan had a small solvency deficit on January 1, 2014, which will require additional funds to eliminate.

The Board will use its available ratemaking tools so as to not discourage OPG from making additional contributions, in addition to its minimum cash requirements, to decrease its unfunded liability without financial hardship. The Board approves a new variance account to track any contributions that differ from the minimum cash requirements, as included in the 2014 and 2015 payment amounts. Interest will apply to this variance account given that it relates to cash payments.

In addition, the Board has approved the establishment of a new deferral account to track the differential between the accrued and cash valuations for pensions and OPEBs. The Board approves the accrual of interest on the variance account balance related to additional cash contributions made, but does not approve the accrual of interest on the deferral account balance given that it tracks non-cash items. This treatment is consistent with OPG's current variance account based on the accrual method.

Given the effective date for OPG's 2014 and 2015 payment amounts, the current payment amounts which include accrued pension and OPEB expense will remain in place until November 1, 2014. Correspondingly, the current Pension and OPEB Cost Variance Account will operate until that date to track variances from actual to forecast accrued expenses. After the effective date, the new variance account will be used to track variances from actual to forecast cash expenses. The new deferral account will capture initially the differences between cash and accrual pension and OPEB amounts included in evidence commencing with the effective date. The deferral account balance should be adjusted for future actuarial valuations and actual cash payments on an annual basis until considered by the Board.

4.3 Corporate Support Costs

(Issue 6.9)

OPG is structured such that certain corporate groups provide services and incur costs in support of the hydroelectric and nuclear businesses. Corporate groups include Business and Administrative Services, Finance, People & Culture, Commercial Operations & Environment, and Corporate Centre. OPG is asking for approval of corporate support costs, which are $505.8M in 2014 and $483.9M in 2015.

As shown in Table 5 (to a minor extent),Table 13 and the following table, corporate support costs have increased significantly over the 2011 - 2013 period due to the implementation of a centre-led organization driven by the Business Transformation initiative.

Table 22: Corporate Support Costs

$millions	2010 Plan	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Nuclear	247.0	226.5	249.2	233.1	450.3	408.4	451.0	428.3	433.9	417.4
Previously Regulated HE	25.1	22.4	24.8	22.0	29.0	24.5	29.7	26.1	29.8	26.9
Newly Regulated HE							38.8	35.2	42.1	39.6
Total	272.1	248.9	274.0	255.1	479.3	432.9	519.5	489.6	505.8	483.9
Source: Exh F3-1-2 Tables 1,2,3 Exh F3-1-1 page 2 and 3, Exh L-1-Staff-2										

Board staff observed that many of the corporate support functions are what AON Hewitt would compare with “general industry”. The AON Hewitt National Utility Survey indicated that the general industry comparable jobs are significantly overpaid by OPG by about 20 to 29% versus P50 (the 50th percentile). The Auditor General’s analysis of administration, finance and human resources jobs indicated that the majority of these jobs are overpaid at OPG as compared with the Ontario Public Service. The Auditor General also observed that the Goodnight benchmarking found that nuclear support functions were generally overstaffed while nuclear operational functions were generally understaffed. OPG replied that it is bound by collective bargaining and committed costs cannot be reduced.

7 CAPITAL STRUCTURE AND COST OF CAPITAL
(Issues 3.1 and 3.2)

7.1 Capital Structure

OPG did not apply for a change in capital structure in this proceeding. Rather, OPG proposed to use the same capital structure (53% debt and 47% equity) for all the regulated facilities, including the newly regulated hydroelectric facilities, which was originally approved in the first cost of service proceeding, EB-2007-0905, and again in the last cost of service proceeding, EB-2010-0008. In the current proceeding, OPG's proposed capital structure was supported by evidence (the "Foster report")[109] and expert testimony from Ms. Kathleen McShane of Foster Associates, Inc.

During the oral hearing, several parties challenged OPG's position that the capital structure was unchanged by the proposed $4 billion addition of the newly regulated hydroelectric facilities and Niagara Tunnel to rate base. These parties submitted that OPG's business risk has changed and that the equity thickness should be 42 to 43%.

SEC disagreed with Ms. McShane's view that the newly regulated hydroelectric facilities are more risky than the previously regulated hydroelectric facilities, but less risky than the nuclear facilities. SEC submitted that Ms. McShane has no independent knowledge of the business risks of the newly regulated hydroelectric facilities or the Niagara Tunnel, including First Nations issues, operating constraints or storage.

Noting that the Board concluded in EB-2007-0905 that the 47% equity thickness recommended by Drs. Kryzanowski and Roberts was appropriate, SEC submitted in the current proceeding that applying the methodology and parameters set out in Drs. Kryzanowski and Roberts' evidence in EB-2007-0905, namely 40% hydroelectric equity thickness and 50% nuclear equity thickness, to the proposed test period rate base would result in an overall equity thickness of 42.34%.

Board staff submitted that the Board did not approve the methodology of Drs. Kryzanowski and Roberts in EB-2007-0905, and that in the EB-2010-0008 proposal for technology specific cost of capital, Drs. Kryzanowski and Roberts revised the parameters to 43% hydroelectric equity thickness and 53% nuclear equity thickness.

[109] Exh L-3.1-SEC-24 Attachment 1

Should the Board accept the methodology and apply 43% equity thickness to all the hydroelectric facilities, Board staff submitted that the OPG equity thickness would be 45 to 46%.

OPG argued that none of the cost of capital experts that appear before the Board, including Drs. Kryzanowski and Roberts, have expertise in hydroelectric generation facilities. While the parties have challenged OPG's evidence and proposed reductions to equity thickness, none of the parties filed expert evidence to support their positions. OPG also argued that matters raised by some parties, e.g. comparisons with lower equity thickness for generators in other provinces by VECC, and the stand alone principle and 90% debt proposed by the Society, were previously addressed in EB-2007-0905. Further, as OPG is planning on spending more than $1.5 billion on the Darlington Refurbishment Project in the test period, OPG contends that its financial risk will increase in the test period.

