CAPITAL STRUCTURE AND RETURN ON EQUITY METHODOLOGY

1.0 PURPOSE

The purpose of this evidence is to provide an overview of OPG's proposals on capital structure and return on capital. This evidence describes the methodology OPG has used to determine its capital structure and return on common equity for the fiscal years from 2005 - 2009 inclusive.

2.0 CAPITAL STRUCTURE

For the 2005 - 2007 fiscal years OPG has applied the capital structure (45 percent equity and 55 percent debt) that was reflected in information provided by OPG to the Province for use in setting the interim period payment amounts.

For the 2008 and 2009 fiscal years OPG proposes to adopt the capital structure and cost of capital recommendations of Foster Associates, Inc. ("Fosters"). Fosters are capitalization and cost of capital experts that OPG engaged to determine the appropriate capital structure and cost of equity for OPG's regulated operations. The study prepared by Fosters is filed in Ex. C2-T1-S1.

Fosters' recommended methodology is consistent with the approach applied by most of Canada's energy industry regulators. The key principles underlying this methodology are that:

- OPG's regulated operations should be treated for regulatory purposes as if they were operating on a "stand-alone" basis.
- OPG's deemed capital structure should be applied to the financing of assets that are devoted to the provision of regulated service, i.e., its rate base.
- OPG's deemed capital structure should only reflect the business risks of the regulated operations.

OPG is seeking a capital structure comprised of 57.5 percent common equity and 42.5 percent debt; the mid-point of the range of 55 percent to 60 percent common equity recommended by Fosters. The common equity component was established by Fosters assuming a return on common equity of 10.5 percent, which is the return determined by Fosters for a “benchmark utility”[1]. This common equity component recommendation reflects OPG’s higher comparative business risks relative to that of a “benchmark utility”.

Fosters’ analysis of the significant business risks associated with OPG’s regulated operations is provided in Ex. C2-T1-S1. This assessment of the business risks associated with the regulated operations is accepted by OPG as a fair and reasonable assessment of these risks. OPG is seeking a regulated capital structure and return on common equity that reflects the business risks associated with its regulated operations.

3.0 RETURN ON COMMON EQUITY

OPG’s return on equity for 2005, 2006 and 2007 is based on the segmented financial information provided in its 2006 and 2007 audited financial statements, adjusted to reflect the impact of regulation. OPG does not determine a stand-alone return on equity for its regulated operations for the purpose of operating its business, financial accounting or tax filing purposes. It is determined as an aid to assessing the adequacy of OPG’s interim payment amounts.

To determine a return on equity for 2005, 2006 and 2007 that is consistent with the return on equity proposed for its test period, OPG used the accounting earnings before interest and income taxes amounts reflected in its 2006 and 2007 audited financial statements for the regulated hydroelectric business segment and the regulated nuclear business segment as the starting point. The difference between accounting earnings before interest and income taxes and OPG’s return on equity for its regulated operations is attributable to three sources: interest, income taxes, and differences between accounting and regulatory earnings. These

[1] The “benchmark utility” is not a specific utility and hence reflects no specific business or financial risk characteristics, but rather the composite of the business and financial risks faced by the proxy utilities used to establish the fair return. The benchmark utility is, however, a relatively low risk A rated utility.

adjustments and the impact on OPG's return on equity in each of 2005, 2006 and 2007 are described in Ex. C1-T2-S1.

As discussed in section 2, Fosters has recommended a 10.5 percent return on common equity in the context of a 57.5 percent common equity ratio. OPG has accepted that recommendation for 2008 and 2009[2]. OPG's proposed capital structure of 42.5 percent debt and 57.5 percent common equity and OPG's proposed rate of return on equity of 10.5 percent are sufficient to enable OPG to maintain its financial integrity and attract capital on reasonable terms.

OPG also sees merit in the recommendation of Fosters to adopt an automatic adjustment mechanism to adjust the rate of return on common equity in future periods. The OEB's EB-2006-0064 report established the regulatory methodology for setting payment amounts for OPG's prescribed generation assets. The OEB stated that OPG will be subject to a series of limited issues cost of service proceedings intended to set the cost base upon which to develop an incentive regulation approach in the future. While OPG's return on equity is an issue in the current hearing, it may not be an issue in these future limited issues hearings. An automatic adjustment mechanism will allow the return on equity to be adjusted to reflect changing market conditions without the requirement to include it as an issue in subsequent limited issues proceedings.

Fosters endorsed the use of the return on equity adjustment mechanism approved by the OEB to establish the cost of capital to be used in adjusting the annual revenue requirement for Ontario's electric distribution facilities for 2007 and beyond. The Report of the Board on

[2] An update was not prepared by Fosters. Fosters reviewed the consensus forecast of 10-year Canada bond yields and the recent spread with 30-year long Canada Bonds and concluded that no change to the ROE or capital structure recommendation was warranted at this time.

Cost of Capital[3] (OEB's Cost of Capital Report) states that an adjustment of 75 basis points in return on equity is required for every one percentage point change in forecast 30-year Canada bond yields. Fosters stated that the OEB's formula is a reasonable reflection of the relationship between the cost of equity and interest rates. OPG supports the application of the OEB's methodology for adjusting its rate of return on equity in future proceedings and asks that the OEB approve an adjustment formula for use in these proceedings.

Fosters also recommended that the formula be reviewed if forecast long Canada bond yields fall below three percent or exceed eight percent, as those extremes could signal a material change in the capital market environment. OPG agrees that the automatic adjustment mechanism should be reviewed in the event capital market conditions experience significant change, and therefore recommends that the OEB review the formula in the event that forecast long Canada bond yields fall below three percent or exceed eight percent.

In addition, Fosters recommended that OPG have the ability to seek a review of the automatic adjustment formula if its ability to attract capital on reasonable terms is at risk. In the alternative, OPG should be able to seek a review of its deemed capital structure should the business risks of its regulated operations change materially or if its access to capital is threatened. While OPG is of the view that the events described above are unlikely, it believes that the automatic adjustment mechanism needs to be flexible enough to deal with these unusual circumstances. Therefore any automatic adjustment mechanism adopted for OPG should preserve OPG's right to seek a review of the formula (and/or the common equity component of the deemed capital structure) should its business risks change dramatically or its access to capital become threatened.

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[3] Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, Issued December 20, 2006 pursuant to EB-2006-0088 (Cost of Capital), EB-2006-0089 (2nd Generation Incentive Regulation Mechanism), and EB 2006-0087 Licence Amendment proceeding (Appendix B).

LONG-TERM DEBT METHODOLOGY

1.0 PURPOSE

This evidence provides an explanation of the methodology used to determine the long-term debt and associated cost for OPG's regulated operations.

2.0 OVERVIEW

The long-term debt supporting OPG's regulated operations is comprised of existing/planned long-term debt issues plus a long-term debt provision required to reconcile OPG's regulated debt to the capital structure recommendations of Foster Associates, Inc. ("Fosters") provided in Ex. C2-T1-S1.

OPG's existing/planned long-term debt is comprised of project-related and general corporate issues. OPG has entered into financial derivatives associated with many existing and planned new issues to reduce its exposure to interest rate fluctuations. The methodology used by OPG to determine the regulated portion of existing and planned new debt issues is discussed in section 3, while the cost of these issues is discussed in section 4. OPG's other long-term debt provision is described in section 5.

3.0 EXISTING AND PLANNED NEW DEBT ISSUES

3.1 Project-Related Long-Term Debt Issues

OPG assigns all existing and planned project-related financing to regulated or unregulated operations based on whether the project is related to the prescribed assets in O. Reg. 53/05. For example, project-related financing associated with nuclear projects, or hydroelectric projects at R.H. Saunders or facilities that comprise the Niagara Plant Group, is assigned to OPG's regulated operations. All project-related financing that is not associated with OPG's prescribed assets is assigned to unregulated operations. OPG also forecasts its financing requirements for projects that are still in the design/assessment phase; however these financing requirements are not assigned to OPG's regulated operations until and unless they are specifically identified as a project in OPG's capital budget for its regulated operations. Actual project-related financing will only occur with respect to defined projects, which will then be directly assigned to regulated or unregulated operations based on whether the project is related to the prescribed assets in O. Reg. 53/05.

3.2 Corporate Long-Term Debt Issues

The existing/planned corporate long-term debt portfolio remaining after project-related financing has been directly assigned must be allocated to regulated and unregulated operations. Consideration of the appropriate allocation methodology begins with the general ratemaking principle that the term of the debt should be assumed to be similar to the life of the assets that are supported by that debt. This principle was endorsed by the OEB in its Report of the Board on Cost of Capital[1] (OEB's Cost of Capital Report). Consistent with this principle, OPG has used the book value of its net fixed assets (gross fixed assets, less accumulated depreciation plus construction work in progress) as the basis for allocating existing long-term debt. OPG determined the ratio of regulated net fixed assets at December 31, 2007 (as reflected in Exhibit B) to the total net fixed assets reflected in OPG's 2007 audited financial statements. OPG has used audited balances as this approach is consistent with O. Reg. 53/05, the asset values are readily available, the amounts are independently verified, and the ratio is not expected to change substantially in the short-term as indicated in Ex. C1-T1-S2 Table 1.

The net fixed asset values determined above were adjusted to remove asset values that were financed pursuant to project specific arrangements. The adjusted relative net fixed asset ratio was then applied to OPG's unassigned debt to determine the amount of existing debt to be included in the long-term debt component of OPG's proposed capital structure for its regulated assets.

For forecasting purposes, OPG has applied the allocation ratio determined using OPG's 2007 audited financial statement balances to planned debt issues that have not been directly assigned to regulated or unregulated operations as described above. OPG has chosen to use 2007 data to determine the allocation factor used to determine the amount of long-term

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[1] Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, Issued December 20, 2006 pursuant to EB-2006-0088 (Cost of Capital), EB-2006-0089 (2nd Generation Incentive Regulation Mechanism), and EB 2006-0087 Licence Amendment proceedings, page 10.

debt for OPG's regulated operations for 2008, and 2009 as it is simple, does not require assumptions of corporate net fixed asset growth, and the ratio of regulated net fixed assets to corporate net fixed assets does not change significantly from year to year[2]. Any year-over-year difference is temporary as the ratio is updated annually as discussed below.

OPG's reporting of historic year information will be based on the information reflected in OPG's most recent audited financial statements to determine the actual debt issued and net fixed asset ratio applicable to corporate debt issued after December 31, 2007. OPG's 2008 and 2009 corporate debt has been allocated to regulated operations based on this allocation ratio.

3.3 Risk Management Activities

OPG's Risk Oversight Committee ("ROC") is a senior management committee that has been delegated the authority to review and approve financial and operational risk mitigation strategies for the Corporation. Commencing in 2005, OPG was exposed to interest rate risk as a result of the financing arrangements with the Ontario Electric Financing Corporation for new debt issuances. As described in Ex. C1-T2-S2 the Ontario Electric Financing Corporation is OPG's primary source of existing and planned long-tem debt issues. The ROC approved interest rate risk management strategies for corporate and project-related debt to mitigate OPG's exposure to interest rate fluctuations. The ROC approved hedging up to 75 percent of the total planned cash expenditures (net of contingencies) for the Niagara Tunnel project, and up to 50 percent of the Ontario Electric Financing Corporation debt maturing in the second half of 2007 and all of 2008. This hedging strategy allows OPG to lock-in the interest rate for a portion of the debt issued. The risk management strategies approved by the ROC required transactions to be completed over a number of months with a number of AA-rated banks and that the execution of such hedging transactions must be in compliance with Generally Accepted Accounting Principles.

OPG entered into hedging transactions associated with planned project-related debt issues for OPG's prescribed assets (the Niagara Tunnel project), and for corporate debt issues

[2] The differences between 2005, 2006 and 2007 are less than two percent per Ex. C1-T1-S2 Table 1.

related to future maturities. The hedges were entered into with a number of AA-rated banks, in accordance with the hedge percentages and total face value amounts reflected in the strategies approved by the ROC.

The primary benefit of the interest rate hedging activity is that it locks in the interest cost on the hedged portion of the debt thereby reducing the exposure to interest rate volatility risk and refinancing risk on corporate debt. OPG's interest rate exposure is especially significant at this time because of the refinancing risk due to the compressed maturity schedule. More than 50 percent of OPG's debt portfolio is due within four years and the average duration of this debt portfolio is less than four years, as described in Ex. C1-T2-S2.

The financial impact of the hedge transactions that have matured is amortized over the life of the underlying debt issue for accounting purposes (i.e., in accordance with Generally Accepted Accounting Principles) and ratemaking purposes, and is reflected in the effective interest rate cost of the debt issue.

4.0 COST OF EXISTING AND PLANNED NEW DEBT ISSUES

4.1 Existing Debt Issues

OPG's debt continuity schedules provided in Ex. C1-T2-S2 reflect the actual cost of debt issues on or before December 31, 2007. OPG's effective debt cost includes the cost of OPG's hedging activities; therefore the cost of each interest rate hedge transaction is allocated consistent with the assignment or allocation of the debt issue underlying the hedge transaction.

4.2 Planned New Debt Issues

OPG's forecast cost of long-term debt (prior to hedging) is between 5.48 percent and 6.58 percent for all project specific financing assigned to regulated operations, refinancing of new and maturing corporate issues, and other long-term debt provisions necessary to reconcile the debt component of OPG's regulated capital structure with the proposed rate base that the financing supports. The long-term interest rate forecast for the 10-year Government of Canada bonds, as published in December 2007 by Global Insight, a third party independent market source, was used to forecast OPG's long-term debt cost. Global Insight has forecast quarterly interest rates of 4.18, 4.26, 4.36 and 4.74 percent in quarters 1 to 4 respectively for 2008, and 4.98, 5.17, 5.25 and 5.28 percent in quarters 1 to 4 respectively for 2009. The mid-point of the range of credit margins applicable to OPG's actual debt issues during the 2005 and 2006 historical period was approximately 80 basis points. An OPG credit margin of 130 basis points has been added for 2008 and 2009 to reflect the results of OPG's December 21, 2007 issue. The market has continued to evolve from one characterized by an abundance of capital being made available at low credit spreads to one where corporate borrowers are seeing upward pressure on credit spreads as investors re-price credit risk and reduce capital. This upward pressure on OPG's corporate risk premium is expected to continue throughout the test period.

OPG's effective debt cost includes the cost of OPG's hedging activities; therefore the cost of each interest rate hedge transaction is allocated consistent with the assignment or allocation of the debt issue underlying the hedge transaction.

5.0 OPG'S OTHER LONG-TERM DEBT

As discussed above, OPG finances long-term assets with long-term financing. OPG has used a provision for long-term debt to reconcile the debt component of OPG's regulated capital structure with the proposed rate base that financing supports. OPG's other long-term debt provision is determined based on the difference between the debt resulting from the application of OPG's proposed capital structure to its proposed regulated rate base, and the project-related and corporate long-term debt assigned or allocated to OPG's regulated operations (as discussed above) plus the portion of short-term debt allocated to regulated operations as described in Ex. C1-T1-S3.

The average unhedged interest rate of new and refinanced debt issued each year for both corporate and project-related borrowing purposes is used to determine the interest rate attributable to the other long-term debt provision.

Table 1
Capitalization and Cost of Capital
Allocation of Existing Long-term Debt ($M)

Line No.	Asset	Amount ($M) 2005	2006	2007
		(a)	(b)	(c)
	Company-Wide:			
1	**Net Fixed Assets**	11,064.0	12,084.0	11,827.0
2	**Adjusted Construction Work in Progress**	348.0	677.0	950.0
3	**Asset Values Using Project Financing**	(356.0)	(644.0)	(860.0)
4	**Adjusted Net Fixed Assets**	11,056.0	12,117.0	11,917.0
	Regulated Operations:			
5	**Net Fixed Assets**[1]	6,454.6	6,830.4	6,696.9
6	**Adjusted Construction Work in Progress**	231.2	417.5	508.7
7	**Asset Values Using Project Financing**	(83.0)	(244.0)	(281.0)
8	**Adjusted Net Fixed Assets**	6,602.8	7,003.9	6,924.6
	Relative Ratio:			
9	**Regulated/Company-Wide Net Fixed Assets**	59.72%	57.80%	58.11%

1 Ex. B2-T3-S1 Table 1 and Ex. B2-T5-S1 Table 1 (Regulated Hydroelectric) and Ex. B3-T3-S1 Table 2 and B3-T5-S1 Table 1 (Nuclear)

SHORT-TERM DEBT METHODOLOGY

1.0 PURPOSE

This evidence provides an explanation of the methodology used to determine the short-term debt and associated cost for OPG's regulated operations.

2.0 METHODOLOGY

OPG proposes that the short-term debt component of its capital structure reflect its forecast short-term borrowings, and that OPG's cost of capital reflect its forecast short-term borrowing cost. OPG's short-term debt proposals reflect a number of comments made by the OEB in its Report of the Board on Cost of Capital[1] (OEB's Cost of Capital Report). The following excerpts are taken from the OEB Report:

> . . . as a general principle for ratemaking purposes, the Board believes that the term of the debt should be assumed to be similar to the life of the assets that are to be acquired with that debt. This suggests that, for an industry [utility] with long-lived assets [like OPG], the majority of debt should be long-term. However, in reality some short-term debt is a suitable tool to help meet fluctuations in working capital levels. Therefore, exclusion of some consideration for short-term debt in the distributors' capital structures going forward would not be appropriate.[2] (parenthesis added)

> . . . short-term debt is generally less expensive than long-term debt and generally provides greater financing flexibility[3].

> . . . although using a distributor's actual short term debt component may seem to be a more accurate approach, it may be problematic. Short-term debt is optimally used as an interim solution for managing a firm's financing requirements. It may fluctuate,

[1] Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, Issued December 20, 2006 pursuant to EB-2006-0088 (Cost of Capital), EB-2006-0089 (2nd Generation Incentive Regulation Mechanism), and EB 2006-0087 Licence Amendment proceedings.
[2] Ibid Page 10
[3] Ibid Page 10

although generally within a limited range. Using a firm's actual short-term debt component would be administratively challenging given the number of electricity distributors and the associated volume of data that would need to be reported and verified. [4]

As OPG's rates are being determined on a utility-specific basis rather than via a generic proceeding, OPG has used the more accurate utility-specific approach to determine the short-term debt component in its capital structure.

The OEB's Cost of Capital Report determined that recent historic short-term borrowing requirements of electricity distribution utilities was an appropriate basis upon which to establish the short-term debt component of their deemed capital structure. As electricity distribution utilities establish rates using a historic test year, the use of historic requirements is a suitable basis for establishing the short-term debt component of an electricity distribution utility's capital structure. As OPG's rates are established based on a forecast test year, the impact of changes in OPG's short-term financing requirements have been included in its test year forecast short-term debt component.

The OEB's Cost of Capital Report provided a generic methodology to be used when determining the short-term debt rate for all of Ontario's electric distribution utilities. This approach is consistent with the OEB's decision to use an industry average approach to determining a short-term debt component. As noted above, OPG proposes to use a utility-specific debt component, and therefore has used a forecast of the rate applicable to the debt sources used to meet its short-term financing requirements.

3.0 ALLOCATION TO REGULATED OPERATIONS

OPG must determine a basis of allocation for its regulated operations, as its short-term borrowing is on a company-wide basis. OPG uses short-term borrowing to finance its working capital requirements and to provide project financing until long-term financing arrangements are completed. Therefore, OPG has allocated short-term debt to its regulated

[4] Ibid, Page 11

operations based on the ratio of the construction work in progress and non-cash working capital amounts (fuel inventory and materials/supplies) for OPG's regulated operations to the total construction work in progress and non-cash working capital amounts reported in OPG's last audited financial statements (December 31, 2007) approved by the Board of Directors prior to the issuance of the OEB's first payment order. OPG has used asset and liability balances from its last audited financial statements as this approach is consistent with the asset values that are readily available, the amounts are independently verified, and the allocation ratio has been relatively consistent as reflected in Ex. C1-T1-S3 Table 1[5].

OPG has not included cash working capital in this ratio as the lead/lag study used to determine cash working capital for OPG's regulated operations is not prepared on a corporate basis. Alternative cash working capital approaches such as the balance sheet method are not suitable in light of the more significant price and production variances associated with OPG's unregulated operations. As OPG's cash working capital allowance is relatively small in comparison to the combined construction work in progress and non-cash working capital balance, it was excluded in determining the allocation of short-term debt to OPG's regulated operations.

