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August 31, 2010

BY COURIER (8 COPIES) AND EMAIL

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
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Dear Ms. Walli:

Re: Pollution Probe – Intervenor Evidence
EB-2010-0008 – Ontario Power Generation – 2011-12 Payment Amounts

Pursuant to *Procedural Order No. 4*, please find enclosed expert evidence prepared by Dr. Lawrence Kryzanowski and Dr. Gordon Roberts on behalf of Pollution Probe.

Yours truly,

Basil Alexander

BA/ba

Encl.

cc: Applicant and Intervenors per Applicant and List of Intervenors attached to *Procedural Order No. 3*

Before the Ontario Energy Board

In the matter of:

EB-2010-0008
2011-2012 Payment Amounts for OPG's Prescribed Facilities

Exhibit M
Tab 10

Evidence Filed on Behalf of
Pollution Probe

On Issue List Items 3.1, 3.3 and Related Issues

<u>Text, Appendices and Schedules</u>

Prepared Testimony of

Dr. Lawrence Kryzanowski and Dr. Gordon S. Roberts

Senior Concordia University Research Chair in Finance, John Molson School of Business, Concordia University, Montreal; and CIBC Professor of Financial Services, Schulich School of Business, York University, Toronto.

August 2010

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1. INTRODUCTION AND SUMMARY

1.1 Qualifications

This evidence is the work of Dr. Lawrence Kryzanowski of Concordia University and Dr. Gordon S. Roberts of York University. Dr. Kryzanowski is currently a Full Professor of Finance and Senior Concordia University Research Chair in Finance (previously Ned Goodman Chair in Investment Finance) at Concordia University. He earned his Ph.D. in Finance at the University of British Columbia. Dr. Gordon S. Roberts is currently CIBC Professor of Financial Services at York University's Schulich School of Business. He earned his Ph.D. in Economics at Boston College.

Dr. Kryzanowski has experience in preparing evidence as an expert witness in utility rate of return applications, stock market insider trading court proceedings, and confidential final offer arbitration hearings for the setting of fair rates for the movement of various products by rail. Together with Dr. Roberts in 1997, he prepared a report for the Calgary law firm, MacLeod Dixon, on rate of return considerations in the pipeline application by Maritimes and Northeast. Drs. Kryzanowski and Roberts provided evidence also for a group of organizations collectively and most recently referred to as the Consumers Group (formerly UNCA Intervenor Group and FIRM Customers) on the fair return on equity and the recommended capital structure for ATCO Electric Limited in its 2001/2002 Distribution Tariff Application and for Aquila Networks Canada (Alberta) Ltd. ("ANCA") in its 2001/2002 Distribution Tariff Application and its 2002 Distribution Tariff Application (DTA) No. 1250392 before the Alberta Energy and Utilities Board. On behalf of the Province of Nova Scotia, they provided evidence and testified before the Nova Scotia Utility and Review Board in the matter of Nova Scotia Power Inc. in 2002. They filed evidence and testified before the Régie de l'Enérgie du Quebec for the Fédération canadienne de l'entreprise indépendante ("FCEI") / Union des municipalities du Québec ("UMQ") & Option consommateurs ("OC") in Hydro Quebec Distribution's 2003 application. Together with Dr. Roberts, and on behalf of Consumers Group, Dr. Kryzanowski prepared testimony and testified in Generic Hearing No. 1271597 before the Alberta Energy and Utilities Board in 2003-2004. Together with Dr. Roberts, he submitted evidence and testified before the Public Utilities Board of the Northwest Territories in the General Rate Application of Northwest

Territories Power Corporation in 2007; and on behalf of Pollution Probe in EB-2007-0905 – OPG – 2008-09 Payments before the Ontario Energy Board in 2008. More recently, Drs. Kryzanowski and Roberts submitted evidence and testified on behalf of the Office of Utilities Consumer Advocate (UCA) in the 2009 Generic proceedings before the Alberta Utilities Commission (AUC).

Dr. Roberts is also experienced in preparing evidence for utility rate of return hearings. From 1995-1997, he submitted prefiled testimony as a Board witness in rate hearings for what was then known as Consumers Gas. In 1996, he served as an expert advisor to the Ontario Energy Board in its Diversification Workshop. As noted above, together with Dr. Kryzanowski, he has also prepared evidence on rate of return and capital structure considerations and appeared before regulatory boards in Nova Scotia, Quebec, Ontario and Alberta.

More broadly, Drs. Kryzanowski and Roberts often provide technical expertise and advice on financial policy. Among our consulting clients in recent years are the Superintendent of Financial Institutions, the federal Department of Finance, Canada Investment and Savings, Canada Mortgage and Housing Corporation, and Canada Deposit Insurance Corporation. Our brief *curricula vitae* are attached as an Appendix.

1.2 Purpose of Evidence and General Approach

Pollution Probe has retained us to provide evidence on the following two items in the Revised Draft Issues List as well as related issues:[1]

3.1 What is the appropriate capital structure and rate of return on equity?

3.3 Should the same capital structure and cost of capital be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure and/or cost of capital parameters are appropriate for each business?

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[1] Ontario Power Generation Inc., 2011-2012 Payment Amounts for Prescribed Generating Facilities, EB-2010-0008, *Revised Draft Issues List,* July 7, 2010.

In preparing our evidence, we considered and used various techniques for determining an appropriate capital structure (and fair rate of return) for a regulated utility and its regulated divisions. Although OPG has a single shareholder (i.e. the Province of Ontario), we follow the stand-alone principle under which capital structure (and the fair return on equity) are determined as if the company were "standing alone" as a shareholder-owned entity.

For determining an appropriate capital structure for OPG, we begin with a brief overview of financial theory focused on the practical implications for capital structure. Our main conclusions are that: 1) the level of equity should increase with the degree of business risk; and 2) capital structures are best set using a heuristic approach given the absence of a generally accepted formula for setting capital structure. We then review the business risks faced by OPG's hydro assets and nuclear assets separately and compare them with those of other utility industry sectors as well as with selected individual regulated companies. We next conduct an analysis of bond ratings, capital structures, interest coverage ratios, returns on equity and equity ratios (both actual and those allowed by regulators) for a comparable sample of utilities. Drawing on the basic principle that the level of equity in the deemed capital structure of a utility should reflect its business risk and combining our risk assessments and benchmarks, we conclude that business risk is unchanged since the Board's Decision in EB-2007-0905 for both divisions and the total regulated OPG. Consistent with the overall equity thickness for the combined regulated entity of 47% recommended in our 2008 Evidence and adopted by the Board, we recommend 40% and 50% as the appropriate equity ratios respectively for OPG's regulated hydro and nuclear assets given their relative business risks.

1.3 Summary of Evidence

1.3.1 Case for maintaining currently allowed equity thickness and return on equity for OPG's aggregate regulated operations

In Section 2, we assess the efficacy of OPG's use of the allowed ROE derived from the modified automatic ROE adjustment mechanism established in the OEB's Cost of Capital Report and the capital structure approved for OPG in EB-2007-0905. Based on the looking-forward survey data of knowledgeable professionals, we find that both the reset Base ROE of 9.75% and the utility-specific equity risk premium (ERP) of 5.5% are: 1) marginally below their corresponding median counterparts for the market as a whole of 10% and 5.7% for a short-term (2010) horizon; 2) substantially above their corresponding median counterparts of 8.0% and 3.0% for a mid-term horizon (2011-2014); and 3) substantially above their corresponding median counterparts of 8.0% and 2.7% for a long-term horizon (2015-2024). We also find the reset utility-specific ERP of 5.5% is considerably higher than that for the market, which has a considerably higher risk than an A-rated regulated utility. This is the case even for the period with the highest market equity risk premiums (MERPs) (namely, the 110-year period of 1900-2009) of 3.7% and 4.2% respectively for Canada and the U.S. Based on these risk assessments, the finding that the Base ROE and implied utility ERP exceed those of the higher-risk market equivalents leads us to the conclusion that the Board's formula continues to provide a generous return for regulated utilities.

1.3.2 Case for setting separate equity thicknesses for OPG's regulated nuclear and hydroelectric operations

In section three, we examine the case for setting separate equity thicknesses for OPG's nuclear and hydro operations. We argue that the main benefits of divisional capital structures (and the resulting costs of capital) are in terms of efficiently allocating the scarce resource of capital since using the same capital structures and costs of funds (i.e. same costs of capital) instead for divisions that differ in riskiness will cause the utility to accept "bad" high-risk projects and reject "good" low-risk projects.

A secondary effect of not reflecting divisional differences in risk is the feedback effect on the rate-setting process. As a utility using a firm-level discount or hurdle rate over time commits to investments that are biased towards "bad" high-risk projects for nuclear and away from "good" low-risk projects for hydro, the weighted-average riskiness of the utility increases as a result. Over time, this in turn leads to utility applications for higher allowed returns on equity and/or greater equity thickness.

The only seemingly material argument made by Ms. McShane (and adopted by OPG) is that none of the cost of capital methodologies that she examined yielded a robust and analytically sound basis for specifying technology-specific costs of capital. However, Ms. McShane's examination inappropriately concentrated on: 1) whether meaningful market model betas could be calculated using various methodologies; and 2) samples of U.S. utilities that do (and do not) differentiate by the proportion of their electricity generation that was nuclear or hydro. Ms. McShane also evaluated a number of methodologies that have been utilized for estimating the cost of equity that is used in the determination of the divisional costs of capital **when the capital structure is already known or can be obtained independently**, which is not applicable here. Her approach also implicitly assumes that a formulaic approach can be used for setting divisional capital structures when one is deemed inappropriate for setting capital structure at the aggregate utility level. Instead, Ms. McShane should have examined differences in divisional debt capacities (e.g. equity thicknesses). This section of our evidence also deals with a number of technical shortcomings of her analysis and her non-consideration of heuristic approaches that are used by practitioners to determine divisional capital structures.

1.3.3 Economic and financial market conditions

In Section 4, we examine current economic and financial market conditions in Canada, the U.S. and Ontario, and review forecasts of those economic variables that we use as inputs in the capital structure tests.

The recent global credit crisis caused increased volatility in equity markets and wider spreads in debt markets. The growth in the Canadian economy is and is expected to be robust with moderate inflation going forward. However, Ontario has been a laggard, and it is expected to continue to be so during the test years due to the strong manufacturing emphasis in the province. In addition, most of the gap between current A-rated Canadian utility credit spreads and where they were prior to the credit crisis has closed. This has occurred while both components to this credit spread have declined over time. Another indicator of the marked improvement in credit conditions is that asset-backed commercial paper has re-emerged as an investment alternative with some issues trading at levels better than pre-crisis rates. The volatility of the Canadian equity market is also now around its historic mean based on the market's expectation of how volatile the stock market will be relatively over the next month. We conclude that the credit crisis is over in Canada and does not impact our recommendations.

Concerns going forward include: sovereign debt crisis spillover effects; weak economic growth in the U.S. and Europe; and an ongoing structural fiscal challenge at the provincial level (particularly, Ontario). In contrast, strengths going forward include: the favorable impact of higher commodity prices; reasonable growth in China and India; and quicker resolution of ongoing federal budget deficits than was previously anticipated.

1.3.4 Capital structure recommendations for OPG Hydro and Nuclear

In the final section, Section 5, we update and extend our analysis that underpins our capital structure recommendations for each type of OPG’s regulated assets originally presented in our evidence in EB-2007-0905. We begin with a brief overview of the practical implication of capital structure theory that no formulaic approach can be used for determining capital structure. Thus, as in EB-2007-0905 and consistent with business practice, we adopt a heuristic approach for determining the business risk input into the determination of appropriate capital structures for the regulated assets of OPG and its two “divisions” (namely, Hydro and Nuclear). Our analysis leads to the conclusions that the business risks of these two “divisions” are materially unchanged since EB-2007-0905. We analyze the bond ratings, capital structures (both actual and allowed), interest coverage ratios and returns on equity for a sample of eight traded Canadian utilities.

Based on these examinations and tests, we arrive at a recommendation for the appropriate equity ratio for each segment of OPG. We assess the business risk faced by OPG Hydro as low to moderate – higher than that of a distribution utility and somewhat above the business risk of an integrated electric utility. This suggests that a fair common equity ratio for OPG Hydro should be at 40%, which is just below the middle of the range of common equity ratios that we find for our comparisons. We set the recommended equity ratio at this level to account for our benchmark of allowed equity ratios being generous. In contrast, our analysis rates the business risk of OPG’s regulated nuclear assets as moderate and greater than that of OPG Hydro. Following similar logic, and taking into account a marginal upward adjustment from the level determined in our EB-2007-0905 evidence, we continue to maintain 50% as the fair level of equity for OPG's nuclear assets. These individual equity percentages are consistent with the overall equity thickness for the combined regulated entity of 47% recommended in our 2008 Evidence and adopted by the Board.

To show that our recommendations of 40% equity for OPG Hydro and 50% for OPG Nuclear are not incompatible with a rating in the A range, we calculate the implied values of three metrics considered by bond rating agencies using the forecast data provided by OPG in its Application. We conclude that our recommendations of 40% and 50% equity for Hydro and Nuclear respectively are in the A range (i.e. A- to A).

2. CASE FOR MAINTAINING CURRENTLY ALLOWED EQUITY THICKNESS AND RETURN ON EQUITY FOR OPG'S AGGREGATE REGULATED OPERATIONS

2.1 Decisions of the OEB

In its EB-2007-0905 Decision, the OEB determined that the cost of capital for OPG's aggregate regulated operations:

- should be consistent with the stand-alone principle (pages 140 to 142);
- reflect the "adoption of a formula approach to setting the ROE" (page 162); and
- reflect differences in OPG's relative (business) risk for its aggregate regulated operations in its capital structure (page 162).

The OEB set OPG's allowed ROE at 8.65 per cent effective April 1, 2008. Based on the Board's view 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" (page 149), the Board prescribed a 47 per cent common equity ratio (page 149) for OPG's aggregate regulated operations.

In EB-2009-0084, the OEB prescribed a reset and refined adjustment mechanism for setting the ROE for rate-regulated utilities that submitted a cost of service rate application for rates effective on or after 2010. One of the reasons given by the OEB for these changes was that (page 33):

> The Board notes that while the current formula today produces results similar to that in 2008, it does not address the observed behaviour of the formula during the financial crisis – lowering the allowed ROE when the amount and price of risk in the market was increasing.

Based on an assumed forecast of the bond yield of long Canada's of 4.25% and a generic (low risk) utility-specific risk premium of 5.5 per cent (including 50 bps for transactional costs), the Board (page 37) set the initial ROE to be embedded in its reset and refined ROE formula at 9.75% (i.e. 4.25% + 5.50% = 9.75%). The reset and refined ROE adjustment formula for the prospective test year was given as follows:

$$ROE_t = BaseROE + 0.5x(LCBF_t - BaseLCBF) + 0.5x(UtilBondSpread_t - BaseUtilBondSpread)$$

where: *BaseROE* is the base for the ROE adjustment formula (i.e. 9.75%);

BaseLCBF is the Long Canada Bond Forecast for the base year (i.e. 4.25%);

BaseUtilBondSpread is the spread in 30-year A-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield (i.e. 1.415%); and

LCBF is the average of the 3- and 12-month yield forecasts of 10-year Canada's published in *Consensus Forecasts* 3 months prior to the rate implementation + the average business day spread of 30-year A-rated Canadian utility bonds or *UtilBondSpread* over 30-year Canada's for the month that is 3 months prior to rate implementation.

Thus, the ROE increases/decreases with both increases/decreases in the proxy for the risk-free rate and for the proxy for the investment risk of the long-term debt of an average A-rated Canadian utility.

2.2 OPG's Application

In its EB-2010-0008 application (Exhibit C1, Tab 1, Schedule 1, page 1), OPG is seeking:

> "approval of the test period cost of capital as presented in Ex. C1-T1-S1 Tables 1 and 2. In determining the cost of capital, OPG has applied the capital structure of 47 per cent equity and 53 per cent debt approved by the OEB in EB-2007-0905. OPG has applied the ROE of 9.85 per cent set by the OEB for use in 2010 cost of service applications in the OEB's letter of February 24, 2010."

OPG goes on to state that (Exhibit C1, Tab 1, Schedule 1, page 3, lines 6-12):

> "For 2011 and 2012 OPG has adopted the results of the OEB's Cost of Capital Report. The Cost of Capital Report establishes a revised base ROE and a modified automatic ROE adjustment mechanism. Given that the revised base ROE and the refined automatic ROE adjustment mechanism represent the same concepts that were adopted for OPG's prescribed assets in EB-2007-0905, both are applicable to OPG at the approved capital structure and appropriate to the business risks of the prescribed assets."

2.3 Critique

A compelling reason to base the current evidence on the ROE derived from the formula is the Board's statement that its "intention was to review capital structure, and not return on equity" (Procedural Order No. 3, page 8). In line with that intention, we are not submitting detailed evidence on the return on equity for OPG. Nonetheless, we provide a brief commentary on the formula as context to support our conclusion that it continues to provide a generous return for the combined entity.

The first issue that we address is the expansion of the adjustment mechanism to include a factor for bond spreads for A-rated utilities. As highlighted below, the economic and financial crisis prevailing at the time when the OEB rendered its Decision EB-2009-0084 had some impact on the Board's Decision. While the OEB clearly stated that "the sum of the elements supporting the Board's decision to reset and refine its formulaic ROE is independent of the recent financial crisis and whether or not the crisis has abated" (page 34), it did judge the adequacy of the previous formula in light of the crisis as noted above. We interpret the addition of a spread term as an attempt to provide for the impact of a future crisis, in case one occurs. We comment briefly on this spread term addition both in light of academic research in this area and practical impact.

Beginning with the academic perspective, Drs. Elton, Gruber, Agrawal and Mann (2001) provide estimates of the size of each component of the credit spread (namely, the default spread, tax spread, and risk premium) for investment-grade corporate bond portfolios. Consistent with other credit-spread studies, they find that default risk accounts for only a small portion of credit spreads and a residual systematic risk factor accounts for the majority of the variation in credit spreads. Consistent with their results, the third term in the reset and refined ROE adjustment formula attempts to hold default risk constant by using the credit spread for 30-year A-rated Canadian utility bonds. Thus, the major driver of the third term would be changes in a systematic factor such as market liquidity that has a credit cycle component.

Turning from the academic perspective to the practical impact of the formula, we note that the third term is asymmetrically distributed since it is truncated at -1.415% if the current *UtilBondSpread* became zero and is unbounded given that there is no upper bound on *UtilBondSpread*. In practical terms, this property would allow utilities governed by the formula to receive an unlimited increment to their required return in the event of a crisis while limiting the reduction in ROE in the event that market conditions became unusually benign.

Looking beyond the formula, it is also possible to judge the fairness of the range of returns on equity it produces. In this regard, the reset BaseROE of 9.75% and the utility-specific equity risk premium of 5.5% embodied in it for the regulated operations of an A-rate utility (i.e. a low risk firm) most comfortably satisfy the Fair Return Standard. We provide two illustrations. First, we compare these values to the return expectations for the Canadian market as proxied by the S&P/TSX Composite (an average risk firm) and for Long Canada's based on a survey of investment professionals conducted by Towers Watson during November 2009. These findings are summarized in Schedule 2.1. We find that both the reset BaseROE of 9.75% and the utility-specific equity risk premium (ERP) of 5.5% are marginally below their corresponding median counterparts for the market as a whole of 10% and 5.7% for a short-term (2010) horizon, substantially above their corresponding median counterparts of 8.0% and 3.0% for a mid-term horizon (2011-2014) and substantially above their corresponding median counterparts of 8.0% and 2.7% for a long-term horizon (2015-2024). The reset BaseROE of 9.75% exceeds the median return expectation for the S&P for all three horizons.

Second, we compare the utility-specific ERP of 5.5% to the realized MERPs for the Canadian and U.S. markets for various periods in Schedule 2.2. For all four periods, the reset utility-specific ERP of 5.5% is considerably higher than that for the market which has a higher risk than an A-rated regulated utility. This is even the case for the period with the highest MERPs (namely, the 110-year period, 1900-2009) of 3.7% and 4.2% for Canada and the U.S., respectively.