Board Findings

In this application OPG did not request a change to its capital structure, claiming there had been no significant changes in the risks faced by its regulated asset portfolio that are not captured elsewhere in the application. While the application was filed in September 2013, no evidence was filed by OPG to substantiate this conclusion with respect to changes in risk until the interrogatory phase of the proceeding in March 2014.

The Foster report dealing with the capital structure and risk was not filed until March 19, 2014 in response to an interrogatory by SEC. The Board finds this late filing to be unfortunate, because the time between the report being publicly available and the date for intervenors to advise the Board of their intentions to file evidence was less than one week. The Board suspects that, had the Foster report been filed sooner, parties may have been in a better position to assess the merits of retaining their own expert on this matter. As it was, no alternative expert analysis was proffered and arguments by all parties were largely based on challenges to the Foster report.

The Board believes it would have been helpful to have had additional expert and independent evidence. The Board notes OPG's assessment that there had been no significant changes in risks was made before Foster Associates, Inc. was retained.[110] OPG appears to have made the initial assessment entirely on its own.

The Board cannot accept that business risk has not changed since the capital structure was last reviewed in 2010. Since that time, 48 additional hydroelectric facilities have been added to the inventory of prescribed assets, accounting for 12.4 TWh of energy forecast to be produced in 2014 and 12.5 TWh in 2015. These assets, together with the Niagara Tunnel which was brought into service in 2013, increase the proportionate share of rate base related to hydroelectric facilities from about half in 2010 to approximately two-thirds now. The relative business risk of hydroelectric generation versus nuclear has been accepted by the Board as being lower in previous proceedings,[111] even though setting the capital structure on a technology specific basis has not. The critical question therefore becomes whether business risk has changed in a significant enough way to warrant a change in capital structure, and in which direction is this change – lower or higher risk?

The Board finds that including additional hydroelectric units to the roster of prescribed assets lowers the business risk for several reasons. Subject to Board approval through this proceeding, these additional assets will be subject to treatment under a number of previously approved Board deferral and variance accounts for a host of variables, all of which reduce business risk. Since the equity component was first set, a new pension variance account has been approved by the Board. This variance account decreases OPG's forecast risk associated with pension and OPEB costs. The proportion of regulated assets between hydroelectric and nuclear generation has changed, with hydroelectric facilities now having a much larger share of the generating capacity of OPG than previously. It was acknowledged by OPG's consultant that hydroelectric facilities have lower risk than nuclear.[112] The new assets being added to rate base have long remaining service lives (average of 58 years for the newly prescribed assets[113]) and 95 years for the Niagara Tunnel. As long as there is rate regulation, these assets will produce power and revenue certainty until the end of their useful lives.

The Board considered the Foster report and makes the following observations.

[110] Application is dated September 27th, 2013 while contract commencement date is September 30th, 2013. (Undertaking J10.2)
[111] Decision with Reasons, EB-2010-0008, page 116
[112] Tr Vol 10 page 30
[113] Undertaking J12.3

- No independent analysis was undertaken of the operating costs and lives of the newly prescribed assets. The consultant's opinion was based on discussions with OPG staff only. While information obtained from operating personnel is an important component to assessing risk, the lack of independent knowledge of the circumstances of OPG's newly regulated hydroelectric operations is a concern.
- The opinion that the newly regulated assets have increased risk due to their location in Northern Ontario within First Nations communities and their traditional ways of life was not substantiated by fact. It appears this was conjecture on the part of the consultant based on conversations with OPG management.
- There was no evidence as to the impact of a change in equity thickness on the credit metrics.

OPG raised various other arguments with respect to the need for at least the same, or higher, equity thickness. One of these arguments was that there is a greater risk associated with the future move to incentive regulation. The Board does not accept that moving to incentive regulation significantly increases risk to the entity such that the capital structure should be reset, and has not done so for any of the other companies that it regulates. For example, the Board set the capital structure for all electricity distributors at a 40% equity to debt ratio in December 2006. As new incentive regulation models for electricity distributors evolved in 2008[114] and 2012[115], this capital structure was not revisited. Similarly, the capital structure for the natural gas distributors did not change as a result of moving to a long-term incentive regulatory mechanism for the setting of rates for these distributors. In addition, OPG is not actually being moved to incentive regulation in the current proceeding, and any potential changes to business risk this may entail could be considered in the incentive regulation proceeding. The Board therefore is not persuaded by the comments made by OPG and its consultant that the future move to an incentive regulatory mechanism for OPG increases business risk such that a higher equity thickness should be considered.

Instead, the Board has determined that business risk has changed for this payment setting period, and that the business risk is reduced. The business risk is reduced because of the addition of significant hydroelectric assets to rate base, which are less risky than nuclear assets.[116] The Board finds that a more appropriate equity thickness

[114] Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 14, 2008
[115] Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012
[116] Exh L-3.1-SEC-24, Attachment 1 page 23, Tr Vol 10 page 30

is 45%. This equity thickness is still considerably higher than any other entity regulated by the Board.

The Board does not accept the Society's argument that due to the change in the energy environment that the well accepted principles of a stand-alone entity should be abandoned and also that OPG can have up to a 90% debt operating structure due to its ownership structure. The Board has previously commented on the validity of the stand-alone principle and as neither of these issues was explored in sufficient detail through cross-examination or the production of independent expert evidence, the Board sees no justification for such a major change.[117]

In reaching this conclusion the Board was mindful of the Fair Return Standard as articulated by the courts, and the need to observe the requirements of consideration of comparable investment, financial integrity and capital attraction. However, the Fair Return Standard is sufficiently broad to allow a regulator to apply informed judgment and discretion in the determination of a rate regulated entity's cost of capital. The Board believes that a reduction to equity thickness is based on the evidence in this case, the Board's best judgment and is a reasonable outcome.

As a result of its review, the Board finds that the capital structure should be based on 45% equity and 55% debt.

7.2 Return on Equity

OPG's current proposal is to apply 9.36%, the Board's ROE for 2014 cost of service applications, for 2014 and 9.53% for 2015 based on Global Insights data from September 2013.

In the event that the Board's ROE for 2015 cost of service applications was available at the time of the payment order, Board staff submitted that the Board's ROE, based on more recent *Consensus Forecasts*, be used instead of the 9.53% proposed by OPG based on Global Insights data from September 2013.