The 2007 ratio of 57.1 percent, described in Ex. C1-T1-S3 Table 1, was applied to OPG's short-term debt amount determined above for the 2008, and 2009 periods.

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[5] The differences between 2005, 2006 and 2007 are less than two percent per Ex. C1-T1-S3 Table 1.

Table 1
Capitalization and Cost of Capital
Allocation of Existing Short-term Debt ($M)

Line No.	Asset	Amount ($M) 2005[1]	2006	2007
		(a)	(b)	(c)
	Company-Wide:			
1	**Adjusted Construction Work-In-Progress (CWIP)**	348.0	677.0	950.0
2	**Fuel**	581.0	669.0	604.3
3	**Materials/Supplies**	388.0	438.0	477.9
4	**CWIP + Non Cash Working Capital**	1,317.0	1,784.0	2,032.2
	Regulated Operations:			
5	**Adjusted Construction Work-In-Progress (CWIP)**	231.2	417.5	508.7
6	**Fuel[2]**	159.7	184.3	233.0
7	**Materials/Supplies[2]**	340.5	383.0	419.0
8	**CWIP + Non Cash Working Capital**	731.4	984.8	1,160.7
	Relative Ratio:			
9	**Regulated/Company-Wide Net Fixed Assets**	55.5%	55.2%	57.1%

1 Provided for the purpose of the overall weighted average cost of capital at Ex. C1-T2-S1 Table 6
2 Ex. B2-T6-S1 Table 1 (Regulated Hydroelectric) and Ex. B3-T6-S1 Table 1 (Nuclear)

CAPITALIZATION, RETURN ON EQUITY AND COST OF CAPITAL

1.0 PURPOSE

This evidence provides OPG's capital structure and its return on common equity for fiscal years ended 2005 - 2009 inclusive.

This evidence also summarizes the capitalization and cost of capital for fiscal years ended 2005 - 2009 inclusive. The summary reflects the capital structure and return on common equity discussed in this evidence, the long-term debt costs described in Ex. C1-T2-S2 and the short-term debt costs described in Ex. C1-T2-S3.

2.0 CAPITAL STRUCTURE

For the 2008 and 2009 fiscal years OPG has applied the capital structure (57.5 percent equity and 42.5 percent debt) recommended by Foster Associates, Inc., as provided in Ex. C2-T1-S1. OPG's 2008 and 2009 proposed capital structure is determined pursuant to the methodology outlined in Ex. C1-T1-S1.

For the 2005 - 2007 fiscal years OPG has applied the capital structure (45 percent equity and 55 percent debt) that was reflected in information provided by OPG to the Province for the purpose of establishing interim payment amounts.

The debt component of OPG's capital structure is determined using the methodologies described in Ex. C1-T1-S2 and Ex. C1-T1-S3 for long-term and short-term debt respectively.

3.0 RETURN ON EQUITY

For the 2008 and 2009 fiscal years OPG has applied the 10.5 percent return on equity recommendation of Foster Associates, Inc., as provided in Ex. C2-T1-S1.

OPG has determined a return on equity for its regulated operations for each of 2005, 2006 and 2007 using a reconciliation approach. OPG's audited financial statements report its accounting earnings before interest and income taxes ("accounting EBIT") for both OPG's regulated hydroelectric business segment and OPG's nuclear business segment. The audited accounting EBIT amounts are amended to include interest, taxes, and other adjustments required to reflect the impact of regulation (discussed below). This approach to determining return on equity effectively addresses the filing guidelines issued by the OEB related to the reconciliation of OPG's evidence to its audited financial statements.

Return on equity information for regulated operations has not been used by OPG for the purpose of operating its business, nor is this information required to support OPG's business or financial planning, financial reporting, or income tax return filings. OPG has determined and presented 2005, 2006 and 2007 return on equity information to provide:

- A general context to assess the adequacy of OPG's interim payment amounts determined prior to regulation by the OEB.
- A level of independent validation of OPG's financial position prior to regulation by the OEB (i.e., the starting point for OPG's return on equity is OPG's audited financial information).

OPG does not expect this information will be necessary to support future payment applications as the regulatory proceeding to establish the initial payment amounts by the OEB will provide:

- Suitable context for assessing the adequacy of payment amounts established by the OEB.
- Sufficient public information to understand OPG's regulated operations and OPG's expected financial position prior to subsequent proceedings.

To determine a return on equity for OPG's regulated operations that is consistent with the return on equity proposed for its test period, the accounting EBIT for OPG's regulated operations reported in OPG's audited financial statements is adjusted to reflect: interest and taxes; certain revenues or expenses included in accounting EBIT that are not included in regulatory income; and differences between the accounting and regulatory methodology used to determine certain revenues or expenses included in both accounting EBIT and regulatory income.

The reconciliation between OPG's accounting EBIT as reported in OPG's 2006 and 2007 audited financial statements and the return on equity for OPG's regulated operations is provided in Ex. C1-T2-S1 Table 1. OPG has provided an explanation for each adjustment to accounting EBIT and the approach OPG has used to determine the adjustment in section 3.1 below. The footnotes to Ex. C1-T2-S1 Table 1b support the derivation of the specific adjustment included in the reconciliation.

The reconciliation is divided into two sections. The first section provides the reconciliation between accounting EBIT and regulatory EBT. OPG uses regulatory EBT as basis for determining the regulatory income tax expense as presented in Exhibit F3-2-1 Table 7 (for 2005 and 2006) and Table 8 (for 2007). The second section provides the reconciliation between regulatory EBT and the return on equity for OPG's regulated operations.

3.1 Adjustment to Accounting 2005/2006/2007 Earnings Before Interest and Taxes to Determine Regulatory Earnings Before Tax

The reconciliation between accounting EBIT and regulatory EBT is based on three adjustments:

- removal of accounting expenses and revenues not included in regulatory EBT
- differences between accounting and regulatory treatment of certain revenues and expenses
- interest expense

3.1.1 Removal of Accounting Expenses and Revenues Not Included in Regulatory EBT

The only revenues or expenses included in accounting EBIT that are not included in regulatory income are accretion expense associated with OPG's fixed asset removal and nuclear waste management obligations and the revenues earned on OPG's segregated funds established to finance these same fixed asset removal and nuclear waste management obligations. Together these two items are considered a "closed system"[1] that are not included in revenue requirement. Only the period expenses associated with OPG's

[1] As characterized by the OEB in RP-1999-0001 Decision for Ontario Hydro Services Corporation

nuclear waste management liabilities as described in Ex. H1-T1-S2 are included in regulatory EBIT.

3.1.2 Differences in Accounting and Regulatory Treatment of Certain Revenues and Expenses

To the extent OPG's accounting treatment and regulatory treatment differ, the accounting numbers are removed (i.e., removing revenue reduces income, removing expenses increases income), and the regulatory amounts are included. OPG has made three adjustments[2] as described below:

- Production in excess of 1900 MW/h: O. Reg. 53/05 provides that OPG earns the difference between the spot market price and the interim payment amount for production in excess of 1900 MW in any hour commencing April 1, 2005. Accounting EBIT reflects these spot market revenues. An adjustment is required to deduct this difference between OPG's interim payment amount and the spot market price. OPG's proposed return on equity and revenue requirement did not include incremental revenue associated with the proposed hydroelectric incentive mechanism; therefore its achieved return on equity will be reported on a consistent basis.
- Capital taxes: Capital taxes included in accounting EBIT are based on an allocation of capital taxes determined on a corporate basis. Capital taxes for regulatory purposes are determined by applying the capital tax rate to OPG's nuclear and regulated hydroelectric rate base
- Unrealized exchange rate adjustments: As a result of a change in Generally Accepted Accounting Principles, OPG is required to include unrealized gains/ (losses) in accounting net income on certain embedded derivative financial instruments commencing January 1, 2007. OPG has a uranium concentrate purchase contract that includes a fixed U.S. dollar rate for these purchases. As a result, this contract is affected by the change in

[2] In December 2006, OPG's nuclear liabilities increased by $1.386B as described in Ex. H1-T1-S1. As presented in the evidence, certain 2007 expenses related to nuclear liabilities, e.g., capital and income tax, return on equity for Bruce Lease Assets, include the impact of this increase. The 2007 expenses in this Ex. C1-T2-S1 remove the impact of the increase of nuclear liabilities from the calculation of Regulatory EBT as detailed in Ex. C1-T2-S1 Table 1b.

GAAP. Consistent with the regulatory treatment of the other financial derivatives (Ex. C1-2-2), unrealized gains/ (losses) are not included in either the ROE for OPG's regulated operations or the regulatory EBT for income tax purposes.

3.1.3 Interest Expense

Interest expense is determined using the capital structure, long-term debt, and short-term debt expense and allocation methodologies provided throughout Exhibit C.[3]

3.2 Adjustments to Regulatory Earnings Before Taxes to Determine ROE

The reconciliation between regulatory EBT and ROE is based on three adjustments:

- income taxes on regulated assets
- approved return on equity for Bruce leased assets
- deferral of 2007 expenses related to the December 31, 2006 increase in ARO

3.2.1 Income Taxes on Regulated Assets

Income taxes are usually determined using the stand-alone utility methodology described in Ex. F3-T2-S1; however OPG has losses for income tax purposes in 2005, 2006 and 2007. OPG's tax expense for 2005 reflects the last year that the large corporation tax was in effect. As the large corporation tax associated with OPG's regulated assets is an after tax cost (i.e., not deductible for tax purposes), the large corporation tax has been deducted from regulatory earnings before tax in determining OPG's 2005 return on equity.

3.2.2 Approved ROE for Bruce Leased Assets[4]

Regulatory EBT includes all earnings associated with Bruce leased assets. The only "cost" not reflected in regulatory EBT is the return on equity OPG is allowed to earn on its Bruce leased Assets. The adjustment is made after the regulatory EBT as OPG's return on equity is an after tax return. To determine the income tax expense on the ROE associated with the

[3] For 2007, interest expense does not include the portion associated with the December 31, 2006 increase in ARO (see footnote 3)

[4] The return on equity costs to OPG's regulated operations does not include the portion associated with the December 31, 2006 increase in ARO (see footnote 3)

Bruce leased assets, OPG has applied the income tax rate as provided in Ex F3-T2-S1, Table 8 for 2005, 2006 and Table 9 for 2007 to the return on equity.

3.2.3 Deferral of 2007 Expenses Related to the December 31, 2006 Increase in ARO

As required by the Regulation, OPG recorded 2007 expenses associated with the December 31, 2006 increase in the Nuclear Liability Deferral Account, Transition as described in Ex J1-1-1. OPG will incur a significantly higher level of expenses as a result of the December 31, 2006 increase in ARO on an on-going basis over the life of its nuclear assets. OPG's 2007 deferred cost amount of $127M[5] is representative of the increased expenses OPG will incur in the test period. As these are significant on-going costs, they have been included in 2007 ROE to provide a more relevant context within which to assess the adequacy of OPG's current payment amount.

4.0 SUMMARY OF CAPITALIZATION AND COST OF CAPITAL: 2005 - 2009

OPG's capitalization and cost of equity reflects the capital structure and return on equity discussed above. The cost of the debt components of OPG's capital structure is discussed in Ex. C1-T2-S2 for long-term debt and Ex. C1-T2-S3 for its short-term debt. OPG has applied this capitalization to rate base as described in Exhibit B. The resulting capitalization and cost of capital for OPG's 2005 to 2009 fiscal years is summarized in Ex. C1-T2-S1 Tables 2 - 6 for 2005 - 2009.

[5] OPG recorded expenses of $130.5M in its Nuclear Liability Deferral Account, Transition for 2007. This includes $3.5M in interest expenses related to the deferred recovery of these costs. Interest expense was not included in the adjustment, as it is not an ongoing cost. All other expenses are reflected in OPG's 2008 revenue requirement

Numbers may not add due to rounding.

Table 1
Capitalization and Cost of Capital
Return on Equity - Reconcilation to Audited Financial Statements ($M)

Line No.	Description	Note	Regulated Hydroelectric 2005	Nuclear 2005	Total 2005	Regulated Hydroelectric 2006	Nuclear 2006	Total 2006	Regulated Hydroelectric 2007	Nuclear 2007	Total 2007
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Accounting EBIT (includes rounding)**	1	374.8	(10.0)	364.8	264.0	70.0	334.0	249.0	(84.0)	165.0
	Accounting Expenses/Revenues not Included in Regulatory EBT										
2	**Add: Fixed Asset Removal and Nuclear Waste Management - Accretion of Liabilities**	2	0.0	467.0	467.0	0.0	489.9	489.9	0.0	498.8	498.8
3	**Deduct: Fixed Asset Removal and Nuclear Waste Management - Fund Earnings**	2	0.0	381.1	381.1	0.0	370.5	370.5	0.0	480.7	480.7
	Differences Between Accounting and Regulatory Treatment										
	(1) PRODUCTION ABOVE 1900 MW/Hr:										
4	**Deduct: Revenue at Market Price Included in Accounting EBIT**	3	210.0	0.0	210.0	169.0	0.0	169.0	158.0	0.0	158.0
5	**Add: Revenue at Current Payment Amount**	4	88.5	0.0	88.5	122.9	0.0	122.9	107.2	0.0	107.2
	(2) CAPITAL TAXES:										
6	**Add: Accounting Capital Tax on Regulated Assets**	5	18.5	10.3	28.8	18.0	11.6	29.6	11.2	7.9	19.1
7	**Deduct: Regulatory Capital Tax on Regulated Assets**	6, 9	12.0	8.6	20.6	11.9	9.0	20.9	8.8	6.8	15.6
8	**Add: Accounting Capital Tax on Bruce Leased Assets**	5	0.0	2.7	2.7	0.0	2.3	2.3	0.0	1.1	1.1
9	**Deduct: Regulatory Capital Tax on Bruce Leased Assets**	6, 9	0.0	1.6	1.6	0.0	1.3	1.3	0.0	0.8	0.8
	(3) UNREALIZED EXCHANGE RATE ADJUSTMENTS:										
10	**Add Back: Losses Included in Accounting EBIT**	7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.8	1.8
11	**Regulatory EBIT** (line 1+2-3-4+5+6+7-8-9+10)		259.8	78.7	338.5	224.0	193.0	417.0	200.6	(62.6)	138.0
	Interest Expense:										
12	**Deduct: Bruce Leased Assets**	9	0.0	16.9	16.9	0.0	13.3	13.3	0.0	10.9	10.9
13	**Deduct: Regulated Assets**	8, 9	125.7	90.0	215.7	119.3	90.6	209.9	119.2	91.9	211.1
14	**Regulatory EBT** (line 11-12-13)	10	134.1	(28.1)	106.0	104.8	89.1	193.8	81.4	(165.4)	(84.0)
	(1) INCOME TAXES ON REGULATED ASSETS:										
15	**Deduct: Income Taxes on Regulated Assets**	10	7.0	5.7	12.7	0.0	0.0	0.0	0.0	0.0	0.0
	(2) APPROVED ROE FOR BRUCE LEASED ASSETS:										
16	**Deduct: Bruce ROE After Tax**	9, 11	0.0	12.1	12.1	0.0	9.9	9.9	0.0	8.1	8.1
17	**Deduct: Income Tax on Bruce ROE**	11	0.0	6.3	6.3	0.0	5.2	5.2	0.0	4.2	4.2
	(3) DEFERRAL OF 2007 EXPENSES RELATED TO THE DECEMBER 31, 2006 INCREASE IN ARO:										
18	**Deduct: 2007 Expenses Recorded in Nuclear Liability Deferral Account - Transition**	12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	127.0	127.0
19	**Return on Equity** (line 14-15-16-17-18)	13	127.2	(52.2)	75.0	104.8	73.9	178.7	81.4	(304.8)	(223.3)

See Ex. C1-T2-S1 Table 1b for notes

Table 1b
Capitalization and Cost of Capital
Return on Equity - Reconcilation to Audited Financial Statements ($M)
Notes to Ex. C1, Tab 2, Sch. 1, Table 1

Notes:

1 Accounting EBIT: Per Audited Financial Statements.Regulated Nuclear Segment and Regulated Hydroelectric Segment details provided in Ex. A2-T1-S1 Appendix A.

2 Fixed Asset Removal and Nuclear Waste Management: Accretion of Liabilities and Fund Earnings provided in the Regulated Nuclear segment information in Ex. A2-T1-S1 Appendix A.

3 Revenue at Market Price: As reflected in management's discussion and analysis accompanying OPG's audited financial statements as provided in Ex. A2-T1-S1 Appendix A.

4 Revenue at Interim Payment Amount: Total hourly production over 1900 MWh x $33/MWh

5 Capital Tax: Accounting EBIT is based on an allocation of capital taxes determined on a corporate basis.

6 Capital Tax: Determined for regulatory purposes in Ex. G2-T2-S1 Table 3 for Bruce Leased Assets, Ex. F3-T2-S1 Table 4 for Regulated Assets (Nuclear), and Ex. F3-T2-S1 Table 1 for Regulated Assets (Hydroelectric).

7 Effective January 1, 2007 OPG is required to include in its accounting income unrealized gains/(losses) associated with certain financial derivatives. OPG is subject to exchange rate gains/(losses) related to some of its purchase obligations. For regulatory purposes, the actual gain/loss will be included in the cost of the purchase as received.

8 Interest Expense: Interest expense is determined by applying the interest rate for OPG's total debt in 2005 and 2006 as summarized in Ex. C1-T2-S1 Table 6 (2005), Table 5 (2006) and Table 4 (2007) to OPG's nuclear and regulated hydroelectric ratebase for 2005, 2006 and 2007 provided in Ex. B1-T1-S1 Table 1 (Regulated Hydroelectric) and Ex. B1-T1-S1 Table 2 (Nuclear).

Table to Note 8 - Interest Expense Calculation ($M)

Line No.	Item	Regulated Hydroelectric 2005	Nuclear 2005	Regulated Hydroelectric 2006	Nuclear 2006	Regulated Hydroelectric 2007	Nuclear 2007
		(a)	(b)	(c)	(d)	(e)	(f)
1	2005 Interest Rate (from Ex. C1-2-1 Table 6)	5.71%	5.71%				
2	2006 Interest Rate (from Ex. C1-2-1 Table 5)			5.48%	5.48%		
3	2007 Interest Rate (from Ex. C1-2-1 Table 4)					5.54%	5.54%
4	Reg. Hydro. Rate Base (from B1-1-1 Table 1)	4,001.3		3,957.3		3,911.1	
5	Nuclear Rate Base (from B1-1-1 Table 2)		2,865.5		3,005.7		3,500.1
6	Debt Ratio (from Ex. C1-2-1 Tables 4, 5 and 6)	55%	55%	55%	55%	55%	55%
7	Interest Expense	125.7	90.0	119.3	90.6	119.2	106.6
	(Interest Rate x Rate Base x Debt Ratio)						

9 December 31, 2006 increase in Asset Retirement Obligation (ARO): A portion of OPG's 2007 expenses as presented in evidence reflect the increase in the ARO (the "ARO Portion"). The ARO Portion is removed for the purpose of determining Regulatory EBT. The following table reflects the 2007 expense presented in evidence and the portion of the expense related to the ARO increase.

Table to Note 9 - ARO Adjustment ($M)

Line No.		Evidence Reference	2007 Expense Incl. Increased ARO Portion	ARO Portion of 2007 Expense	2007 Expense Excl. Increased ARO Portion
		(a)	(b)	(c)	(d)
1	Capital Taxes on Regulated Assets	F3-T2-S1 Tbl 4	7.9	1.1	6.8
2	Capital Taxes on Bruce Leased Assets	G2-T2-S1 Tbl 3	2.8	2.0	0.8
3	Interest Expense on Regulated Assets	Note 10, col. (f)	106.6	14.7	91.9
4	Interest Expense on Bruce Leased Assets	G2-T2-S1 Tbl 3	37.6	26.7	10.9
5	Bruce ROE After Tax	G2-T2-S1 Tbl 3	27.7	19.6	8.1

10 Regulatory EBT used for income tax purposes at Ex. F3-T2-S1. OPG's regulated operations did not incur a tax expense in 2005-2007, however in 2005 OPG's regulated operations were subject to Large Corporations Tax (Ex. F3-T2-S1), which is removed in calculating an after-tax rate of return.