To reach a conclusion on fairness, we note that our comparisons are between equity risk premiums and ROEs for utilities as against comparable values for the Canadian and U.S. equity markets as a whole. In Section 4 we show that utilities in general and OPG in particular have low levels of business risk. Further, in past evidence in recent hearings we have consistently demonstrated that the level of systematic risk measured by beta (total risk) for an average Canadian utility is approximately half that of the market (an average firm in the market). Based on these risk assessments, the finding that the BaseROE and implied utility ERP exceed those of the higher-risk market equivalents leads us to the conclusion that the Board’s formula continues to provide a generous return for regulated utilities.

3. CASE FOR SETTING SEPARATE EQUITY THICKNESSES FOR OPG'S NUCLEAR AND HYDROELECTRIC OPERATIONS

3.1 Decisions of the OEB

The Board's finding in the previous proceeding (EB-2007-0905) on separate capital structures for the regulated hydroelectric business and the nuclear business is found on page 161 of the decision with reasons. Specifically:

> "The Board concludes that this is an approach worthy of further investigation which will be explored in OPG's next proceeding. In examining whether to set separate costs of capital, the Board intends only to examine whether separate capital structures should be set for the regulated hydroelectric and nuclear businesses. The Board expects that the same ROE would be applicable to both types of generation. This is consistent with the general approach of setting a benchmark ROE and recognizing risk differences in the capital structure.
>
> The Board recognizes that this approach will not alter the overall cost of capital for OPG's prescribed facilities. However, in all other significant respects the specific costs [of] the hydroelectric and nuclear businesses are used to derive the specific payments for each type of generation. Specific and separate costs of capital for hydroelectric and nuclear would be consistent with the separate nature of these businesses and would provide a more transparent link between the payment amounts for each type of generation and the underlying costs."

3.2 OPG's Application

In its EB-2010-0008 application (Exhibit C1, Tab 1, Schedule 1, page 1, lines 15-25), OPG states that it hired Foster Associates Inc. ("Fosters") to examine the feasibility of determining separate costs of capital for its regulated nuclear and hydroelectric facilities as directed by the Board. Ms. McShane in the Fosters report (included as Ex.

C3-T1-S1 in OPG's application) concluded that none of the cost of capital methodologies that she examined yielded a robust and analytically sound basis for specifying technology-specific costs of capital. OPG also argued that it continues to support the use of a single cost of capital for its prescribed facilities because this approach was used in the last application and this approach is "consistent with the manner in which OPG is actually financed".

3.3 Critique

Both OPG and Ms. McShane argue against the application of different costs of capital for OPG's regulated nuclear and hydroelectric operations. Since neither OPG nor Ms. McShane provide any of the arguments in favor of determining different capital structures and by extension different costs of capital for OPG's regulated nuclear and hydroelectric facilities, we begin with that discussion.

3.3.1 The arguments for divisional costs of capital

The major advantage of using divisional costs of capital when divisional risks differ is to ensure that the scarce resource of capital is allocated efficiently (referred to as "allocational efficiency"). To explain this concept, we suppose that a utility has two regulated divisions, such as nuclear and hydro electricity generation, and that nuclear is more risky. It follows then that the cost of capital ordering from lowest to highest would be hydro, the firm and then nuclear due to their different levels of risk. Thus, when evaluating the desirability of an investment opportunity that has a risk similar to the average-risk of the capital assets already in place in each division using the net present value (NPV) criterion, each division should discount the stream of expected cash flows at its *divisional* cost of capital. If each division instead uses the utility-wide cost of capital as the discount rate, then nuclear would accept some investment projects that should have been rejected and hydro would reject some investment projects that should have been accepted. Thus, the utility will have accepted bad high-risk projects and rejected good low-risk projects.

The same logic applies if the utility and its two divisions use the internal rate of return (IRR) criterion to evaluate the desirability of investments. Using this approach, an investment is acceptable if its IRR is not less that the applicable cost of capital (referred to as the "cutoff" or "hurdle" rate). If the multidivisional utility uses a firm-wide hurdle rate for the evaluation of its investment opportunities, the utility will accept some bad high-risk projects and reject some good low-risk projects because its hurdle rate will be too high for low-risk divisions and too low for high-risk divisions.

A secondary effect of not using such risk-adjusted discount or hurdle rates is the feedback effect on the rate-setting process. As a utility using a company-level discount or hurdle rate over time commits to investments that are biased towards bad high-risk projects for nuclear and away from good low-risk projects for hydro. The weights of the nuclear and hydro divisions thus become respectively higher and lower than they would have been if their divisional costs of capital had been used. In turn, the increased risk will lead to a higher utility-level cost of capital over time.

The bottom line is that even less precise estimates of divisional capital structures and costs of capital are preferable to pretending that there are no differences in both measures between divisions when it has already been acknowledged that such differences exist.

3.3.2 The arguments against divisional costs of capital

We now address each argument presented in the OPG application against the adoption of separate capital structures and costs of capital for OPG's regulated nuclear and hydroelectric operations.

3.3.2.1 <u>OPG's evidence</u>

In its EB-2010-0008 application (Exhibit C1, Tab 1, Schedule 1, page 1, lines 15-25), OPG states that it continues to support the use of a single cost of capital for its prescribed facilities because this approach was used in the last application. With due respect, we fail to see the logic behind this argument. Setting divisional capital structures and costs of capital that result in the same OPG-level capital structure and cost of capital is not inconsistent with the approach used in the last application.

In its EB-2010-0008 application (Exhibit C1, Tab 1, Schedule 1, page 1, lines 15-25), OPG states that it continues to support the use of a single cost of capital for its prescribed facilities because this approach is "consistent with the manner in which OPG is actually financed". However, under the "pool-of-funds" approach to utility funding and capital allocation, the utility-level cost of capital reflects the "average" risk of the utility's assets in place and this cost of capital should be used to evaluate its average-risk investment opportunities. Since the addition of higher risk investments into the assets in place at the utility level increases its "average" risk (all else held constant), these higher risk investment opportunities need to be assessed using a higher (risk-adjusted) cost of capital.

OPG position is in opposition to its position presented to the consultative process for the treatment of infrastructure investment where it argued that:

> "Whether or not a given infrastructure investment qualifies for the modified treatment should be based on whether the investment represents increased risk over other projects in the entity's portfolio, not by who happens to be proposing them."[2]

It summarized its position as: "Accordingly, OPG reiterates that infrastructure investments should be evaluated based on increased risk."[3]

[2] Comments of Ontario Power Generation Inc. on the staff discussion paper on the regulatory treatment of infrastructure investment (EB-2009-0152), July 7, 2009, page 3.
[3] Comments of Ontario Power Generation Inc. on the staff discussion paper on the regulatory treatment of infrastructure investment (EB-2009-0152), July 7, 2009, page 4.

In its response to Pollution Probe's Interrogatory 016, OPG states that it uses the same discount rate of 7% in its financial analysis for all investments with respect to Prescribed Assets, and that risks are taken into account in the cash flows.[4] OPG prescribes distributions for various input variables and uses a Monte Carlo simulation to generate a cumulative probability distribution, which they refer to as an S-curve, for its evaluator variable(s), which in the case of the Darlington Refurbishment results in a LUEC (Levelized Unit Energy Cost).[5] It is not obvious from its application how OPG deals with the contemporaneous interrelationships between the input variables and the tendency of simulation to underweight tail observations. To evaluate the sensitivity of the Darlington LUEC, for example, OPG conducts a sensitivity (and not a more robust scenario) analysis using the "low and high ends of these ranges for each of the key input Factors".[6] To evaluate the sensitivity of the Darlington LUEC, for example, OPG has a range for the discount rate of 7% plus or minus 1%.[7] It finds that the results of the Updated Economic Assessment are most sensitive to five input factors, where the fifth factor is the discount rate.[8] While specifying the S-curve for factor inputs reflects the uncertainty associated with those factor inputs, it does not account for the project risks.

However, the traditional purpose of a Monte Carlo simulation is to determine the project's business risk and thus its appropriate risk-adjusted discount rate. Therefore, the most appropriate discount rate to use in a Monte Carlo simulation is the risk-free rate of interest since it adjusts for the time value of money and not for risk.[9] The appropriate risk

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[4] OPG's Response to Pollution Probe Interrogatory #016, EB-2010-0008, Issue 3.3, Exhibit L, Tab 10, Schedule 016.
[5] Transcript, Technical Conference, August 26, 2010, line 3, page 169 to line 10, page 170.
[6] Ontario Power Generation, *Economic Feasibility Assessment of Darlington Refurbishment,* November 13, 2009, EB-2010-0008, Exhibit D2-2-1, Attachment 4, page 33 of 35.
[7] Ontario Power Generation, *Economic Feasibility Assessment of Darlington Refurbishment,* November 13, 2009, EB-2010-0008, Exhibit D2-2-1, Attachment 4, page 34 of 35.
[8] Ontario Power Generation, *Economic Feasibility Assessment of Darlington Refurbishment,* November 13, 2009, EB-2010-0008, Exhibit D2-2-1, Attachment 4, page 33 of 35.
[9] Pioneering studies in the use of Monte Carlo Simulation for the assessment of capital projects include: Mr. D.B. Hertz, Investment policies that pay off, *Harvard Business Review* 46: 1 (January-February 1968), pages 96-108; and Drs. Lawrence Kryzanowski, Peter Lusztig and Bernhard Schwab, Monte Carlo Simulation and capital expenditure decisions – A case study, *The Engineering Economist* 18:1 (1972), pages 31-48. A less technical description of the use of Monte Carlo Simulation for project analysis is found in: Drs. Lawrence Kryzanowski, Devinder K. Gandhi and Lawrence J. Gitman, *Principles of Managerial Finance* (New York, Harper & Row Publishers, 1982), pages 480-482.

premium should then be added to the risk-free rate after the determination of the project's business risk to determine the project's appropriate risk-adjusted discount rate.

In its EB-2010-0008 application (Exhibit C1, Tab 1, Schedule 1, page 1, lines 15-25), OPG states that the Fosters report (included as Ex. C3-T1-S1 in OPG's application) concluded that none of the cost of capital methodologies that were examined by Ms. McShane yielded a robust and analytically sound basis for specifying technology-specific costs of capital. We now address that evidence.

3.3.2.2 Ms. McShane's evidence

3.3.2.2.1 Ms. McShane's evidence: Overview

Most of Ms. McShane's analysis concentrates on whether meaningful market model betas could be calculated using various methodologies and samples of U.S. utilities that are not differentiated by the proportion of their electricity generation that was nuclear or hydro. Thus, Ms. McShane evaluated a number of methodologies that have been utilized for estimating the cost of equity that is used in the determination of the divisional costs of capital *when the capital structure is known or can be obtained independently*. Instead, Ms. McShane should have examined differences in divisional debt capacities (e.g. equity thicknesses). The task at hand is not to calculate separate allowed rates of return on equity for nuclear and hydro but to determine the capital structures for each "division".

If one calculates the divisional equity beta or the cost of equity using an analytical approach, one must somewhat use that information to determine the divisional capital structures. Ms. McShane describes her conversion process as follows: "To the extent required by the analysis, the conversion of differences in the cost of equity among proxy samples into capital structure equivalents will be based on the premise that the overall cost of capital is constant across the relevant range of capital structures".[10] This

[10] Kathleen McShane, Technology-specific capital structures: An assessment, Exhibit C3-1-1, page 3.

ATWACC approach invokes the unrealistic assumption that ATWACC (or the overall cost of capital) is the same for each utility used in the estimation (even if their bond ratings vary from BBB- to A). This will result in divisional equity ratios with large estimation errors and unknown biases.

However, this is interestingly the approach that Ms. McShane used to derive her capital structure recommendation for OPG at the benchmark return in EB-2007-0905.[11] In that evidence, she used the residual beta model, which she now concludes is not robust in her current evidence, to derive a generation-only levered beta from the high generation sample. The model then included the levered beta for "wires" operations estimated from a sample of utilities with primarily "wires" operations and an assumed levered beta for "other" operations that was assumed to be 1.0 (i.e. equal to the beta of an average risk stock or the market). In her evidence filed in EB-2007-0905, she thus used a more judgmental approach to conclude that OPG's regulated operations were not subsidizing its unregulated operations.[12]

Consistent with our evidence in EB-2007-0905, we recommend that the determination of divisional capital structures is best achieved using a two-step procedure where the first step is to determine divisional debt capacities (e.g. equity thicknesses) if both nuclear and hydro are allowed the same generic rate of return on equity. Consistent with our evidence in EB-2007-0905, we recommend that the first step is best implemented using a heuristic-based approach. Then, the calculation of the divisional cost of capital for nuclear and hydro for OPG in the second step is fairly straightforward. The Board appears to have agreed with the result of our judgmental approach in Decision EB-2007-0905 (pages 149-150):

> "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."

[11] Evidence of Ms. McShane, EB-2007-0905, Exhibit C2, Tab 1, Schedule 1, pages 91-97.
[12] Evidence of Ms. McShane, EB-2007-0905, Exhibit C2, Tab 1, Schedule 1, page 97.

3.3.2.2.2 Ms. McShane's evidence: Analogies

Ms. McShane dismisses the use of a sample of Canadian utilities because all "four conventionally structured publicly traded companies in Canada with significant amounts of generation that are either regulated or governed by contractual arrangements which have cost of service characteristics" are relatively diversified with "no significant amount of hydroelectric capacity" and only one "owns any nuclear capacity".[13] She also dismisses the use of a sample of Canadian utilities structured as income trusts as being "problematic from a cost of capital perspective due to the change in the *Income Tax Act* announced by the Department of Finance in the 2006 Tax Fairness Plan". This dismissal is based on her untested conjecture that "the reaction of the capital markets to the announcement would have an impact on market measures of risk (e.g. beta) that is unrelated to the fundamental operating risks to which the underlying assets of the trusts may be subject." However, empirical evidence contradicts Ms. McShane's conjecture: Dr. Kryzanowski and Ms. Lu report that the betas did not change significantly after this announcement for 29 business income trusts.[14]

The U.S. samples used by Ms. McShane suffer from many of the problems involved in selecting matching or proxy samples. For example, her sample of 44 U.S. electric utilities used in the instrumental variables analysis have mean and median S&P debt ratings of BBB+ and BBB, respectively.[15] The failure to address carefully how the sample risk differs from that of Canadian utilities is particularly problematic as Ms. McShane previously pointed out these very differences. In EB-2007-0905, Ms. McShane provided various reasons why a rating lower than A would not be appropriate for OPG, including "[o]f particular concern would be that a BBB rated utility would, at times, be completely shut out of the long-term (30-year) debt market".[16]

[13] Ms. Kathleen McShane, Technology-specific capital structures: An assessment, Exhibit C3-1-1, page 37.
[14] Dr. Lawrence Kryzanowski and Ms. Ying Lu, In government we trust: Rise and fall of Canadian business income trust conversions, *Managerial Finance* 35: 9 (September 2009), pages 784-802.
[15] Ms. Kathleen McShane, Technology-specific capital structures: An assessment, Exhibit C3-1-1, Schedule 3, page 1.
[16] Evidence of Ms. McShane, EB-2007-0905, Exhibit C2, Tab 1, Schedule 1, page 80.

Furthermore, Ms. McShane makes no adjustments for a number of transactions involving the exchange of existing nuclear power plants since 1999. These include:

- In July 2005, FPL Energy agreed to pay $380 million for 70% of the Duane Arnold BWR (600 MWe capacity) from an Alliant Energy subsidiary, which continued to buy the power;
- In July 2006, Entergy agreed to buy the 798 MWe Palisades nuclear power plant from CMS subsidiary Consumers Energy for $242 million plus $83 million for the fuel and $55 million for other assets;
- In December 2006, FPL Energy agreed to buy the Point Beach nuclear plant (two units for a total 1012 MWe) from Wisconsin's We Energies, who continues to buy the power from the nuclear plant; and
- In December 2008, the bid by Electricité de France (EDF) was accepted for half of the nuclear business of Constellation Energy, which consisted of two reactors at Calvert Cliffs in Maryland, two reactors at Nine Mile Point in New York and the Ginna reactor in New York.

As stated earlier, her evidence focuses on the cost of equity traditionally used in valuation. Given this emphasis, it is surprising that she did not make any inferences from these valuation data.

3.3.2.2.3 Ms. McShane’s evidence: Analytical approaches for divisional beta estimation

As a prelude to testing the applicability of various approaches for estimating divisional betas, Ms. McShane examines the time-series behavior of the mean nonstandard beta (i.e. adjusted towards the market beta of one) obtained from Value Line for a sample of 28 U.S. electric utilities from 1997 to 2009. Based on this examination, she concludes:

> "The instability of betas from measurement period to measurement period may be problematic for analyses that attempt to measure differences in return requirement for investments exposed to fundamentally different levels of business and/or financial risk."[17]

Deriving such a conclusion based on a price (and not return) beta is inappropriate for a sample where the dividend yield represents a material portion of the total return. Checking the Glossary on the Value Line website, we find that the Value Line beta is derived from a 5-year regression between the relationship of the weekly percentage changes in the New York Stock Exchange Composite Average and the weekly percentage changes in the <u>price</u> of the stock with no adjustment for dividends. As such, the Value Line beta is a measure of the sensitivity of price changes for a utility to price level changes of the market proxy, and is not a measure of the sensitivity of the total returns for a utility to the changes in the total returns of a market proxy.

As Ms. McShane notes for the electric utility business, "there are few, if any, companies that operate in a single function, i.e., regulated distribution, transmission or generation".[18] In turn, this effectively eliminates the use of the "pure-play",[19] "residual beta" and "instrumental beta" approaches to estimate a divisional equity beta for publicly traded companies and severely diminishes the efficacy of using the "full information" approach to estimate divisional betas. Considering this flaw together with the mis-targeted objective of the evidence (i.e. to estimate divisional capital structures and not equity betas), we pay little attention in our evidence to the various econometric problems implicit in her implementations of the various analytical approaches for divisional beta estimation with the exception of the full information approach.

With regard to the "full information" approach, there are several problems with its implementation by Ms. McShane where she uses each utility's levered beta in the cross-

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[17] Ms. Kathleen McShane, Technology-specific capital structures: An assessment, Exhibit C3-1-1, page 49.
[18] Ms. Kathleen McShane, Technology-specific capital structures: An assessment, Exhibit C3-1-1, page 40.
[19] Other "analogy" approaches calculate divisional betas from industry betas. For example, Drs. R.A. Brealey and S.C. Myers, S.C., *Principles of corporate finance*, 5th edition, New York: McGraw-Hill, 1996.

sectional regressions to obtain a leveraged beta for each division. A conceptual problem arises because her implementation makes two untenable implicit assumptions; which are aptly stated in a journal article as follows:

> "Since we estimate a single beta for each line of business in which a division may be engaged, we must implicitly assume that the same capital structure is embedded in the estimated divisional beta for all the multidivisional firms in the sample. But if capital structure affects beta, this can be true only if all multidivisional firms finance their divisions exactly the same way. Actually, our method also assumes implicitly that two multidivisional firms operating in the same combination of lines of business will have the same firm-level capital structure. Clearly, neither of these implicit assumptions is likely to be true in practice."[20]

While the estimation of divisional unlevered betas using the utility-level unlevered betas avoids this conceptual problem, one needs to assume that either the Modigliani and Miller or Hamada formula is appropriate for converting the utility-level levered betas into unlevered betas for conducting the cross-sectional regressions. One also needs to assume that either formula is also appropriate for converting the divisional unlevered beta estimates obtained from the cross-sectional regressions into divisional levered beta estimates. These latter computations require that we know the divisional capital structures, although this is what we are supposed to be estimating here.

Furthermore, a missing variables problem occurs if not all lines of business are included in the cross-sectional regressions. Since these missing variables are likely to be correlated with the error term of the regressions, the estimated coefficients will contain a bias of unknown magnitude.

3.3.2.2.4 Ms. McShane's evidence: DCF divisional equity cost estimation

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[20] Drs. Jess Chua, Philip C. Chang and Zhenyu Wu, The full-information approach for estimating divisional betas: Implementation issues and tests, *Journal of Applied Finance* (Spring/Summer, 2006), pages 53-61.