OPG replied that Board staff's proposal would involve data after the close of record and would be a departure from the methodology used for setting the ROE in the second

[117] Decision with Reasons, EB-2007-0905, pages 137–142

PRODUCTION FORECAST AND METHODOLOGY
NUCLEAR

1.0 PURPOSE

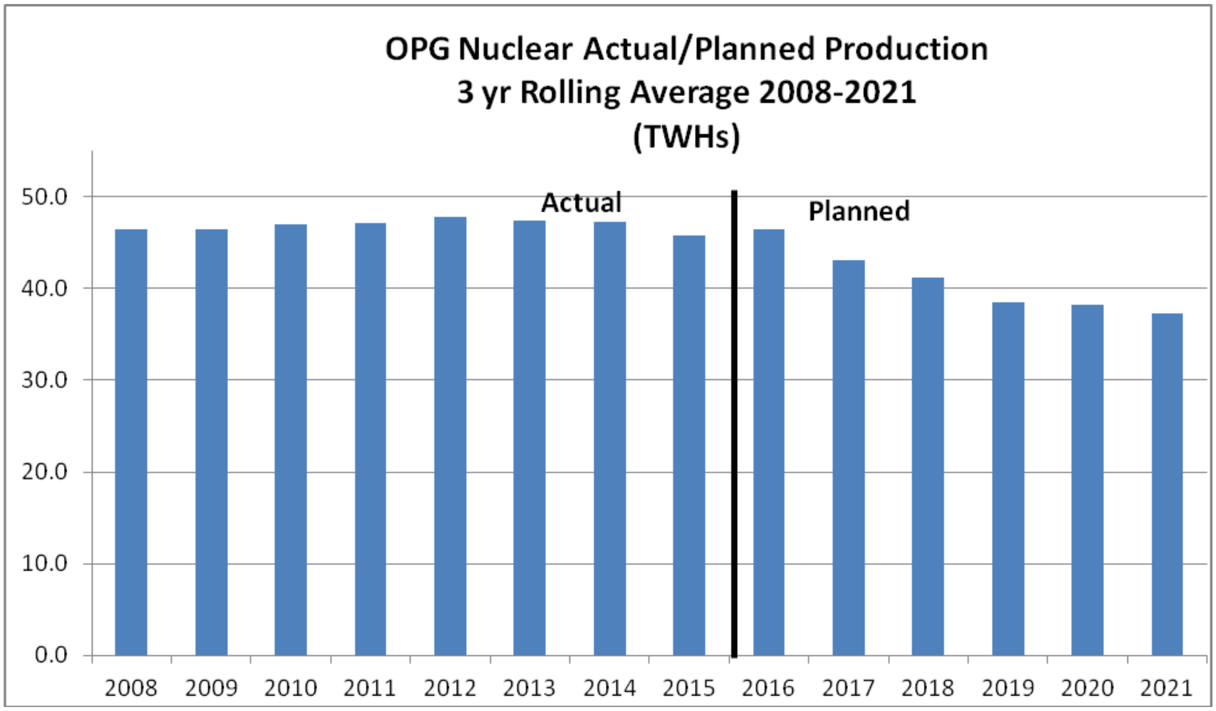
This evidence provides the production forecast for the nuclear facilities and a description of the methodology used to derive the forecast.

2.0 OVERVIEW

OPG is seeking approval of a nuclear production forecast of 38.1 terawatt-hours ("TWh") for 2017, 38.5 TWh for 2018, 39.0 TWh for 2019, 37.4 TWh for 2020 and 35.4 TWh for 2021. This amounts to a total 188.3 TWh nuclear production forecast for the 2017-2021 test period. The nuclear production forecast for the years 2013-2021 is presented in Ex. E2-1-1 Table 1. A monthly nuclear production forecast for 2017-2021 is presented in Ex. E2-1-1 Table 2. As discussed below, this represents a challenging production forecast for OPG's nuclear facilities during a period of significant and unprecedented change in OPG's nuclear operations due to the Darlington Refurbishment Program and Pickering Extended Operations.

Nuclear production (three year rolling average) over the 2008-2021 period peaked in 2012 as shown in Chart 1. From 2012 onward, actual and planned production primarily reflects the loss of generation due to the Darlington Vacuum Building Outage ("VBO") in 2015, the first unit outage for the Darlington Refurbishment Program in 2016, the Pickering VBO in 2021 and the increase in the number of planned outage days over the test period required for Pickering Extended Operations, and to address life cycle and aging equipment issues such as replacement of Primary Heat Transport ("PHT") pump motors at Darlington. OPG continues to pursue initiatives that focus on improving planned outage execution to meet planned outage days targets, and initiatives to improve plant equipment reliability and fuel handling to meet Forced Loss Rate ("FLR") targets. These initiatives are addressed in the discussion of OPG's gap closure initiatives in the Benchmarking and Business Planning evidence (Ex. F2-1-1).

Chart 1



The OEB approved nuclear production for the period 2008 to 2015 was greater than actual production. As shown on Chart 2 below, the average annual production shortfall for this period was 3.2 TWh. This resulted in an average negative revenue impact of $154.0M borne each year by OPG's shareholder. Consequently, in EB-2013-0321 OPG identified a change in OPG's approach in developing its nuclear production forecast. This change entailed increased scrutiny to more fully and realistically recognize the scope, risks and complexity of work performed during outages and where possible, basing the forecast on actual experience with similar work performed in the past at OPG and other organizations. In EB-2013-0321 the OEB accepted OPG's approach. The OEB noted, however, that the increased rigor had negated the need for adjustments for major unforeseen events going forward. OPG's methodology used to develop the 2017-2021 nuclear production forecast maintains the approach set out in EB-2013-0321. OPG's projected planned outage days, FLR, and

Board Staff Interrogatory #10

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

Interrogatory

Reference:
Ref: Exh C1-1-1, Chart 1

Chart 1, from page 1 of Exh C1-1-1, is replicated below.