11 Income Taxes on Bruce Lease Net Revenues

Table to Note 11 - Income Taxes on Bruce Lease Net Revenues ($M)

Line No.	Cost Item	2005 Actual	2006 Actual	2007 Actual
		(a)	(b)	(c)
1	Bruce ROE After Tax*	12.1	9.9	8.1
2	Income Tax on Bruce Lease ROE**	34.12%	34.12%	34.12%
3	Income Tax on Bruce Net Revenue***	6.3	5.2	4.2

* From Ex. G2-T2-S1 Table 3. Adjusted for the removal of the December 31, 2006 increase in ARO as illustrated in Note 6 line 5 col. (f).

** From Ex. F3-T2-S1 Table 8, line 34 and Ex. F3-T2-S1 Table 7, line 32

*** Line 1 / (1-line 2) - line 1

12 Total 2007 Expenses recorded in Nuclear Liability Deferral Account: Per Ex. J1-T1-S1 127.0 ($M)

13 Adding revenues at market prices for Regulated Hydroelectric production (see Notes 3 and 5 above) to Return on Equity (Ex. C1-T1-S1 Table 1, line 18) equals the following:

Year	$M	ROE
2005	196.5	6.36%
2006	224.8	7.17%
2007	(172.5)	-5.17%

Numbers may not add due to rounding.

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Table 2

Table 2
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital ($M)
Calendar Year Ending December 31, 2009

Line No.	Note	Capitalization	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
		Capitalization and Return on Capital:				
1	1	**Short-term Debt**	189.3	2.6%	5.98%	11.3
2	2	**Existing/Planned Long-Term Debt**	2,362.7	32.1%	5.79%	136.8
3	3	**Other Long-Term Debt Provision**	573.2	7.8%	6.47%	37.1
4	4	**Total Debt**	3,125.3	42.5%	5.92%	185.2
5	4	**Common Equity**	4,228.4	57.5%	10.50%	444.0
6	5	**Rate Base**	7,353.7	100%	8.56%	629.1

Notes:
1 Short Term Financing allocated at: 55.2%
2 Ex. C1-T2-S2 Table 5 (line 35)
3 Debt required to balance capital structure with proposed rate base. See Ex. C1-T2-S2, Table 5b for interest rate calculation
4 Capital Structure and Return on Equity Proposal per Ex. C1-T2-S1
5 Ex. B1-T1-S1 Table 1 (Regulated Hydroelectric) and Ex. B1-T1-S1 Table 2 (Nuclear)

Table 3
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital ($M)
Calendar Year Ending December 31, 2008

Line No.	Note	Capitalization	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
		Capitalization and Return on Capital:				
1	1	**Short-term Debt**	189.3	2.6%	5.83%	11.0
2	2	**Existing/Planned Long-Term Debt**	2,197.2	29.7%	5.79%	127.2
3	3	**Other Long-Term Debt Provision**	758.9	10.3%	5.65%	42.9
4	4	**Total Debt**	3,145.4	42.5%	5.76%	181.1
5	4	**Common Equity**	4,255.5	57.5%	10.50%	446.8
6	5	**Rate Base**	7,400.8	100%	8.48%	627.9

Notes:
1 Short Term Financing allocated at: 55.2%
2 Ex. C1-T2-S2 Table 4 (line 32)
3 Debt required to balance capital structure with proposed rate base. See Ex. C1-T2-S2, Table 4b Note 11 for interest rate calculation
4 Capital Structure and Return on Equity Proposal per Ex. C1-T2-S1
5 Ex. B1-T1-S1 Table 1 (Regulated Hydroelectric) and Ex. B1-T1-S1 Table 2 (Nuclear)

Table 4
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital ($M)
Calendar Year Ending Dec. 31, 2007

Line No.	Note	Capitalization	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
		Achieved Capitalization and Return on Capital:				
1	1	**Short-term Debt**	182.7	2.5%	5.30%	9.7
2	2	**Existing/Planned Long-Term Debt**	1,855.8	25.0%	5.90%	109.5
3	3, 6	**Other Long-Term Debt Provision**	2,037.7	27.5%	5.23%	106.6
4	4, 7	**Total Debt**	4,076.1	55.0%	5.54%	225.8
5	4, 7	**Common Equity**	3,335.0	45.0%	-6.70%	(223.3)
6	5, 7	**Rate Base**	7,411.2	100%	0.03%	2.4

Notes:
1 Short Term Financing allocated at: 55.2%
2 Ex. C1-T2-S2 Table 3 (line 27)
3 Debt required to balance capital structure with proposed rate base. Average unhedged interest rate of 2007 issues.
4 Applied the capital structure reflected in the information OPG supplied to the Province for the purposes of establishing the interim payment amounts. Return in $M determined in Ex. C1-T2-S1 Table 1
5 Ex. B1-T1-S1 Table 1 (Regulated Hydroelectric) and Ex. B1-T1-S1 Table 2 (Nuclear)

6

Other Long Term Debt Provision Rate:	Amount ($M)	Rate
Issue 23	100	5.44%
(See Ex. C1-T2-S2 Table 3--unhedged--actual issue rate on June 22)		
Issue 24	200	5.55%
(See Ex. C1-T2-S2 Table 7--unhedged - actual issue rate on Sept 24)		
Issue 25	400	5.31%
(See Ex. C1-T2-S2 Table 3--unhedged - actual issue rate on Dec 21)		
Niagara 2	50	4.89%
(See Ex. C1-T2-S2 Table 6--underlying bond--line 10)		
Niagara 3	30	4.97%
(See Ex. C1-T2-S2 Table 6--underlying bond--line 14)		
Total		26.16%
Average Rate (unweighted average of 4 issues)		5.23%

7 The cost of capital for 2007 is calculated using a rate base amount that includes the increase in the Nuclear Liabilities recorded on Dec. 31, 2006. The component of the cost of capital related to this increase has been deferred in the Nuclear Liability Deferral Account discussed in Ex. J1-T1-S1.

Numbers may not add due to rounding.

Table 5
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital ($M)
Calendar Year Ending Dec. 31, 2006

Line No.	Note	Capitalization	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
		Achieved Capitalization and Return on Capital:				
1	1	**Short-term Debt**	165.6	2.4%	4.80%	7.9
2	2	**Existing Long-Term Debt**	1,983.0	28.5%	5.96%	118.2
3	3	**Other Long-Term Debt Provision**	1,681.1	24.1%	4.99%	83.8
4	4	**Total Debt**	3,829.7	55.0%	5.48%	209.9
5	4	**Common Equity**	3,133.4	45.0%	5.70%	178.7
6	5	**Rate Base**	6,963.0	100%	5.58%	388.6

Notes:

1 Short Term Financing allocated at: 55.2%
2 Ex. C1-T2-S2 Table 2 (line 27)
3 Debt req'd to balance capital structure with proposed rate base. Rate is unhedged cost of 2006 Niagara Tunnel issue. See Ex. C1-T2-S2 Table 6, Column h.
4 Applied the capital structure reflected in the information OPG supplied to the Province for the purposes of establishing the interim payment amounts. Return in $M determined in Ex. C1-T2-S1 Table 1
5 Ex. B1-T1-S1 Table 1 (Regulated Hydroelectric) and Ex. B1-T1-S1 Table 2 (Nuclear)

Numbers may not add due to rounding.

Table 6
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital ($M)
Calendar Year Ending Dec. 31, 2005

Line No.	Note	Capitalization	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
		Achieved Capitalization and Return on Capital:				
1	1	**Short-term Debt**	166.6	2.4%	3.44%	5.7
2	2	**Existing Long-Term Debt**	2,116.2	30.8%	5.95%	125.9
3	3	**Other Long-Term Debt Provision**	1,493.9	21.8%	5.62%	84.0
4	4	**Total Debt**	3,776.7	55.0%	5.71%	215.6
5	4	**Common Equity**	3,090.0	45.0%	2.43%	75.0
6	5	**Rate Base**	6,866.8	100%	4.23%	290.6

Notes:
1 Short Term Financing allocated at: 55.5%
2 Ex. C1-T2-S2 Table 1 (line 30)
3 Debt required to balance capital structure with proposed rate base. Average unhedged interest rate of 2005 issues. See Ex. C1-T2-S2 Table 5b, Note 9.
4 Applied the capital structure reflected in the information OPG supplied to the Province for the purposes of establishing the interim payment amounts. Return in $millions determined in Ex. C1-T2-S1 Table 1.
5 Ex. B1-T1-S1 Table 1 (Regulated Hydroelectric) and Ex. B1-T1-S1 Table 2 (Nuclear)

COST OF LONG-TERM DEBT

1.0 PURPOSE

This evidence provides the details of OPG's existing and planned annual long-term borrowing and associated costs for 2005 - 2009 determined pursuant to the methodology discussed in Ex. C1-T1-S2.

2.0 OVERVIEW

2.1 Existing Long-Term Debt Issues: Year End 2005, 2006 and 2007

OPG's long-term debt outstanding at December 31, 2007, as reflected in OPG's audited financial statements, is $3,853M. This balance consisted of corporate debt held by the Ontario Electricity Financing Corporation ("OEFC") of $3,195M, and project-related debt held by the OEFC related to regulated and unregulated operations of $240M and $230M respectively. The remaining $188M of OPG's long-term debt obligation outstanding as of December 31, 2007 is non-OEFC project-related financing associated with OPG's unregulated operations.

A summary of corporate and project-related debt related to OPG's regulated operations, as reflected in OPG's audited financial statements, is provided at Ex. C1-T2-S2 Tables 1-3.

The majority of OPG's corporate debt at December 31, 2007 was issued as part of OPG's initial capitalization. All OPG debt issues with the OEFC contain the standard covenant conditions that apply to corporate debt issued in the public debt markets. The average remaining term of these long-term debt issues is approximately 4.7 years[1].

OEFC debt outstanding at December 31, 2007 consists of both senior and subordinate notes under which the OEFC has different rights. The existence of subordinate debt in OPG's debt portfolio could make any senior issue offered into the capital market more

[1] The issuance of $400M on December 21, 2007 and refinancing for 10 year terms of issues maturing in 2007 increased the average term of OPG's debt by 1.2 years from the 3.5 year average remaining term of OPG's corporate debt portfolio at December 31, 2006.

attractive to investors. Payments on subordinated notes (issues 16, 19, 20, and 21 in Ex. C1-T2-S2 Tables 1 and 2) are made only after full payment is made on senior notes obligations. The maturity of the subordinated notes cannot be accelerated upon the occurrence of an event of default unless the maturity of the senior debt has also been accelerated. At any time OPG may defer the payment of any interest of any subordinated note for not more than the earlier of five years or the maturity of the subordinated note. During any period that the payment of interest is deferred, OPG cannot make any payment of principal or interest in respect of any indebtedness ranking equally with OPG's other notes.

Existing OEFC debt will be retired or refinanced at maturity, depending on OPG's liquidity at the time of maturity. OPG does not plan to redeem the debt prior to its maturity since its current agreements with the OEFC contain a standard Canada Call provision[2] which makes it more expensive to redeem the debt compared to the potential benefit of refinancing in a lower interest rate environment.

The maturity dates for $500M of debt issues scheduled to mature in March and September of 2005 (issues 13, 14, 17, and 18) were extended to March and September 2010 respectively pursuant to an agreement between OPG and the OEFC. The interest rate on the notes remained unchanged. The OEFC and OPG also agreed to defer all the interest due and payable on March 22, 2005 in respect of all of these notes, converting OPG's interest payment obligation into a new loan for $95M (issue number 21). In addition, on April 29, 2005 OPG borrowed $400M under a new credit agreement with the OEFC for notes issued with a seven-year term (issue number 22).

In September 2006, OPG reached an agreement with the OEFC to provide debt financing for the Niagara Tunnel project. OPG may borrow up to $1B over the duration of the project to meet the financial requirements of the project. This agreement enables OPG to issue notes each quarter with a term of up to 10-years to meet OPG's financing obligations for this project. On October 22, 2006 OPG borrowed $160M pursuant to this

[2] Government of Canada bond yield of equivalent maturity plus one-quarter of the issue spread.

agreement for notes with a ten-year term (Niagara 1), and in 2007 OPG borrowed a further $80M on the same basis (Niagara 2 and 3).

OPG refinanced all outstanding debt issues maturing during 2007, with the exception of one issue (issue 7). For this issue which matured March 22, 2007, OPG did not require the full $200M. Instead, OPG issued $100M in new debt on June 22, 2007.

In 2007 OPG began to issue debt under two new credit facilities established with the OEFC. A $500M facility and a $950M facility were established to enable OPG to refinance its existing debt and finance a deferred payment on OPG's nuclear liability obligation associated with the Bruce Lease. At the time these facilities were negotiated, OPG planned to borrow the full amount of debt allowed under each of these credit facility arrangements. This refinancing plan is designed to extend the term of OPG's debt portfolio and smooth its maturity profile to better match OPG's cash flows.

2.2 Planned Long-Term Debt Issues: 2008 and 2009

Approximately $1.6B in new borrowing is needed to finance new generation projects over the 2008 - 2009 period. In addition, OPG will retire approximately $0.75B of debt maturing between 2008 and 2009 as follows: 2008 - $400M, and 2009 - $350M. OPG's updated forecast was based on the assumption that the OEB would approve its application for an interim rate increase. OPG forecasts that it will refinance $350M of its $400M of outstanding debt issues maturing in 2008. OPG forecasts that it will repay $50M maturing in 2008 and all debt maturing in 2009 based on its current business plan.

OPG has made arrangements to refinance its current debt maturing in 2008 and 2009 under a credit facility agreement established with the OEFC. OPG is also developing plans to issue new incremental corporate debt into the public market and intends to be in a position to issue corporate debt in 2009, should OPG's updated long-term borrowing requirements turn out to be greater than currently forecast.

Borrowings under project-related credit facility agreements between OPG and the OEFC are for the purpose of financing construction requirements of specific projects; however, the OEFC has recourse against the entire company (not just the project) in the event of a default.

3.0 COST OF DEBT

3.1 Ontario Electricity Financing Corporation Debt Issues

The interest rate associated with OEFC debt is fixed at the time the funds are advanced. The rate of interest is determined prior to the date the funds are advanced based on the prevailing benchmark Government of Canada 10-year bond as published by a verifiable market monitoring service (currently Bloomberg) on the day prior to the date funds are advanced, plus a credit margin determined five business days before the date funds are advanced. The credit margin is determined based on a sample of quotes for OPG's credit margin as provided by a selected group of Canadian banks.

The cost of planned new and refinanced corporate debt and project-related debt for 2008 and 2009 is based on the December 2007 Global Insight forecast of the 10-year Long Canada Bond. The forecast quarterly interest rates are 4.18, 4.26, 4.36 and 4.74 percent in quarters 1 to 4 respectively in 2008 and 4.98, 5.17, 5.25 and 5.28 percent in quarters 1 to 4 respectively in 2009. A credit risk spread for OPG of 130 basis points as discussed in Ex. C1-T1-S2 is added to the Global Insight rates noted above to determine the forecast rate for OPG's OEFC debt in 2008 and 2009.

OPG does incur costs to set-up each new credit facility with the OEFC (e.g., legal fees), these costs are relatively minor and are reflected in OPG's forecast OM&A costs for its legal department in the period the credit facility is forecast to be established. OPG may incur expenses to compensate the OEFC in the event of default; however OPG has not planned to incur such expenses in 2008 or 2009.

The cost of OPG's existing long-term debt financing attributable to specific assets in-service or projects under development associated with OPG's regulated operations is directly assigned to OPG's regulated operations, as discussed in Ex. C1-T1-S2. The Niagara Tunnel project is part of OPG's prescribed assets; therefore the cost of debt issued pursuant to this financing agreement is directly assigned to OPG's regulated operations. The Niagara Tunnel project is the only existing or planned project specifically assigned to OPG's regulated operations.

OPG has hedged its interest rate risks for a number of OPG's existing and planned OEFC debt issues. OPG's hedging activity and costs are described in section 3.5.

3.2 Existing Long-Term Debt Issues: Year End 2005, 2006 and 2007

2005 and 2006 Summary

The majority of OPG's corporate debt issues outstanding at December 31, 2007 were issued as part of OPG's initial capitalization. OPG issued corporate long-term debt during 2005 and 2006 primarily to replace maturing debt. To the extent the amount and type of corporate long-term debt was extended, the interest rate applicable to that debt was also extended. OPG also replaced maturing debt with subordinated debt issues at rates determined to reflect the increased risks associated with these agreements. The interest expense for all other debt is determined using the method discussed in section 3.1 above.

OPG's first project-related financing was issued on October 23, 2006 pursuant to the Niagara Tunnel project agreement (listed as Niagara 1 in Table 2 of Ex. C1-T2-S2). OPG hedged a portion of this debt issue in accordance with the direction approved by OPG's Risk Oversight Committee described in Ex. C1-T1-S2. The effective interest rate after these interest rate swap transactions is 5.23 percent as discussed in section 3.5 below.

2007 Summary

On March 22, 2007, OPG met its debt retirement obligation by repaying $200M of maturing debt notes (issue 7), temporarily replacing the debt with borrowings under its commercial paper program pending finalization of a new general corporate credit facility with the OEFC. OPG reached an agreement with the OEFC in June, 2007 for a $500M general credit facility covering the period June 1, 2007 to March 31, 2008. The interest rate associated with this credit facility is consistent with the methodology described above.

On June 22, 2007, OPG borrowed $100M in the form 10-year term notes (issue 23) under this facility at a rate of 5.435 percent. The 10-year Government of Canada bond rate was 4.692 percent as published by Bloomberg the day before the debt issue and the applicable OPG spread was 0.7425 percent. OPG did not enter into any interest rate swap transactions associated with this debt given the uncertainty of the timing of the OEFC review/approval of a new credit facility. Absent the availability of this new credit facility, OPG would have continued to borrow on a short-term basis beyond June.

On December 21, 2007, OPG borrowed the remaining $400M available from the $500M general credit facility that is maturing March 31, 2008. The 10-year Government of Canada bond rate was 4.01 percent as published by Bloomberg the day before the debt issue and the applicable OPG spread was 1.30 percent. This debt issue was not hedged.

To ensure adequate financing resources are available beyond the borrowing limit of its short-term bank credit facility, OPG agreed to a $950M refinancing credit agreement with the OEFC to refinance senior notes as they mature over the period September 2007 - September 2009. This facility will allow OPG to fix the term of notes issued for periods up to 10 years. Therefore, as OPG refinances its existing debt, it will be able to extend the average term of approximately 4.7 years that is reflected in OPG's December 31, 2007 corporate current debt portfolio. Refinancing is permitted under the terms of the agreement with the OEFC, subject to a notice period and prepayment of the interest and principal owing to the OEFC using the market rate (including OPG corresponding credit spread) for the remainder of the original term to calculate the payment. In essence, OPG will make a payment for the difference between the rate on the original debt and the market rate for the remaining term of the original debt, with the market rate applying to the new debt.

OPG fulfilled its $200M debt retirement obligation on September 22, 2007 (issue 8) by issuing $200M ten-year term notes (issue 24) pursuant to its $950M credit facility. An effective interest rate of 5.53 percent is applied to this $200M debt issue. This represents the blend of hedged and unhedged debt costs, and is consistent with the accounting and rate making approach used to determine the effective interest cost as described in section 3.5 below. The effective interest rate is determined in Ex. C1-T2-S2 Table 7.

OPG completed two debt issues pursuant to the Niagara Tunnel project financing agreement in 2007. The interest rates for the two completed debt issues (listed as Niagara 2 and Niagara 3 in Ex. C1-T2-S2 Table 3b) are:

- Niagara 2: $50M on January 22, 2007 at a rate of 4.893 percent reflecting a rate of 4.185 percent and an applicable spread for OPG of 0.7075 percent.
- Niagara 3: $30M on April 23, 2007 at a rate of 4.973 percent reflecting a rate of 4.263 percent and an applicable spread for OPG of 0.71 percent.

OPG did not borrow funds in either Q3 or Q4 of 2007 as a result of delays experienced by OPG's contractor.