When Ms. McShane used the constant growth model for each year 2006-2009 to obtain cost of equity estimates, she obtained her expected cost of equity ordering from lowest to highest as being Wires, then High Generation and finally High Nuclear. This is not surprising given that the DCF model is arguably the most important model for determining allowed rates of return on equity in the U.S. for regulated utilities. Furthermore, there is an analytical approach for deriving betas from earnings growth regressions.[21] While a number of conceptual and implementation issues limit the usefulness of the DCF constant growth model in this application, given that she chose to estimate the model, it is surprising that Ms. McShane did not provide any divisional capital structure estimates based on the divisional costs of equity derived from this approach.

3.3.2.2.5 Ms. McShane's evidence: Lone judgmental approach for divisional capital structure estimation

Ms. McShane only examines one approach (i.e. judgmental) for estimating divisional capital structure. This heuristic-based approach for "establishing technology-specific capital structures on the basis of differences in business risk" uses S&P and Moody's guidelines to assess the reasonableness of utility capital structures.[22] She concludes:

> "While the S&P guidelines may be useful for assessing the reasonableness of utility capital structures, they provide little or no guidance for the specification of technology specific capital structures.
>
> …
>
> Although the Moody's guidelines do apply specifically to regulated companies, in contrast to the S&P guidelines, their usefulness for the estimation of technology-specific capital structures is similarly limited. Significant judgment would be required to infer the implied ratings that Moody's would assign on a stand-alone basis to each

[21] Drs. Myron J. Gordon and Paul J. Halpern. Cost of capital for a division of a firm, *Journal of Finance* 29 (1974), pages 1153–64.
[22] Ms. Kathleen McShane, Technology-specific capital structures: An assessment, Exhibit C3-1-1, page 62.

> of the business risk factors. However, as with S&P, while the guidelines provide a perspective on differences in capital structure which may be warranted for different levels of business risk from a debt investor's point of view, they do not address return requirements from an equity investor's perspective."[23]

However, the four reasons that she presents for why these guidelines "provide little or no guidance for the specification of technology-specific capital structures" are equally applicable to the determination of capital structure at the OPG-level.

3.3.2.2.4 Ms. McShane's evidence: Heuristic approaches not considered

Heuristic-based approaches are used by practitioners to deal with unobserved systematic risk measures when estimating the cost of capital for divisions that are not publicly traded.[24] Both approaches described below are two-step processes. The firm-level cost of capital is estimated in the first step, and this total cost is then adjusted to a divisional basis using the aggregate subjective rating of a division's risk relative to the mean-centered aggregate firm-level risk for a predefined list of specific risk criteria. Although the implementation is different, these approaches are conceptually similar to that employed in Section 4 of this evidence.

3.3.2.2.4.1 BCG's implementation of the heuristic-based approach

The implementation of the heuristic-based approach by the Boston Consulting Group (BCG) rates the risk of a division relative to that at the firm-level using six criteria and a five-point scale (see Schedule 3.1). The aggregate firm-level score is normalized at 18 (i.e. median score of 3 times 6 criteria). The aggregate score at the divisional level can range from 6 to 30 with scores above (below) 18 indicating that the division is more (less) risky than the firm. The normalized aggregate score at the divisional level is

[23] Ms. Kathleen McShane, Technology-specific capital structures: An assessment, Exhibit C3-1-1, page 64 and 65.

[24] This section is drawn from Drs. Juergen Bufka, Oliver Kemper and Dirk Schiereck, A note on estimating the divisional cost of capital for diversified companies: An empirical evaluation of heuristic-based approaches, *The European Journal of Finance* 10 (February 2004), pages 68-80.

obtained by dividing the original aggregate score at the divisional level by 18 so that a normalized aggregate score at the divisional level above (or below) 1 indicates that the division is more (or less) risky than the firm as a whole. Using a linear extrapolation, the divisional cost of capital equals the firm-level cost of capital multiplied by the divisional normalized aggregate score. Other weighting schemes are possible, and the logic behind this approach can be transferred to making adjustments to firm-level debt capacity to obtain divisional debt capacity estimates.

3.3.2.2.4.2 Fuqua Industries approach

Fuqua Industries is a U.S. company with 20-plus divisions that has also developed a multi-stage approach for the estimation of divisional costs of capital that uses multidimensional screens.[25] Fuqua adjusts the firm-level cost of equity based on the CAPM with two risk measures: (i) variability of operating profit using comparisons of forecasted operating profits for the current and subsequent year against the most recently completed year; and (ii) the normalized aggregate divisional risk score, whose only difference from the BCG approach is that it has 14 (different) criteria (see Schedule 3.2). Its application is the same as for the BCG approach. Again, other weighting schemes are possible, and the logic behind this approach can be transferred to making adjustments to firm-level debt capacity to obtain divisional debt capacity estimates.

3.4 Use of Non-Canadian Analogies

To assess the feasibility of using non-Canadian analogies for benchmark purposes, we obtained the proportions of total electric power generated from various fuels in various countries that is reported in Schedule 3.3. When we use a double screen that at least 10% of the electric power must be generated by nuclear and by hydro, we are left with only two countries, Finland and Sweden. Countries with more traditional return regulation, such as Australia, the U.K. and the U.S., do not meet the double-screen criterion.

[25] Drs. Benton E. Gup and Samuel W. Norwood, Divisional cost of capital: A practical approach, *Financial Management* 11: 1 (Spring, 1982), pages 20-24.

Countries such as Germany rely materially on nuclear but not hydro, and countries such as New Zealand rely materially on hydro but not nuclear.

Two countries satisfy our double screen. The four nuclear reactors in Finland that are owned by two utilities provide around 30% of the electricity in Finland. The Finnish Government has a controlling interest in both of these owners. Furthermore, the production and supply of electricity has been deregulated since the *Finnish Electricity Market Act* went into effect in November 1995. Similarly, with the deregulation of its electricity market on January 1, 1996, Sweden joined Norway to form the wholesale market Nord Pool. The membership of Nord Pool was later expanded to include Denmark and Finland. Nord Pool sets the price of electricity based on supply and demand bids. Due to their deregulated environments and state control ownership in Finland, we conclude that Finnish and Swedish utilities are questionable analogies for the purposes of our testimony.[26]

4. ECONOMIC AND FINANCIAL MARKET CONDITIONS

To provide a back-drop for the business risk assessment in the fifth section of our evidence, we now briefly review the economic performance and prospects in Canada, the U.S. and Ontario.

4.1 Economic Performance and Prospects in Canada

We first examine the economic performance and expectations for Canada drawn from the July 2010 issue of *Consensus Forecasts*. While GDP growth was minimal in 2008 at 0.5% and dismal in 2009 at -2.5%, the consensus forecast is for more normal growth of 3.5% and 2.8% in 2010 and 2011. The growth rate in machinery and equipment investment was absent in 2008 at -0.9% and dismal in 2009 at -20.3%. However, the consensus forecast is for more normal growth of 4.0% and 7.2% in 2010 and 2011. In

[26] Ms. McShane raises a number of the same concerns in her response to a Board Staff Interrogatory (see EB-2010-0008, Issue 3.3, Exhibit L, Tab 1, Schedule 017).

2008, pre-tax corporate profits were robust at 8.0% and dismal in 2009 at -32.3%, and the consensus forecast for 2010 and 2011 is for robust growth of 23.7% and 10.3%. While CPI was higher in 2008 at 2.4% and near deflation in 2009 at 0.3%, the consensus forecast is for an increasing rate of growth of CPI of 1.9% and 2.2% in 2010 and 2011. The federal budget deficit of -$5.8 bn CAD in 2008 and an estimated -$45.0 bn CAD in 2009 is expected to continue in 2010 and 2011 at -$40.1 bn CAD and -$26.3 bn CAD respectively.

As noted above, the time-series evolutions of two particular series (i.e. the re-pricing of corporate bond risk and the term premium) are of interest. Schedule 4.1 contains two relevant figures. The top figure contains a plot of the credit spreads for 30-year A-rated Canadian utility bonds over 30-year Canada's and the term premium of 30- over 20-year Canada's for the period from March 5, 2002 through July 28, 2010. Most of the gap between current A-rated Canadian utility credit spreads and where they were prior to the credit crisis has closed. Current A-rated 30-year Canadian utility credit spreads are still about 25.5 basis points above their historical mean for the studied period.

Examining spreads does not capture the downward trend in yields for both bond rating categories (i.e. 30-year A-rated Canadian utility bonds and 30-year Canada's) over the studied period depicted in the bottom figure of Schedule 4.1. The figure also shows the two series moving in opposite directions during the credit crisis but now moving in the same direction.[27] The percentage yield to maturity on a diversified index of investment grade Canadian corporate bonds is the lowest in at least 16 years.[28] Going forward, the expected strengthening of the Canadian economy, expected increases in inflation and continuing budgetary deficits are expected to increase yields on government bonds to more "normal" levels and further reduce credit spreads.

[27] The correlation between the two series increases from 0.67 to 0.82 when the months from September 2008 to February 2009 are deleted.

[28] John Heinzl, Bond investors pile into corporate debt despite yields, *Globe and Mail*, Thursday, August 26, 2010, page B9.

ABCP or asset-backed commercial paper has re-emerged as an investment alternative with some issues trading at levels better than pre-crisis rates. Some issues are trading at about 10 bps below the CDOR (Canadian dealer offered rate or average rate of Canadian bankers' acceptances), which is the benchmark for floating rate issues.[29]

The average volatility of the overall Canadian equity market at the daily close of 15.88% for July 2010 (ending with July 28) is below its full-period mean of 19.01% (see the time-series plot in Schedule 4.2). The volatility of the Canadian market is measured using the Montreal Exchange's Volatility Index (MVX), which reflects the market's expectation of how relatively volatile the stock market will be over the next month. The MVX is calculated from current prices of at-the-money options on the iShares of the CDN S&P/TSX 60 Fund (Ticker symbol: XIU).

Concerns going forward, which include spillover effects from the sovereign debt crisis in Europe, weak economic growth (or a double dip recession) in the U.S. and Europe and a ongoing structural fiscal challenge at the provincial level (particularly, Ontario) due to rising health costs, are contrasted against the favorable impact of higher commodity prices, reasonable growth in China and India and the Conference Board's prediction that federal budget deficits will end one year earlier than planned.[30]

4.2 Economic Performance and Prospects in the United States

We now examine the economic performance and expectations for the United States. While GDP growth was minimal in 2008 at 0.4% and dismal in 2009 at -2.4%, the consensus forecast is for more normal growth of 3.1% and 3.0% in 2010 and 2011 respectively. In 2008, business investment was minimal at 1.6% and dismal in 2009 at -17.8%, but the consensus forecast is now for low growth of 3.0% in 2010 and more

[29] Based on Tim Kiladze, ABCP-on-the-comeback-trail, *Globe and Mail*, Tuesday, July 27, 2010. Available at: http://www.theglobeandmail.com/globe-investor/investment-ideas/abcp-on-the-comeback-trail/article1652513/?cmpid=rss1.

[30] Glen Hodgson and Matthew Stewart, Canadian Feds Ahead of Plan on Fiscal Rebalancing, *Hot Topics in Economics*, Conference Board of Canada, July 29, 2010. Available at: http://www.conferenceboard.ca/economics/hot_eco_topics/default/10-07-29/Canadian_Feds_Ahead_of_Plan_on_Fiscal_Rebalancing.aspx.

normal growth of 8.0% in 2011. Similarly, growth in pre-tax corporate profits was dismal at -11.8% and -3.8% in 2008 and 2009 respectively. However, the consensus forecast is for robust growth of 23.1% and 6.6% in 2010 and 2011. While the CPI growth rate was higher in 2008 at 3.8% and in deflation in 2009 at -0.3%, the consensus forecast is for moderate growth of the CPI of 1.7% and 1.5% in 2010 and 2011. The federal budget deficit of -$459 bn USD and -$1,417 bn USD in respectively 2008 and 2009 is expected to continue in 2010 and 2011 at -$1,335 bn USD and -$1,181 bn USD.

Concerns going forward include spillover effects from the sovereign debt crisis in Europe, constrained household consumption, weakening inflation, continuing depressed housing market, increasing government debt levels and the possibility of a W-shaped and not a V-shaped economic recovery. However, these concerns are contrasted against stronger market demand in Asia and emerging markets and accommodating fiscal and monetary policies.

4.3 Economic Forecast for Ontario

In 2009, Ontario's economic performance was one of the worst among the provinces with real GDP shrinking by 3.1% in contrast with a smaller decline of 2.5% for Canada.[31] This reversed in 2010 with a revival in the manufacturing sector led by increased demand for housing and strong auto production. To illustrate, based on improved performance in sales in June 2010, Scotiabank recently raised its full-year 2010 sales forecast for vehicles from 1.525 million to 1.565 million units. According to BMO Capital Markets, real GDP of Ontario is expected to grow 3.4% this year before slowing to below-average growth compared to other provinces in 2011. Due to the sharp decline in GDP resulting from the global recession, Ontario real GDP is expected to remain below its pre-recession level until the first quarter of 2011. The activities in the manufacturing and exports sectors, although much recovered from 2008 and 2009 levels, are likely to remain well below peaks seen this past decade owing to the strong Canadian dollar.

[31] Our forecasts are from BMO Capital Markets, Economics Research, *Provincial Monitor*, June 2010; Scotiabank Group, Global Economics Research, *Provincial Trends*, June 16, 2010 and Auto News Flash, August 4, 2010; and RBC Economics, *Provincial Outlook*, June 2010.

Service sector employment has risen to a record level with the private sector creating 120,000 jobs during the past year. The unemployment rate in Ontario peaked in the manufacturing sector but due to service jobs growth, the unemployment rate is forecasted by RBC Economics as 8.7% for 2010 and improving to 7.9% for 2011. Household income advanced by 1.3% in Q1, 2010 reflecting increased employment and strong earnings in the quarter while personal disposable income increased by 0.7% and personal consumption expenditure rose by 1%.

The housing market was strong in the first half of 2010 due to low mortgage rates and pre-HST buying, but this market is currently slowing down (e.g. house prices in Toronto fell 3.3 % in July and sales fell 34% in July compared to June despite low interest rates and a fully loaded inventory).

5. CAPITAL STRUCTURE RECOMMENDATIONS FOR OPG HYDRO AND NUCLEAR

5.1 Overview of this Section

This section updates and extends our discussion of capital structure for each type of OPG's regulated assets originally presented in our evidence in EB-2007-0905. Following the same outline, we begin with a brief overview of the practical implications of financial theory for our analysis of the appropriate capital structure for OPG. Our main conclusion is that, although no generally accepted formula exists for setting capital structure, the level of equity should increase with the degree of business risk. This provides the conceptual underpinning for our adopting a heuristic approach.

To implement this approach, we next review the business risks faced by OPG hydro assets (OPG Hydro) and nuclear assets (OPG Nuclear) separately. As in our 2008 evidence, our review of market, operational and regulatory risks leads to the conclusion that OPG's regulated hydro business carries low to moderate risk (1.8 on a scale of 5 where 1 is the lowest risk and 5 the highest). In contrast, OPG's regulated nuclear generation has a higher level of business risk that we assess as approaching moderate (2.6 on our 5-point scale). We review factors that could potentially cause a change in these levels of business risk and conclude that the risks are materially unchanged since EB-2007-0905.

In order to gain perspective on these measures of business risk, we briefly compare them against the risks of generic electricity transmission and distribution businesses as well as those of integrated electric utilities. This allows us to benchmark our recommendations for OPG against capital structures allowed by this Board and by other Canadian regulators for other companies in these categories. Our approach also facilitates comparisons with our own analysis in prior testimony. We assess the average risk for transmission as low (1 on our 5-point scale). We also study the business risk associated with generic distribution and rate it as low to moderate (1.4 on our scale). Based on these inputs, we assess the business risk of an integrated company by taking an asset-weighted average of the risks of OPG hydro, generic transmission and generic distribution. Our analysis sets the business risk of an integrated electricity company at 1.5 on our scale or low to moderate.

We then turn to examining relevant financial data for a sample of eight Canadian gas and electric utilities and pipelines that have publicly traded common shares chosen to be consistent with our past evidence in which we required the included companies to be publicly traded. We analyze bond ratings, capital structures, interest coverage ratios and returns on equity for our sample companies.

Drawing on the basic principle that the level of equity in the deemed capital structure of a utility should reflect its business risk and combining our risk assessments and benchmarks, we conclude that business risk is unchanged since the Decision in EB-2007-0905 for both divisions and the total regulated OPG. Our analysis of benchmarks contains nothing to suggest that the benchmark levels used in our 2008 Evidence require revision. In that Evidence we concluded that being considerably riskier than a generic transmission and somewhat riskier than an integrated company or a generic distribution company, OPG hydro should carry a higher level of equity than any of these three comparators. We assigned 40% as the appropriate equity ratio for OPG’s hydro assets. Following similar logic, and taking into account a marginal upward adjustment from the level determined in our EB-2007-0905 Evidence, we continue to maintain 50% as the fair level of equity for OPG’s nuclear assets.

These individual equity percentages are consistent with the overall equity thickness for the combined regulated entity of 47% recommended in our 2008 Evidence and adopted by the Board.

5.2 Implications of Financial Theory

Finance theory has several important implications for setting the appropriate level of the equity ratio for a regulated electric utility. First, theory teaches us to be suspicious of attempts to determine an appropriate equity ratio using a formula. Unlike other areas in finance, research on capital structure can offer only qualitative policy advice. To quote a leading, current corporate finance textbook:

> "No exact formula is available for evaluating the optimal debt-equity ratio."[32]

While we expect an introductory textbook to contain an element of simplification in order to present material to beginning students, this statement has yet to be superseded by advanced research.

This important implication of finance theory provides the conceptual foundation for our use of a heuristic approach in setting capital structures – a methodology that has been accepted by Canadian regulators, including this Board as well as the Alberta Utilities Commission (formerly the Alberta Energy and Utilities Board). In Decision 2004-052, page 35, the AUC wrote:

> "In the Board's view, setting an appropriate equity ratio is a subjective exercise that involves the assessment of several factors and the observation of past experience. The assessment of the level of business risk of the utilities is also a subjective concept. Consequently, the Board considers that there is no single accepted mathematical way to make a determination of equity ratio based on a given level of business risk."

The Commission took the same approach in its 2009 Generic Cost of Capital AUC Decision 2009-216 (November 12, 2009), pages 88-89:

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[32] S.A. Ross, R.W. Westerfield, J. F. Jaffe and G.S. Roberts, *Corporate Finance*, 5th Canadian Edition, Toronto: McGraw-Hill Ryerson, 2008, page 500.

> "… the Commission will first consider the record of the Proceeding on the overall risk of regulated utilities posed by the current credit environment and current utility credit metrics. The Commission will then assess, on the basis of the record of the Proceeding, the risk of each of the utility sectors and determine a relative ranking of risk for each sector and the commensurate equity ratio that, in the Commission's judgment, will allow the utilities in each sector to maintain the desired credit rating. Finally, the Commission will turn to an assessment of each individual utility to determine whether specific adjustments to each company's equity ratio are warranted."

The OEB similarly endorsed a qualitative, heuristic approach in its Decision in EB-2007-0905 at page 136:

> "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."

Although it does not offer a formula, finance theory does highlight key considerations in determining capital structure. In the same textbook we find the following:

> "How should companies establish target debt-equity ratios? While there is no mathematical formula for establishing a target ratio, we present three important factors affecting this ratio:
>
> - Taxes. As pointed out earlier, firms can only deduct interest for tax purposes to the extent of their profits before interest. Thus, highly profitable firms are more likely to have larger target ratios than less profitable firms.
> - Types of assets. Financial distress is costly, with or without formal bankruptcy proceedings. The costs of financial distress depend on the types of assets that the firm has. For example, if a firm has a large investment in land, buildings, and other tangible assets, it will have smaller costs of financial distress than a firm with a large investment in research and

development. Research and development typically has less resale value than land; thus, most of its value disappears in financial distress. Therefore, firms with large investments in tangible assets are likely to have higher target debt-equity ratios than firms with large investments in research and development.

- Uncertainty of operating income. Firms with uncertain operating income have a high probability of experiencing financial distress, even without debt. Thus, these firms must finance mostly with equity. For example, pharmaceutical firms have uncertain operating income because no one can predict whether today's research will generate new drugs. Consequently, these firms issue little debt. By contrast, the operating income of utilities generally has little uncertainty. Relative to other industries, utilities use a great deal of debt [emphasis added]."[33]

Taken together, these three factors are central to establishing the appropriate amount of debt for a utility. In particular, factors 2 and 3 determine the level of business risk that restrains the company's use of debt in order to reduce the cost of financial distress and the probability that such distress will occur due to low operating income. Turning from speaking in general about any company to focusing on a regulated electric utility, we believe that factors 2 and 3 are largely mitigated by the special features of this industry.