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

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

a) Please confirm whether the rate base values shown are: i) beginning of year; ii) mid-year or average of the year; or iii) end-of year.

b) OPG proposes that the equity thickness for the combined hydroelectric and nuclear generating regulated assets be increased to 49% for the whole period of the five- year term, in light of increased risk. The significant capital additions are mainly due to the Darlington Refurbishment Program, which significantly increases the relative percentage of OPG's regulated asset rate base related to nuclear generation. However, from Chart 1, significant additions to the nuclear rate base only begin to occur in 2020, when the nuclear rate base becomes approximately equal to the hydroelectric rate base, and exceeds it only in the last year of the plan 2021. For the first three years of the plan (2017-19), regulated hydroelectric rate base remains more than double the nuclear rate base.

   Please explain why OPG is proposing that the 49% equity thickness apply to all years in the five-year plan. On an assumption that there could be increased risk due to the increased risk from significant nuclear capital investments, why wouldn't the increased thickness only apply, if necessary, beginning in 2020 or 2021?

Response

a) The rate base values in Chart 1, from page 1 of Ex. C1-1-1 Attachment 1, are determined using a mid-year average methodology. As discussed at Ex. B1-1-1 page 4: "for large in-service additions or adjustments, where the in-service addition amount of the amount of an adjustment exceeds $50M, the month in which the addition or adjustment is reflected is used, instead of a mid-year average, to improve accuracy."

b) The following response was prepared by Concentric Energy Advisors:

OPG is proposing that the 49% equity thickness apply to all years in the five-year plan for several reasons. As discussed in Concentric's Common Equity Ratio Report (Ex. C1-1-1 Attachment 1, pages 13 and 14) the cost of capital (including the capital structure) is a forward-looking concept from the perspective of investors. OPG requires ongoing access to capital on reasonable terms in order to finance the Company's significant capital spending program over the 2017 to 2021 period and beyond. Investors and credit rating agencies are aware of OPG's elevated capital spending program and shifting rate base between 2017 and 2021. In order to ensure investors and rating agencies that there is regulatory support for cost recovery and credit quality, OPG's rates should reflect the increased risk profile of its elevated capital spending program and its shifting rate base to a higher percentage of nuclear assets relative to hydroelectric assets.

Although the first refurbished Darlington unit will not be brought into service until late in the test period, OPG will be making substantial capital investments over the next five years that will require access to capital on reasonable terms and that will place pressure on OPG's cash flows and credit metrics during this period. In particular, OPG forecasts total capital expenditures of approximately $5.25 billion on the DRP from 2017-2021 (Ex. D2-2-10, Table 1). DBRS has commented specifically on the risk associated with the DRP as follows:

> *DBRS believes that given the complexity and scale of the Darlington Refurbishment, there is significant execution risk as well as the potential for cost overruns. The high capital expenditures (capex) required, albeit spread over a ten-year period, in addition to ongoing maintenance capex (total capex forecast of approximately $2 billion in 2016), are expected to pressure OPG's key credit metrics.*[1]

DBRS also notes that OPG is expected to generate a free cash flow deficit in 2016 due to the large capital expenditure program.[2]

Credit rating agencies have also commented more generally about the credit risk associated with large capital spending programs. For example, DBRS writes:

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1 Ex. A2-3-1, Attachment 1, at 1
2 *Ibid.*

> *For utilities undergoing significant multi-year capital expansion programs, capital spending may be considered a primary rating factor. This would be particularly relevant for companies with significant nuclear generation development.*[3]

Moody's has commented on the credit risk associated with capital spending plans:

> *Given the long-term nature of utility assets and the often lumpy nature of their capital expenditures, it is important to analyze both a utility's historical performance as well as its prospective future performance, which may be different from backward-looking measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance. In the illustrative mapping examples in this document, the scoring grid uses three year averages for the financial strength sub-factors. Multi-year periods are usually more representative of credit quality because utilities can experience swings in cash flows from one-time events, including items such as rate refunds, storm cost deferrals that create a regulatory asset, or securitization proceeds that reduce a regulatory asset. Nonetheless, we also look at trends in metrics for individual periods, which may influence our view of future performance and ratings.*[4]

In an August 2016 report, S&P explains the importance of regulatory support for large capital projects:

> *When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors*[5]*.*

The proposed 49% equity thickness for OPG is conservative as compared to the authorized equity ratios for the operating companies held by Concentric's proxy group,

[3] DBRS, Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry, October 2015, at 7.
[4] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, December 23, 2013, at 22.
[5] S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

none of which is a pure generation company like OPG. As discussed in Ex. C1-1-1 Attachment 1, page 32, Moody's views power generation as the highest risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operations, including the risk that incurred costs will either not be recovered in rates or recovered with material delays. In addition, nuclear generation is generally considered to be the highest risk generation source. DBRS explains:

> *Nuclear generation faces higher operating risk than other types of generation because of its complex technology (approximately 57% of OPG's production in 2015). Financial implications of forced outages, especially with older units (e.g., Pickering Nuclear Generating Station), are greater given the high fixed-cost nature of these plants as well as the fact that lost revenues from outages are not recoverable through rates.*[6]

[6] Ex. A2-3-1, Attachment 1, at 2

SEC Interrogatory #8

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

Interrogatory:

Reference: Exhibit M3

[p.22] Please confirm that the expert assumes OPG has 100% of its generation under regulation for the purposes of its equity thickness, and thus has zero market exposure. Please explain how this expert has adjusted the peer group risk to reflect the higher market exposure for the peer group compared to OPG.

Response:

The following response was provided by The Brattle Group:

Confirmed as to the generation relevant for OEB regulation. At the same time, the refined sample of comparable companies was selected to ensure that they too have minimal exposure to market price risk. As discussed in Ex. M3 (see the discussion on Market Risk on Pg. 18-21), the average market price exposure for Dr. Villadsen's refined sample was also very small at about 2%. Therefore, Dr. Villadsen found OPG's regulated generation and the refined sample are highly comparable with respect to the exposure to market price risk, having, respectively, none and trivial proportions of their generation capacity exposed to market price risk.