OPG hedged its interest rate exposure with respect to its forecast quarterly borrowing for the Niagara Tunnel project in accordance with the direction approved by OPG's Risk Oversight Committee described in section 3.5 below. The effective costs of OPG's Niagara 2 and 3 debt issues is 5.10 and 5.09 percent respectively as determined in Ex. C1-T2-S2 Table 6.

3.3 Planned Corporate Long-Term Debt Issues: 2008 and 2009

OPG's planned debt issues are listed in Ex. C1-T2-S2 Table 4 (2008), and Table 5 (2009). In 2008, OPG will retire one $200M debt issue on March 22 (issue 9), replacing it with a $200M issue of 10-year term debt also on March 22 (issue 26). OPG will retire a second $200M debt issue on September 22 (issue 10), replacing it with a $150M issue of 10-year term debt forecast to also be issued on September 22 (issue 27), and $50M funded from operations based on the current business plan. The $350M in replacement debt issues will be financed under the $950M refinancing agreement with the OEFC. OPG has hedged $100M associated with each of these forecast debt issues. The effective interest rates after these interest rate swap transactions are 5.53 percent for issue 26 and 5.71 percent for issue 27 as determined in Ex. C1-T2-S2 Table 4b.

OPG forecasts that it will repay the $175M debt issue maturing on March 22, 2009 (issue 11) and a second $175M debt issue maturing on September 22, 2009 (issue 12) from operations based on its current business plan. However, both of these debt issues (issues 11 and 12) could be refinanced under the $950M refinancing agreement with the OEFC if sufficient cash flow is not available.

3.4 Planned Project-Related Long-Term Debt Issues: 2008 and 2009

Other than the Niagara Tunnel project, OPG does not plan to undertake projects involving project-related financing for the prescribed assets during the test period. Any cost associated with nuclear refurbishments are reflected in OM&A expense during the test-period, and no specific borrowing requirement has been identified at this time.

Quarterly borrowing associated with financing progress payments to OPG's contractor for the Niagara Tunnel project are forecast to resume in Q1 2008 and continue through 2009. OPG plans to borrow $210M under its Niagara Tunnel project related debt facility during 2008. OPG forecasts borrowing $40M in January 2008 and the remaining $170M in three instalments, $50M drawn in April, $50M draw in July and $70M drawn in October (listed as Niagara 4 - Niagara 7 in Ex. C1-T2-S2 Table 4 (2008) and Table 5 (2009). OPG has hedged all four of its forecast debt issues during 2008. The effective cost of these issues is determined in Ex. C1-T2-S2 Table 4b.

In 2009, OPG forecasts borrowing $350M under its Niagara Tunnel project-related debt facility, comprised of $80M in January, $90M in April, $80M in July and $100M in October (listed as Niagara 8 - Niagara 11 in Ex. C1-T2-S2 Table 5). OPG has hedged all four of its forecast debt issues during 2009. The effective cost of these issues is determined in Ex. C1-T2-S2 Table 5b.

3.5 Hedging Costs

OPG's risk management initiative is described in section 3.3 of Ex. C1-T1-S2. The impact of hedging activities on OPG's effective debt cost is described below. As only a portion of theforecast face value of the debt is hedged in any period, the interest rate cost for each specific debt issue reflects a weighted average of the hedge amount and the unhedged amount.

In 2005 and 2006, OPG entered into transactions to hedge a portion of its interest rate exposure on the project-related financing associated with the Niagara Tunnel project. Forward interest rate swaps were used to minimize volatility and to mitigate the risk of an increase in the interest rate since the planned draw dates are in the future, and correspond to the projected cash flow schedule for the project, net of any contingencies. The interest rate swap requires OPG to sell the "floating" OEFC debt rate determined at the date funds are advanced and receive the "fixed" interest rate established in the interest rate swap agreement. Since the maximum term of the debt notes from the OEFC is 10-years, each of OPG's debt notes and hedges will have a 10-year term.

For the Niagara Tunnel project, the total amount of all hedges maturing each quarter did not exceed 75 percent of the total planned cash expenditures for the project. The percentage of each corporate debt issue hedged was exactly 50 percent of the maturing amount. The hedges entered into were consistent with the recommendations approved by the Risk Oversight Committee.

OPG entered into six interest rate hedges amounting to $140M in total for the Niagara Tunnel project debt issued in 2006. OPG issued debt with the OEFC of $160M at a rate of 4.986 percent reflecting a bank of Canada rate of 4.254 percent and a corporate spread for OPG of 0.7325 percent. The financial impact of the six matured hedges resulted in an effective rate of 5.23 percent on the Niagara 1 debt issue, and is summarized in Table 6 of Ex. C1-T2-S2. The settlement on the hedges resulted in a payment of $3.8M by OPG. For accounting purposes, the difference between the interest rate swaps (4.975 percent) as illustrated in Ex. C1-T2-S2 Table 6 and the settlement of the hedges ($3.8M) on the date OPG received the debt from the OEFC is recognized over the 10-year duration of the agreement. OPG proposes to follow its accounting treatment and amortize this payment for the purposes of establishing payment amounts; therefore it has reflected the financial impact of the hedge transaction in its effective interest rate. The amortized $3.8M converted into basis points based on the amount of debt from the OEFC ($160M) results in an incremental cost of 0.24 percent above the OEFC debt rate of 4.986 percent.

OPG has hedged a portion of the interest rate exposure on the 2007 Niagara Tunnel project debt and hedged a portion of the interest rate exposure on its forecast corporate debt refinancing of new issues during 2007.

The two debt issues related to the Niagara Tunnel project reached maturity before December 31, 2007; therefore the financial impact of these transactions is provided in Ex. C1-T2-S2 Table 6. The interest rate difference is realized over the duration of the interest rate swap agreement for accounting and ratemaking purposes. The financial impact of these matured hedges results in an effective rate of 5.10 percent and 5.09 percent for the Niagara 2 and Niagara 3 debt issues respectively.

OPG anticipated higher financial requirements associated with the Niagara Tunnel project during Q3 and Q4 of 2007. As a result of lower than forecast borrowings, OPG had hedges of $30M and $35M relating to the undrawn debt in the third and fourth quarters of 2007 maturing on July 22, 2007 and October 22, 2007 resulting in payments to OPG of $0.9M (as described in Table 6). The accounting rules require OPG to recognize this income in the period since no debt was drawn relating to the hedge.

On September 22, 2007 OPG issued $200M in debt (issue 24). As it is corporate debt, OPG hedged the maximum 50 percent ($100M) as discussed in Ex. C1-T1-S2 Section 3.3. The interest rate difference is realized over the duration of the interest rate swap agreement for accounting and ratemaking purposes. The financial impact of the matured hedges results in an effective rate of 5.53 percent as described in Ex. C1-T2-S2 Table 7.

Details of hedge transactions that have not matured are provided in Ex. C1-T2-S2 Table 8 for the Niagara Tunnel project and Table 9 for corporate debt. The financial impact of these hedge transactions cannot be determined until the issue reaches maturity. For illustrative purposes the market value (market-to-market) of each of the hedges as at December 31, 2007 has been shown in the tables. A negative market value corresponds to a payment owing by OPG if the hedge had to be settled as at December 31, 2007, similarly a positive market value corresponds to a payment owing to OPG. The consolidated market value of all hedges that had not matured as at December 31, 2007 and that are forecast to mature prior to the end of the test period amounts to a negative $4.5M.

3.6 Other Long-Term Debt Costs

As discussed in Ex. C1-T1-S2 OPG determines a provision for long-term debt to reconcile the debt component of OPG's regulated capital structure with the proposed rate base that financing supports. OPG's other long-term debt provision is determined based on:

- The difference between the debt resulting from the application of OPG's proposed capital structure to its proposed regulated rate base.
- The project-related and corporate long-term debt assigned or allocated to OPG's regulated operations as discussed above.
- The portion of short-term debt allocated to regulated operations. This calculation is described in Ex. C1-T1-S3.

The average amount of new and refinanced debt issued each year for both corporate and project-related borrowing purposes is applied to the unhedged interest rate to determine the interest rate attributable to the other long-term debt provision necessary to reconcile the debt component of OPG's regulated capital structure with the proposed rate base that financing supports. OPG has provided a calculation identifying all debt issued in the year, the unhedged interest rate and the resulting average interest rate applicable to its other long-term debt provision in the footnotes of Ex. C1-T2-S2 Table 1 (2005), Table 2 (2006), Table 3 (2007), Table 4 (2008), and Table 5 (2009).

Numbers may not add due to rounding.

Table 1
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2005

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Coupon Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
							(Note 8)	
1	**Refinanced-Issue 17**	1	22.2			3/22/2005	5.49%	1.2
2	**Refinanced-Issue 18**	2	33.3			3/22/2005	5.71%	1.9
3	**Refinanced-Issue 19**	3	72.6			9/22/2005	5.49%	4.0
4	**Refinanced-Issue 20**	4	108.9			9/22/2005	5.71%	6.2
5	**Issue 1**		150.0			3/22/2006	5.62%	8.4
6	**Issue 2**		150.0			3/22/2006	5.78%	8.7
7	**Issue 3**		150.0			9/22/2006	5.62%	8.4
8	**Issue 4**		150.0			9/22/2006	5.78%	8.7
9	**Issue 5**		100.0			12/29/2006	5.94%	5.9
10	**Issue 6**		100.0			12/29/2006	5.44%	5.4
11	**Issue 7**		200.0			3/22/2007	5.85%	11.7
12	**Issue 8**		200.0			9/22/2007	5.85%	11.7
13	**Issue 9**		200.0			3/22/2008	5.90%	11.8
14	**Issue 10**		200.0			9/22/2008	5.90%	11.8
15	**Issue 11**		175.0			3/22/2009	6.01%	10.5
16	**Issue 12**		175.0			9/22/2009	6.01%	10.5
17	**Issue 13**	6	187.5			3/22/2010	6.60%	12.4
18	**Issue 14**	6	187.5			9/22/2010	6.60%	12.4
19	**Issue 15**	6	187.5			3/22/2011	6.65%	12.5
20	**Issue 16**	6	187.5			9/22/2011	6.65%	12.5
21	**Issue 17**	1	77.8	3/22/2005	5.0	3/22/2010	5.49%	4.3
22	**Issue 18**	2	116.7	3/22/2005	5.0	3/22/2010	5.71%	6.7
24	**Issue 19**	3	27.4	9/22/2005	5.0	9/22/2010	5.49%	1.5
25	**Issue 20**	4	41.1	9/22/2005	5.0	9/22/2010	5.71%	2.3
23	**Issue 21**	5	73.9	3/22/2005	5.0	3/22/2010	5.62%	4.2
26	**Issue 22**	5	269.6	4/29/2005	7.0	4/30/2012	5.72%	15.4
27	**Total**		3,543.5				5.95%	211.0
	Regulated Portion of Company-Wide Borrowing							
28	**Allocation**	7	2,116.2				5.95%	125.9
	Project Financing--Regulated Projects							
29	Not Applicable		0.0					0.0
	Total Regulated Long-Term Debt							
30	Line 28+29		2,116.2				5.95%	125.9

See Ex. C1-T2-S2 Table 1b for notes

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

Table 1b
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2005
Notes to Ex. C1, Tab 2, Sch. 2, Table 1

		Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1:	Refinancing--Issue 17	100.0	81.0	22.2
Note 1:	Issue 17	100.0	284.0	77.8
Note 2:	Refinancing--Issue 18	150.0	81.0	33.3
Note 2:	Issue 18	150.0	284.0	116.7
Note 3:	Refinancing--Issue 19	100.0	265.0	72.6
Note 3:	Issue 19	100.0	100.0	27.4
Note 4:	Refinancing--Issue 20	150.0	265.0	108.9
Note 4:	Issue 20	150.0	100.0	41.1
Note 5:	Issue 21	95.0	284.0	73.9
	Issue 22	400.0	246.0	269.6

Note 6: Issues 13, 14, 15, 16 are subordinated debt issues

Note 7: Percentage of Debt Allocated to Regulated Operations: 59.7%

Note 8: Includes related costs of issuance/redemption and the amortization of debt discount or premium

Note 9: Other Long-Term Debt Provision

	Weights	Unhedged Rates
Issue 17	1.0	5.490%
Issue 18	1.0	5.710%
Issue 19	1.0	5.490%
Issue 20	1.0	5.710%
Issue 21	1.0	5.620%
Issue 22	1.0	5.715%
Average Rate		5.623%

Numbers may not add due to rounding.

Table 2
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2006

Line No.	Issue	Note	Weighted Principal* ($M)	Issue/Redemption Date	Duration (years)	Maturity Date	Coupon Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
							(Note 11)	
1	**Issue 1**	1	33.3			3/22/2006	5.62%	1.9
2	**Issue 2**	2	33.3			3/22/2006	5.78%	1.9
3	**Issue 3**	3	108.9			9/22/2006	5.62%	6.1
4	**Issue 4**	4	108.9			9/22/2006	5.78%	6.3
5	**Issue 5**	5	99.5			12/29/2006	5.94%	5.9
6	**Issue 6**	6	99.5			12/29/2006	5.44%	5.4
7	**Issue 7**		200.0			3/22/2007	5.85%	11.7
8	**Issue 8**		200.0			9/22/2007	5.85%	11.7
9	**Issue 9**		200.0			3/22/2008	5.90%	11.8
10	**Issue 10**		200.0			9/22/2008	5.90%	11.8
11	**Issue 11**		175.0			3/22/2009	6.01%	10.5
12	**Issue 12**		175.0			9/22/2009	6.01%	10.5
13	**Issue 13**	8	187.5			3/22/2010	6.60%	12.4
14	**Issue 14**	8	187.5			9/22/2010	6.60%	12.4
15	**Issue 15**	8	187.5			3/22/2011	6.65%	12.5
16	**Issue 16**	8	187.5			9/22/2011	6.65%	12.5
17	**Issue 17**		100.0			3/22/2010	5.49%	5.5
18	**Issue 18**		150.0			3/22/2010	5.71%	8.6
19	**Issue 19**		100.0			9/22/2010	5.49%	5.5
20	**Issue 20**		150.0			9/22/2010	5.71%	8.6
21	**Issue 21**		95.0			3/22/2010	5.62%	5.3
22	**Issue 22**	9	400.0			4/30/2012	5.72%	22.9
23	**Total**		3,378.3				5.97%	201.6
	Regulated Portion of Company-Wide Borrowing							
24	Allocation	10	1,952.7				5.97%	116.6
	Project Financing--Regulated Projects							
25	**Niagara 1**	7	30.2	10/23/2006	10.0	10/22/2016	5.23%	1.6
26	**Total**		30.2				5.23%	1.6
	Total Regulated Long-Term Debt							
27	Line 24+26		1,983.0				5.96%	118.2

Notes:

		Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
1	Issue 1:		150	81	33.3
2	Issue 2:		150	81	33.3
3	Issue 3:		150	265	108.9
4	Issue 4:		150	265	108.9
5	Issue 5:		100	363	99.5
6	Issue 6:		100	363	99.5
7	Niagara 1	10/23/2006	160	69	30.2
	See Ex. C1-T2-S2 Table 6 for effective interest rate				

8 Issues 13, 14, 15, 16 are subordinated debt issues
9 Issue 22: Post 1999 Facility
10 Percentage of Debt Allocated to Regulated Operations: 57.8%
11 Includes related costs of issuance/redemption and the amortization of debt discount or premium
* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Numbers may not add due to rounding.

Table 3
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2007

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Coupon Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
1	**Issues 1-6 Redeemed During 2006**							
2	**Issue 7**	1	44.4			3/22/2007	5.85%	2.6
3	**Issue 8**	2	145.2			9/22/2007	5.85%	8.5
4	**Issue 9**		200.0			3/22/2008	5.90%	11.8
5	**Issue 10**		200.0			9/22/2008	5.90%	11.8
6	**Issue 11**		175.0			3/22/2009	6.01%	10.5
7	**Issue 12**		175.0			9/22/2009	6.01%	10.5
8	**Issue 13**	6	187.5			3/22/2010	6.60%	12.4
9	**Issue 14**	6	187.5			9/22/2010	6.60%	12.4
10	**Issue 15**	6	187.5			3/22/2011	6.65%	12.5
11	**Issue 16**	6	187.5			9/22/2011	6.65%	12.5
12	**Issue 17**		100.0			3/22/2010	5.49%	5.5
13	**Issue 18**		150.0			3/22/2010	5.71%	8.6
14	**Issue 19**		100.0			9/22/2010	5.49%	5.5
15	**Issue 20**		150.0			9/22/2010	5.71%	8.6
16	**Issue 21**		95.0			3/22/2010	5.62%	5.3
17	**Issue 22**		400.0			4/30/2012	5.72%	22.9
18	**Issue 23**	3	52.6	6/22/2007	10.0	6/22/2017	5.44%	2.9
19	**Issue 24**	4, 8	53.7	9/24/2007	10.0	9/22/2017	5.53%	3.0
20	**Issue 25**	4b	11.0	12/21/2007	10.0	12/22/2017	5.31%	0.6
21	**Total**		2,801.8				6.00%	168.1
	Regulated Portion of Company-Wide Borrowing							
22	**Allocation**	7	1,628.1				6.00%	97.7
	Project Financing--Regulated Projects							
23	**Niagara 1**		160.0	10/23/2006	10.0	10/22/2016	5.23%	8.4
24	**Niagara 2**	5	47.0	1/22/2007	10.0	1/23/2017	5.10%	2.4
25	**Niagara 3**	5	20.7	4/23/2007	10.0	4/24/2017	5.09%	1.1
26	**Total**		227.7				5.19%	11.8
	Total Regulated Funded Long-Term Debt							
27	(line 22+26)		1,855.8				5.90%	109.5

See Ex. C1-T2-S2 Table 3b for notes

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

Numbers may not add due to rounding.

Table 3b
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2007
Notes to Ex. C1, Tab 2, Sch. 2, Table 3

		Issue/Redemption Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1:	Issue 7:	3/22/2007	200.0	81.0	44.4
Note 2:	Issue 8:	9/22/2007	200.0	265.0	145.2
Note 3:	Issue 23	6/22/2007	100.0	192.0	52.6
Note 4:	Issue 24	9/24/2007	200.0	98.0	53.7
Note 4b:	Issue 25	12/21/2007	400.0	10.0	11.0
Note 5:	2007 Niagara 2-3	1/22/2007	50.0	343.0	47.0
		4/23/2007	30.0	252.0	20.7
	See Ex. C1-T2-S2 Table 2 for Niagara 1 financing				
	See Ex. C1-T2-S2 Table 6 for effective interest rate				

Note 6: Issues 13, 14, 15, 16 are subordinated debt issues

Note 7: Percentage of Debt Allocated to Regulated Operations: 58.1%

Note 8: See Ex. C1-T2-S2 Table 7 for effective interest rate

Numbers may not add due to rounding.

Updated: 2008-03-14
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Exhibit C1
Tab 2
Schedule 2
Table 4

Table 4
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2008

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Coupon Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
							(Note 10)	
1	**Issues 1-6 Redeemed During 2006**							
2	**Issues 7 and 8 Redeemed During 2007**							
3	**Issue 9**	1	44.9			3/22/2008	5.90%	2.7
4	**Issue 10**	2	145.8			9/22/2008	5.90%	8.6
5	**Issue 11**		175.0			3/22/2009	6.01%	10.5
6	**Issue 12**		175.0			9/22/2009	6.01%	10.5
7	**Issue 13**	7	187.5			3/22/2010	6.60%	12.4
8	**Issue 14**	7	187.5			9/22/2010	6.60%	12.4
9	**Issue 15**	7	187.5			3/22/2011	6.65%	12.5
10	**Issue 16**	7	187.5			9/22/2011	6.65%	12.5
11	**Issue 17**		100.0			3/22/2010	5.49%	5.5
12	**Issue 18**		150.0			3/22/2010	5.71%	8.6
13	**Issue 19**		100.0			9/22/2010	5.49%	5.5
14	**Issue 20**		150.0			9/22/2010	5.71%	8.6
15	**Issue 21**		95.0			3/22/2010	5.62%	5.3
16	**Issue 22**	7	400.0			4/30/2012	5.72%	22.9
17	**Issue 23**	8	100.0	6/22/2007		6/22/2017	5.44%	5.4
18	**Issue 24**	8	200.0	9/24/2007		9/22/2017	5.53%	11.1
19	**Issue 25**	7	400.0	12/21/2007		12/22/2017	5.31%	21.2
20	**Issue 26**	4, 10	155.6	3/22/2008	10.0	3/22/2018	5.53%	8.6
21	**Issue 27**	5, 10	41.1	9/22/2008	10.0	9/22/2018	5.71%	2.3
22	**Total**		3,182.4				5.88%	187.0
	Regulated Portion of Company-Wide Borrowing							
23	**Allocation**	9	1,849.2				5.88%	108.7
	Project Financing - Regulated Projects							
24	**Niagara 1**		160.0	10/23/2006		10/22/2016	5.23%	8.4
25	**Niagara 2**		50.0	1/22/2007		1/23/2017	5.10%	2.5
26	**Niagara 3**		30.0	4/23/2007		4/24/2017	5.09%	1.5
27	**Niagara 4**	6, 10	37.7	1/22/2008		1/22/2018	5.57%	2.1
28	**Niagara 5**	6, 10	34.7	4/22/2008		4/22/2018	5.57%	1.9
29	**Niagara 6**	6, 10	22.2	7/22/2008		7/22/2018	5.57%	1.2
30	**Niagara 7**	6, 10	13.4	10/22/2008		10/22/2018	5.82%	0.8
31	**Total**		348.0				5.31%	18.5
	Total Regulated Funded Long-Term Debt							
32	(line 23+31)		2,197.2				5.79%	127.2

See Ex. C1-T2-S2 Table 4b for notes

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

Numbers may not add due to rounding.