For a regulated electric utility, the costs of financial distress (factor 2) are reduced because its assets make excellent collateral. Further, the regulation process virtually ensures that the company will recover its debt payments and other costs. Further, regulation allows the company to go back to its regulator to apply for relief in the unlikely event that it does not earn its fair rate of return in a given year, and especially if its ability to service its debt were in jeopardy. Additionally, in the extreme event that an electric utility became insolvent, it is highly likely that the regulator (and other governmental bodies) would work with the company to find new investors or a merger partner so that service (and thus, asset usage) would not be interrupted. This is what

[33] S.A. Ross, R.W. Westerfield, J. F. Jaffe and G.S. Roberts, *Corporate Finance*, 5th Canadian Edition, Toronto: McGraw-Hill Ryerson, 2008, page 502.

occurred with the bankruptcy of Pacific Gas and Electric Company in California.[34] As a result, the cost of financial distress is far lower than for a non-regulated firm.

The third factor is the probability of financial distress. As stated in the quotation, this probability is low for utilities because operating income has low variability, which is further diminished if the utilities make extensive use of deferral accounts.

The special nature of regulated utilities was clearly reflected in the 2008 decision by S&P to change its application of notching criteria for U.S. utility companies from relative to absolute, and to increase the rating of the senior unsecured debt of 32 utilities to be the same as each utility's corporate credit rating, even when a considerable amount of secured debt is outstanding.[35] The press release states on page one that:

> "… our criteria have evolved so that the notching analysis can also focus on the value of assets available in a bankruptcy and whether those assets are sufficient to satisfy claims, regardless of the debt's priority. This approach is beneficial for the debt ratings of utilities because the value of their regulated assets is resilient and because their ability to add debt is restricted. As a result, creditors of defaulted utilities have realized higher average recovery rates than the creditors of companies in other sectors."

The press release provides the following justification for this change on page two:

> "In our view, this conclusion and the recovery prospects of unsecured regulated utility obligations benefit from several unique factors. First, utility assets are more likely to retain value in a bankruptcy scenario because of the essential nature of the service those assets provide. The experience of pure utility defaults (albeit few

[34] K. Gaudette, Bankrupt Pacific Gas and Electric hopes to avoid state laws, Associated Press, *The Nando Times*, January 25, 2002. Available at: www.nando.net/business/story/228567p-2199342c.html.
[35] Standard and Poor's, Criteria | Corporates | Utilities: Notching Of U.S. Investment-Grade Investor-Owned Utility Unsecured Debt Now Better Reflects Anticipated Absolute Recovery, November 10, 2008. Available at:
http://www2.standardandpoors.com/portal/site/sp/en/us/page.search/search/0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0.html.

> in number) shows that bankruptcy is normally caused by management missteps that lead to regulatory problems that in turn constrain cash flows. The situation is rehabilitated in the post-bankruptcy restructuring in a way that leaves regulated asset values essentially intact.
>
> Second, most utilities must obtain regulatory permission to issue new debt, and this requirement acts as a constraint on the utilities' ability to add debt in the event of a default spiral.
>
> Third, utility mortgage indentures restrict the issuance of FMBs to a percentage of bondable property, as defined in the indenture. The bondable property definition is normally tied to a utility's physical plant, and the percentage is typically 70% or less. Other indenture provisions may be more expansive, but usually not to a significant degree. These industry-specific and jurisdictional factors indicate that in most distressed situations we can reasonably anticipate recovery above 30% for utility unsecured debt."

In conclusion, we come back to the beginning of our answer to this question. If we set aside factors 2 and 3 (i.e. the costs of financial distress and the probability of financial distress), the theory suggests that a company should use a high proportion of debt. Our comments on factors 2 and 3 explain why it makes sense to expect these factors to carry less importance in practice for this industry. With the focus then on the first factor, taxes, we would expect regulated electric utilities to be among the most highly leveraged industries.

We now turn from electric utilities as an industry to examine the business risk of OPG both on its own and relative to that of other sectors of the industry.

5.3 Business Risk of Ontario Power Generation

5.3.1 Framework for analysis

Our assessment of business risk focuses on uncertainty of operating income introduced earlier in our overview of important factors in the determination of capital structure. Factors that increase costs to a utility such as higher fuel prices do not necessarily translate directly into increased business risk. Management can prevent these factors from increasing the uncertainty of operating income in several ways. First, it can forecast their impacts and build them into proposed pricing. In a fair regulatory environment, such costs will be allowed and passed on to customers. Second, management can engage in risk mitigation to control the impact of such factors on operating income. Third, risk can be mitigated by use of deferral accounts. Business risk is only increased to the extent that these three approaches to control risk only work incompletely.

Our analysis of business risk begins with an examination of the risks of hydroelectric and nuclear generation for OPG. Drawing on our 2008 Evidence, we introduce each of the three major categories of business risk for utilities: market, operational and regulatory, and discuss each in detail first for the regulated hydro and then for the nuclear operations of OPG. Our discussion presents a detailed breakdown of the components of business risk within each category and a numerical ranking of each on a scale of low (1), moderate (3) or high (5). We create a summary table, Schedule 5.1, displaying the rankings of each of nine individual risks covering our three categories. Our conclusion is that the regulated hydro generation activities of OPG carry a low to moderate level of business risk (i.e. 1.8 on our 5-point scale, with a score of 1 representing low risk and 5 the highest risk for a utility). The regulated nuclear operations are rated as approaching moderate risk (2.6 on our 5-point scale).

Our use of a scoring model is validated by research documenting the effectiveness of quantitative credit scoring and its widespread use by financial institutions for assessing the credit risk of loans to individuals and small businesses.[36] For these small loans, large

[36] A.N. Berger, W.S. Frame and N.H. Miller, Credit scoring and the availability, price and risk of small business credit, Federal Reserve Bank of Atlanta Working Paper No. 2002-6. Available at SSRN:

sample sizes allow the development of quantitative scoring. As detailed above, for application to divisions within a company, smaller numbers make it more appropriate to employ a qualitative approach. This approach is commonly applied to utilities. For example, Standard & Poor's identifies five factors on which it bases its business risk assessments for utilities: regulation, markets, operations, competitiveness and management. Examination of ratings reports from DBRS and Moody's confirms that these agencies address the same factors in appraising business risk.

To provide perspective on our business risk rankings, we next use our framework to measure the business risks of other sectors of the utilities industry and explain why we agree with the commonly held view that transmission (wires) carries the lowest business risk followed by distribution and then by generation with the highest business risk. We assess the business risk of transmission utilities as low (score of 1 out of 5) and distribution utilities as somewhat higher at low to moderate (1.4). These assessments form the basis for our capital structure recommendations for OPG Hydro and OPG Nuclear below. The analysis of business risks in the transmission and distribution sectors provides the basis for comparisons with deemed capital structures in those sectors.

5.3.2 Business risk of OPG's regulated hydroelectric generating assets

5.3.2.1 Market Risk

Market risk is the risk that a hydro generator will not be able to meet its target sales due to weak markets, to competition or to other related factors. However, OPG is the market leader in Ontario accounting for 71% of the electricity sold in 2007.[37] DBRS expects that the company will retain this position for the near future as well as after 2014 – the target date for closing coal-fired generation facilities. As discussed in Section 4, the Ontario economy is recovering in 2010 and expected to continue slow growth in 2011 led

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http://ssrn.com/abstract=315044 or DOI: 10.2139/ssrn.315044. L. Kryzanowski, M.C. To and Roger Seguin, 1990, Chapter 4: An analytical framework for the assessment of solvency risk, *Business Solvency Risk Analysis* (Montreal: Institute of Canadian Bankers, Volume 1, Revised September 1990).

[37] Our discussion draws on Ontario Power Generation, *Ratings Direct*, Standard & Poor's, October 16, 2009 and April 30, 2010 and DBRS Rating Report, August 12, 2009.

by manufacturing and service sector employment. The province experienced long-term growth of annual electricity consumption peaking in 2005 and declining through 2009 as a result of the impacts of conservation and a slowdown in economic growth, particularly in industrial production. In the near term, the IESO is predicting a modest increase in energy use in 2010 and continued slow growth out to 2014 consistent with the economic forecast summarized earlier. After 2014, the IESO is calling for a moderate decline that will return usage to 2009 levels by 2018.[38] Since the regulated part of OPG is a base-load, low marginal cost generator, it is not expected to experience a significant level of demand or dispatch risk as noted by the Board in its EB-2007-0905 Decision at page 147. Standard & Poor's reached the same conclusion:

> "OPG's strong competitive position in the Ontario wholesale electricity spot market is founded on its market dominance and the low marginal operating costs of its hydroelectric and nuclear generating facilities. If the company lost its regulatory support, it would have little, if any, dispatch risk for these baseloaded assets. Although there are other independent generators participating in the Ontario wholesale spot market, the demand for energy and capacity is such that all nuclear and most hydroelectric generators have relatively modest exposure to dispatch risk."[39]

In addition, competitive cost structure and transmission limitations protect OPG from competitive supply threats from Quebec and Manitoba. We thus assign a rating of low (1 out of 5) for competition / demand risk as shown in Schedule 5.1.

Our view of competition/demand risk disagrees with that of Ms. McShane in two respects. First, her forecast of electricity demand is overly pessimistic as it is based on dated sources: she limits her comments on the Ontario economy to quoting the Ministry of Finance's 2009 *Ontario Economic Outlook and Fiscal Review* released on October 22, 2009 and the IESO's *18-Month Outlook from December 2009 to May 2011* published

[38] *Ontario Reliability Outlook*, Independent Electricity System Operator (IESO), December 2009, www.ieso.ca.
[39] Ontario Power Generation, *Ratings Direct*, Standard & Poor's, October 16, 2009, page 11.

November 17, 2009 (Technology Specific Capital Structures: An Assessment, Kathleen C. McShane, 2010-0008, Exhibit C3-1-1, page 24). These sources document Ontario's economic decline in 2009 and state that "the economic recovery is unlikely to stimulate a significant rebound in electricity demand". More current IESO material quoted earlier projects modest growth consistent with economic recovery documented in Section 4 of this evidence. Ms. McShane accepts that the outlook is more positive in her response to Pollution Probe Interrogatory #031 (Exhibit L, Issue 3.1, Tab 10, Schedule 031, page 1).

Second, Ms. McShane overstates the impact of green legislation on page 25:

> "Subsequent to the 2008 regulated payments proceeding, the Ontario government passed the Green Energy and Green Economy Act, to position Ontario as a world leader in green energy. The legislation created a Feed-in Tariff program (replacing the previous Renewable Energy Standard Supply Program); the Feed-in Tariff program provides for attractive long-term contractually guaranteed prices for wind, hydroelectric, and biomass projects, designed to attract additional new investment in the renewable energy sector. The development of green energy projects under the Feed-in Tariff program will potentially lead to an increasing occurrence of surplus baseload generation. The adoption of the Green Energy and Green Economy Act and the potential softening of demand support the conclusion that the dispatch risk to which OPG's regulated operations are exposed is rising."

The concern over the impact of green legislation is not shared by DBRS and S&P: a search of the rating documents turned up no reference to this legislation. This is likely the case for two reasons. First, green energy, aside from hydroelectricity, is a minor component of Ontario supply. In response to part a of Pollution Probe Interrogatory #032, Ms. McShane identifies "renewable generation under contract with the OPA supplied generation [as] equivalent to 3 percent of Ontario demand in 2009 and anticipates that renewable generation under contract with the OPA will supply generation equivalent to 9 percent of Ontario demand in 2011."[40] Second, in her response to part b of

[40] Response to Pollution Probe Interrogatory No. 032 (Exhibit L, Issue 3.1, Tab 10, Schedule 032).

the same Pollution Probe Interrogatory, Ms. McShane agrees that "increased dispatch risk … represents an increased forecasting risk" and such risk is mitigated by deferral accounts. As she states in her response to part b of Pollution Probe Interrogatory #033:

> "The use of deferral and variance accounts mitigates forecasting risks related to costs over which the utility has little or no control, or are difficult to forecast. The extent to which deferral accounts lower the forecasting risk is a function of the scope of the accounts and the materiality of the costs that are covered by those accounts. The existence of such accounts does not, however, guarantee recovery of the costs nor does it change the utility's fundamental risks."[41]

A related component of market risk is the credit risk that may arise if a utility's customers default on their payments. This element of market risk is also low (1 out of 5) for OPG because it does not sell directly to ultimate power users.

With competition/demand risk and customer credit risk both rated low, we conclude that market risk is low (1 out of 5) for OPG's hydro generation business.

5.3.2.2 Operational Risk

Operational risk represents the risk that OPG will not meet production and profitability targets. We identify four elements of operational risk and discuss them in turn. We also discuss how deferral accounts serve to mitigate the various elements of operational risk. The first component of operational risk is operating leverage which arises when operations such as hydro generation are characterized by a high level of fixed costs, which make operating cash flow more sensitive to changes in production. We assess operating leverage as moderate (3 out of 5) in Schedule 5.1. Related to operating leverage, advanced technology also impacts fixed costs and makes production more sensitive to technical breakdowns. We assign a risk rating of low to moderate (2 out of 5) to technology risk.

[41] Response to Pollution Probe Interrogatory No. 033 (Exhibit L, Issue 3.3, Tab 10, Schedule 033).

Capacity risk relates to forced outages due to unanticipated breakdowns or prolonged maintenance. Hydroelectric generation is typically subject to a low rate of forced outages. Capability factors measure reliability as the ratio of available energy generation to reference energy generation defined as production under full power. Available energy generation may fall below reference levels due to "limitations within control of plant management, i.e., plant equipment and personnel performance, and work control" according to the International Atomic Energy Agency.[42] In a regulatory perspective, such a shortfall does not constitute a risk for which a utility should be compensated. OPG continues its traditional record of high capability factors for its hydro units.

Further, hydro generating units are not subject to the risk of increasing fuel costs as are fossil fuel and nuclear units. Nor do they fall prey to significantly increased risks of environmental compliance. However, availability of water does create a production risk as lower water levels could reduce output and create unrecovered costs. Historically, water availability has not been a problem for OPG due to its diversification of regulated hydro assets on two river systems (i.e. the St. Lawrence and Niagara Rivers).[43]

Further, OPG currently has a deferral account (Hydroelectric Water Conditions Variance Account) which allows the company to collect cost recovery in years with lower water levels and to replenish the account when water levels are above forecast.

In addition, OPG is requesting a new deferral account to be called the IESO Non-Energy Charges Variance Account (Exhibit H1, Tab 3, Schedule 1, Page 8 of 9). This account will address variances in charges to wholesale customers that are difficult to forecast and can be material. These include charges for Debt Retirement Charges, Rural Rate Assistance, Transmission Charges, and Global Adjustment among others. According to OPG:

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[42] *Financing of new nuclear power plants*, IAEA Nuclear Energy Series, No NG-T-4.2, International Atomic Energy Agency, Vienna, 2008. Available at: www.iaea.org.
[43] *Corporate Credit Rating*, Standard & Poor's, October 16, 2009.

> "… the Global Adjustment – typically the largest of all non-energy charges – exhibits substantial variability month over month. It represents the difference between the total payments made to certain contracted or regulated generators and conservation and demand management projects, and any offsetting market revenues."[44]

Considering all the elements of capacity risk produces a rating of moderate (3 out of 5). The presence of a water deferral account mitigates capacity risk and leads to a rating of low risk (1 out of 5) under deferral accounts.

A further aspect of operational risk arises from costs that can arise from the obligatory retirement of assets and construction of new generation. For its hydro generation, environmental issues related to asset retirement are not a major concern as they are for coal burning and nuclear units. Hydro generators do face risks with regard to capital expenditures. However, the recovery of fixed capital costs such as depreciation is included in the allowed rate and addressed by a capacity refurbishment variance account to cover variances to forecasts during the test period. Longer term, DBRS believes that these risks will be largely mitigated by financial structuring and regulation:

> "It is expected that OPG will not undertake any major capital projects without having its financing and a cost-recovery mechanism in place, thus minimizing the financial risks. Although OPG may be able to reduce its risks through fixed price contracts, the extent to which overrun risk can be placed on a contractor for large construction projects remains to be seen."[45]

In brief, our assessment of risks associated with asset retirement and construction leads us to conclude that this risk is low to moderate for OPG Hydro.

5.3.2.3 Regulatory Risk

[44] EB-2010-0008, Exhibit F4, Tab 4, Schedule 1, Page 4 of 6.
[45] Ontario Power Generation Inc., *DBRS Rating Report*, August 12, 2009, page 3.

Regulatory risk can arise when costs are disallowed, allowed returns do not fit market expectations or rate design (including allowed capital structures) varies from what is fair and reasonable in view of business risks. Alternatively, regulation can mitigate risks through the introduction of deferral accounts and by allowing generous allowed returns and capital structures as discussed in other parts of this evidence.

We believe that regulation by the Board plays the second, positive role for OPG and assess the regulatory risk as low for a number of reasons. First, as discussed earlier, deferral and variance accounts allowed by the Board reduce operational risk. Second, as also explained above, we expect that the Board will approve appropriate structures that will mitigate the risk of future construction. Third, it is our understanding that the Board regulates in a fair manner. It follows that it is logically contradictory for the Board to recognize possible future political interference as a risk for which the company should be compensated:

> "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 (EB-2007-0905 Decision, page 142)."

Regulatory risk may also arise due to unanticipated shifts in environmental or safety regulations or in their enforcement. Because hydro generation does not involve the burning of fossil fuels or the potential dangers of nuclear generation, we rate this element of risk as low to moderate (2 out of 5).

5.3.2.4 Summary on Business Risk for OPG's Hydroelectric Assets

Our review assesses nine dimensions falling within the three main areas of business risk (market, operational and regulatory) and the ratings presented above are summarized in Schedule 5.1 in the column marked OPG Hydro. As the Schedule shows, the average-risk rating is 1.8, thus producing a low to moderate level of business risk for OPG's regulated hydro assets unchanged since Decision EB-2007-0905 in November 2008.

Notwithstanding her concern about dispatch risk which we addressed above, Ms. McShane reaches a similar overall conclusion regarding the business risk of these assets on page 26:

> "With the exception of a modest increase in dispatch risk during the test period due to the passage of the Green Energy and Green Economy Act and low demand conditions, the business risks faced by OPG's regulated hydroelectric operations remain largely unchanged since EB-2007-0905."

5.3.3 Business risk of OPG's regulated nuclear generating assets

5.3.3.1 Market Risk

Market risk is the same for nuclear as for hydro generation. Therefore, we assess both competition and customer credit risks as low for the reasons explained earlier.

5.3.3.2 Operational Risk

Nuclear technology is more advanced and characterized by a greater degree of fixed costs (operating leverage) and higher technology risk. We rate both as moderate to high (4 out of 5) and unchanged since the Decision in EB-2007-0905.

Nuclear generation is also subject to more intense environmental and safety regulations that create the potential for lengthy unplanned outages. In the case of OPG the greater risk of nuclear generation is magnified by issues related to unplanned maintenance and inspection outages.

Unpredicted fuel cost increases represent an added potential capacity risk to nuclear generation. In its Decision in EB-2007-0905 (page 33), the Board noted that the price of uranium increased up to mid-2007 and then fell sharply. This fall has continued: at the time of the Board Decision in November 2008, uranium was priced around $87 U.S. per pound while on August 3, 2010 the price was $46 U.S.[46] Further, it is only the unexpected component of any price increase that is a source of risk and OPG has two lines of defense against fuel cost risk. First, the company traditionally engages in fuel price hedging for both fossil and nuclear fuels. Second, uranium fuel price risk is covered by the nuclear fuel expense variance account approved by the Board in its EB-2007-0905 Decision.