OCTOBER 2015

METHODOLOGY

Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry

PREVIOUS RELEASE: OCTOBER 2014

Appendix: Regulation

- In determining the BRA for regulation (see page 6), DBRS reviews the following ten considerations to assess the regulatory framework in which the utility conducts its business.
- The ranking of the factors is based on a five-point scale (excellent, good, satisfactory, below average and poor).
- The first four factors are generally of greater importance than the others when assessing regulatory risk; however, the factors are not given a specific weighting when assessing the regulatory framework.

CONSIDERATION 1: DEEMED EQUITY

Definition

Deemed equity is the percentage of equity investment in the rate base on which a utility could earn a return. In general, the higher the Deemed Equity portion, the higher the earnings for a utility. In addition, utilities tend to maintain their actual capital structure in line with the regulatory capital structure.

Score	Item	Definition
Excellent	50%+	• Deemed equity represents 50% or more of utility's rate base • The treatment of deemed equity is consistent historically
Good	45.00% to 49.99%	• Deemed equity represents 45.00% to 49.99% of utility's capital structure • The treatment of deemed equity is consistent historically
Satisfactory	40.00% to 44.99%	• Deemed equity represents 40.00% to 44.99% of utility's capital structure • The treatment of deemed equity has not been consistent historically
Below Average	35.00% to 39.99%	• Deemed equity represents 35.00% to 39.99% of utility's capital structure • The treatment of deemed equity has not been consistent historically
Poor	Below 34.99%	• Deemed equity represents less than 34.99% of utility's capital structure • The treatment of deemed equity has not been consistent historically

CONSIDERATION 2: ALLOWED ROE

Definition

Allowed ROE is a measurement of returns on the deemed equity portion of the rate base. The regulator sets an allowed ROE based on a utility's business risk level (which is assessed by the regulator). In a supportive regulatory environment, utilities' actual ROEs are generally in line with the allowed ROE or exceed the allowed ROE. In an unsupportive regulatory regime, utilities often generate much lower actual ROE than the allowed ROE. DBRS will consider the utility's track record of its actual ROE outperformance/underperformance relative to allowed ROE and assess whether the key drivers of ROE outperformance/underperformance could be sustained going forward.

Score	Item	Definition
Excellent	10%+	• An allowed ROE is set at 10.00% or higher • The regulatory treatment of allowed ROE has been consistent historically
Good	9% to 10%	• An allowed ROE is set at 9.00% to 10.00% • The regulatory treatment of allowed ROE has been consistent historically
Satisfactory	8.00% to 8.99%	• An allowed ROE is set at 8.00% to 8.99% • The regulatory treatment of allowed ROE has been consistent historically
Below Average	7.00% to 7.99%	• An allowed ROE is set at 7.00% to 7.99% • The regulatory treatment of allowed ROE has NOT been consistent historically
Poor	Below 7%	• An allowed ROE is set at below 7.00% • The regulatory treatment of allowed ROE has NOT been consistent historically

WAPA[12] by the proportion that OPG production comprises of a typical residential customer's consumption in the year.[13] Ex. N3-1-1 Tables 1 and 2 provide the computation of these impacts for 2017 through 2021. OPG used the inputs described below to calculate the consumer impacts, consistent with the pre-filed evidence:

Typical residential consumption: 789 kWh is based on the typical monthly consumption (750 kWh) in the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), available at: http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Your+Electricity+Utility. Typical Consumption includes line losses (Assumed loss factor of 1.0525).

Typical residential bill: $150.58 is taken from the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), available at: http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Your+Electricity+Utility. OPG runs this bill calculator tool for all local distribution companies available in the bill calculator and uses a simple average of all of the bills as the typical bill.

Forecast of 2017 Provincial Demand: Based on forecast demand for 2017 (137.6 TWh) from Table 3.1 of IESO 18-Month Outlook Update for April 2016 to September 2017, published on March 22, 2016.

6.0 PROPOSAL AND ALTERNATIVE RATE SMOOTHING SCENARIOS

Following the amendments to the Regulation, OPG identified a range of scenarios that produce a more stable WAPA (and, by extension, more stable customer bill impacts). These scenarios are set out in Chart 3, below. As a threshold, OPG determined that it would not consider scenarios that increased the forecast cost of rate smoothing (i.e., the cumulative

[12] N3-1-1 Table 1, line 8.
[13] N3-1-1 Table 1, line 2.

interest amount over the deferral and recovery periods) relative to the company's proposal under the previous revision of the Regulation.

Since the OEB is not approving payment amounts or RSDA deferral amounts beyond 2021 in this application, Chart 3 includes illustrative trends for OPG's WAPA and the average year-over-year change in a typical residential customer's monthly bill throughout the 20-year deferral and recovery period. Chart 3 also includes the approximate peak RSDA account balance, the credit metrics associated with each option, and the final smoothed rate at the end of the recovery period. As with the scenarios originally presented in Ex. A1-3-3 Chart 3, the actual trajectory of payment amounts will depend on the OEB's decisions throughout the remainder of the deferral and recovery periods.

For reference, Chart 3 also includes the original 11% nuclear payment amount smoothing proposal filed in Ex. A1-3-3, updated to reflect current nuclear revenue requirement amounts (per the first and second impact statements, Ex. N1-1-1 and Ex. N2-1-1).