Table 4b
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2008
Notes to Ex. C1, Tab 2, Sch. 2, Table 4

Also see notes on Ex. C1-T2-S2 Table 5b			Issue/Redemption Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1:	Issue 9:		3/22/2008	200.0	82.0	44.9
Note 2:	Issue 10:		9/22/2008	200.0	266.0	145.8
Note 3:	Issue 26		3/22/2008	200.0	284.0	155.6
Note 4:	Issue 27		9/22/2008	150.0	100.0	41.1
Note 5:	2008 Niagara 4-7		1/22/2008	40.0	344.0	37.7
			4/22/2008	50.0	253.0	34.7
			7/22/2008	50.0	162.0	22.2
			10/22/2008	70.0	70.0	13.4
	See Ex. C1-T2-S2 Table 3 for Niagara 1-3 financing.					

Note 6: Issues 13, 14, 15, 16 are subordinated debt issues

Note 7: Issue 23, 24 & 25 2007 Issue - general corp debt

Note 8: Percentage of Debt Allocated to Regulated Operations: 58.1%

Note 9: Includes related costs of issuance/redemption and the amortization of debt discount or premium

Note 10: Future issue rate reference global insight (December 2007) & Interest Rate Hedges

Issue 26

GOC & OPG Spread		Swap Rate+75bps	Effective Rate
GOC Q1-08	4.18%	4.82%	
OPG spread	1.30%	0.75%	
	5.48%	5.57%	5.53%
	100.0	100.0	

Issue 27

GOC & OPG Spread		Swap Rate+75bps	Effective Rate
GOC Q3-08	4.36%	4.98%	
OPG Spread	1.30%	0.75%	
	5.66%	5.73%	5.71%
	50.0	100.0	

Niagara 4

GOC & OPG Spread		Swap Rate+75bps	Effective Rate
GOC Q1-08	4.18%	4.83%	
OPG spread	1.30%	0.75%	
	5.48%	5.58%	5.57%
	5.0	35.0	

Niagara 5

GOC & OPG Spread		Swap Rate+75bps	Effective Rate
GOC Q2-08	4.26%	4.83%	
OPG Spread	1.30%	0.75%	
	5.56%	5.58%	5.57%
	20.0	30.0	

Niagara 6

GOC & OPG Spread		Swap Rate+75bps	Effective Rate
GOC Q3-08	4.36%	4.75%	
OPG Spread	1.30%	0.75%	
	5.66%	5.50%	5.57%
	20.0	30.0	

Niagara 7

GOC & OPG Spread		Swap Rate+75bps	Effective Rate
GOC Q4-08	4.74%	4.78%	
OPG Spread	1.30%	0.75%	
	6.04%	5.53%	5.82%
	40.0	30.0	

Average Unhedged Rate (simple avg)	5.65%

Table 5
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2009

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Coupon Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
1	**Issues 1-6 Redeemed During 2006**							
2	**Issues 7 and 8 Retired During 2007**							
3	**Issues 9 and 10 Redeemed During 2008**							
4	**Issue 11**	1	38.8			3/22/2009	6.01%	2.3
5	**Issue 12**	2	127.1			9/22/2009	6.01%	7.6
6	**Issue 13**	4	187.5			3/22/2010	6.60%	12.4
7	**Issue 14**	4	187.5			9/22/2010	6.60%	12.4
8	**Issue 15**	4	187.5			3/22/2011	6.65%	12.5
9	**Issue 16**	4	187.5			9/22/2011	6.65%	12.5
10	**Issue 17**		100.0			3/22/2010	5.49%	5.5
11	**Issue 18**		150.0			3/22/2010	5.71%	8.6
12	**Issue 19**		100.0			9/22/2010	5.49%	5.5
13	**Issue 20**		150.0			9/22/2010	5.71%	8.6
14	**Issue 21**		95.0			3/22/2010	5.62%	5.3
15	**Issue 22**		400.0			4/30/2012	5.72%	22.9
16	**Issue 23**		100.0			6/22/2017	5.44%	5.4
17	**Issue 24**		200.0			9/22/2017	5.53%	11.1
18	**Issue 25**		400.0			12/22/2017	5.31%	21.2
19	**Issue 26**		200.0			3/22/2018	5.53%	11.1
20	**Issue 27**		150.0			9/22/2018	5.71%	8.6
21	**Total**		2,960.9				5.85%	173.3
	Regulated Portion of Company-Wide Borrowing							
22	**Allocation**	5	1,720.5				5.85%	100.6
	Project Financing - Regulated Projects							
23	**Niagara 1**		160.0	10/23/2006		10/22/2016	5.23%	8.4
24	**Niagara 2**		50.0	1/22/2007		1/23/2017	5.10%	2.5
25	**Niagara 3**		30.0	4/23/2007		4/24/2017	5.09%	1.5
26	**Niagara 4**		40.0	1/22/2008		1/22/2018	5.57%	2.2
27	**Niagara 5**		50.0	4/22/2008		4/22/2018	5.57%	2.8
28	**Niagara 6**		50.0	7/22/2008		7/22/2018	5.57%	2.8
29	**Niagara 7**		70.0	10/22/2008		10/22/2018	5.82%	4.1
30	**Niagara 8**	3, 6	75.2	1/22/2009		1/22/2009	6.02%	4.5
31	**Niagara 9**	3, 6	62.4	4/22/2009		4/22/2019	6.22%	3.9
32	**Niagara 10**	3, 6	35.5	7/22/2009		7/22/2019	6.17%	2.2
33	**Niagara 11**	3, 6	19.2	10/22/2009		10/22/2019	6.25%	1.2
34	**Total**		642.2				5.62%	36.1
	Total Regulated Funded Long-Term Debt							
35	(line 22+34)		2,362.7				5.79%	136.8

See Ex. C1-T2-S2 Table 5b for notes

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

Table 5b
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt ($M)
Outstanding During Calendar Year Ending Dec. 31, 2009
Notes to Ex. C1, Tab 2, Sch. 2, Table 5

		Issue/Redemption Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1:	Issue 11	3/22/2009	175.0	81.0	38.8
Note 2:	Issue 12	9/22/2009	175.0	265.0	127.1
Note 3:	2009 Niagara 8-11	1/22/2009	80.0	343.0	75.2
		4/22/2009	90.0	253.0	62.4
		7/22/2009	80.0	162.0	35.5
		10/22/2009	100.0	70.0	19.2
	See Ex. C1-T2-S2 Table 3 for Niagara 1-3 financing, and Ex. C1-T2-S2 Table 4 for Niagara 4-7 financing				

Note 4: Issues 13, 14, 15, 16 are subordinated debt issues

Note 5: Percentage of Debt Allocated to Regulated Operations: 58.1%

Note 6: Future issue rate reference global insight (December 2007) & Interest Rate Hedges

Niagara 8

GOC & OPG Spread		Swap Rate+75bps	Effective Rate
GOC - 09	4.98%	4.83%	
OPG Spread	1.30%	0.75%	
	6.28%	5.58%	6.02%
	50.0	30.0	

Niagara 9

GOC & OPG Spread		Swap Rate+75bps	Effective Rate
GOC - 09	5.17%	5.08%	
OPG Spread	1.30%	0.75%	
	6.47%	5.83%	6.22%
	55.0	35.0	

Niagara 10

GOC & OPG Spread		Swap Rate+75bps	Effective Rate
GOC - 09	5.25%	4.93%	
OPG Spread	1.30%	0.75%	
	6.55%	5.68%	6.17%
	45.0	35.0	

Niagara 11

GOC & OPG Spread		Swap Rate+75bps	Effective Rate
GOC - 09	5.28%	4.88%	
OPG Spread	1.30%	0.75%	
	6.58%	5.63%	6.25%
	65.0	35.0	

Average Unhedged Rate: 6.47%

Numbers may not add due to rounding.

Table 6
Capitalization and Cost of Capital
Interest Rate Swap Agreements - Niagara Tunnel Project
Existing Debt Issues up to December 31, 2007

Line No.	**Year**	**Deal**	**Amount**	**Fixed Rate (%)**	**Deal Date**	**Underlying Bond FV ($K)**	**Underlying Bond Issue Date[1]**	**Underlying Bond Maturity**	**Underlying Bond Rate**	**Impact ($)**
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**2006**	67631	25,000,000	4.986%	Jul 12, 06					(716,160)
2		67632	25,000,000	4.985%	Jul 12, 06					(704,442)
3		67633	25,000,000	4.980%	Jul 12, 06					(679,000)
4		67634	25,000,000	4.980%	Jul 12, 06					(688,000)
5		67635	25,000,000	4.980%	Jul 12, 06					(686,692)
6		67636	15,000,000	4.919%	Jul 24, 06					(349,970)
7			140,000,000	4.975%		160,000,000	10/23/2006	10/22/2016	4.986%	(3,824,264)
		Effective Rate[2]							5.225%	
8	**2007**	67637	30,000,000	4.663%	Nov 08, 05					(374,920)
9		67638	15,000,000	5.035%	Jul 13, 06					(635,193)
10			45,000,000	4.787%		50,000,000	1/22/2007	1/23/2017	4.893%	(1,010,113)
11		**Effective Rate[2]**							5.095%	
12		70594	20,000,000	4.680%	Nov 08, 05					(60,000)
13		70595	10,000,000	5.010%	Jul 21, 06					(292,700)
14			30,000,000	4.790%		30,000,000	4/23/2007	4/24/2017	4.973%	(352,700)
		Effective Rate[2]							5.091%	
15		50968	$20,000,000	4.620%	Nov 16, 05					816,200
16		59873	$10,000,000	5.075%	Jul 12, 06					57,750
17			30,000,000	4.772%						873,950
18		**Effective Rate[2]**								
19		50969	25,000,000	4.650%	Nov 16, 05					283,000
20		60131	10,000,000	5.130%	Jul 19, 06					(267,000)
21			35,000,000							16,000
22	**Total**		280,000,000	4.880%		240,000,000			4.965%	(4,297,127)
23	**Effective Rate**								5.144%	

Notes:
1 The underlying bond issue date also corresponds to the maturity of the swap deals
2 The Effective rate = underlying bond rate + $impact of the hedge settlement/ 10 years/ the notional value of the bond = h+ ((i)/10/(e))

Numbers may not add due to rounding.

Table 7
Capitalization and Cost of Capital
Interest Rate Swap Agreements - Non Project Related
Existing Debt Issues up to December 31, 2007

Line No.	Year	Deal	Amount	Fixed Rate (%)	Underlying Bond FV ($K)	Underlying Bond Issue Date[1]	Underlying Bond Maturity	Underlying Bond Rate	Impact ($)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**2007**	70234	$25,000,000	4.659%					458,250
2		70597	$25,000,000	4.650%					475,800
3		71316	$25,000,000	4.875%					37,050
4		72051	$25,000,000	5.265%					(723,450)
5			100,000,000		200,000,000	9/24/2007	9/22/2017	5.546%	247,650
6		**Effective Rate[2]**						5.534%	

Notes:

1 The underlying bond issue date also corresponds to the maturity of the swap deals

2 The Effective rate = underlying bond rate + $impact of the hedge settlement/ 10 years/ the notional value of the bond = h+ ((i)/10/(e))

Numbers may not add due to rounding.

Table 8
Capitalization and Cost of Capital
Interest Rate Swap Agreements - Niagara Tunnel Project
Planned Debt Issues after December 31, 2007

Line No.	**Year**	**Deal**	**Face Value**	**Mark-to-Market (12/31/07)**	**Fixed Rate (%)**	**Deal Date**	**Start Date**	**Maturity Date**
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**2008**	50931	$25,000,000	($78,155)	4.749%	Nov 15, 05	Jan 22, 08	Jan 22, 18
2		60496	$10,000,000	($259,483)	5.037%	Jul 27, 06	Jan 22, 08	Jan 22, 18
3			$35,000,000	($337,637)	4.831%			
4		50930	$25,000,000	($119,902)	4.780%	Nov 15, 05	Apr 22, 08	Apr 22, 18
5		60284	$5,000,000	($145,385)	5.090%	Jul 24, 06	Apr 22, 08	Apr 22, 18
6			$30,000,000	($265,287)	4.832%			
7		51231	$25,000,000	$114,180	4.680%	Nov 22, 05	Jul 22, 08	Jul 22, 18
8		60285	$5,000,000	($147,464)	5.120%	Jul 24, 06	Jul 22, 08	Jul 22, 18
9			$30,000,000	($33,284)	4.753%			
10		51232	$25,000,000	$135,238	4.695%	Nov 22, 05	Oct 22, 08	Oct 22, 18
11		60133	$5,000,000	($171,860)	5.215%	Jul 19, 06	Oct 22, 08	Oct 22, 18
12			$30,000,000	($36,622)	4.782%			
13	**2009**	51227	$25,000,000	$86,529	4.747%	Nov 22, 05	Jan 22, 09	Jan 22, 19
14		60132	$5,000,000	($169,042)	5.240%	Jul 19, 06	Jan 22, 09	Jan 22, 19
15			$30,000,000	($82,513)	4.829%			
16		50574	$25,000,000	($283,686)	4.973%	Nov 04, 05	Apr 22, 09	Apr 22, 19
17		59751	$10,000,000	($402,572)	5.360%	Jul 07, 06	Apr 22, 09	Apr 22, 19
18			$35,000,000	($686,258)	5.084%			
19		51233	$25,000,000	$110,440	4.790%	Nov 22, 05	Jul 22, 09	Jul 22, 19
20		60130	$10,000,000	($324,863)	5.290%	Jul 19, 06	Jul 22, 09	Jul 22, 19
21			$35,000,000	($214,422)	4.933%			
22		51230	$30,000,000	$116,858	4.825%	Nov 22, 05	Oct 22, 09	Oct 22, 19
23		60232	$5,000,000	($129,287)	5.233%	Jul 21, 06	Oct 22, 09	Oct 22, 19
24			$35,000,000	($12,430)	4.883%			
25	**2010**	51311	$20,000,000	$164,340	4.790%	Nov 24, 05	Jan 22, 10	Jan 22, 20
26		60113	$10,000,000	($306,853)	5.330%	Jul 19, 06	Jan 22, 10	Jan 22, 20
30			$30,000,000	($142,513)	4.970%			
27		51490	$25,000,000	$80,164	4.875%	Nov 29, 05	Apr 22, 10	Apr 22, 20
28		51776	$15,000,000	$26,747	4.895%	Dec 06, 05	Apr 22, 10	Apr 22, 20
29		51777	$15,000,000	$26,747	4.895%	Dec 06, 05	Apr 22, 10	Apr 22, 20
30		60123	$10,000,000	($306,004)	5.350%	Jul 19, 06	Apr 22, 10	Apr 22, 20
31			$65,000,000	($172,346)	4.957%			
32		52078	$25,000,000	$66,202	4.898%	Dec 14, 05	Jul 22, 10	Jul 22, 20
33			$25,000,000	$66,202	4.898%			
34	**Total**		$380,000,000	($1,917,110)	4.895%			

Numbers may not add due to rounding.

Table 9
Capitalization and Cost of Capital
Interest Rate Swap Agreements - Non-Project Related
Planned Debt Issues after December 31, 2007

Line No.	Year	Deal	Face Value	Mark-to-Market (12/31/07)	Fixed Rate (%)	Issue Date	Start Date	Maturity Date
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**2008**	70458	$25,000,000	$125,851	4.650%	Apr 25, 07	Mar 24, 08	Mar 22, 18
2		70789	$25,000,000	$27,585	4.700%	May 07, 07	Mar 24, 08	Mar 22, 18
3		70916	$25,000,000	$47,238	4.690%	May 11, 07	Mar 24, 08	Mar 22, 18
4		71940	$25,000,000	($1,039,580)	5.243%	Jun 08, 07	Mar 24, 08	Mar 22, 18
5			$100,000,000	($838,905)	4.821%			
6		70598	$25,000,000	$80,490	4.715%	Apr 30, 07	Sep 22, 08	Sep 22, 18
7		71315	$25,000,000	($345,783)	4.937%	May 24, 07	Sep 22, 08	Sep 22, 18
8		71666	$25,000,000	($457,151)	4.995%	May 30, 07	Sep 22, 08	Sep 22, 18
9		72099	$25,000,000	($1,004,393)	5.280%	Jun 14, 07	Sep 22, 08	Sep 22, 18
10			$100,000,000	($1,726,837)	4.982%			
11	**Total**		$200,000,000	($2,565,742)	4.901%			

COST OF SHORT-TERM DEBT

1.0 PURPOSE

This evidence provides the details of OPG's annual short-term borrowing and associated costs for 2005 - 2009 determined pursuant to the methodology discussed in Ex. C1-T1-S3.

2.0 DESCRIPTION OF SHORT-TERM DEBT

OPG uses its commercial paper program and accounts receivable securitization program as its two main sources of short-term financing; however it also maintains a bank credit facility as the primary backstop to its commercial paper program. The bank credit facility provides protection to investors by allowing OPG to borrow by way of bankers' acceptances in the event OPG is unable to re-issue its commercial paper in the market place. The bank facility is $1B in size, comprised of a $500M 364-day tranche and a $500M five-year tranche. The facility has a current annual cost of $1.3M which is forecast to increase to $1.4M in 2008 and 2009 in response to OPG's request to reduce certain reporting requirements and to extend the term of the 364-day $500M tranche by one year.

OPG's commercial paper program is supported by the bank credit facility discussed above and is used to fund intra-month borrowing requirements. OPG did not use the commercial paper program extensively in 2005 or 2006, for the following reasons:

- In 2005 OPG was a net short-term borrower of commercial paper until April at which point OPG became an investor of cash for the remainder of the year. The interest cost on borrowed funds averaged 2.53 percent and totaled $445,000.
- In 2006 OPG was a net investor of cash until late December when it borrowed $15M as a bridge until OPG received its monthly revenue payment from the IESO in mid-January. The commercial paper borrowing rate at that time was 4.25 percent. OPG borrowed the $15M as its revenues for December 2006 were significantly less than forecast and OPG was required to retire certain OEFC borrowings (issue numbers 5 and 6, as shown in Ex. C1-T2-S2 Table 2).

OPG was able to fund intra-month working capital requirements during this period primarily as a result of a change in the market structure in 2005 and the timing of rebate payments as prescribed by regulation. OPG has used its commercial paper financing more extensively in 2007 to fund intra-month working capital requirements, and expects to continue to use this source of financing in 2008 and 2009. OPG borrowed an average of $30.9M on a daily basis in 2007 and will continue to make greater use of this program in 2008 and 2009. OPG forecasts that an average of $60M on a daily basis is required for a period of 20 days each month ($43M based on the average number of days each month) to finance OPG's normalized intra-month working capital requirements in both 2008 and 2009.