As we noted earlier, the costs of decommissioning assets and disposing of used fuel are higher for nuclear than for hydro generation. For OPG, these risks are mitigated by funding of a Used Fuels Fund and a Decommissioning Fund under the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province. As stated in the EB-2007-0905 Decision at page 66:

> "Under the ONFA, the Province limits OPG's financial exposure for used fuel management with respect to the first 2.23 million used fuel bundles, a threshold that OPG expects will be reached in 2011. OPG is fully responsible for costs of managing used fuel bundles in excess of that amount. The Province also guarantees an annual rate of return of 3.25% above the Ontario Consumer Price Index on the portion of the used fuel fund related to the first 2.23 million used fuel bundles. Actual returns in excess of the guaranteed return accrue to the Province, not OPG."[47]

While DBRS takes a balanced view of waste and decommissioning costs rating the limit to OPG's liability as a Strength and the balance as a Challenge, the Board emphasized the risk reduction aspect:

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[46] Available at: http://www.infomine.com/.

[47] OPG has since revised its estimate of when the fuel bundle limit will be reached to 2012 (see EB-2010-0008, Exhibit C2, Tab 1, Schedule 1, page 6, lines 29-30.

> "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."[48]

A further aspect of operational risk derives from the need to build new generation assets leading to financing challenges and construction risk. Because the largest proportion of OPG's planned future growth is in nuclear, this risk is higher than for hydro generation and is noted as a challenge by both DBRS and S&P. As indicated in our discussion of hydro risks, this risk is however mitigated through project structuring as well as by a capacity refurbishment variance account to cover variances to forecasts during the test period. There is also protection against long-term planning changes:

> "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."[49]

[48] Decision in EB-2007-0905 at page 141.
[49] Decision in EB-2007-0905 at page 148.

Deferral accounts moderate the operational risk of nuclear generation arising from waste disposal and capacity as discussed above. Rate structure can have the same effect. In particular, in the last hearing OPG requested a 25% fixed charge for nuclear generation. We agree with Ms. McShane (at page 27), that, had the Board approved the requested fixed charge, the effect would have been to mitigate operating leverage. The business risk assessment in our 2008 Evidence was based on the counterfactual assumption that the Board would approve the fixed charge. As a result, our prior assessment marginally understated the operational risk of OPG. We addressed this in our prior evidence referring to OPG's request for the fixed charge:

> "Should the Board deny this request the impact would be to reduce risk mitigation. In our framework, this falls under the deferral account category in the OPG Nuclear column Schedule 3.1. Under the scenario in which the Board disallowed OPG's request for a 25% fixed charge, business risk would be increased raising the rating for this category from Low (1) to Moderate (3)."

Recognizing that the Board did not approve the fixed charge we adjust the deferral account category as indicated.

In addition to increasing the risk of forced outages, as discussed earlier, higher technology risk also increases the risk associated with financing asset replacement as documented by the Director-General of the OECD Nuclear Agency:

> "It appears that there is very little likelihood at the present stage of development of nuclear technology and the nuclear construction industry to finance a new NPP by using non-recourse financing (where a stand-alone project company raises the capital it needs to build the plant using only the NPP project itself as collateral). Even for hybrid schemes which include a significant proportion of equity, debt investors at present are unlikely to be willing to provide significant funding for a

> nuclear plant without recourse against the balance sheet of a strong and creditworthy utility."[50]

Summarizing our discussion of operational risk in OPG's nuclear assets, the company faces moderate to high levels of both operating leverage and technology risks both rated 4 out of 5. Its moderate (3 out of 5) exposure to capacity risk arises from aspects of nuclear generation outside of management control. Further, OPG faces moderate risk associated with decommissioning and construction. Finally, deferral accounts related to fuel costs and funds supporting used fuel and decommissioning costs partially mitigate the associated risks leading to a moderate rating (3) for deferral accounts.

5.3.3.3 Regulatory Risk

Regulatory risk associated with the primary regulator is subject to the same factors for nuclear as for hydro assets. The difference is that the stakes are higher due to the higher operational risk of nuclear generation. On this point we agree with Standard & Poor's, which states:

> "In our opinion, OEB regulation reduces uncertainty surrounding cost recovery and supports OPG's strong business risk profile but does not fully alleviate volume risk linked to nuclear output and available hydrology. Furthermore, OPG's nuclear segment is highly susceptible to poorer-than-targeted performance (aging assets), and cost overruns that, we believe, heighten regulatory risk."[51]

A further aspect of regulatory risk arises from OPG's request to increase nuclear payment amounts by including construction work in progress (CWIP) arising from the Darlington Refurbishment Project in the test period rate base. The factors to be considered by the OEB in considering such a proposal that are specified in EB-2009-

[50] How to Finance a Nuclear Program, Roundtable moderated by Luis Echavarri, OECD Nuclear Energy Agency, March 8, 2010.
[51] *Corporate Credit Rating*, Standard & Poor's, October 16, 2009, page 5.

0152 include "the cost of the project in proportion to the current rate base of the utility".[52] The rationale for this criterion is that including CWIP in rate base increases cash flow to assist utilities undergoing a large capital build in controlling challenges to their credit metrics arising from the need to grow their rate bases substantially. In the current case the cost is small relative to the rate base. Total generation capital associated with the Darlington Refurbishment is $105.2 M for 2010 and $255.8 M for 2012.[53] For the same test years, Rate Base Financed by Capital Structure is $6,321.4 M and $6,448.1 M, respectively. Assuming that CWIP is 100% of generation capital (which is optimistic) produces estimates of CWIP as being not more than 1.7% of rate base in 2011 and 4% in 2012. It follows that any impact on business risk arising from the possible allowance of CWIP for Darlington Refurbishment must come from other sources.

One possible such impact could be that regulatory risk associated with a possible disallowance of the initial costs could be reduced. This would occur because allowing CWIP for the initial stages of the project would be interpreted as a sign that the Board would allow the full costs even in the event that the refurbishment does not go ahead in 2014. To encourage the initial project by allowing CWIP in rate base and then denying full cost recovery could be interpreted as retrospective rate making and a departure from best regulatory practices. Second, an opposite effect of increasing business risk could also arise as, encouraged by the Board's approval of initial project CWIP, OPG could develop a bias in favour of refurbishment and decide to go ahead with the full project despite the fact that better, lower cost alternatives were available. In this scenario, the project would have a negative net present value thus increasing the business risk of OPG as a standalone entity.

In addition to any possible impact should CWIP be allowed, nuclear assets are subject to additional regulatory risks relating to environmental and safety regulation under the supervision of the Canadian Nuclear Safety Commission (CNSC). The CNSC regulates

[52] FIT was not an alternative mechanism that was considered or brought up in this consultative process. EB-2009-0152, Report of the Board, The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario, January 15, 2010, page 21.
[53] Response to Pollution Probe Interrogatory #014, EB-2010-0008, Exhibit L, Issue 4.5, Tab 10, Schedule 014.

Canada's seven nuclear power plants including those of OPG along with other nuclear reactors.[54] Due to the high level of regulation, it is possible that an enhancement to regulations or an unexpectedly strict interpretation by CNSC could cause unforeseen costs or unplanned outages at one of OPG's plants. Such a closure occurred at the Chalk River nuclear research facility operated by Atomic Energy of Canada Ltd. in November 2007. At issue was the classification of a redundant safety system as either an optional safety enhancement or a necessary condition of licensing.[55] Further, future legislation could impose more onerous safety regulations on OPG.

While we recognize that shifts in environmental and safety regulation do pose a risk to OPG in its nuclear operations, we assess this risk as moderate. Should the risk from shifts in environmental and safety regulation materialize, it can be mitigated by a deferral account in the same way that OPG is protected against changes to the nuclear liabilities Reference Plan.

In brief, our review of OPG's regulatory risk in its nuclear generation results in a rating of low regulatory risk with respect to the Board based on our earlier discussion of regulatory risk. Additional regulatory risk arises from possible shifts in environmental and safety regulations regarding nuclear operations but this is mitigated by the minor role currently played by this risk and the company's right to request a deferral account should the risk become material in the future. Overall, we assign a rating of moderate to this second aspect of regulatory risk arising from OPG's nuclear operations.

5.3.3.4 Summary of Business Risk of Nuclear Generation

Our review examines the three main areas of business risk (market, operational and regulatory) using nine dimensions. We summarize the ratings presented above in Schedule 5.1 in the column marked OPG Nuclear. As the Schedule shows, the average-risk rating is 2.6, thus approaching a moderate level of business risk for OPG's nuclear

[54] Available at: www.nuclearsafety.gc.ca.
[55] Peter Calamai, Medical isotope power struggle, Toronto Star, February 25, 2008. Available at http://www.thestar.com/news/canada/article/306604.

assets. As for OPG's hydro assets, we again conclude that the level of business risk is unchanged since the EB-2007-0905 Decision in November 2008.

Our qualititative assessment of the business risk of OPG's nuclear assets agrees with that of Ms. McShane. However, she goes on to discuss two aspects of the Board's ruling in that Decision which denied requests from OPG: rejection of OPG's request for a 25% fixed charge for nuclear production and setting a lower rate for the accretion of OPG's nuclear liabilities. As explained above, these denials are immaterial to the comparison of business risk since the Decision in EB-2007-0905. Our discussion of operational risk details how we updated our assessment to take into account the absence of fixed charges.

5.4 Relative Risks of Electricity Sectors

With our business risk analysis of OPG's hydro and nuclear generation complete, we now turn to an examination of the relative business risks of electricity transmission and distribution. Because there are a number of regulated companies in these sectors in Canada, such a comparison provides a useful perspective.

Market competition risk is low for transmission because of its status as a natural monopoly. While electricity distribution also has the characteristics of a monopoly it carries higher market competition risk due to the possibility of customers switching to natural gas or increasing reliance on co-generation. Further, because distribution companies sell to wholesale and retail customers, they face credit risk to a larger degree than do transmission companies whose sole customer is a distribution firm. More importantly, distribution companies are subject to operating leverage risk as they levy variable charges to cover fixed costs.

We summarize our view of the relative risks of electricity distribution and electricity transmission on the first page of Schedule 5.1. Using our risk rating criteria introduced earlier, the schedule shows the risk rating of electricity transmission as 1 or Low and distribution as 1.4 or Low-moderate. Our ranking is consistent with the opinion of the

Alberta Utilities Commission (formerly the Alberta Energy and Utilities Board) in EUB Decision 2004-052 (July 2, 2004) at page 48:

> "The Board notes the consensus that electric distribution companies are subject to more business risk than electric transmission companies, principally due to their recovery of a significant amount of fixed costs in variable charges and their greater exposure to credit risks."

The Commission restated this view in its Decision 2009-216 at page 98, paragraphs 370-371:

> "The Commission observes that there is a general consensus on the rank ordering of risk by sector. The electric transmission sector is considered to have the least risk. No party argued otherwise and the Commission agrees. The Commission also finds in general that the electricity distribution segment is slightly more risky than electricity transmission."

Electricity generation carries higher business risk than distribution along a number of dimensions. As explained above, because it is not a natural monopoly, generation faces potential competition from independent electricity producers locally as well as from generating facilities in neighboring provinces or states. Generation also carries a higher degree of operating leverage as a result of a higher level of fixed assets and more complex technology. On the production side, capacity risk arises from unplanned outages, fuel costs and water availability. Further electricity generators are subject to risks from unplanned costs of asset retirement and construction of new generating facilities.

Reinforcing our relative ranking of electricity generation as riskier than either transmission or distribution, their risk ratings in Schedule 5.1 are lower than those derived earlier for either division of OPG. Further, our view that generation is the riskiest sector is consistent with the thinking of the Board in its Decision in EB-2007-0905 at page 149:

> "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)."

One additional useful business risk benchmark is the risk of an integrated utility, conducting generation, transmission and distribution business. To assess the business risk of such an entity we take a weighted average of the individual business risks. To illustrate, we take Emera as an example. In 2009, Emera reported total book value of assets of $2,933.7 million of which generation assets were $1,106.2 million, transmission $473.5 million, distribution $703.2 million and Other $224.2. Excluding other assets and calculating the percentage of each type of asset gives: 48.46% for generation; 20.74% for transmission; and 30.80% for distribution. To derive the business risk of an integrated company, we round these weights to 50% generation, 20% transmission and 30% distribution and apply each to the sector business risk as shown in Schedule 5.1. The calculation shows that the business risk of an integrated company is Low-moderate, i.e. higher than either transmission or distribution alone and lower than generation.

5.5 Bond Ratings and Capital Structures for Canadian Utilities

In this section, we examine the bond ratings and capital structures, both actual and allowed for a sample of Canadian utilities. Our purpose is to develop benchmarks of capital structures for different segments of the industry. With these benchmarks in hand, we can then draw on our analysis of business risk above to recommend an appropriate equity ratio for OPG Hydro, OPG Nuclear and for OPG's total regulated rate base. In the context of the Issues List in this Hearing, we focus on the individual equity ratios for OPG's two regulated divisions taking into account the overall equity ratio for the total regulated rate base as given at 47%.

Beginning with bond ratings, Schedule 5.2 displays Dominion Bond Rating Service (DBRS) and Standard & Poor's (S&P) bond ratings in August 2010 for our eight Canadian utilities and their regulated subsidiaries spanning different parts of the industry: gas, electric and pipelines. These companies represent a current sample of utilities with publicly traded shares. In forming this sample, we seek to measure ratings and financial ratios for the traded entity associated with the regulated utility. We recognize, however, that many of the traded companies include non-regulated businesses in addition to the regulated utility. We control for any bias by commenting on the differences as well as comparing our conclusions to those drawn strictly for regulated entities.

The bond ratings are from the websites of DBRS and S&P. Starting with the DBRS ratings, Schedule 5.2 shows that these range from A for Canadian Utilities, Enbridge, Newfoundland Power and TransCanada Corporation down to BBB (low) for Pacific Northern Gas. The Schedule shows that the typical Canadian energy utility is rated A (low) by DBRS. We next turn to the S&P ratings and make a similar comparison. The S&P ratings for the utilities in our sample range from A for Atco and Canadian Utilities down to BBB for Emera and TransAlta. S&P does not rate Pacific Northern Gas or the Fortis subsidiaries. The Schedule shows that the typical Canadian energy utility is rated A- by S&P.

The next step is to examine the actual, long-term capital structures of the companies in our sample for 2007 through 2009, the latest three years for which data are available in the *Financial Post Advisor* and company annual reports. These ratios show common equity, long-term debt and preferred shares as percentages of long-term capital excluding short-term debt. Focusing on the 2009 common equity ratios, Schedule 5.3 reveals that there is considerable variation across companies from a high of 52.67% for Pacific Northern Gas to a low of 34.95% for Fortis. The average percentage of common equity was 40.46% in 2009, which is down slightly from 41.76% in 2008. The equity ratio for these companies has been stable over the last three years.

In addition, Schedule 5.3 shows the percentages of long-term debt and preferred shares (separated from common equity) in the capital structures of these companies. Again, there was considerable variation in the proportionate use of financing across companies. On average, the companies employed 57.06% long-term debt and 2.48% preferred shares in 2009.

The presentation of ratios for the same group of companies continues in Schedule 5.4. The first three columns show the coverage ratio, EBIT/Interest expense.[56] The average coverage ratio was 2.65 times in 2009. The next three columns display cash flow to debt which averaged 16.42% in 2009.[57]

The schedules show that, from the vantage point of DBRS, Canadian Utilities, Enbridge, Newfoundland Power and TransCanada Corporation are the only companies which enjoy an A credit rating. The other companies are all rated A (low) or lower. For S&P, only two companies in our sample (ATCO and Canadian Utilities) are rated A. As stated earlier, the typical company is rated A (low) by DBRS and given an equivalent A-rating by S&P for its smaller set of ratings. Of the eight traded companies and five subsidiaries in our sample, six received a rating of BBB from at least one of the agencies. Yet, despite their lower ratings, with the exception of Pacific Northern Gas, a small company which experienced financial distress, these companies have had no difficulties in accessing capital markets to raise long-term financing. We conclude that the experiences of the companies in Schedules 5.2 - 5.4 suggest that a bond rating of BBB or higher is sufficient to maintain good access to capital markets.

Schedule 5.4 also contains data on ROEs for the companies in our sample which support our argument that a bond rating of BBB or above is sufficient for a regulated utility. The ROE figures for 2007 through 2009 show that all of the companies were profitable and earned positive ROEs in all three years.

[56] EBIT are earnings before interest and taxes.
[57] Cash flow from operations divided by the sum of long- and short-term debt. The result is expressed as a percentage.

Although the comparison is somewhat imprecise due to the inclusion of unregulated businesses in the traded companies, it is instructive to compare actual earned ROEs against the allowed ROEs set by regulators. A focus on the most recent year reveals that the actual ROEs earned by the parent holding company in 2009 exceeded ROE targets for 7 of the 11 regulated entities in Schedule 5.5 (i.e. all of the four ATCO regulated entities as well as Nova Scotia Power, Enbridge Gas and TransCanada Pipelines). Only four traded companies failed to earn the return on equity allowed for the regulated entity [i.e. three Fortis subsidiaries (Alberta, British Columbia and Newfoundland Power) and Pacific Northern Gas]. The average 2009 allowed return for this sample was 8.95%, while the average actual ROE for the consolidated company was 11.64%. The difference of 269 basis points represents the out-performance of allowed returns. This strongly suggests that having a bond rating of BBB did not impede these companies from profitably conducting their businesses.

5.6 Common Equity Ratio Benchmarks

Our discussion shows that the typical Canadian utility in our sample has a bond rating of A (low) from DBRS and A- from S&P. Further, a number of companies have BBB ratings. While OPG falls into this range with a bond rating of A (low) from DBRS and BBB+ from S&P, its bond rating is enhanced by the support it receives from the Province of Ontario. Further, ownership by the Province of Ontario impacts the goals of the company according to *The Government Backgrounder*, which stated:

> "The Ontario government has established prices for electricity produced by Ontario Power Generation (OPG) effective April 1, 2005. These prices are designed to:
>
> a) Better reflect the true cost of producing electricity
>
> b) Ensure a reliable, sustainable and diverse supply of power in Ontario
>
> c) Protect Ontario's medium and large businesses by ensuring rates are stable and competitive

d) Provide an incentive for OPG to contain costs and to maximize efficiencies

e) Allow OPG to better service its debt while earning a rate of return that balances the needs of customers and ensures a fair return"

Under the stand-alone principle of regulation, we must set aside the impact of provincial ownership of OPG and assess a fair capital structure from the standpoint of an investor-owned utility of comparable risk. This standard is provided by our sample in Schedule 5.2. Our analysis establishes that the sample represents a group of companies which, with appropriate adjustments discussed below, can proxy for the risk that would be faced by OPG if it were investor owned. Mindful of the goals set by the province but emphasizing the stand-alone principle, we use this sample to establish an appropriate capital structure for OPG.

5.6.1 Sample benchmarks

First, we turn to Schedule 5.3 where we observe that the average actual equity ratio for utilities in our sample was 40.46% for 2009, the most recent year for which we have data. This represents one useful benchmark for the equity ratio for a Canadian utility. Other benchmarks are helpful for two reasons. First, like any sample average, our average equity ratio depends on the sample drawn and can vary somewhat for this reason. Second, as we indicated earlier, the average is based on equity ratios for traded companies which include non-regulated activities which are likely to be more risky than regulated utilities. Academic research by Drs. Sanyal and Bulan documents the increase in business risk with U.S. deregulation which was accompanied by a decrease from 38% to 32% in the average book value leverage ratio for U.S. electrical utilities (i.e. with deregulation, these companies do not have their leverage ratios set by regulators so these declines reflect adjustments to shifts in business risk).[58] Their paper demonstrates that for individual companies key factors explaining the decline in leverage were introduction of

[58] Sanyal, Paroma and Bulan, Laarni T., Regulatory Risk, Market Risk and Capital Structure: Evidence from U.S. Electric Utilities (August 1, 2008). Available at SSRN: http://ssrn.com/abstract=781230.

deregulation, uncertainties in the market environment in the absence of a safety net and the degree of competition.