Chart 3: Proposed and Alternative Rate Smoothing Scenarios

	Original 11% Proposal[1]	A	B (Proposed)	C	D	E
2017-2021 Average Annual Change in WAPA	**4.3%**	2.0%	**2.5%**	3.0%	3.5%	4.0%
2022-2026 Average Annual Change in WAPA[2]	**6.9%**	8.3%	**7.0%**	5.7%	4.3%	3.0%
2027-2036 Average Annual Change in WAPA[2]	**(1.9)%**	(1.5)%	**(1.0)%**	(0.3)%	0.5%	1.2%
Peak RSDA Balance ($B)	**$3.3**	$3.2	**$2.9**	$3.0	$3.2	$3.4
Total Interest ($B)	**$1.4**	$1.4	**$1.4**	$1.4	$1.4	$1.4
Interest Cost / Deferred Revenue Ratio	**0.5**	0.5	**0.5**	0.5	0.5	0.4
FFO Interest Coverage > = 3 (2017-2021) / (2022-2026)	**3.6 / 5.3**	4.5 / 5.0	**4.6 / 5.4**	4.6 / 5.8	4.7 / 6.2	4.8 / 6.7
DEBT to EBITDA < = 5.5 (2017-2021) / (2022-2026)	**6.2 / 5.3**	5.9 / 5.3	**5.9 / 5.2**	5.8 / 5.0	5.8 / 4.9	5.7 / 4.7
Nuclear Payment Amount Transition Impact ($/MWh)	**($4.3)**	$1.0	**($3.7)**	($9.3)	($16.8)	($22.7)
Average Annual Bill Impact (2017-2021) in %	**0.7%**	0.3%	**0.4%**	0.5%	0.6%	0.7%
Average Annual Bill Impact (2017-2021) in $	**$1.05**	$0.51	**$0.65**	$0.79	$0.93	$1.07
Average Annual Bill Impact (2017-2036) in %[2]	**0.3%**	0.3%	**0.3%**	0.4%	0.4%	0.4%
Average Annual Bill Impact (2017-2036) in $[2]	**$0.43**	$0.43	**$0.47**	$0.53	$0.60	$0.65

Notes

[1] Updated to reflect changes to Nuclear revenue requirement in Ex. N1-1-1 and Ex. N2-1-1. Nuclear Payment Amount smoothing is inherently more volatile than smoothing based on WAPA. This is primarily due to the impact that year-over-year production differences have on the annual WAPA, as well as the expiry of higher payment riders in effect during 2016. The average year-over-year change in the WAPA shown for the Original 11% Proposal is therefore not directly comparable with the more consistent year-over-year change in the period in the smoothing scenarios under the amended Regulation.

[2] Calculated assuming that hydroelectric payment amounts continue to escalate at 1.5% per year throughout the 2017-2036 period pursuant to the price-cap as proposed in Ex. I1-2-1 Table 1 and no payment riders beyond those proposed in this application.

Based on its assessment of the alternatives above, using the considerations described in section 4.0 above, OPG proposes an average annual WAPA increase of 2.5% per year during the 2017-2021 period. This rate of increase would result in an average year-over-year increase of approximately $0.65 on the typical residential customer’s monthly bill during the 2017-2021 period. The methodology by which OPG calculated customer bill impacts in Chart 3 is provided in Section 5.2 above.

OPG has calculated the nuclear payment amount (NPA) required to arrive at a 2.5% increase in WAPA in Ex. N3-1-1 Table 3.

OPG applied the following rationales to evaluate each option for each of the assessment considerations:

Financial Viability (Leverage and Cash Flow Impacts): Higher values for the FFO Adjusted Interest Coverage ratio and lower values for the Debt to EBITDA credit metric reduce financial risk to OPG. OPG's assessment was based on at least one of the two metrics cited above being within threshold at all times during each of the two 5-year deferral periods (i.e., 2017 to 2021 and 2022 to 2026). All scenarios in Chart 3 meet this threshold.

Rate Stability: All of the scenarios in Chart 3 result in a constant year-over-year change in WAPA within the two halves of the deferral period and within the recovery period. In each scenario, the year-over-year change in WAPA varies between the two halves of the deferral period, and again at the beginning of the recovery period. Lower variances at each of these points are better.

Long-Term Perspective: The assessment was based on the size of the average year-over-year change in WAPA during the recovery period (closer to 0 per cent is better).

Post-Recovery Transition: The assessment was based on the size of the change in the nuclear payment amount at the end of the recovery period (smaller is better) to the forecast post-transition payment amount of approximately $120/MWh.

Intergenerational Equity: The assessment was based on the ratio of total interest costs to total amounts deferred (total interest / total amounts deferred). A lower ratio implies a lower cost of deferring revenue under that alternative.

Intergenerational equity involves striking a balance between the benefits of deferring revenue and the costs of the deferral; therefore OPG's assessment placed value on a ratio that best reflects this balance (i.e., neither the highest nor the lowest ratio).

Customer Bill Impact: Each scenario was assessed based on the resulting average year-over-year change in a typical residential customer's monthly bill, both in the 2017-2021 period and over the full deferral and recovery periods.

In OPG's assessment, Scenario B results in the best overall balance based on the application of the above considerations. While Scenarios A, B, and C each perform well on several considerations, Scenario B best balances the considerations outlined above. Scenario A has the steepest rate change in the recovery period and the least stable WAPA in 2022 and 2027, and although Scenario C produces a smaller change in WAPA between the two halves of the deferral period, it also produces less optimal results than Scenario B in terms of bill impact and the transition rate. Scenario B also produces the lowest peak RSDA balance. Overall, Scenario B best addresses the considerations and reflects the best overall proposal.

Relative to OPG's proposal under the previous version of the Regulation, the main benefit of the revised proposal is a significantly lower average annual bill impact in the 2017-2021 period. Under the previous proposal, the annual average of year-over-year increases in customers' monthly bills over the period was forecast at approximately $1.05, as opposed to a less variable $0.65 under the revised proposal.

Under the revised proposal, OPG expects that the rate of change in the company's WAPA will be different between the first and second halves of the deferral period. However the average annual rate of change in WAPA is expected to be consistent within each five-year period, meaning that the proposal would result in a consistent rate of increase during the deferral period (except for the transition between 2021 and 2022) and a consistent average annual decrease in WAPA during the recovery period.

OPG's proposal results in deferring the collection of approximately $1B in revenue in the 2017 to 2021 period, as reflected in Chart 4 below. This is approximately $0.4B less than OPG proposed to defer under the previous proposal (after adjustments to account for the reduced nuclear revenue requirement in the previous impact statements). The nuclear payment amounts have been updated based on the level of deferred recovery associated with this proposal.