OPG's other primary source of short-term financing is its accounts receivable securitization program with the Royal Bank of Canada, under which it sold $300M of receivables in each of 2005, 2006 and 2007. The $300M is a portion of the month-end accounts receivable balance owing to OPG from the IESO for the prior month (OPG's month-end accounts receivable balances has ranged from $380M to $780M during this period). The accounts receivable securitization balance of $300M rolls over on a monthly basis and is supported by the amount of the IESO monthly payment. By selling its receivables, OPG is in essence borrowing money in advance of the monthly receipt from the IESO and the interest is the cost of that borrowed money. The accounts receivable securitization program is in effect until 2009; however OPG expects to continue the program after 2009. OPG's forecast reflects continued borrowing of $300M under this program throughout the test periods. Under the program OPG continues to service the receivables and pays a short-term cost of funds on a monthly basis to an independent trust.

3.0 SHORT-TERM DEBT COST

The pricing under the bank credit facility is market-based, and subject to the amount drawn and the term of the financing. If the facility is drawn in excess of 50 percent of the total amount ($1B), the rate added to the bankers' acceptance rate is 55 basis points (0.55 percent) otherwise the rate is 50 basis points. The cost of this borrowing (50 to 55 basis points above the bankers' acceptances rate) is more expensive than either OPG's commercial paper or securitization program. OPG did not borrow funds using this facility in either 2005, 2006 or 2007 and has not forecast specific borrowing under this facility in 2008 or 2009. The annual cost of maintaining the bank credit facility is currently $1.3M, which is forecast to increase to $1.4M in 2008 and 2009 to reflect changes in the bank facility discussed previously, and is included with OPG's commercial paper program costs, as the bank credit facility is required to support OPG's commercial paper program.

The fee associated with the accounts receivable securitization program is 0.3375 percent, which is added to the bankers' acceptances rate for OPG. The total rate is applied to the outstanding balance of the securitized funds on a daily basis. For 2005 the cost of the accounts receivable securitization program (inclusive of the program fee) was $9.1M or 3.02 percent, in 2006 the cost was $13.1M or 4.38 percent and in 2007 the cost was $14.9M or 4.98 percent. Although the accounts receivable securitization program is slightly more expensive than OPG's commercial paper program, it represents an alternative form of financing, and a more permanent component of OPG's short-term debt which does not fluctuate month to month. The pricing uncertainty in the asset-backed commercial paper market in Canada since the August 2007 liquidity crisis has increased the borrowing costs of the independent trust. The cost of borrowing over the bankers' acceptances rate has increased from nil to 50 basis points in 2007. The spread over the bankers' acceptance rate is forecast to be 20 basis points for 2008. For 2009, a spread of 10 basis points has been used to reflect a return to more normal business conditions.

OPG's borrowing rate under the commercial paper program is market-based, comprised of a ten basis point dealer fee and a corporate spread over the bankers' acceptances rate for OPG. There has been significant credit tightening since August 2007 causing short-term borrowing cost on bankers' acceptances to soar above the yield on treasury securities. The indicative corporate spread on OPG's short-term borrowings increased from 3 basis points to 20 basis points in the latter part of 2007, and is currently around 10 basis points. OPG's forecast is based on the current corporate spread of 10 basis points in 2008 and 5 basis points in 2009 reflecting a return to more normal business conditions.

OPG has used the Global Insight forecast for December 2007 as the basis for the bankers' acceptances interest rate forecast after adjusting for the spread differential between bankers' acceptances and the yield on treasury securities. For 2008 the bankers' acceptances rate used is 4.9275 percent and for 2009 it is 5.17 percent.

Ex. C1-T2-S3 Table 1 summarizes OPG's forecast company-wide cost of short-term debt.

4.0 ALLOCATION TO REGULATED OPERATIONS

OPG's allocation methodology for determining the regulated portion of its short-term debt is described in Ex. C1-T1-S3. The rates of 55.5 percent (2005), 55.2 percent (2006) and 57.1 percent (for 2007 - 2009) have been applied to the short-term debt costs determined above and are reflected in the capitalization and cost of capital evidence provided in Ex. C1-T2-S1 Tables 2 - 6.

Numbers may not add due to rounding.

Table 1
Capitalization and Cost of Capital
Summary of OPG's Forecast Cost of Short-term Debt

Line No.	Description	2005	2006	2007	2008	2009
		(a)	(b)	(c)	(d)	(e)
1	**Commercial Paper Amount[1] ($M)**	0.0	0.0	30.9	43.0	43.0
2	**Interest Rate**	2.53%	4.25%	4.35%	5.13%	5.32%
3	**Facility Cost ($M)**	1.3	1.3	1.3	1.4	1.4
4	**Commercial Paper Cost ($M)**	1.3	1.3	2.6	3.6	3.7
5	**A/R Securitization Amount[1] ($M)**	300.0	300.0	300.0	300.0	300.0
6	**Interest Rate**	3.02%	4.38%	4.98%	5.47%	5.61%
7	**A/R Securitization Cost ($M)**	9.1	13.1	14.9	16.4	16.8
8	**Short-term Debt Amount[1] ($M)**	300.0	300.0	330.9	343.0	343.0
9	**Interest Rate**	3.44%	4.80%	5.30%	5.83%	5.98%
10	**Short-term Debt Cost**	10.3	14.4	17.5	20.0	20.5
	Regulated Portion of Short-Term Debt[2] ($M)					
11	**Short Term Debt Amount**	166.6	165.6	182.7	189.3	189.3
12	**Interest Rate**	3.44%	4.80%	5.30%	5.83%	5.98%
13	**Short-term Debt Cost**	5.7	7.9	9.7	11.0	11.3

1 Actual daily weighted average balance for 2005, 2006 and 2007.
Working Capital funding with commercial paper is assumed to be outstanding for the first 20 days of each month
2 Allocation factor determined at Ex. C1-T1-S3 Table 1.

Opinion

on

Capital Structure and Fair Return on Equity

Prepared for

ONTARIO POWER GENERATION

Prepared by

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.

November 2007

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I. INTRODUCTION AND EXECUTIVE SUMMARY

A. INTRODUCTION

My name is Kathleen C. McShane and my business address is 4550 Montgomery Avenue, Suite 350N, Bethesda, Maryland 20814. I am President of Foster Associates, Inc., an economic consulting firm. I hold a Masters in Business Administration with a concentration in Finance from the University of Florida (1980) and the Chartered Financial Analyst designation (1989).

I have testified on issues related to cost of capital and various ratemaking issues on behalf of local gas distribution utilities, pipelines, electric utilities and telephone companies, in more than 150 proceedings in Canada and the U.S. My professional experience is provided in Appendix J.

I have been requested by Ontario Power Generation Inc. ("OPG") to recommend a capital structure and fair return on equity for the Company's prescribed assets. OPG's prescribed assets include six hydroelectric generating stations comprising 3332 MW of capacity and three nuclear generation stations comprising 6606 MW of capacity.[1]

[1] Regulated operations also include the costs and revenues from the lease arrangements between OPG and Bruce Power for the Bruce Nuclear Generating Stations.

B. CONCLUSIONS

1. The return and capital structure for OPG's regulated operations are governed by the fair return standard.

2. A fair return for OPG's regulated operations, which encompasses both capital structure and return on equity, should respect the stand-alone principle.

3. OPG is entitled to the opportunity to earn a fair return on the assets that are devoted to, and are used and useful in, the provision of regulated service, i.e., its rate base. An original cost rate base should be used for purposes of determining the capital structure and the application of the return on equity.

4. A deemed capital structure should be adopted for OPG because:
   a. It is compatible with the premise that the allowed return should be based on the stand-alone risk of the regulated operations,
   b. It provides a means to implement the basic principle of finance that the higher the business risk, the lower should be the debt ratio, and
   c. OPG has significant non-regulated operations whose business risks and cost of capital may be different from the risks and cost of capital of its regulated business.

5. To estimate a reasonable return on equity and capital structure for OPG, I estimated the return on equity that would be applicable to a benchmark (average risk) Canadian utility. I subsequently estimated the deemed capital structure for OPG that:
   a. Is compatible with its business risks;
   b. Would permit it to achieve a stand-alone debt rating similar to that of the proxy utilities used to establish the benchmark return; and,

c. Would equate the level of total (business and financial) risk faced by OPG to that of a benchmark (average risk) Canadian utility.

6. The benchmark return on equity was estimated at 10.25-10.75%. The fair return for a benchmark utility reflects the following:

a. The return on equity is based on the results of three tests, equity risk premium, discounted cash flow and comparable earnings.

b. The equity risk premium test results are based on three separate approaches. The equity risk premium test supports the following return:

Risk-Free Rate	5.0%
Equity Risk Premium	4.25-5.25%
Financing Flexibility Adjustment	0.5%
Return on Equity	9.75-10.75%

c. The discounted cash flow test, applied to a sample of benchmark low risk U.S. utilities supports a cost of equity of 9.25-9.5%. With a 0.50% adjustment to the "bare-bones" market cost of equity for financing flexibility, a fair return based on the DCF test is 9.75-10.0%.

d. The comparable earnings test shows that, based on the achievable earnings returns of low risk competitive non-regulated Canadian firms, a fair return applicable to a benchmark utility would be approximately 12.5%.

e. With primary weight given to the two capital market tests, equity risk premium and discounted cash flow, the fair return for a benchmark Canadian utility is 10.25-10.75% (mid-point of 10.5%).

7. A return of 10.5% is applicable to OPG's regulated operations at a deemed common equity ratio sufficient to equate their total risk (business and financial) to that of the proxies used to estimate the benchmark return.

8. The deemed capital structure for OPG should respect the following principles:
   a. The stand-alone principle.
   b. Compatibility of the capital structure with OPG's business risks.
   c. Maintenance of creditworthiness/financial integrity.
   d. Compatibility with the benchmark return on equity.

9. With respect to relative business risk, OPG's regulated operations face significantly higher business risks than a benchmark average risk Canadian utility, or a low risk U.S. utility.

10. To ensure access to the public debt markets, the capital structure for OPG's regulated operations should be sufficient to achieve debt ratings on a stand-alone basis in the A category. The reasons for targeting an A rating include:
    a. OPG is facing the potential of significant capital expenditures, for which it may require public debt market access on reasonable terms and conditions. An A rating will help ensure access on reasonable terms and conditions when the debt capital is required.
    b. The market for BBB rated debt in Canada remains relatively small, and is particularly limited for long-term (i.e., 30 year) issues. OPG should have the ability to access the long-term debt market to finance long-term assets.
    c. The benchmark equity return recommended for OPG is intended to represent the return applicable to an average risk, A rated, Canadian utility. Targeting an A rating through the deemed capital structure ensures compatibility of the ROE and capital structure.

11. The current DBRS and S&P debt ratings for OPG's consolidated operations are based on equity ratios in the range of 55-60%. Based on an analysis of the debt rating reports, including the rating agencies' assessment of the business risks of the regulated

operations, the deemed common equity ratio for OPG's regulated operations would need to be in a similar range to maintain similar stand-alone debt ratings.

12. The quantitative guidelines of the debt rating agencies for a utility facing a similar business risk profile to OPG's regulated operations and an A debt rating support a deemed common equity ratio in the range of 55-60%.

13. The average common equity ratio for the electric utility industry in North America is approximately 45%, which, in conjunction with returns on equity in the 11-12% range, is associated with a debt rating of BBB. The deemed common equity ratio for OPG at the benchmark return on equity of 10.5% is premised on achieving an A rating. The deemed equity ratio will need to be materially higher than the industry average of 45% to notionally achieve an A debt rating.

14. OPG's regulated generation operations face higher business risk than the benchmark utilities, which are largely "wires" or "pipes" companies. To estimate the common equity ratio for OPG's regulated operations that would permit the application of the benchmark return of 10.5%, I estimated the incremental cost of equity for OPG from the cost of equity for utilities with a high proportion of generation assets. From their cost of equity, I also derived a generation-only cost of equity. The incremental costs of equity for the "high generation" utilities and for generation-only were then translated into the common equity ratio required to equate OPG's total risk to that of a low risk benchmark utility based on capital structure theory. The analysis, which takes account of the application of two capital structure theories, indicates that the range of the required common equity ratio for OPG's regulated operations consistent with the benchmark return is 55-60%.

15. A review of capital market participants' views indicates that the returns available to comparable U.S. utilities are materially higher than the returns that are allowed to Canadian utilities, the returns allowed for Canadian utilities are generally regarded as too low, and the returns that investors expect and are achieving from the traded utility entities in Canada are considerably higher than the returns that have been allowed by regulators. These factors are legitimate considerations to be taken into account in setting a fair and reasonable return for OPG's regulated operations, and are supportive of the recommended capital structure and return on equity.

16. I recommend the adoption of an automatic adjustment formula for return on equity for OPG. Since OPG is facing multiple limited issue proceedings, with ROE assigned to the first, the implementation of an automatic adjustment mechanism to operate until full rebasing of regulated payments is complete is particularly warranted.

The Board's existing formula, that is, a 75 basis point change in ROE for every one percentage point change in forecast 30-year Canada bond yields is a reasonable reflection of the relationship between the cost of equity and interest rates. However, the key to the success of the formula is the initial adoption of a reasonable return on equity.

The automatic adjustment mechanism needs to preserve OPG's right to seek a review of the formula if OPG's ability to attract capital on reasonable terms is at risk. In the alternative, OPG should be able to seek a review of its deemed capital structure, should its business risks change materially or its access to capital is threatened.

The formula should also be reviewed if forecast long Canada bond yields fall below 3.0% or exceed 8.0%, as those extremes could signal a material change in the capital market environment.

II. PRINCIPLES OF ANALYSIS FOR CAPITAL STRUCTURE AND RETURN ON EQUITY

A. THE FAIR RETURN STANDARD

The standards for a fair return arise from legal precedents[2] which are echoed in numerous regulatory decisions across North America.[3] A fair return gives a regulated utility the opportunity to:

1. earn a return on investment commensurate with that of comparable risk enterprises;
2. maintain its financial integrity; and,
3. attract capital on reasonable terms.

A fair return on the capital provided by investors not only compensates the investors who have put up, and continue to commit, the funds necessary to deliver service, but benefits all stakeholders, including ratepayers. A fair and reasonable return on the capital invested provides the basis for attraction of capital for which investors have alternative investment opportunities. Fair compensation on the capital committed to the utility provides the financial means to pursue technological innovations and build the infrastructure required to support long-term growth in the underlying economy.

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

[3] In EB-2005-0421(Toronto Hydro), dated April 12, 2006, the OEB stated, "And, as a matter of law, utilities are entitled to earn a rate of return that not only enables them to attract capital on reasonable terms but is comparable to the return granted other utilities with a similar risk profile." (pages 32-33)

An inadequate return, on the other hand, undermines the ability of a utility to compete for investment capital. Moreover, inadequate returns act as a disincentive to expansion, may potentially degrade the quality of service or deprive existing customers from the benefit of lower unit costs that might be achieved from growth. In short, if the utility is not provided the opportunity to earn a fair and reasonable return, it may be prevented from making the requisite level of investments in the existing infrastructure in order to reliably provide utility services for its customers. The OEB has recognized the importance of a financially viable energy sector and the need for additional energy infrastructure, particularly generation and transmission, in its Strategic Business Objectives set out in its 2006-2009 Business Plan (December 2005). Fair and reasonable returns are central to the achievement of those objectives.

B. THE STAND-ALONE PRINCIPLE

A fair return for OPG's regulated operations, which encompasses both capital structure and return on equity, should respect the stand-alone principle. The stand-alone principle has been respected by virtually every Canadian regulator, including the OEB, in setting both regulated capital structures and allowed returns on equity.

The stand-alone principle is the notion that the cost of capital incurred by ratepayers should be equivalent to that which would be faced by the regulated operations if they were raising capital in the public markets on the strength of their own business and financial parameters. In other words, application of the stand-alone principle to OPG’s regulated operations means they should be treated for regulatory purposes as if they were operating separately from the other activities of the firm. The cost of capital borne by ratepayers should reflect neither subsidies given to, nor taken from, other activities of the firm.

The evaluation of the appropriate capital structure and common equity return on a “stand-alone” basis avoids: (1) the misconception that the cost of raising capital to invest in a project (the financing decision) is the same as the cost of capital (required return) of the project (the investment decision); and (2) the potential that hidden subsidies created by using an inappropriate cost of capital can distort the economics of the project itself. To illustrate, the Federal Government can raise long-term debt at relatively low interest rates because its taxing power assures the cash flows needed to reimburse investors. If the Federal Government were to consider investing either in natural gas exploration and development or a water utility, its evaluation of the two potential investments should be based on required returns that reflect the different business risks of the two projects, not the cost to the Federal Government of raising debt to finance its investment. A failure to do so, that is a failure to respect the "stand-alone" principle, could lead to the erroneous conclusion that the oil and gas development project was the superior project and thus to an uneconomic allocation of capital resources. Effectively, the Federal Government would be subsidizing natural gas exploration and development, while potentially allowing a superior project to fail to attract investment funds. Respect for the stand-alone principle ensures that scarce capital resources are efficiently allocated to their best use. The allowed return should thus represent the stand-alone risk and associated cost of capital of the operations, not the happenstance of ownership.

C. RELATIONSHIP BETWEEN CAPITAL STRUCTURE AND COST OF CAPITAL

The stand-alone principle is grounded in the basic tenet of financial theory that the opportunity cost of capital to a firm, or division of a firm, is a function of its business risk. Business risk comprises the operating elements of the business that together determine the probability that future returns to investors will fall short of their expected and required returns. Business risk is a function of the fundamental characteristics of the operations, i.e., of the firm's assets. In the absence of income taxes and the added costs related to the loss of financial flexibility and financial distress or ultimately bankruptcy, the overall cost of capital would not change as the manner in which it was financed changed. The cost of capital would be the same if a firm were financed with 100% equity or 100% debt. In the absence of income taxes, the sum of the cash flows, available to both the debt holders and equity holders does not change as the capital structure changes. However, the use of debt creates a class of investors whose claims on the cash flows of the firm take precedence over those of the equity holder. Since the issuance of debt carries unavoidable servicing costs which must be paid before the equity shareholder receives any return, the potential variability of the equity shareholder's return rises as more debt is added to the capital structure. Thus, as the debt ratio rises, the cost of equity rises, but the overall cost of capital is constant.

However, two factors alter the conclusion that the cost of capital stays constant as the capital structure changes. First, the facts that (1) debt is less expensive than equity because debt investors take precedence over equity investors, and (2) interest expense on debt is deductible for corporate income tax purposes means that there is a cost advantage to using debt. Thus, financing with a combination of debt and equity can lower the overall (weighted average) cost of capital. Second, and partly offsetting the cost advantage of adding debt, are the additional costs that are incurred as more debt is added to the capital structure. As the debt in the capital structure increases, additional costs are incurred in the form of loss of financial flexibility and financial distress, e.g., more stringent debt covenants, restrictions on the amount and term of debt the market is willing to accept, and a decreased ability to access the market at the time funds are required. These additional costs negatively impact not only explicit costs of debt and equity financing, but can ultimately impact the ability to operate the business efficiently. As a result, too much debt will increase the weighted average cost of capital, as the costs of financial distress will outweigh the benefits of additional debt.

Two other factors can offset some of the advantage of using debt in the capital structure. The first factor is the impact of personal income taxes on interest income. While interest expense is deductible at the corporate level, the corresponding interest income is taxable to individual investors at higher rates than equity income. Second, in the case of utilities, the benefits of the tax deductibility of interest expense flow to ratepayers, not shareholders, as the utility revenue requirement is reduced to reflect the lower income tax expense. (In contrast, for unregulated companies, the benefits of interest expense deductibility will flow to equity shareholders in the form of a higher return.)

In theory, when all these factors are taken into account, there should be an optimal capital structure, i.e., one that minimizes the overall cost of capital. In practice, the interactions of the various factors make the optimal capital structure impossible to pin-point, and there exists a range of capital structures over which the average cost of capital does not change materially. Within this range, an increase in the debt ratio will result in an increase in both the cost of debt and the cost of equity, but the overall cost of capital will not change measurably. A key message is that the capital structure and the required return on equity are inter-dependent: As the debt ratio of the regulated operations rises, the cost of equity also rises. That relationship needs to be reflected in OPG's capital structure and allowed return on equity.