As a check on our calculations, we examine the equity ratios allowed by various Canadian regulatory bodies for the companies in our sample for which we obtained data from past decisions. The sample includes ATCO Electric Transmission and Distribution, ATCO Gas and Pipelines, Enbridge Gas Distribution, Emera (Nova Scotia Power), Fortis Alberta, Fortis British Columbia, Maritime Electric, Newfoundland Power, Pacific Northern Gas, TransAlta, and TransCanada Pipelines. In Schedule 5.6, we report the average allowed equity ratio for these 13 companies as 40.09%. Schedule 5.6 reinforces our conclusion that the average "generous" equity ratio for our sample of electric and gas utilities is around 40%. The same benchmark common equity ratio was chosen by the Board when it set the equity ratio at 40% for all Ontario electricity distributors.[59]

We call this average equity ratio "generous" because it represents the result of a regulatory process in which decisions by regulatory bodies take as input the views of opposing parties that are each representing its own interest. We already showed how the regulatory process may be regarded as generous as it protects utilities from losses and typically results in the regulated companies earning an ROE in excess of the allowed return. Focusing the discussion of generosity on the common equity ratio leads to a similar conclusion. Regulated utilities have little incentive to optimize the use of debt in their capital structures. Having a capital structure with insufficient debt increases the weighted cost of capital because equity is the most expensive form of financing. In the case of regulated utilities, this "extra" cost associated with insufficient debt may be recovered through the process of regulation. If the company can persuade its regulator to approve this unwarranted extra equity, there is no cost to the company from a higher cost of capital. If this occurs, then the regulated company has unused debt capacity which can be a benefit to the parent holding company. The assets of the regulated utility can then serve as collateral to increase the borrowing power of the unregulated part of the holding

[59] Ontario Energy Board. *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*. December 20, 2006. page 5.

company, thereby adding value for the shareholders. If this occurs, the shareholders gain unfairly at the expense of the customers of the regulated utility who have to pay higher rates to "compensate" the regulated utility for the cost of carrying unwarranted extra equity.

Our final benchmark is derived by focusing on one company from Schedule 5.5: ATCO Pipelines. We select ATCO Pipelines because it represents an example of a utility with greater business risk than a relevant set of comparison companies drawn from different segments of the utility industry in Alberta – the eleven utilities included in the AEUB's Generic Decision 2004-052 and the fifteen in the AUC's Generic Decision 2009-216. In the 2009 hearing, we recommended a common equity ratio for ATCO Pipelines of 42% on a standalone basis independent of the merger with NGTL. The Board awarded 45%. Based on these numbers and recalling our earlier discussion of "generosity" in past decisions, we regard 42% to 45% as an appropriate range for a higher risk utility.

We summarize our discussion of utility industry benchmark equity ratios as falling into a range of 40% to 45%. We form three estimates of the appropriate equity ratio for a utility. The first is 40.46% (Schedule 5.3) and represents the average of actual equity ratios for eight traded utility companies. The second estimate is the average equity ratio allowed 13 regulated entities within these companies by their regulatory boards of 40.09% (Schedule 5.6) combined with the Board's award of 40% for Ontario electric distributors. The third estimate is the range from our recommendation to the equity thickness allowed by the AUC in 2009 for ATCO Pipelines, a high-risk utility, of 42 to 45%. These benchmark equity ratios all fall in a range of 40% to 45%.

5.6.2 Relating the benchmarks to OPG Hydro

In order to use benchmarks to set a recommended capital structure for OPG's two types of assets, it is necessary to draw on our earlier updated business risk analysis. Our analysis of the business risk faced by OPG Hydro assesses this risk as low to moderate –

higher than that of a distribution utility and somewhat above the business risk of an integrated electric utility. This suggests that a fair common equity ratio for OPG Hydro should be at 40%, at the middle of our generous range.

To explore the reasonableness of this conclusion, we reconsider our four benchmarks in turn. Our first benchmark, the average of actual equity ratios for 8 traded utilities is 40.46%. These companies are transmission, distribution or integrated utilities. However, because this measure also includes capital for unregulated activities, which tend to be riskier than regulated businesses, we believe that it exceeds the appropriate level of equity for an average-risk utility. We confirm this view when we look next at our second benchmark of allowed average equity thickness of 40.09% reinforced by our third benchmark of 40% allowed by the Board for electricity distributors. It follows from our view of allowed returns as generous measures of appropriate capital structures that this 40% benchmark should be appropriate for a higher level of business risk. To illustrate, Schedule 5.7 shows that in its Generic Decision, the AUC awarded 39% equity thickness for electricity distribution while we recommended 35%. Given our view that OPG Hydro's level of business risk is above those of the transmission, distribution and integrated utilities in our sample, our second benchmark indicates that a level of equity of no less than 40% is required.

We reinforce this view with our fourth benchmark of 42 to 45% equity recommended and generously allowed by the AUC for a high-risk Alberta utility. Given OPG Hydro's level of business risk, we believe that its target equity ratio should fall toward the low end of this range.

Schedule 5.7 summarizes this discussion and restates our recommendation to set the common equity ratio for OPG Hydro at 40%.

5.6.3 Relating the benchmarks to OPG Nuclear

We take a similar approach in reaching a recommendation for the equity ratio for OPG Nuclear. As we discuss above and summarize in Schedule 5.7, OPG's nuclear assets carry higher levels of operational risk compared to its hydro assets. Further, regulatory risks associated with environmental and safety issues are also elevated compared to that of OPG Hydro. Our analysis rates the business risk of OPG's regulated nuclear assets as moderate (2.6 on our 5 point scale).

Schedule 5.7 shows that this business risk rating for OPG Nuclear exceeds the rating for OPG Hydro (1.8). It also signals that OPG Nuclear bears higher business risk than generic integrated companies (rated 1.5) or generic distribution utilities rated (1.4). The higher business risk of OPG Nuclear should translate into a significant increase in its common equity ratio on the order of 5-10% over that for OPG Hydro producing a recommended equity ratio for OPG Nuclear of 45 to 50%. In the interests of conservatism and to ensure fairness to the shareholder, we stand by our 2008 recommendation of the higher number of 50% for the equity ratio.

As stated earlier, our business risk analysis is updated from our 2008 Evidence to reflect the modest increase resulting from the Board's denial of OPG's request in that hearing for a 25% fixed charge for nuclear assets. In that Evidence, we recommended a modest increase in the equity ratio for OPG Nuclear in the event that the fixed charge request was denied. Such an adjustment is no longer necessary due to the generous equity risk premium awarded by the Board which more than compensates OPG Nuclear for the modest increase in business risk associated with the absence of a fixed charge. In our 2008 Evidence we recommended a utility equity risk premium of 325 basis points for 2008 and 300 basis points for 2009. The Board set the utility equity risk premium at a far higher level of 550 basis points in Decision EB-2009-0084.

5.6.4 Capital structure for OPG's overall rate base

It remains to reconcile our recommendations for OPG Hydro and Nuclear with the capital structure of 47% equity recommended in our 2008 Evidence and mandated by the

Board for the combined entity. Our 2008 Evidence calculated a weighted average of our individual capital structures using the asset breakdown in the *Electricity Restructuring Act* of Ontario of 2004, which set OPG's prices for electricity for 6,606 MW from regulated nuclear generation and 3,332 MW for hydro generation. These two sources total 9,938 MW of which 66.47% is nuclear and 33.53% hydro. Applying these weights to our two separate capital structure recommendations results in an overall rounded recommended equity ratio of 47% for OPG's rate base consistent with the Board's mandate.[60] We summarize our analysis in Schedule 5.7.

5.6.5 Projected coverage ratios for OPG Hydro and Nuclear if they were stand-alone entities

Our recommendations for the capital structures for OPG Hydro and Nuclear flow from our analysis of the business risks of each type of assets and from our review of appropriate industry and regulatory benchmarks. Those benchmarks include bond ratings and we concluded above that a rating of BBB would be sufficient to allow a stand-alone utility to conduct its business properly and to access capital markets. To show that our recommendations of 40% equity for OPG Hydro and 50% for OPG Nuclear are not incompatible with a rating in the A range, we calculate and report the implied Interest and Free Cash Flow (FFO) coverage and Cash Flow to Debt ratios for 2011 and 2012 in Schedules 5.8 using the data supplied by OPG in its application.

To illustrate, we explain our calculations in Schedule 5.8A for OPG Hydro for 2012 in detail. We start with the total rate base of $6,448.1 M financed by capital structure from Table 1 from EB-2010-0008, Exhibit C1, Tab 1, Schedule 1. To obtain the rate base of OPG Hydro of $2,162.1 M for 2012, we multiply by 33.53%, the percentage of

[60] Updating the weights to reflect the numbers in the current Application leaves the weights unchanged except for minor rounding error. OPG states its total regulated capacities as 6,606 MW nuclear and 3,302 MW hydroelectric for a total of 9,908 MW (EB-2010-0008, Exhibit A1, Tab 4, Schedule 1, page 1). The weights are 66.67% nuclear and 33.33% hydro. The weight of hydro capacity is expected to decrease slightly for the test period to 27.97% (38.4 TWh) vs. 72.03% (98.9 TWh) for nuclear (EB-2010-0008, Exhibit E1, Tab 1, Schedule 1, Page 1 and EB-2010-0008, Exhibit E2, Tab 1, Schedule 1, Page 1). Using these forward-looking weights, the overall capital structure becomes 47.2% equity.

hydro assets discussed above. Applying the capital structure weights gives the principal amounts for Debt and Equity, $1,297.2 M and $864.8M, respectively. We also use OPG's estimate of the cost of total debt for 2012 at 5.58%. We fill in the Board's mandated return on equity for 2010 of 9.85% as a placeholder for 2012. Next, we use these numbers to calculate the allowed costs of capital in dollars for debt and equity for OPG Hydro and Nuclear. Finally, we include an adjustment for taxes on the equity return to reflect the additional pre-tax equity return necessary to pay corporate income taxes. This value is obtained from EB-2010-0008, Exhibit F4, Tab 2, Schedule 1, Table 1. Since interest is paid from pre-tax earnings, no adjustment is necessary to the cost of debt. Our adjustment is similar to the methodology employed by the AUC in calculating coverage ratios in Decision 2009-216.[61] Summing these three amounts, we compute the total allowed dollar cost of capital for the rate base of OPG Hydro as $185.0 M for 2012.

To obtain a projected Interest coverage ratio for the rate base of OPG Hydro, we divide the total allowed cost of capital (allowed earnings on rate base) of $185.0 M by the total cost of debt of $72.4M to obtain a projected Interest coverage ratio for rate base of 2.56 times for 2012.[62] For 2011, we perform a similar set of calculations in Schedule 5.8B. The projected Interest coverage ratio for OPG Hydro for 2011 is 2.61 times, slightly higher than for 2012.

Schedule 5.8C and 5.8D show similar calculations for OPG Nuclear. Following the same approach, the rate base for this division is determined as 67.47% of the total for each year and the capital structure set as 50% debt and 50% equity. The EBIT coverage ratio for OPG Nuclear is 3.39 and 3.22 times for 2012 and 2011 respectively.

In brief, the analysis in Schedule 5.8 shows that our recommended capital structures imply interest coverage ratios in 2012 and 2011 of respectively 2.56 and 2.61 times for OPG Hydro and respectively 3.39 and 3.22 times for OPG Nuclear. We compare these projected coverage ratios against the average actual coverage ratios for traded utilities in

[61] Alberta Utilities Commission, *Generic Cost of Capital Decision 2009-216*, pages 92- 93.
[62] Schedule 5.8A.

our sample shown as 2.65 times for 2009 in Schedule 5.4. However, we note that the sample includes higher risk unregulated activities as well as goodwill, which could potentially decrease the equity ratio if removed. Comparing this average Interest coverage level to our projection for OPG Hydro first, we conclude that the projected Interest coverage ratio of 2.56 and 2.61 times falls marginally below the middle of the range of observed Interest coverage ratios for our sample of companies with an average bond rating of A (low) or A- that has varying portions of unregulated assets unlike the regulated assets of OPG Hydro. In addition, in light of the Board's and AUC's common position in targeting a rating in the A range, we refine our comparison to the subset of five companies that received a rating of A or A- from at least one bond rating agency: ATCO, Canadian Utilities, Enbridge, Fortis and TransCanada. Of these five companies, three had Interest coverage ratios higher than 2.59 and two had lower levels. Taken in isolation, these two comparisons suggest that there is no reason to believe that OPG Hydro as a stand-alone company with our recommended level of 40% common equity in its capital structure could not achieve a bond rating in the A range. Similarly, for OPG Nuclear, we observe that the projected interest coverage ratios for 2012 and 2011 of respectively 3.39 and 3.22 times far exceeds the sample average and is of the order of magnitude of the A rated companies in our sample, which again includes non-regulated assets. While these higher Interest coverage levels are warranted to some degree by the greater business risk of nuclear operations, our comparisons with levels for publicly traded companies suggests that our recommended equity thickness for OPG Nuclear is conservatively high.

Our conclusion that 40% and 50% equity for Hydro and Nuclear, respectively, are in the A range (A- to A) is consistent with the views of the AUC on its review of Interest (i.e. EBIT) coverage ratios and bond ratings: "The Commission observes from the above table that EBIT coverage ratios of approximately 2.0 to 2.3 appear to be sufficient to obtain credit ratings in the lower A range", and that there is "some indication that the lower end of the EBIT coverage range necessary to maintain a credit rating in the A range is approximately 1.8".[63]

[63] Alberta Utilities Commission, *Generic Cost of Capital Decision 2009-216*, page 92.

Schedules 5.8A to 5.8D extend the ratio analysis to encompass implied Funds From Operations (FFO) coverage and Cash flow to debt ratios again following the practice of the AUC in Decision 2009-216, pages 94 - 95:

> "The Commission has also calculated, and set out in Table 14 below, the ratio of the Funds From Operations (FFO) (net income plus depreciation) divided by debt that would result at different equity ratios assuming an ROE of 8.75 (the 2009 placeholder level) and assuming a range of depreciation rates (as a percentage of invested capital) from 4 percent to 9 percent based on actual depreciations rate results calculated from the 2007 reports on finances and operations. These range from 4.8 percent to 8.5 percent and average 6.0 percent.
>
> Table 14 shows that when the annual depreciation expense as a percentage of invested capital is equal to the utility average of 6 percent, minimum equity ratios in the range of 30 to 36 percent will achieve FFO/Debt percentages of 11.1 to 14.3, which Table 12 shows is associated with credit ratings in the lower A range.
>
> The Commission has calculated, and set out in Table 15, the coverage ratio of the Funds From Operations (net income plus depreciation) divided by interest expense that would result at different equity ratios and depreciation rates assuming an ROE of 8.75 percent (the 2009 placeholder level) and an embedded interest cost of 6.5 percent.
>
> It appears from Table 15 that when the annual depreciation expense as a percentage of investment capital is equal to the utility average of 6 percent, a minimum equity ratio of 33 percent is required to achieve an FFO coverage ratio of at least 3, which Table 7 shows is the minimum FFO coverage associated with credit ratings in the lower A range."

Turning to Schedules 5.8A-5.8D, we see that, compared to the AUC's benchmark of 3 times FFO coverage for credit ratings in the lower A range, the OPG Hydro values are

3.4 and 3.5 times in 2012 and 2011, respectively, and the OPG Nuclear values are 5.5 times and 5.2 times in 2012 and 2011, respectively.

Schedules 5.8A-5.8D also show the Cash flow to debt ratios for both divisions. Compared to the AUC's benchmark of 11.1% to 14.3% for credit ratings in the lower A range, the OPG Hydro values are 11.5% and 11.5% in 2012 and 2011, respectively, and the OPG Nuclear values are 21.6% and 20.9% in 2012 and 2011, respectively.

We qualify this analysis by noting that rating agencies consider other factors in addition to coverage ratios in setting ratings and that bond ratings have shortcomings as a timely measure of risk. Nonetheless, we conclude from our analysis of Interest and FFO coverage and cash flow to debt ratios that, to the extent that such ratios constitute relevant input into bond ratings, the ratios implied by our recommendations are consistent with a bond rating well in the A range.

APPENDIX

BRIEF CURRICULUM VITAE FOR LAWRENCE KRYZANOWSKI

Dr. Lawrence Kryzanowski is currently a Full Professor of Finance and Senior Concordia University Research Chair in Finance (previously Ned Goodman Chair in Investment Finance) at Concordia University. He was until June 2002 the Co-Director of the Concordia-McGill-Xiamen (CMX) Project of the Canada-China University-Industry Partnership Program in Financial Services. He is currently a member of CIRPÉE, a scientific committee member of Institut de Finance Mathématique de Montréal (IFM2), and a member of the scientific advisory board of CEFUP at the University of Porto in Portugal. He is a member of the Board of Governors and its Pension and Benefit Committees at Concordia University, and he was formerly on the Board's Executive Committee. He has been a visiting scholar at the University of British Columbia, a research associate at the University of Rochester, a resident consultant at the Federal Department of Finance, and the first representative of retail investors on the Regulation Advisory Committee (RAC) of Market Regulation Services Inc. (now called IIROC).

Dr. Kryzanowski has extensive experience teaching undergraduates, MBA, MSC and Ph.D. students, and executives for the Institute of Canadian Bankers, Shanghai Banking Institute, CMX, Concordia University, Dalhousie University, McGill University and York University. He has taught "asset allocation and performance measurement" in Concordia's Goodman Institute Program (a private program at the MBA level). This third year course deals with a major component of the level III curriculum of the CFA program. Dr. Kryzanowski has extensive experience in developing or managing the development of instructional textbooks for the Institute of Canadian Bankers (ICB) and the Canadian Securities Institute (CSI), which includes the *Business Solvency Analysis* and *Investment and Portfolio Management* texts for the ICB, and the *Canadian Securities Course* text for the CSI.

Dr. Kryzanowski is an active educator, mentor, consultant and expert witness in financial economics, including investment management, risk pricing and management, and regulation and operations of global financial markets, institutions and participants. He is author or co-author of over 110 refereed journal articles, seven books or monographs, over 195 papers presented at academic conferences and a number of chapter contributions to books of readings/annuals. Dr. Kryzanowski is the first recipient of Prix ACFAS/Caisse de dépôt et placement du Québec, which recognizes an exceptional contribution to research in finance. Dr. Kryzanowski was the inaugural recipient, with co-authors, of the BGI Canada Award and OSFI Award (latter with Dr. Roberts) for excellence in research on capital markets and on regulation of financial institutions, respectively. His 13 other paper awards for co-authored work are from the *Multinational Finance Journal* and various North American academic conferences including the Financial Management Association in 2008. Dr. Kryzanowski is a former Editor of the *Multinational Finance Journal*, co-editor of finance with Dr. Roberts at the *Canadian Journal of Administrative Studies*, and founding chairperson of the Northern Finance Association. Dr. Kryzanowski is currently an Advisory Editor of the *European Journal of Finance*, an Associate Editor of the *International Review of Financial Analysis* and of *Frontier of Finance and Economics*, is member of the Editorial Advisory Boards of *Managerial Finance* and *Studies in Economics and Finance*; and is on the editorial board of *Finance India*.

Dr. Kryzanowski has experience in preparing evidence as an expert witness in utility rate of return applications, stock market insider trading court proceedings, and confidential final offer arbitration hearings for the setting of fair rates for the movement of various products by rail. Together with Dr. Roberts, he prepared a report and briefed counsel on rate of return considerations in the pipeline application in 1997 of Maritimes and Northeast, and prepared evidence on the fair return on equity and the recommended capital structure for the 2001/2002 Distribution Tariff Application (DTA) of ATCO Electric and the 2001/2002 DTA and the 2002 DTA (No. 1250392) of Utilicorp Networks Canada (Alberta) Ltd. before the Alberta Energy and Utilities Board. Together with Dr. Roberts, and on behalf of the Province of Nova Scotia, he provided evidence and testified before the Nova Scotia Utility and Review Board in the matter of Nova Scotia Power Inc. in 2002. Together with Dr. Roberts, and on behalf of the Fédération canadienne de l'entreprise indépendante ("FCEI") / Union des municipalities du Québec ("UMQ") & Option consommateurs ("OC"), he prepared testimony and testified on capital structure and fair return on equity in the matter of Hydro Québec Distribution before the Régie de l'Energie du Québec in 2003. Together with Dr. Roberts, and on behalf of Consumers Group, he prepared testimony and testified in Generic Hearing No. 1271597 before the Alberta Energy and Utilities Board in 2003-2004. Together with Dr. Roberts, and on behalf of the Hydro Communities (Hay River, Yellowknife and Fort Smith), he prepared testimony and testified in NTPC GRA 2006/07 and 2007/08 before the Public Utilities Board of the Northwest Territories in 2007. Together with Dr. Roberts, and on behalf of Pollution Probe, he prepared testimony and testified in EB-2007-0905-OPG-2008-09 Payments before the Ontario Energy Board in 2008. Together with Dr. Roberts, and on behalf of Office of Utilities Consumer Advocate (UCA), he prepared testimony and testified in the Generic proceeding of the Alberta Utilities Commission (AUC), Application No. 1578571, Proceeding ID. 85, 2008-2009.