Chart 4: OPG Proposed Deferred Revenue Requirement

	2017	2018	2019	2020	2021	Total
Proposed Revenue Requirement ($M)	$ 3,161	$ 3,186	$ 3,273	$ 3,783	$ 3,398	$ 3,617
Forecast Production (TWh)	38.10	38.47	39.03	37.36	35.38	26.01
Smoothed Rate ($/MWh)	$ 76.39	$ 78.60	$ 84.83	$ 88.21	$ 92.02	N/A
Smoothed Revenue ($M)	$ 2,910	$ 3,024	$ 3,311	$ 3,295	$ 3,256	$ 15,796
Deferred Revenue Requirement ($M)	$ 251	$ 162	$ (38)	$ 488	$ 142	$ 1,005

7.0 IMPLEMENTATION

The specific revenue requirement deferral amounts proposed in section 6.0 are produced by adjusting the approved nuclear payment amounts to achieve the desired annual rate of change in the total WAPA. The OEB's findings on the proposed nuclear revenue requirements, nuclear production forecast, hydroelectric and nuclear payment riders and the hydroelectric IRM formula will necessarily impact the 2017-2021 NPA, the annual deferred nuclear revenue requirement, and the resulting WAPA.

Nuclear rate smoothing is unique in terms of the magnitude of the proposed deferred amounts, and the number of interrelated decisions required. To the extent the OEB's decision changes the rate smoothing inputs, it may be expedient for the OEB to make a decision on the nuclear revenue requirements and the inputs (steps 2 and 3 of the chart in section 3.1 above), and withhold its final decision on the "outputs" (i.e., the annual change in WAPA, the resulting nuclear payment amount, and the amount to be deferred in the RSDA) until the Payment Amount Order approval process (steps 4, 5 and 6).

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 23/07, s. 3.

5.3 REVOKED: O. Reg. 312/13, s. 3.

Nuclear development variance account

5.4 (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under section 78.1 of the Act, differences between actual non-capital costs incurred and firm financial commitments made and the amount included in payments made under that section for planning and preparation for the development of proposed new nuclear generation facilities. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 27/08, s. 1.

Darlington refurbishment rate smoothing deferral account

5.5 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the commencement of the deferral period, the difference between,

(a) the revenue requirement amount approved by the Board that, but for subparagraph 12 i of subsection 6 (2) of this Regulation, would have been used in connection with determining the payments to be made under section 78.1 of the Act each year during the deferral period in respect of the nuclear facilities; and

(b) the portion of the revenue requirement amount referred to in clause (a) that is used in connection with determining the payments made under section 78.1 of the Act, after determining, under subparagraph 12 i of subsection 6 (2) of this Regulation, the amount of the revenue requirement to be deferred for that year in respect of the nuclear facilities. O. Reg. 353/15, s. 2.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account at a long-term debt rate reflecting Ontario Power Generation Inc.'s cost of long-term borrowing that is determined or approved by the Board from time to time, compounded annually. O. Reg. 353/15, s. 2.

Rules governing determination of payment amounts by Board

6. (1) Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. O. Reg. 53/05, s. 6 (1).

(2) The following rules apply to the making of an order by the Board that determines payment amounts for the purpose of section 78.1 of the Act:

1. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the variance account established under subsection 5 (1) over a period not to exceed three years, to the extent that the Board is satisfied that,

   i. the revenues recorded in the account were earned or foregone and the costs were prudently incurred, and

   ii. the revenues and costs are accurately recorded in the account.

2. In setting payment amounts for the assets prescribed under section 2, the Board shall not adopt any methodologies, assumptions or calculations that are based upon the contracting for all or any portion of the output of those assets.

3. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5 (4). The Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 15 years.

4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs and firm financial commitments incurred in respect of the Darlington Refurbishment Project or incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,

   i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or

   ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,

   i. the costs were prudently incurred, and

   ii. the financial commitments were prudently made.

5. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., the Board shall accept the amounts for the following matters as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors of Ontario Power Generation Inc. before the effective date of that order:

   i. Ontario Power Generation Inc.'s assets and liabilities, other than the variance account referred to in subsection 5 (1), which shall be determined in accordance with paragraph 1.

   ii. Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations.

   iii. Ontario Power Generation Inc.'s costs with respect to the Bruce Nuclear Generating Stations.

6. Without limiting the generality of paragraph 5, that paragraph applies to values relating to,

   i. capital cost allowances,

   ii. the revenue requirement impact of accounting and tax policy decisions, and

   iii. capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2.

7. The Board shall ensure that the balance recorded in the deferral account established under subsection 5.2 (1) is

recovered on a straight line basis over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the account, based on the following items, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.,

i. return on rate base,

ii. depreciation expense,

iii. income and capital taxes, and

iv. fuel expense.

7.1 The Board shall ensure the balance recorded in the variance account established under subsection 5.4 (1) is recovered on a straight line basis over a period not to exceed three years, to the extent the Board is satisfied that,

i. the costs were prudently incurred, and

ii. the financial commitments were prudently made.

8. The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.

9. The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.

10. If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear generation facilities referred to in paragraphs 3, 4 and 5 of section 2.

11. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc. that is effective on or after July 1, 2014, the following rules apply:

i. The order shall provide for the payment of amounts with respect to output that is generated at a generation facility referred to in paragraph 6 of section 2 during the period from July 1, 2014 to the day before the effective date of the order.

ii. The Board shall accept the values for the assets and liabilities of the generation facilities referred to in paragraph 6 of section 2 as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors before the making of that order. This includes values relating to the income tax effects of timing differences and the revenue requirement impact of accounting and tax policy decisions reflected in those financial statements.

12. For the purposes of section 78.1 of the Act, in setting payment amounts for the nuclear facilities during the deferral period,

i. the Board shall determine the portion of the Board-approved revenue requirement for the nuclear facilities for each year that is to be recorded in the deferral account established under subsection 5.5 (1), with a view to making more stable the year-over-year changes in the OPG weighted average payment amount over each calculation period,

ii. the Board shall determine the approved revenue requirements referred to in subsection 5.5 (1) and the amount of the approved revenue requirements to be deferred under subparagraph i on a five-year basis for the first 10 years of the deferral period and, thereafter, on such periodic basis as the Board determines,

iii. for greater certainty, the Board's determination of Ontario Power Generation Inc.'s approved revenue requirement for the nuclear facilities shall not be restricted by the yearly changes in payment amounts in subparagraph i,

iv. the Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5.5 (1), and the Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 10 years commencing at the end of the deferral period, and

v. the Board shall accept the need for the Darlington Refurbishment Project in light of the Plan of the Ministry of Energy known as the 2013 Long-Term Energy Plan and the related policy of the Minister endorsing the need for nuclear refurbishment. O. Reg. 23/07, s. 4; O. Reg. 27/08, s. 2; O. Reg. 312/13, s. 4; O. Reg. 353/15, s. 3; O. Reg. 57/17, s. 2.