D. RATE BASE AND CAPITALIZATION

Under the fair return standard, a utility is entitled to the opportunity to earn a fair return on the investor-supplied capital that finances the assets that are devoted to, and are used and useful in, the provision of regulated service. The rate base represents the measurement of the assets that are used and useful in the delivery of public utility service; it corresponds to the amount of capital that has been provided by investors and upon which investors are allowed the opportunity to earn a fair return.

The most prevalent construct for measuring rate base in North America is a historic cost model, often referred to as "original cost rate base." Under the original cost methodology, the rate base is measured using the cost of the assets at the time they are first devoted to public service. When an original cost rate base is used, the return on rate base reflects the embedded cost of debt and a nominal (inclusive of inflation) return on equity. The domination of original cost ratemaking reflects the results of more than half a century of regulatory and court decisions.[4] Virtually every regulated utility in Canada relies on an original cost rate base for purposes of determining the allowed return on capital.

While the benefits of alternative models for rate base determination continue to be debated in North America from time to time, there is no evidence that the original cost methodology for rate base valuation would preclude utilities from attracting capital on reasonable terms and conditions or from earning a return that is comparable to that of similar risk enterprises as long as the level of the return itself recognizes the manner in which the rate base is measured. Moreover, the requirement that the OEB accept the financial statement asset and liability values of OPG as per Regulation 53/05 effectively eliminates from consideration any of the methodologies that are not derived from original cost (e.g., reproduction or replacement cost).

E. CAPITAL STRUCTURE: DEEMED VERSUS ACTUAL[5]

As indicated in Chapter II.C, the cost of capital to the utility is a function of business risk. It is also a function of financial risk. Financial risk refers to the additional risk that is borne by the equity shareholder because the firm is using fixed income securities – debt and preferred shares to finance a portion of its assets. The capital structure, comprised of debt, preferred share and common equity, can be viewed as a summary measure of the financial risk of the firm. While there is no universal agreement whether a single optimal capital structure for a firm exists, there is agreement that, as a general proposition, companies with less business risk can safely assume more debt than those with higher business risk without impairing their ability to access the capital markets on reasonable terms and conditions. In principle, higher business risk can be "offset" by assuming less financial risk. Thus, two utilities with different levels of business risk

[4] Original cost rate base became the standard after the watershed U.S. Supreme Court decision, *Federal Power Commission v. Hope Natural Gas (320 U.S. 391 (1944))*, which addressed the controversy between original cost and fair value. In its decision, the Court held that it is the end result, not the method employed to value the rate base that is important. As a result of the Court's findings in *Hope*, the original cost rate base became the standard, and the focus of regulation shifted from the valuation of the rate base to the fairness of the rate of return and the end result.
[5] Appendix A contains more detail on the history of, and issues related to, deemed capital structures.

can face similar costs of debt and equity if the utility facing higher business risk maintains a lower debt ratio than the utility facing lower business risk.

The concept of a deemed, or hypothetical, capital structure can be viewed as a means of imputing for regulatory purposes a level of financial risk that is "consistent" or "compatible" with the level of business risk that a utility faces. The term "deemed capital structure" simply refers to the imputation, for ratemaking purposes, of a capital structure that is different from the actual or reported capital structure as derived from the utility's financial statements. A deemed capital structure is typically applied by estimating the rate base, applying a specified percentage of common equity to the rate base, assigning to the rate base actual outstanding and forecast issues of long-term debt and preferred shares, and then, to the extent that the capital structure does not equal the rate base, "deem" the gap to be debt.

I recommend the adoption of a deemed capital structure for OPG's regulated operations.[6] The principal reasons for this recommendation are as follows:

1. Using a deemed capital structure is consistent with basing the allowed return on an opportunity cost of capital that reflects the use of funds (the risks of the operations to which the funds are committed), rather than the source of those funds.

2. Using a deemed capital structure is consistent with regulatory practice (consistent with financial theory) of adherence to the stand-alone principle as followed by Canadian regulators, including the OEB, in setting the allowed return on rate base.

3. Using a deemed capital structure allows the general principle to be applied that the higher is the regulated operations' business risk, the lower the debt ratio should be. Recognizing

[6] Issues relating to the specification of the appropriate deemed capital structure for OPG's regulated operations are addressed in Chapter IV.

the level of the regulated operations' business risks primarily through the allowed capital structure is a reasonable and accepted regulatory approach for differentiating among utilities and compensating them for differences in business risk.

4. OPG has significant non-regulated operations whose business risks and cost of capital may be different from the risks and cost of capital of its regulated business.

5. The use of a deemed capital structure provides assurance that ratepayers are protected from any negative impacts on the consolidated firm's cost of capital of unregulated operations.

III. BENCHMARK RETURN ON EQUITY

A. CONCEPT OF BENCHMARK RETURN ON EQUITY

As indicated in Chapter II, the cost of equity is a function of both business and financial risk. Financial risk, in turn, is a function of capital structure; the lower the common equity ratio, the higher is the financial risk and the higher is the cost of equity. When a utility is regulated on the basis of its actual capital structure or a previously approved deemed capital structure, its financial risk must be addressed through the return on equity. The fair return for a utility with a "fixed" capital structure would then be determined by (1) selecting a sample or samples of proxy companies of relatively similar business risk to the utility; (2) estimating the samples' cost of equity; (3) quantifying any difference in equity return requirement between the utility and the proxies due to differences in their capital structure; and (4) applying the financial-risk adjusted return on equity to the utility. However, for OPG both an appropriate deemed capital structure and fair return need to be determined. In setting the two values simultaneously, two basic principles need to be recognized. First, the higher the business risk that a utility faces, the lower would be an appropriate debt component, that is, one that would ensure the utility's ability to attract capital on reasonable terms and conditions. Second, the higher the debt component that is chosen for a regulated firm facing a given level of business risk, the higher would be the cost of equity and the reasonable allowed return on equity.

It is not possible to identify close proxies with equity market data, particularly within the Canadian capital market context, that can be used to directly estimate either a reasonable capital structure or the cost of equity for OPG's regulated operations, for two reasons. First, OPG's regulated operations are unique. Second, there are a very limited number of publicly-traded regulated companies in Canada. In the absence of Canadian proxies of similar risk to OPG, there are essentially two approaches that can be used. The first approach entails estimating and applying to OPG the equity return that would be applicable to a "benchmark" or average risk Canadian utility. That return will be referred to as a "benchmark return". A deemed capital structure for OPG would then be determined that (a) is compatible with its business risks; (b) would permit it to achieve a stand-alone debt rating similar to that of proxy companies used to establish the benchmark return; and (c) would equate the level of total (business and financial) risk faced by OPG to that of the proxies used to estimate the benchmark cost of equity. Under this approach, the benchmark return on equity is "fixed" and the deemed common equity ratio for OPG's regulated operations established so that no adjustment to the benchmark return on equity is required.[7]

The second approach sets the deemed capital structure first, relying on factors such as debt rating agency guidelines for an investment grade debt rating and capital structure ratios maintained by peers in the industry. This approach entails establishing a deemed common equity ratio that is reasonable, but would not necessarily equate OPG's total (business plus financial) risk to that of a benchmark utility. In the implementation of this approach, OPG's total risks would be compared to those of the proxy firms used to establish the benchmark. If OPG's total risk, at the specified deemed common equity ratio is higher than that of the benchmark utility, the incremental equity return requirement needs to be estimated and added to the return on equity applicable to a benchmark utility. The key difference between the first and second approaches is that in the second, both capital structure and return on equity are essentially "moving parts." Because there are so few publicly-traded utilities in Canada, both approaches rely on the measurement of a benchmark return on equity as a point of departure for estimating the return on equity applicable to a particular utility.

[7] In this regard, Standard & Poor's notes that the business and financial risk components are inextricable. "For example, a utility with a strong business profile could have less financial protection than one with a weaker business profile, yet they could still achieve the same rating. Conversely, a utility with a weak business profile could require a more robust financial profile than one with a stronger business profile in order to get the same rating." Standard & Poor's, *Research: Rating Methodology for Global Power Utilities*, August 30, 1999.

The term "benchmark utility" is a hypothetical construct, because it does not refer to a specific utility and hence reflects no specific business or financial risks. Since the estimate of the cost of equity is derived from market data for utilities across industries (electric, gas distribution and gas pipeline), the "benchmark utility" reflects, in effect, the composite of the business and financial risks faced by the utilities used to establish the benchmark return. However, one objective measure of what constitutes a benchmark utility would be its ability, on a stand-alone basis, to achieve debt ratings in the A category. The typical, average risk, Canadian utility is rated in the A category by both of the major debt rating agencies, DBRS and Standard & Poor's.

Designation of the debt rating as an indicator of relative risk recognizes that (1) debt ratings reflect both business and financial risk, and (2) the equity return requirement is a function of both business and financial risk. Thus, the benchmark return on equity would be one that is applicable to a specific utility whose capital structure is adequate to achieve, on a stand-alone basis, debt ratings in the A category (See Chapter IV.C for reasons). The estimation of the benchmark return on equity must then be derived from proxy groups whose total risk permits them to achieve debt ratings in the A category.

Both of the approaches described above have been taken by regulators in Canada. The first approach was employed by the National Energy Board (NEB) when it established its automatic adjustment mechanism for a number of oil and gas pipelines in 1995. The individual pipelines were deemed capital structure ratios that were intended to compensate for their different levels of business risks, so that a single "benchmark" return on equity could be applied across all of the pipelines. In the years since the multi-pipeline return on equity was adopted, the NEB has changed the allowed capital structure, rather than the allowed return, to recognize changes in business risk.

It is also the approach that was adopted by the Alberta Energy and Utilities Board (AEUB) in Decision 2004-052 (July 2, 2004). In that decision, the AEUB set different capital structures for eleven electric and gas distribution and transmission entities, based on their different business risk profiles, and then established a common return on equity to be applied to each of the utilities under its jurisdiction.

In contrast to the NEB and AEUB approach, the British Columbia Utilities Commission has allowed for both different capital structures and different equity risk premiums among the various utilities it regulates. The Commission explicitly specifies the low risk benchmark return on equity; each utility's risk premium is expressed in relationship to the low risk benchmark risk premium. It also has designated one utility (Terasen Gas) as the low risk benchmark utility.

In Ontario, the OEB has used both approaches. For the two large gas distribution utilities, the Board historically had approved the same deemed common equity ratios for Enbridge Gas Distribution and Union Gas and allowed a somewhat higher equity risk premium for Union Gas. As a result of its recent settlement (RP-2005-0520, June 29, 2006), Union Gas currently has a somewhat higher equity risk premium and a one percentage point higher deemed common equity ratio. As a result of the Board's Reasons for Decision in EB-2005-0544 (September 20, 2006), Natural Resource Gas is allowed a higher common equity ratio and a higher equity risk premium than either Enbridge or Union. For the electricity distribution utilities, from 2000-2006 the Board allowed a range of deemed common equity ratios using size of rate base as the distinguishing risk factor and applied the same return on equity to each of the utilities.

In my opinion, both approaches are valid as long as the combination of capital structure and return on equity for a particular utility reasonably compensates for the shareholders for the utility's combined business risk and financial risks relative to that of its peers.

For OPG, I have relied on the approach that was adopted by the OEB for electricity distributors in 2000, and by the NEB (1995) and AEUB (2004). Specifically, I estimated a benchmark return on equity and then determined the deemed capital structure for OPG's regulated operations that is compatible with its business risks, would permit it to achieve the same debt rating on a stand-alone basis as the utilities used to estimate the benchmark return, and would equate its level of total business and financial risks to those of the proxy samples.

B. APPROACH TO ESTIMATION OF BENCHMARK RETURN ON EQUITY

To ensure that the allowed return considers all of the relevant factors that bear on a fair return, I recommend application of the three tests that have traditionally been used to set a fair return for regulated companies: the equity risk premium test, the discounted cash flow test and the comparable earnings test. Reliance on multiple tests recognizes that no one test produces a definitive estimate of the fair return.[8] Each test is a forward-looking estimate of investors' equity return requirements. However, the premises of each of the three tests differ; each test has its own strengths and weaknesses. In principle, the concept of a fair and reasonable return does not reduce to a simple mathematical construct. It would be unreasonable to view it as such.

Moreover, the three criteria that define a fair return, set forth in Chapter II.A, give rise to two separate standards, the capital attraction standard and the comparable returns, or comparable earnings, standard. A fair and reasonable return gives weight to both the cost of attracting capital Standard and comparable earnings standard.[9] The two standards are applied using different tests. The equity risk premium and discounted cash flow tests establish the cost of attracting capital. The comparable earnings test is a measure of the comparable return, or comparable earnings, standard. To establish the benchmark return on equity, I have applied all three. The application of each of the tests is discussed in the sections below.

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[8] As stated in Bonbright, "No single or group test or technique is conclusive." (James C. Bonbright, Albert L. Danielsen, David R. Kamerschen, *Principles of Public Utility Rates*, 2nd Ed., Arlington, Va.: Public Utilities Reports, Inc., March 1988).
[9] Appendix B discusses the distinctions between the two standards.

C. EQUITY RISK PREMIUM TESTS

C.1. Conceptual Underpinnings

The equity risk premium test is derived from the basic concept of finance that there is a direct relationship between the level of risk assumed and the return required. Since an investor in common equity takes greater risk than an investor in bonds, the former requires a premium above bond yields in compensation for the greater risk. The equity risk premium test is a measure of the market-related cost of attracting capital, i.e., a return on the market value of the common stock, not the book value.

The equity risk premium test, similar to the other tests used to arrive at a fair return, is forward-looking, that is, it is intended to estimate investors' future equity return requirements. The magnitude of the differential between the required/expected return on equities and the risk-free rate is a function of investors' willingness to take risks[10] and their views of such key factors as inflation, productivity and profitability. Because the risk premium test is forward-looking, historic risk premium data need to be evaluated in light of prevailing economic/capital market conditions. If available, direct estimates of the forward-looking risk premium should supplement estimates of the risk premium made using historic data as the point of departure.

[10] To illustrate, equity market volatility has picked up significantly in 2007, as investors have become less sanguine about the future of the equity market, in light of the recent housing market and sub-prime mortgage market crises. The VIX index, an equity volatility index calculated by the Chicago Board Option Exchange (often referred to as the "Fear Gauge"), indicates that, during much of 2004-2006, the equity market was perceived as unusually stable; that is no longer the case. The VIX index has been rising throughout 2007, increasing by approximately 150% from the beginning of the 2007 to the middle of the 4th Quarter, with much of the increase in the latter half of the year. During November of 2007, the VIX index reached its highest levels since 2003. An increase in the VIX index signals rising risk aversion and an increase in the required equity risk premium.

C.2. Risk-Free Rate

The application of the equity risk premium tests requires a forecast of the risk-free rate to which the equity risk premium is applied. Reliance on a long-term government bond yield as the risk-free rate recognizes (1) the administered nature of short-term rates; and (2) the long-term nature of the assets to which the equity return is applicable. The risk-free rate, for purposes of this analysis, is the forecast 30-year Canada yield which is based on the consensus forecast for 10-year Canada bonds plus the spread between 10- and 30-year Canada bond yields.[11] *Consensus Forecasts*, Consensus Economics (August 13, 2007) anticipates that the 10-year yield will be approximately 4.7% by November 2007 and 5.0% by August 2008 (average of 4.85).

At the end of August 2007, the yield curve was relatively flat; the yields on 10- and 30-year bonds were only approximately 10 basis points apart. On average, historically, the spread has been a positive 30 basis points, reflecting a normal upward sloping yield curve. For purposes of applying the equity risk premium test for the test period, I have estimated the 30-year Canada bond yield at approximately 5.0%, reflecting a continuation of a relatively flat yield curve.[12]

C.3. Risk-Adjusted Equity Market Risk Premium Test

C.3.a. Conceptual and Empirical Considerations

The risk-adjusted equity market risk premium approach to estimating the required utility equity risk premium entails (1) estimating the equity risk premium for the equity market as a whole; (2) estimating the relative risk adjustment required for a benchmark Canadian utility; and (3) applying the relative risk adjustment to the equity market risk premium, to arrive at the equity risk premium required for a benchmark Canadian utility. The cost of equity is thus estimated as:

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[11] There is no consensus forecast of 30-year Canadian bond yields.

[12] The long-term Canada bond yield (and resulting ROE) will be updated for the most recent available forecast prior to the hearing.

$$\text{Risk-Free Rate} + \left\{ \text{Relative Risk Adjustment} \times \text{Market Risk Premium} \right\}$$

The risk-adjusted equity market risk premium test is a variant of the Capital Asset Pricing Model (CAPM). The CAPM attempts to measure what an equity investor should require as a return within the context of a diversified portfolio. Its focus is on the minimum return that will allow a company to attract equity capital.

In the CAPM, risk is measured using the beta. Theoretically, the beta is a forward looking estimate of the contribution of a particular stock to the overall risk of a portfolio. In practice, the beta is a calculation of the historical correlation between the overall equity market, as proxied in Canada by the S&P/TSX Composite, and individual stocks or portfolios of stocks.

The CAPM, framed in an elegant, simple construct, has an intuitive appeal. However, in addition to its restrictive premises, the CAPM does have disadvantages that caution against placing sole reliance on it for purposes of determining a fair return on equity. The disadvantages are summarized in Appendix C.

C.3.b. <u>Equity Market Risk Premium</u>

C.3.b.(1) Globalization

My estimate of the expected/required equity market risk premium was made by reference to an analysis of historic (experienced) market risk premiums. Analysis of historic risk premiums should not be limited to the Canadian experience, but should also take into account the U.S. equity market as a relevant benchmark for estimating the equity risk premium from the perspective of Canadian investors.

The historic Canadian equity and government bond returns incorporate various factors that make them questionable as a realistic representation of future risk premiums (e.g., capital held captive in Canada as a matter of policy, lack of equity market liquidity and diversity, and the higher risk of the Government of Canada bond market historically, which has since dissipated).

Of particular importance has been the historic impact of the Foreign Property Rule (FPR), which capped the proportion of foreign investment that could be held by individuals (in RRSPs) and by pension funds. The combination of mediocre returns and small size of the Canadian market relative to the total global market (approximately 2%) put pressure on the government to increase and finally eliminate the cap on foreign investment that could be held in RRSPs and pension funds. This cap has been as low as 10% of the book value of assets (from 1971 to 1990) and was at 30% when it was removed entirely in August 2005 effective January 1, 2005.[13] Historic Canadian equity returns therefore are likely to understate investor return requirements.

The investor reaction to the increasingly less restrictive FPR supports that conclusion. Equity investment outside of Canada has grown rapidly as the barriers to foreign investment (in terms of both transactions and information costs as well as the foreign investment cap) have declined. Foreign stock purchases by Canadians have increased over seven-fold over the past decade. Purchases in 1995 were $83 billion; in 2006, they were $570 billion.[14] In 2006, although the total percentage of foreign assets in the top 100 Canadian pension funds was only 33%, the percentage of foreign equity to total equity was close to 56%.[15] While the FPR was in effect, pension funds concentrated their foreign investment allocations to the equity markets, with the preponderance of their fixed income allocations to domestic bonds.

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[13] From 1957 to 1971 no more than 10% of income could come from foreign sources.

[14] The IFIC's report "Year 2002 in Review" stated,

> During the period of 1991-1998, the percentage of sales in equity mutual funds that were comprised of non-domestic equities has hovered around the 41-58% range. This has significantly increased in 1999 and onwards. While performance in the markets is the major factor affecting such an increase, these figures can also be attributed to increases in foreign content limits in registered retirement savings plans as well as increased interest and availability of foreign clone funds.

[15] Benefits Canada, "2007 Top 100 Pension Funds", May 2007.

The relevance of the U.S. experience to the estimation of the risk premium from a Canadian perspective has increased as the relationship between Canadian and U.S. interest rates has changed. From 1947-2006, the achieved risk premiums in Canada were 140 basis points lower than in the U.S. Of that amount, approximately 80 basis points are accounted for by historically higher bond yields in Canada. With the vastly improved economic fundamentals in Canada (e.g., lower inflation, balanced budgets), the risk of investing in Canadian government bonds has declined. Consequently, the differential between Canadian and U.S. government bonds that existed historically, on average, is not expected to persist in the future.