Dr. Kryzanowski is often sought for his technical ability and advice on various matters in financial economics. He has consulted for the Superintendent of Financial Institutions, Federal Department of Finance, CMHC, CDIC, External Affairs Canada, Canada Investment and Savings, Hydro Quebec, the National Bank, Bombardier, and others.

Dr. Kryzanowski received a B.A. in Economics and Mathematics from the University of Calgary and earned his Ph.D. in Finance at the University of British Columbia.

BRIEF CURRICULUM VITAE FOR GORDON S. ROBERTS

Dr. Gordon S. Roberts is currently CIBC Professor of Financial Services at York University's Schulich School of Business. Prior to joining York University, he was Bank of Montreal Professor of Finance at the School of Business, Dalhousie University. Dr. Roberts has held positions as Visiting Professor and Visiting Scholar at the National Institute for Development Analysis (Bangkok, Thailand), the University of Chile, Tilburg University (the Netherlands), Deakin University (Melbourne, Australia), University of Toronto, University of Arizona, Xiamen University (China) and the University of Zimbabwe.

In addition to teaching undergraduates, MBA and Ph.D. students at these universities, Dr. Roberts has extensive experience in executive teaching for the Kellogg–Schulich Executive MBA Program, the Institute of Canadian Bankers and in the Pension Investment Management School sponsored by the Schulich School jointly with pension consulting firms William Mercer Inc. and Frank Russell.

An active researcher in the areas of corporate finance, bond investments and financial institutions, Dr. Roberts is author or co-author of over forty journal articles and three corporate finance textbooks. In 2000, he shared with Dr. Kryzanowski the OSFI award for excellence in research on the regulation of financial institutions. Dr. Roberts is a former co-editor of finance with Dr. Kryzanowski of the *Canadian Journal of Administrative Studies*. He is a former Associate Editor of the *Journal of Banking and Finance*, and currently serves on the editorial boards of *FINECO* and the *Banking and Finance Law Review*.

Dr. Roberts is experienced in preparing evidence for utility rate of return hearings. From 1995–1997 he submitted prefiled testimony as a Board witness in rate hearings for Consumers' Gas. In 1996, he served as an expert advisor to the Ontario Energy Board in its Diversification Workshop. In 1997, he co-prepared (with Dr. Kryzanowski) a report for the Calgary law firm, MacLeod Dixon, on rate of return considerations in the pipeline application by Maritimes and Northeast. With Dr. Kryzanowski, he filed evidence on three electricity regulatory matters in Alberta in 2001, evidence on regulatory matters before the Alberta Energy and Utilities Board and the Nova Scotia Utility and Review Board in 2002, evidence on regulatory matters dealing with Hydro Quebec Distribution in 2003, evidence in Generic Hearing No. 1271597 before the Alberta Energy and Utilities Board in 2003-2004, evidence in NTPC GRA 2006/07 and 2007/08 before the Public Utilities Board of the Northwest Territories in 2007, and evidence in EB-2007-0905-OPG- 2008-09 Payments before the Ontario Energy Board in 2008.

Often sought for his advice on financial policy, Dr. Roberts has consulted for the Superintendent of Financial Institutions, the federal Department of Finance, Canada Investment and Savings, Canada Mortgage and Housing Corporation, and Canada Deposit Insurance Corporation, among others.

Dr. Roberts received a B.A. in Economics from Oberlin College and earned his Ph.D. at Boston College. He has been listed in the Canadian Who's Who since 1990.

Schedule 2.1

This table summarizes the forecasts of a sample of professionals for the yields and total returns on a number of asset classes, and the Market Equity Risk Premium or MERP implied by the total returns on stock indexes and long government bonds.

Index	Sample size	Percentiles				
		10th	25th	50th (median)	75th	90th
Panel A: Distribution of short-term (2010) return expectations						
30-yr Canada Bonds	30	3.7%	4.0%	4.3%	4.5%	4.9%
S&P/TSX Composite Index	37	4.0%	7.0%	10.0%	12.0%	20.0%
S&P 500 Index	34	2.0%	7.0%	9.0%	14.0%	15.7%
Implied MERP S&P/TSX		0.3%	3.0%	5.7%	7.5%	15.1%
Panel B: Distribution of mid-term (2011-2014) return expectations						
30-yr Canada Bonds	28	4.5%	4.5%	5.0%	5.4%	6.5%
S&P/TSX Composite Index	31	6.0%	7.0%	8.0%	10.0%	10.0%
S&P 500 Index	29	5.0%	7.0%	8.0%	10.0%	12.0%
Implied MERP S&P/TSX		1.5%	2.5%	3.0%	4.6%	3.5%
Panel C: Distribution of long-term (2015-2024) return expectations						
30-yr Canada Bonds	25	4.3%	4.9%	5.3%	5.8%	6.0%
S&P/TSX Composite Index	30	6.0%	7.0%	8.0%	8.0%	9.5%
S&P 500 Index	28	5.0%	7.0%	8.0%	8.8%	10.0%
Implied MERP S&P/TSX		1.7%	2.1%	2.7%	2.2%	3.5%

Source: Towers Watson, *Economic Expectations 2010*, 29th Annual Canadian Survey, page 9. Survey is described as follows on page 2:

> "The results of Towers Watson's 29th Annual Canadian Survey of Economic Expectations (SEE) are based on the projections of the country's leading business economists, strategists and portfolio managers from more than 50 organizations, such as chartered banks, investment management firms and other corporations. In November 2009, participants were asked to provide forecasts for 24 economic and financial indicators as well as views on pension investment strategies."

Schedule 2.2

This table reports the Market Equity Risk Premiums (MERPs) over bonds reported by Credit Suisse for Canada and the U.S. over the last 10 to 110 years.

Period	Canadian MERP	U.S. MERP
2000-2009	-2.0%	-7.4%
1985-2009	-0.9%	0.7%
1960-2009	1.5%	2.3%
1900-2009	3.7%	4.2%

Source: Credit Suisse, *Credit Suisse Global Investment Returns Yearbook 2010* (Research Institute, February 2010). The MERPs for Canada are found in Figure 2, page 30, and those for the U.S. in Figure 2, page 46. The underlying data are available through Morningstar Inc.

Schedule 3.1

The criteria and rating scale used by BCG when adjusting the firm-level cost of capital to obtain a divisional cost of capital.

Criteria	Values				
	1 or low risk	2	3	4	5 or high risk
Control	Low external influence on return				High external influence on return
Market	Stable, without cycles				Dynamic, cyclical
Competitors	Few, constant market shares				A lot, variable market shares
Products/concepts	Long life cycle, no substitutes				Short life cycle, substitutes
Barriers to entry	High				Low
Cost structure	Low fixed cost				High fixed cost

Schedule 3.2

The criteria and rating scale used by Fuqua Industries when adjusting its firm-level cost of capital to obtain divisional costs of capital.

Criteria	Values				
	1 or low risk	2	3	4	5 or high risk
Customer base dispersion	Many small				A few big
Operational flexibility	High				Low
Loss of asset value	Low				High
Cyclical business	Non-cyclical				Cyclical
Seasonal business	Non-seasonal				Seasonal
Government involvement	Low				High
Changes in technology	Scarce				Often
Market position	Good				Bad
Management	Highly qualified				Little experience
Brand distinction	High				Low
Unionisation	Low				High
Environmental impact	Low				High
Availability of resources	High				Low
Backlogs	High				Low

Schedule 3.3

Proportion of electricity that is generated by various fuel inputs (or of generating capacity) for various countries is presented in this table. The data source is http://www.world-nuclear.org. "Fossil fuel" is represented by the merger of the "Gas" and "Coal" cells in the table.

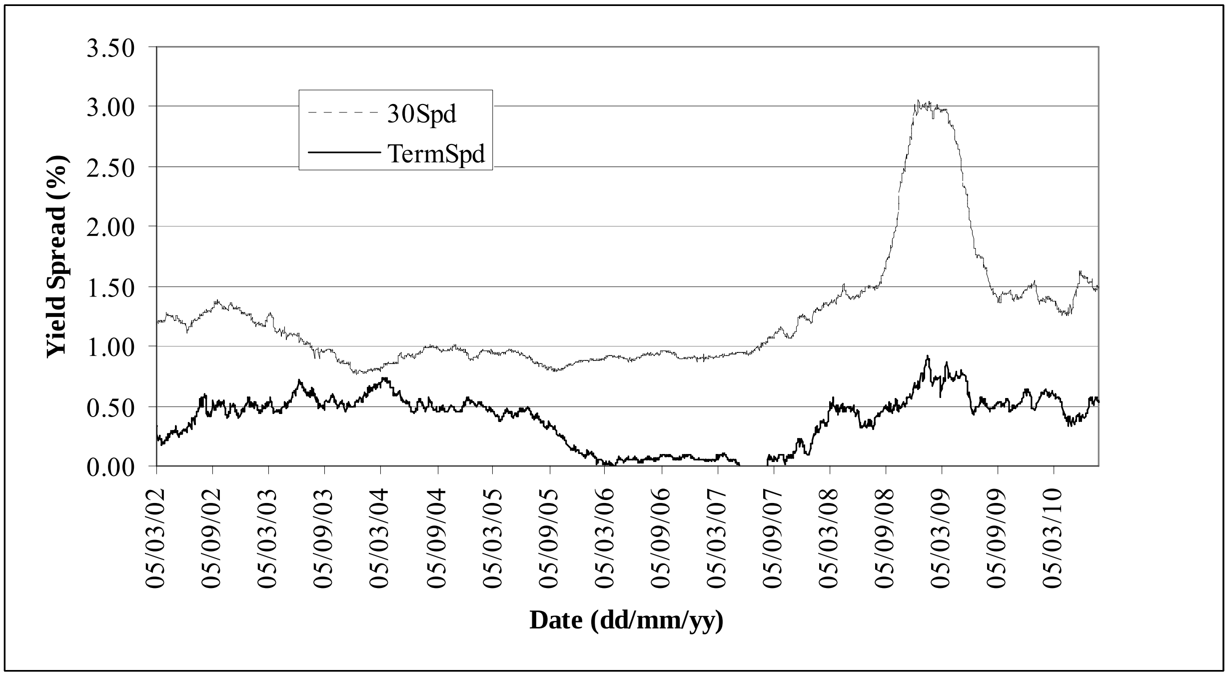
	Nuclear	Hydro	Gas	Coal	Geothermal	Wind	Other	Year
Australia		7%	12%	80%			1%	2006
Denmark			18	51		18	13%	2007
Finland	27.8	15.5						2009
France	>75%							2009
Germany	≈25% ?		12	≈50		6		2007
New Zealand	0	54	27	7	8	2	2.0	2007
*Sweden	42	46.9				1.4	9.7	2008
*Switzerland	43							2007
United Kingdom	19		36	38				2006
USA	20	6	22	49				2008

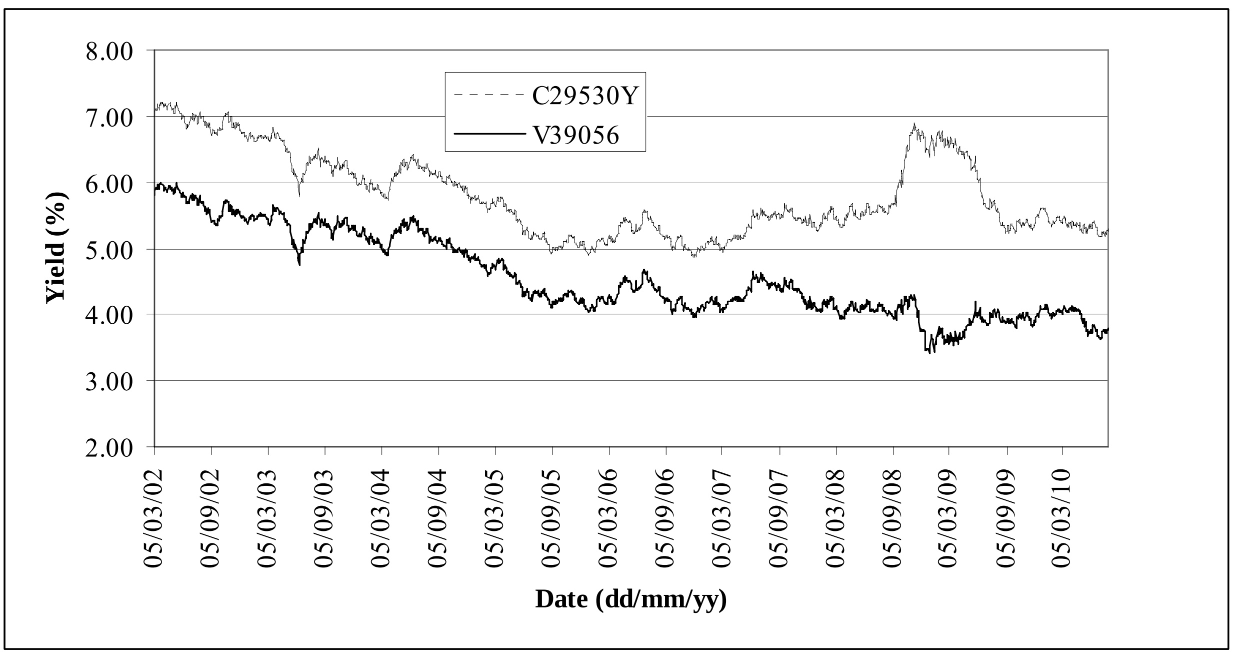
[**Denmark**]: Parliamentary resolution exists against building nuclear power plants. Power imported from Sweden (half nuclear & half hydro) and Germany (largely brown coal & nuclear). Has amongst highest electricity prices in world.
[**Finland**]: Four nuclear reactors provide nearly 30% of its electricity. Fifth reactor is under construction with two more planned. Much of the consumed electricity is either imported (15.3% net in 2009) or generated from imported fuels (mostly coal and some gas). Coal is imported from Russia and Poland, all gas comes from Russia, and 14% of 2009 electricity was from Russia. Two reactors owned by TVO (27% owned by Fortum; supplies generated electricity to shareholders at cost) and two by Fortum Corporation, a public listed energy company which is 51% owned by the Finnish government.
[**France**]: France derives over 75% of its electricity from nuclear energy due to a longstanding policy based on energy security. France is the world's largest net exporter of electricity to Belgium, Germany, Italy, Spain, Switzerland and the U.K. due to its very low cost of generation. France has 59 nuclear reactors operated by Electricite de France (EdF), which is world's largest utility. EdF has two subsidiaries in regulated sector (RTE EdF Transport, and ERdF, comprising the deregulated activities (mainly Generation and Supply), network activities (Distribution and Transmission) and island activities). EDF had a debt ratio [i.e. net financial debt / (net financial debt + equity including minority interests)] of 49.5% and 56.5% in 2008 and 2009, respectively, and a ratio of FFO to EBITDA of 1.7 and 2.4 in 2008 and 2009, respectively. As of December 31, 2009, it long-term debt ratings were: A+, stable outlook, S&P and Fitch; and Aa3, stable outlook, Moody's. [Management Report EdF 2009 Financial Report, page 178. Available at: http://www.edf.com/html/RA2009/uk/pdf/EDF_RFI09_full_va.pdf]. The French government partially floated shares of the company on Paris Bourse in November 2005, although it retains ≈ 85% ownership as of the end of 2008.
[**Germany**]: Germany obtains one quarter of its electricity from nuclear energy from 17 operating nuclear power reactors that represent 20.6% of installed capacity. The new 2009 government in 2009 put the phase-out of nuclear energy on hold. Germany is one of the biggest importers of gas, coal and oil worldwide. Construction and operation licensing responsibility of all nuclear facilities is shared between the federal and Länder governments (essential veto power to both). Pursuant to the Energy Law of 2005, electricity rate regulation was abandoned on July 1, 2007 (E.ON AG, Form 20-F, US SEC, page 103. Available at: http://www.eon.com/de/downloads/eon_form20f_2005.pdf).
[**New Zealland**]: One of the few developed countries not using electricity (indigenous or imported) from nuclear energy. 1.8% of other is from biomass. Growth in demand since 1990 has been mostly met by gas-fired plants. State-owned Meridian Energy, which is the largest generator in New Zealand, accounting for 27% of production in 2008. Contact Energy is the second largest generator in New Zealand and in 2008 accounted for 24% of the country's electricity generation. The company was split from the state-owned Electricity Corporation of New Zealand (ECNZ) in 1996 and is 51% owned by Australian company Origin Energy. State-owned Genesis Energy is the third largest generating company in New Zealand (after Meridian Energy and Contact Energy) supplying about 20% of the country's electricity.

[**Sweden**]: Parliament voted in June 2010 to repeal the phase out of nuclear power. Has 10 operating nuclear power reactors. The 9.7% under other is fossil fuel. Unlike retail prices, transmission and distribution of electricity are subject to regulation as they are considered to be natural monopolies (E.ON AG, Form 20-F, US SEC, page 103. Available at: http://www.eon.com/de/downloads/eon_form20f_2005.pdf). Sweden deregulated its electricity market on January 1, 1996. With deregulation in 1996, Sweden together with Norway formed the wholesale market Nord Pool, which now also includes Denmark and Finland. Nord Pool sets the price of electricity every hour, based on supply and demand bids.
[**Switzerland**]: 2007 electricity production was mostly from nuclear and hydro, with imports from France and Germany and exports to Italy. Has 5 nuclear reactors generating over 40% of its electricity. In 2009 ATEL (utility consortium) merged with EOS to form Alpiq Holding SA, the country's largest power utility. Early in 2009 EdF increased its stake in Alpiq to 25%. One third of Alpiq's electricity is nuclear. Does not appear to have traditional rate regulation.
[**United Kingdom**]: The UK has 19 reactors generating up to 20% of its electricity and all but one of these will be retired by 2023. The first of some 16 new-generation plants are expected on line about 2017. Due to problems with some old plants, nuclear dropped to 15% in 2007 and 13.5% in 2008. About 3% of domestic demand is from imports of French nuclear power. Thus, overall nuclear in UK consumption is normally about 22%.
[**USA**]: World's largest producer of nuclear power, accounting for more than 30% of worldwide nuclear electricity generation. The country's 104 nuclear reactors in 31 states account for over 20% of total electrical output. Following a 30-year period with few new reactors being built, 4-6 new units are expected by 2018. The first of those resulting from 16 licence applications to build 24 new nuclear reactors made since mid-2007 (changed government policy). The $32 billion merger of Unicom and PECO in 2000 to form Exelon created the largest nuclear power producer in the USA, and the third largest in the world. Exelon has 10 operating nuclear plants with 17 reactors that generated 20% of U.S. nuclear production in 2007. Since 1999, there have been many purchases of existing nuclear power plants.