7. OMITTED (PROVIDES FOR COMING INTO FORCE OF PROVISIONS OF THIS REGULATION). O. Reg. 53/05, s. 7.

SCHEDULE

1. Abitibi Canyon.
2. Alexander.
3. Aquasabon.
4. Arnprior.
5. Auburn.
6. Barrett Chute.
7. Big Chute.
8. Big Eddy.
9. Bingham Chute.
10. Calabogie.
11. Cameron Falls.
12. Caribou Falls.
13. Chats Falls.
14. Chenaux.
15. Coniston.
16. Crystal Falls.
17. Des Joachims.
18. Elliott Chute.
19. Eugenia Falls.
20. Frankford.
21. Hagues Reach.

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

OEB Staff Report

EB-2009-0084

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

January 14, 2016

Table 1: Current Cost of Capital Methodology[2]

	Electricity Distributors and Transmitters	**OPG's prescribed generation assets**	**Natural Gas Distributors**		
			Enbridge Gas Distribution Inc.	**Union Gas Limited**	**Natural Resource Gas**
Deemed Capital Structure	40% equity, 56% long-term debt, 4% short term debt	45% equity, 55% debt, on rate base adjusted for the lower of Asset Retirement Obligations or Unfunded Nuclear Liabilities (EB-2013-0321)	36% equity, 64% debt (combination of actual long-term, short-term debt and preferred shares)	36% equity, 64% debt (combination of actual long-term, short-term debt and preferred shares)	40% equity, 56% long-term debt, 4% short term debt
Return on Equity (formula)	$ROE_t = 9.75\% + 0.5 \times (LCBF_t - 4.25\%) + 0.5 \times (UtilBondSpread_t - 1.415\%)$, where ROE_t is the Return on Equity for year t, $LCBF_t$ is the Long Canada(30 year Government of Canada) Bond (yield) forecast for year t, and $UtilBondSpread_t$ is the spread between 30-year A-rated Utility Corporate Bond yields and Long Canada Bond Yields. The data for $LCBF_t$ and $UtilBondSpread_t$ are derived from Consensus Forecasts, and from Statistics Canada/Bank of Canada and Bloomberg LP data for the month 3 months in advance of the first effective date of the cost of capital parameters. Thus, for cost of capital updates effective January 1, September data are used.				
Long-term debt rate	Weighted average of embedded (actual) debt plus forecasted debt rate(s) of new debt in the test period. For electricity distributors and transmitters, a deemed long-term debt rate based on the following formula serves as a ceiling on affiliated debt at the time of issuance, on variable rate debt or on debt without a fixed term (e.g. Demand or Promissory Notes): $LTDR_t = LCBF_t + UtilBondSpread_t$				
Short-term debt rate	Formula: $STDR_t = AvgBA_t + AnnSpread_t$, where $AvgBA_t$ is the average 3-month Bankers' Acceptance rate for the month 3 months prior to the cost of capital update, taken from Statistics Canada/Bank of Canada, and $AnnSpread_t$ is the average estimate of the spread for 3-month Corporate loans over the overnight Bankers' Acceptance rate from a confidential survey with major Canadian banks, conducted annually.	Estimated short term debt cost. OPG and the natural gas distributors have methodologies that have been approved by the OEB in earlier decisions.			
Note	Preferred shares, if applicable, will be taken into account in the deemed capital structure and determining the weighted average cost of capital.				

[2] Table 1 provides a summary of the cost of capital methodology as it currently applies to rate-regulated utilities in Ontario. This reflects the 2009 Cost of Capital Report and subsequent OEB letters and decisions. Subsequent letters and decisions have changed the timing for updates and the capital structure for rate-setting purposes for some utilities; the basic methodology determined in the 2009 Cost of Capital Report is unchanged.

Ontario Power Generation Inc.

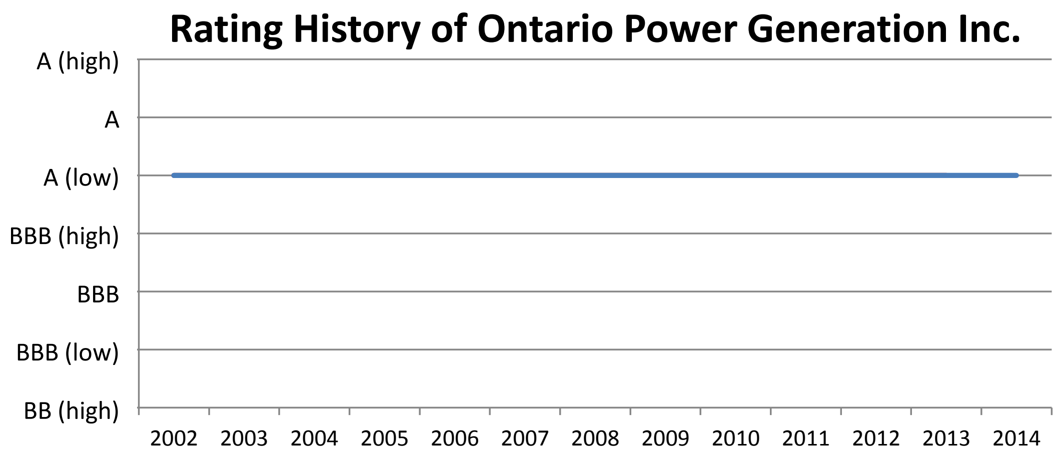
Report Date:
March 25, 2014

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable
Unsecured Debt	A (low)	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating History

	Current	2013	2012	2011	2010	2009
Issuer Rating	A (low)	A (low)	A (low)	NR	NR	NR
Unsecured Debt	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)



Note:
All figures are in Canadian dollars, unless otherwise noted.