Schedule 4.1

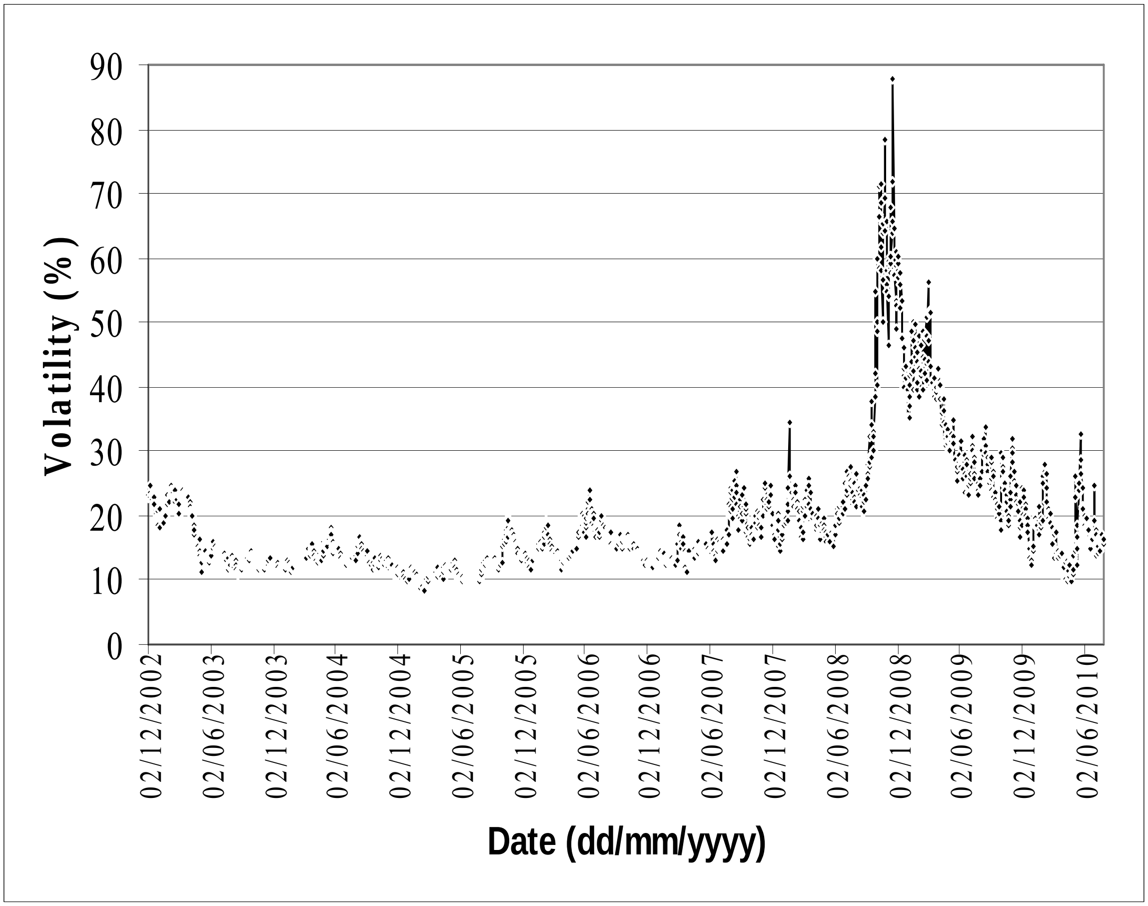
The top figure plots the yield spread (30Spd) between two series, 30-year A-rated Canadian utility bonds (Bloomberg Series C29530Y) and the 30-year benchmark Government of Canada bond (Cansim V39056), and the term spread (TermSpd) between 30- and 10-year Canada's (i.e. Cansim V39056 minus Cansim V39055). The bottom figure plots the yield on 30-year A-rated Canadian utility bonds (Bloomberg Series C29530Y) and the 30-year benchmark Government of Canada bond (Cansim V39056).





Schedule 4.2

This figure plots the expected volatility of the Canadian market as proxied by the S&P/TSX Composite Index. The values are those reported by the Montreal Exchange in its MVX Index on a daily basis from 02122002 (December 2, 2002) to 28072010 (July 28, 2010).



Schedule 5 .1

Electric Utilities Business Risk Rating

Risk	Transmission		Distribution	
Market				
Competition/ demand	Low	1	Low-moderate	2
Credit	Low	1	Low-moderate	2
Operational				
Operating Leverage	Low	1	Moderate	3
Technology	Low	1	Low	1
Capacity	Low	1	Low	1
Asset retirement/construction	Low	1	Low	1
Deferral accounts	Low	1	Low	1
Regulatory				
Primary regulation	Low	1	Low	1
Environmental/safety	Low	1	Low	1
Overall	**Low**	**1**	**Low-moderate**	**1.4**

Schedule 5.1 Continued

Electric Utilities Business Risk Rating

Risk	OPG Hydro		Integrated*
Market			
Competition/demand	Low	1	1.3
Credit	Low	1	1.3
Operational			
Operating Leverage	Moderate	3	2.6
Technology	Low-moderate	2	1.5
Capacity	Moderate	3	2
Asset retirement/construction	Low-moderate	2	1.5
Deferral accounts	Low	1	1
Regulatory			
Primary regulation	Low	1	1
Environmental/safety	Low-moderate	2	1.5
Overall	**Low-moderate**	**1.8**	**1.5**

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* Weighted average of transmission 20%, distribution 30% and generation 50% based on Emera 2009 rounded, *Annual Report*, Note 16.

Schedule 5.1 Concluded

Electric Utilities Business Risk Rating

Risk	OPG Nuclear	
Market		
Competition	Low	1
Credit	Low	1
Operational		
Operating Leverage	Moderate-high	4
Technology	Moderate-high	4
Capacity	Moderate	3
Asset retirement/construction	Moderate	3
Deferral accounts	Moderate	3
Regulatory		
Primary regulation	Low	1
Environmental/safety	Moderate	3
Overall	**Moderate**	**2.6**

Schedule 5.2

Senior Unsecured Debt Ratings for the Sample of Canadian Utilities

Corporate Issuer	DBRS		Standard & Poor's Rating
	Rating	Debt Rated	
ATCO Ltd.	A (low)	Corporate	A
Canadian Utilities	A	Corporate	A
Emera Incorporated Nova Scotia Power	BBB (high) A (low)	MTN	BBB BBB+
Enbridge Gas Distribution Inc. / Enbridge Inc.	A	MTN and Unsecured Debentures	A-
Fortis Inc. Fortis Alberta Fortis BC Newfoundland Power Maritime Electric	BBB (high) A (low) BBB (high) A --	Unsecured Debentures 1st Mortgage Bonds Corporate	A- A- -- -- BBB+
Pacific Northern Gas	BBB (low)	Senior Secured	--
TransAlta Corp.	BBB	Senior Unsecured Debentures	BBB
TransCanada Pipelines	A	Senior Unsecured Debentures	A-
Median	**A (low)**		**A-**

Sources: Dominion Bond Rating Service website: www.dbrs.com, Standard & Poor's website: www.standardandpoors.com, August 3, 2010 and Maritime Electric Company Ltd., Testimony of Kathleen McShane, April 2010.

Schedule 5.3

Capital Structure for Utilities 2007-2009 (percentage of long-term capital).

	Long term debt and debentures			Preferred Shares			Common Equity		
	2007	2008	2009	2007	2008	2009	2007	2008	2009
ATCO LTD.	68.25%	66.67%	64.03%	0.00%	0.00%	0.00%	31.75%	33.33%	35.97%
CANADIAN UTILITIES LTD.	49.47%	49.10%	47.43%	10.04%	9.42%	10.77%	40.49%	41.48%	41.79%
EMERA INC.	57.77%	59.74%	62.02%	0.00%	0.00%	0.00%	42.23%	40.26%	37.98%
ENBRIDGE INC.	63.65%	63.73%	64.12%	0.86%	0.69%	0.62%	35.49%	35.59%	35.27%
FORTIS INC.	64.48%	60.53%	61.25%	1.59%	4.04%	3.80%	33.93%	35.43%	34.95%
PACIFIC NORTHERN GAS LTD.	45.78%	45.65%	44.25%	3.14%	3.06%	3.08%	51.07%	51.28%	52.67%
TRANSALTA CORP.	42.59%	45.80%	60.10%	0.00%	0.00%	0.00%	57.41%	54.20%	39.90%
TRANS CANADA PIPELINES LTD.	59.25%	57.50%	53.28%	0.00%	0.00%	1.60%	40.75%	42.50%	45.12%
Average	**56.41%**	**56.09%**	**57.06%**	**1.95%**	**2.15%**	**2.48%**	**41.64%**	**41.76%**	**40.46%**

Source: Annual reports and Financial Post Advisor

Schedule 5.4

Coverage ratios, earned ROEs for selected utilities 2007-2009

Utility	Interest Coverage			Cash Flow to Debt %			ROE %		
	2007	**2008**	**2009**	**2007**	**2008**	**2009**	**2007**	**2008**	**2009**
ATCO LTD.	3.31	3.52	3.49	23.71	25.03	23.13	16.69	16.23	14.98
CANADIAN UTILITIES LIMITED	3.25	3.41	3.52	22.46	23.70	21.04	15.96	15.67	16.10
EMERA INCORPORATED	2.54	2.24	2.29	16.85	8.76	10.57	10.93	9.92	11.52
ENBRIDGE INC.	2.37	3.69	3.36	13.19	10.50	14.21	14.53	22.69	22.82
FORTIS INC.	1.78	1.86	1.85	6.37	11.33	10.22	9.96	8.68	8.40
PACIFIC NORTHERN GAS LIMITED	1.75	2.02	2.56	- 3.12	21.04	24.46	5.01	6.79	7.32
TRANSALTA CORPORATION	3.17	2.68	2.06	33.75	36.97	13.06	13.07	9.77	6.66
TRANS CANADA CORPORATION	2.60	2.76	2.08	18.62	14.10	14.69	13.99	12.70	9.77
Average	2.60	2.77	2.65	16.48	18.93	16.42	12.52	12.81	12.20

Source: Financial Post Advisor.

Schedule 5.5

Allowed vs. Actual Rates of Return on Equity for 2009

Utility	Allowed Return (%)	Actual ROE for Consolidated Company (%)
ATCO LTD.		14.98
ATCO ELECTRIC TRANSMISSION	9.00	
ATCO ELECTRIC DISTRIBUTION	9.00	
ATCO GAS	9.00	
ATCO PIPELINES	9.00	
CANADIAN UTILITIES LIMITED		
EMERA (NOVA SCOTIA POWER)	9.35	11.52
ENBRIDGE GAS DISTRIBUTION	8.39	22.82
FORTIS INC.		8.40
ALBERTA	9.00	
BRITISH COLUMBIA	8.87	
MARITIME ELECTRIC		
NEWFOUNDLAND POWER	8.95	
PACIFIC NORTHERN GAS LIMITED	9.12	7.32
TRANSALTA CORPORATION	--	6.66
TRANS CANADA PIPELINES LTD.	8.57	9.77
Average	**8.95**	**11.64**

Sources: Schedule 5.4, Board decisions, Ms. McShane's Schedule 2, page 1, Evidence in Maritime Electric Hearing, April 2010. TransAlta has no allowed return since this company is not regulated.

Schedule 5.6

Allowed Common Equity Ratios

Utility	Allowed	Decision
ATCO LTD.		
ATCO ELECTRIC		
TRANSMISSION	36.00	EUB 2009-216,
DISTRIBUTION	39.00	
ATCO GAS	39.00	
ATCO PIPELINES	43.00	
CANADIAN UTILITIES LIMITED		
ENBRIDGE GAS DISTRIBUTION	36.00	OEB RP-2002-0158; EB-2006-0034; EB-2007-0615 NSUARB 2006 NSUARB 23, 2008 NSUARB 140
EMERA (NOVA SCOTIA POWER)	37.50	
FORTIS INC.		
ALBERTA	41.00	EUB 2009-216
BRITISH COLUMBIA	40.00	G-52-05; G-158-09
MARITIME ELECTRIC	40.50	UE-09-02
NEWFOUNDLAND POWER	44.14	PU43 (2009)
PACIFIC NORTHERN GAS LIMITED	40.00	G-55-07, L-55-08
TRANSALTA CORPORATION	45.00	U99099
TRANS CANADA PIPELINES LTD.	40	NEB letter 12-09
Average	**40.09**	

Source: Board decisions and Ms. McShane's Schedule 2, page 1, Evidence in Maritime Electric Hearing, April 2010 .

Schedule 5.7

Electric Utilities Business Risk Rating and Capital Structures

	Transmission	Distribution	OPG Hydro	Integrated	OPG Nuclear	OPG Regulated
Business risk[a]	L 1	L-M 1.4	L-M 1.8	L-M 1.5	M 2.6	M 2.3
Equity Component Deemed by Regulators						
AUC 2009	35%	39%				
NSUARB 2007				37.5%		
OEB 29006, 2007	40%	40%				47%
Fortis Alberta		37%				
Fortis BC				**40%**		
Maritime Electric				40.50%		
Newfoundland Power				44.14%[64]		
Recommended by Drs. Kryzanowski And Roberts Prior Evidence	33%[65]	35%[66]		35%[67] 42%[68]		
For OPG			**40%**		**50%**	**47%**[69]

[a]L refers to low business risk; L-M refers to low to medium business risk; and M refers to medium business risk. L 1 refers to low business risk based on a business risk rating of 1 to 5 where 5 is the highest numerically business risk rating.

[64] Integrated company, buys 90% of power from Newfoundland and Labrador Hydro.
[65] Generic hearing, Alberta, 2009.
[66] Generic hearing, Alberta, 2009.
[67] NSPI 2002.
[68] Northwest Territories Power Corporation 2007, included business risk premium for size and isolation.
[69] 6,606 regulated MW nuclear (66.47%), 3,332 MW hydro (33.53%).

Schedule 5.8A

This schedule uses OPG' s projections of EBITDA, Taxes, Capitalization and Costs of Equity and Debt to calculate its Interest Coverage Ratio, its FFO Coverage Ratio and its Cash Flow to Debt Ratio for OPG's Hydro Assets for 2012. 'Interest Coverage Ratio' is calculated by dividing 'Allowed $ return on rate base' or 'EBIT' by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'FFO Coverage Ratio' is 'EBITDA (i.e. Funds From Operations or FFO or EBIT as given by 'Allowed $ return on rate base' plus Depreciation & Amortization) divided by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'Cash Flow to Debt Ratio' is calculated by dividing 'Earnings After Tax' + 'Depreciation & Amortization' by 'Total Debt'.

Capital Structure	Principal	Component (%)	Cost (%)	Cost of Capital ($)
Total debt (% of total)	1,297.23	60.00%	5.58%	72.39
Common equity (% of total)	864.82	40.00%	9.85%	85.18
Adjustment for taxes on equity return[a]				27.40
Rate base financed[b]	2,162.05	100.00%		
Allowed $ return on rate base (EBIT)				184.97
Depreciation & Amortization[c]				63.80
EBITDA				248.77

Interest Coverage Ratio (times)	2.56
FFO Coverage Ratio (times)	3.44
Cash Flow to Debt Ratio (%)	11.48

Notes:

[a] Corporate income tax from EB-2010-0008, Exhibit F4, Tab 2, Schedule 1, Table 1, Filed: 2010-05-26.

[b] Total rate base financed by capital structure of 6448.1 million from EB-2010-0008, Exhibit C1, Tab 1, Schedule 1, Table 1, Filed: 2010-05-26, multiplied by 33.53%.

[c] Depreciation & Amortization of 63.4 million plus 0.4 million from EB-2010-0008, Exhibit B2, Tab 4, Schedule 1, Table 2. Filed: 2010-05-26.

Schedule 5.8B

This schedule uses OPG' s projections of EBITDA, Taxes, Capitalization and Costs of Equity and Debt to calculate its Interest Coverage Ratio, its FFO Coverage Ratio and its Cash Flow to Debt Ratio for OPG's Hydro Assets for 2011. 'Interest Coverage Ratio' is calculated by dividing 'Allowed $ return on rate base' or 'EBIT' by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'FFO Coverage Ratio' is 'EBITDA (i.e. Funds From Operations or FFO or EBIT as given by 'Allowed $ return on rate base' plus Depreciation & Amortization) divided by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'Cash Flow to Debt Ratio' is calculated by dividing 'Earnings After Tax' + 'Depreciation & Amortization' by 'Total Debt'.

Capital Structure	Principal	Component (%)	Cost (%)	Cost of Capital ($)
Total debt (% of total)	1,271.74	60.00%	5.58%	70.96
Common equity (% of total)	847.83	40.00%	9.85%	83.51
Adjustment for taxes on equity return[a]				30.6
Rate base financed[b]	2,119.57	100.00%		
Allowed $ return on rate base (EBIT)				185.07
Depreciation & Amortization[d]				63.20
EBITDA				248.27

Interest Coverage Ratio (times)	2.61
FFO Coverage Ratio (times)	3.50
Cash Flow to Debt Ratio (%)	11.54

Notes:

[a] Corporate income tax from EB-2010-0008, Exhibit F4, Tab 2, Schedule 1, Table 1, Filed: 2010-05-26.

[b] Total rate base financed by capital structure of 6321.4 million from EB-2010-0008, Exhibit C1, Tab 1, Schedule 1, Table 2, Filed: 2010-05-26, multiplied by 33.53%.

[c] Depreciation & Amortization of 62.9 million plus 0.3 million from EB-2010-0008, Exhibit B2, Tab 4, Schedule 1, Table 2. Filed: 2010-05-26.

Schedule 5.8C

This schedule uses OPG' s projections of EBITDA, Taxes, Capitalization and Costs of Equity and Debt to calculate its Interest Coverage Ratio, its FFO Coverage Ratio and its Cash Flow to Debt Ratio for OPG's Nuclear Assets for 2012. 'Interest Coverage Ratio' is calculated by dividing 'Allowed $ return on rate base' or 'EBIT' by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'FFO Coverage Ratio' is 'EBITDA (i.e. Funds From Operations or FFO or EBIT as given by 'Allowed $ return on rate base' plus Depreciation & Amortization) divided by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'Cash Flow to Debt Ratio' is calculated by dividing 'Earnings After Tax' + 'Depreciation & Amortization' by 'Total Debt'.

Capital Structure	**Principal**	**Component (%)**	**Cost (%)**	**Cost of Capital ($)**
Total debt (% of total)	2,175.27	50.00%	5.58%	121.38
Common equity (% of total)	2,175.27	50.00%	9.85%	214.26
Adjustment for taxes on equity return[a]				75.90
Rate Base financed[b]	4,350.53	100.00%		
Allowed $ return on rate base (EBIT)				411.54
Depreciation & Amortization[d]				255.60
EBITDA				667.14

Interest Coverage Ratio (times)	3.39
FFO Coverage Ratio (times)	5.50
Cash Flow to Debt Ratio (%)	21.6

Notes:
[a] Corporate income tax from EB-2010-0008, Exhibit F4, Tab 2, Schedule 1, Table 3, Filed: 2010-05-26.
[b] Total rate base financed by capital structure of 6448.1 million from EB-2010-0008, Exhibit C1, Tab 1, Schedule 1, Table 1, Filed: 2010-05-26, multiplied by 67.47%.
[c] Depreciation & Amortization of 239.5 million plus 16.1 million from EB-2010-0008, Exhibit B3, Tab 4, Schedule 1, Table 1. Filed: 2010-05-26.

Schedule 5.8D

This schedule uses OPG' s projections of EBITDA, Taxes, Capitalization and Costs of Equity and Debt to calculate its Interest Coverage Ratio, its FFO Coverage Ratio and its Cash Flow to Debt Ratio for OPG's Nuclear Assets for 2011. 'Interest Coverage Ratio' is calculated by dividing 'Allowed $ return on rate base' or 'EBIT' by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'FFO Coverage Ratio' is 'EBITDA (i.e. Funds From Operations or FFO or EBIT as given by 'Allowed $ return on rate base' plus Depreciation & Amortization) divided by 'Cost of Capital $' for 'Total Debt' (i.e. interest expense). 'Cash Flow to Debt Ratio' is calculated by dividing 'Earnings After Tax' + 'Depreciation & Amortization' by 'Total Debt'.

Capital Structure	Principal	Component (%)	Cost (%)	Cost of Capital ($)
Total debt	2,132.52	50.00%	5.58%	118.99
Common equity	2,132.52	50.00%	9.85%	210.05
Adjustment for taxes on equity return[a]				53.9
Rate base financed[b]	4,265.05	100.00%		
Allowed $ return on rate base (EBIT)				382.95
Depreciation & Amortization[d]				234.50
EBITDA				617.45

Interest Coverage Ratio (times)	3.22
FFO Coverage Ratio (times)	5.19
Cash Flow to Debt Ratio (%)	20.85

Notes:
[a] Corporate income tax from EB-2010-0008, Exhibit F4, Tab 2, Schedule 1, Table 3, Filed: 2010-05-26.
[b] Total rate base financed by capital structure of 6321.4 million from EB-2010-0008, Exhibit C1, Tab 1, Schedule 1, Table 2, Filed: 2010-05-26, multiplied by 67.47%.
[c] Depreciation & Amortization of 218.9 million plus 15.6 million from EB-2010-0008, Exhibit B3, Tab 4, Schedule 1, Table 1. Filed: 2010-05-26.