The most recent consensus of long-term forecasts of government bond yields anticipates that yields will be slightly lower in Canada than in the U.S. in the future. Consensus Economics, *Consensus Forecasts,* April 2007 anticipates an average 10-year government bond yield over the period 2009-2017 of 5.1% for Canada and 5.25% for the U.S.[16] With lower interest rates in Canada, the differential between equity and bond returns in the two countries should, *ceteris paribus*, be closer in the future than it was historically. Consequently, the U.S. historic equity market risk premium is a relevant benchmark in the estimation of the forward-looking equity market risk premium for Canadian investors.

On the equity side of the equation, the Canadian equity market composite is dominated by two sectors, financial services and energy. These two sectors alone accounted for approximately 58% of the total market capitalization of the S&P/TSX Composite at the end of August 2007. In contrast to the S&P/TSX Composite, the historic U.S. equity returns have been generated by a more diversified and liquid market. In addition, the U.S. equity market has historically been the principal alternative for Canadian investors to domestic equity investments. Approximately 50% of Canadian portfolio investment in foreign equities at the end of 2006 was in the U.S.[17] The

[16] Blue Chip *Financial Forecasts* (June 2007), which canvasses economic forecasters at over 50 North American financial institutions, anticipates a 10-year U.S. Treasury yield of 5.15% from 2008-2017.
[17] Source: Statistics Canada, *Canada's International Investment Position – First Quarter 2007*. Of the remaining 51%, the next largest allocation of foreign portfolio equity investment is the U.K., which accounted for 13%.

diversified nature of the U.S. equity market and the close relationship between the Canadian and U.S. capital markets and economies warrant giving significant weight to U.S. historical equity risk premiums in the estimation of the required equity risk premium for a benchmark Canadian utility.

C.3.b.(2) The Post-World War II Period

The estimation of the expected/required market risk premium from achieved market risk premiums is premised on the notion that investors' return expectations and requirements are linked to their past experience. Basing calculations of achieved risk premiums on the longest periods available reflects the notion that it is necessary to reflect as broad a range of event types as possible to avoid overweighting periods that represent "unusual" circumstances. On the other hand, the objective of the analysis is to assess investor expectations in the current economic and capital market environment. Consequently, I focused on post-World War II returns, that is, 1947-2006, a period more closely aligned with what today's investors are likely to anticipate over the longer-term.[18]

C.3.b.(3) Historic Risk Premiums

As previously indicated, in arriving at an estimation of the market risk premium, my point of departure was both Canadian and U.S. historic returns and risk premiums during the post-World War II period. The average U.S. and Canadian historic risk premiums during that period were as follows:

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[18] Key structural economic changes have occurred since the end of World War II, including:

1. The globalization of the North American economies, which has been facilitated by the reduction in trade barriers of which GATT (1947) was a key driver;
2. Demographic changes, specifically suburbanization and the rise of the middle class, which have impacted on the patterns of consumption;
3. Transition from a resource-oriented/manufacturing economy to a service-oriented economy;
4. Technological change, particularly in the areas of telecommunications and computerization, which have facilitated both market globalization and rising productivity.

Table 1

Historic Average Risk Premiums (1947-2006)		
	Arithmetic	**Geometric**
Canada	5.5%	4.7%
U.S.	6.9%	6.1%

Source: Schedule 3.

In light of the increase in Canadian investors' purchases of U.K. equities,[19] I also looked at the historic U.K. indicated market risk premiums over the same period. The U.K. historic premiums were in the range of 6.0% to 6.3% (geometric and arithmetic averages respectively) from 1947-2006 (see Schedule 3).

C.3.b.(4) Superiority of Arithmetic Averages

When historic risk premiums are used as a basis for estimating the expected risk premium, arithmetic averages, not geometric (compound) averages, should be used. The geometric average, which is appropriate for use in describing historic portfolio performance, represents the achieved return as if it had been a constant average annual return. Using the arithmetic average of all past returns recognizes the probability distribution of future outcomes based on past variations in annual returns. Expressed simply, the arithmetic average recognizes the uncertainty in the stock market; the geometric average removes the uncertainty by smoothing over annual differences.

[19] In 1995, U.K. equities represented only 4.5% of all foreign equities purchased by Canadian investors. In 2005 and 2006, they represented 53% and 23% respectively. Purchases of U.S. and U.K. equities, in total, accounted for 76% of all foreign equities purchased by Canadian investors in 2006 (Statistics Canada).

C.3.b.(5) Future vs. Historic Risk Premiums

The 1998-2002 equity market "bubble and bust" spawned a number of studies of the equity market risk premium that have speculated that the U.S. market risk premium will be lower in the future than in the past. The speculation stems in part from the hypothesis that the magnitude of the achieved risk premiums is due to an increase in price/earnings (P/E) ratios. That is, the historic U.S. equity market returns reflect appreciation in the value of stocks in excess of that supported by the underlying growth in earnings or dividends. The increase in P/E ratios, it has been argued, reflects a decline in the rate at which investors are discounting future earnings, i.e., a lower cost of capital.

I have analyzed the trends in P/E ratios, equity market returns, and bond returns.[20] Briefly, that analysis demonstrates:

- ♦ The increase in price/earnings ratios experienced during the market bubble of the 1990s has not resulted in a higher and unsustainable level of equity market returns. The arithmetic average equity returns in both Canada and the U.S. from 1947-1989 (prior to the "bubble") are actually higher than the average returns for the full 1947-2006 period.
- ♦ An analysis of non-overlapping 10-year average equity returns reveals no upward or downward trend in equity market returns in Canada or the U.S. over the post World War II period.
- ♦ The observed decline in the experienced risk premium is due to the unsustainable increase in bond returns, not a decline in equity returns. The observed historic bond returns are significantly higher than a reasonable estimate of future bond returns (that is, forecast yields of long Canada bond yields).

Given the absence of any upward or downward trend in the historic equity market returns, a reasonable expected value of the future equity market return is a range of 11.5-12.25%, based on

[20] See Appendix C for further discussion.

both the Canadian and U.S. equity market returns (see Appendix C). Based on both the near-term and the longer-term forecasts for long Canada bond yields of 5.0% (2008) and 5.25% (average of 2009-2017),[21] and an expected equity market return of 11.5-12.5%, the indicated Canadian equity market risk premium would be in the range of 6.5-7.25%.[22]

C.3.b.(6) Estimate of Equity Market Risk Premium

Based on the analysis of the historic risk premiums, primarily in Canada and the U.S., with focus on the arithmetic averages, and with consideration given to trends in the equity and government bond markets in both countries, a reasonable estimate of the expected value of the equity market risk premium at the forecast levels of long-term government bond yields is approximately 6.5%. This estimate explicitly recognizes the expected value of the equity market return developed from historic values in conjunction with the current and forecast low levels of interest rates.

C.3.c. <u>Relative Risk Adjustment</u>

C.3.c.(1) Total Market Risk

The market risk premium result needs to be adjusted to recognize the relatively lower risk of utilities. The relative risk adjustment that is applicable to a benchmark Canadian utility is approximately 0.65-0.70, based on total risk as measured by standard deviations of market returns and adjusted betas.

My analysis of the relative risk adjustment starts with a recognition that investors are not perfectly diversified, do look at the risks of individual investments, and require compensation for assuming company-specific or investment-specific risk. It also recognizes that, while investors

[21] Consensus Economics, *Consensus Forecasts*, April 2007 anticipates the 10-year Canada bond yield to average approximately 5.1% from 2009 to 2017. Adding a spread of approximately 10 (as of August 2007) to 30 (historic average) basis points to the 5.1% forecast results in a 30-year Canada bond yield forecast of close to 5.25%.

[22] 11.5% - 5.0% = 6.5%
12.5% - 5.25% = 7.25%

can diversify their portfolios, the stand-alone utility to which the allowed return is applied cannot. Thus, a risk measurement that reflects those considerations is relevant for estimating the utility equity risk premium. These considerations support focusing on total market risk, as well as on beta, which is intended to measure solely non-diversifiable risk. The drawbacks of beta as the sole measure of risk, as well as the absence of an observable relationship between "raw" betas[23] and the achieved market returns on equity in the Canadian market, provide further support for reliance on other measures of risk to estimate the required equity return (see Appendix C).

The standard deviation of market returns is the principal measurement of total market risk. To compare the relative total risk of Canadian utilities, I calculated the monthly standard deviations of total market returns for each of the 10 major Sectors of the S&P/TSX Index, over recent five-year periods ending 1997 through 2006 (Schedule 5).

To translate the standard deviation of market returns into a relative risk adjustment, utility standard deviations must be related to those of the overall market. The relative market volatility of Canadian utility stocks was measured by comparing the standard deviations of the Utilities Index to the simple mean and median of the standard deviations of the 10 Sectors. Schedule 5 shows the ratios of the standard deviations of the Utilities Index to those of the 10 S&P/TSX Sectors. The ratio of the standard deviation of the Utilities Index to the mean and median standard deviations of the 10 major Sector Indices suggests a relative risk adjustment for a benchmark Canadian utility in the range of 0.55-0.74, with a central tendency of approximately 0.65-0.70.

[23] The "raw" beta refers to the simple regression between the monthly percentage changes in the price of a utility or utility index and the corresponding percentage change in the price of the equity market index (the S&P/TSX Composite).

C.3.c.(2) Historic Raw Betas

Since beta remains the risk measure that underpins the application of the Capital Asset Pricing Model (CAPM) (of which the risk-adjusted equity market risk premium test is a variant), I also considered betas in arriving at the estimated relative risk adjustment for a benchmark utility. Schedule 8 summarizes "raw" betas for individual publicly-traded Canadian regulated electric and gas companies, the TSE Gas/Electric Index, and the S&P/TSX Utilities Sector over five-year periods ending 1993 through 2006.[24]

As Schedule 8 indicates, there was a significant decline in calculated "raw" betas between 1993-1998 and 1999-2005 (from approximately 0.50-0.60 to 0.0 and slightly negative) followed by an increase in 2006 to the 0.25 to 0.35 range. The observed levels of "raw" utility betas in 1999-2006 can be traced to three factors: (1) the technology sector bubble and subsequent bust; (2) the dominance in the TSE 300 of two firms during the early part of the "bubble and bust" period, Nortel Networks and BCE; (3) the negative impact of rising interest rates on utility stock prices while the equity market composite is otherwise increasing (e.g., during the "bubble" of 1999 and early 2000 and during the first half of 2006).

Chart 1 in the Statistical Exhibit graphically demonstrates the "decoupling" between utility stocks and the S&P/TSX Composite between 1999 and mid-2002 period, when the equity market "bubble and bust" was most prevalent. As a result, the disparate movements in utility equities relative to the S&P/TSX Composite during this period produced lower measured utility betas.

Chart 1 also shows that, beginning in mid-2002, the equity market composite and the utility equities began to once again exhibit a correlation that, graphically, resembled more closely the

[24] The S&P/TSX Utilities Sector was created in 2002 (with historic data calculated from year-end 1987), when the TSE 300 was revamped to create the S&P/TSX Composite. The Utilities Sector was essentially an amalgamation of the former TSE 300 Gas/Electric and Pipeline sub-indices. In May 2004, the pipelines were moved to the Energy Sector, and no longer comprise a separate sub-index.

typical relationship observed prior to the market "bubble and bust". Utility betas calculated over recent periods that largely eliminate the "bubble and bust" period are higher than those that include data from this period. However, rising interest rates in early 2006 and the resulting negative impact on utility stock prices has again reduced the calculated "raw" utility betas (Schedule 9).[25]

The decoupling between utility shares and the rest of the market during both the technology "bubble and bust" and the first half of 2006 should not be interpreted as a change in the relative riskiness of utility shares,[26] but rather as an indication of the weakness of beta as the sole measure of the relative equity return requirement, particularly within the Canadian equity market context.[27]

[25] Calculated with Nortel excluded from the Composite to remove any lingering effects on the behaviour of the Composite.
[26] Schedule 7 shows that utilities were not the only companies whose betas were negatively impacted by the speculative bubble and subsequent market decline. To illustrate, the 60-month beta ending 1997 of the Consumer Staples Sector was 0.62; the corresponding betas ending 2003 and 2004 were -0.08 and -0.07 respectively. In contrast, over the same periods, the beta of the Information Technology Sector rose from 1.57 to 2.87.
[27] For example, with the rise in energy stock prices the 60-month betas for the S&P/TSX Energy Sector rose from 0.17 in 2004, to 0.48 in 2005 to over 1.0 in 2006 suggesting a five-fold increase in risk for these companies. (Schedule 7)

C.3.c.(3) Impact of Interest Sensitivity on Relative Risk

Utilities are interest-sensitive stocks and thus tend to move with interest rates, which frequently move counter to the equity market. Consequently, utility equity price movements are correlated not only with the stock market, but also with movements in the bond market. Thus, the interest-sensitivity of utility shares is not fully captured in the calculated "raw" betas, which simply measure the covariability between a stock and the equity market composite.[28] An analysis of the relative historic sensitivity of utility shares to both interest rates and the equity market indicates a relative risk adjustment of close to 80% (see Appendix C).

C.3.c.(4) Use of Adjusted Beta

The deficiencies in "raw" beta can be mitigated by using adjusted betas. Adjusting betas entails moving betas above and below the market mean of 1.0 toward the market mean. The adjustment that is used by the major commercial suppliers of betas uses a formula that gives approximately two-thirds weight to the stock's own beta and one-third weight to the market mean beta of 1.0.[29] Use of adjusted betas implicitly recognizes that "raw" utility betas do not adequately explain utility returns. For example, as illustrated above, "raw" betas do not capture utilities' interest rate sensitivity. Further, the objective of the relative risk adjustment is to predict the investors' required return. Since utility returns have consistently been higher than what raw betas would indicate, adjusted betas are better predictors of utility returns than "raw" betas.[30]

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[28] In theory, the beta should be measured against the entire "capital market" including short-term debt securities, bonds, real estate, etc. In practice, it is measured using the equity market only.

[29] *Value Line*, Bloomberg and Merrill Lynch, major sources of financial information for investors, all publish adjusted betas. Their formulas for adjusting the calculated raw betas are slightly different, but all give approximately two-thirds weight to the "raw" beta of the specific stock and one-third weight to the market beta of 1.0.

[30] More generally, a number of empirical studies on CAPM have shown that the return requirement is higher (lower) for a low (high) beta stock than the CAPM would predict.

Table 2 below summarizes the average of the adjusted five-year betas ending in 1993 to 1998 (pre-"Nortel effect") and those calculated over various periods subsequent to the market "bubble and bust".[31]

Table 2

Canadian Utility Adjusted Betas			
Periods	**Individual Canadian Utilities (Median)**	**TSE 300 Gas/Electric Utility Index**	**S&P/TSX Utilities Index**
Five-Year Betas ended 1993 to 1998 (Average)	0.65	0.66	0.73
42-Month Betas (7/2002 to 12/2005)[1/]	0.68	N/A	0.69
30-Month Betas (7/2003 to 12/2005)[1/]	0.66	N/A	0.71
60-Month Betas (7/2002 to 7/2007)	0.63	N/A	0.56

[1/] Excludes Nortel from the Composite.

Source: Schedules 8 and 9.

The adjusted betas indicate a relative risk adjustment of approximately 0.65-0.70.

C.3.c.(5) Relative Risk Adjustment

Based on the preceding analysis of standard deviations of market returns and betas, in my opinion, the relative risk adjustment for a benchmark low risk utility is approximately 0.65-0.70.

[31] Adjusted utility beta = 2/3 ("raw" beta) + 1/3 (market beta of 1.0).

C.3.d. Benchmark Utility Equity Risk Premium

I previously estimated the equity market risk premium at the long Canada yield of 5.0%, at approximately 6.5%. At an equity market risk premium of 6.5% and a relative risk adjustment of 0.65-0.70, the indicated benchmark utility equity risk premium is approximately 4.25-4.50%.[32]

C.4. Utility-Specific Equity Risk Premium Analysis

The risk-adjusted equity market risk premium test (discussed above) estimates the required utility equity risk premium indirectly. That is, it estimates an equity risk premium for the equity market as a whole, and then adjusts it for the relative risk of a benchmark utility. The following analyses estimate the equity risk premium for a benchmark utility directly, by analyzing utility equity return data. The analyses below focus on both long-term historic utility equity risk premiums and an equity risk-premium test derived from forward-looking monthly estimates of the required utility equity return.

The following two sections provide the results of that analysis.

C.4.a. Historic Utility Equity Risk Premiums

The historic experienced returns for utilities provide an additional perspective on a reasonable expectation for the forward-looking utility equity risk premium. Reliance on achieved equity risk premiums for utilities as an indicator of what investors expect for the future is based on the proposition that over the longer term, investors' expectations and experience converge. The more stable an industry, the more likely it is that this convergence will occur.

Over the longer-term (1956-2006),[33] achieved utility equity risk premiums were 4.1-4.8% for Canadian electric and gas utilities, based on geometric and arithmetic average returns

[32] (0.65-0.70) x 6.5% = 4.25-4.50%

respectively.[34] For U.S. electric utilities, the corresponding geometric and arithmetic average historic equity risk premiums were approximately 4.5-5.2% over the entire post-World War II period (1947-2006). The corresponding risk premiums for U.S. gas utilities were 5.5-6.2% (Schedule 10).

Similar to the risk premiums for the market composite, the magnitude of achieved utility risk premiums is a function of both the equity returns and the bond returns, as summarized for Canadian utilities in the table below.

Table 3

Average	**Canadian Utility Risk Premiums 1956-2006**		
	Utility Equity Returns	**Bond Returns**	**Achieved Risk Premiums**
Arithmetic	12.6%	7.8%	4.8%
Geometric	11.5%	7.4%	4.1%

Source: Schedule 10.

An analysis of the underlying data indicates there has been no upward or downward trend in the utility equity returns (Schedule 11); the utility returns in both the U.S. and Canada have clustered in the approximate range of 11.0-12.0%. However, as noted in Appendix C, the bond returns have risen over the fifty-year period to a level that cannot persist, given the low level of interest rates. The low level of interest rates limits further capital gains on bonds (which have given rise to the high observed bond returns in recent years). The best estimate of the expected bond return is the forecast yields on long Canada bond yields, which are in the range of 5.0-5.25%, based on

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[33] The longest period for which Canadian utility data are available from the TSE.

[34] Based on the Gas/Electric Index of the TSE 300 (from 1956 to 1987) and on the S&P/TSX Utilities Index from 1988-2006.

both near-term and long-term forecasts. When that yield is compared to a utility equity return of 11.0-12.0%, the indicated equity risk premium is approximately 6.0-6.75%.[35]

Focusing on the arithmetic average risk premiums, and recognizing that historic bond returns overstate the expected bond return, the experience of Canadian and U.S. utilities supports an expected equity risk premium estimate for a benchmark Canadian utility in the approximate range of 5.0-5.5%.

C.4.b. DCF-Based Equity Risk Premium Test

A forward-looking equity risk premium test was also performed, using the discounted cash flow model (DCF) to estimate expected utility returns over time. Monthly cost of equity estimates were constructed for the period 1993-2007 (2nd Qtr)[36] using the DCF model and a sample of low risk U.S. electric and gas utilities as a proxy for a benchmark Canadian utility.[37] The reasons for choosing U.S. utilities are as follows:

First, there are an insufficient number of forward-looking estimates of long-term growth rates for Canadian utilities that would permit the creation of a consistent series of DCF costs of equity and corresponding risk premiums from Canadian data. A consensus estimate of investors' growth expectations is key to the application of the discounted cash flow model. The availability of a consensus of analysts' forecasts means that the resulting growth estimate reflects the market view.

[35] 11.0% - 5.0% = 6.0%
12.0% - 5.25% = 6.75%

[36] The period 1993-2007 (2nd Qtr) encompasses a full business cycle. It also represents the period of Open Access (implemented via FERC Order 636) for gas distributors which make up close to 50% of the benchmark low risk utility sample.

[37] The selection criteria for the proxy utilities and the construction of the DCF estimates are described in Appendix D.

Second, U.S. and Canadian utilities are reasonable proxies for one another, particularly in today's global capital market. Although there may be company-specific differences in business and financial risk, the impact of those differences is minimized by selecting only relatively pure-play U.S. utilities with similar debt ratings to the typical Canadian utility. The selected U.S. utilities are of relatively low business risk; the sample, which is limited to utilities with debt ratings in the A category, is of similar total risk to a benchmark Canadian utility.

The DCF costs of equity were estimated as the sum of the consensus of analysts' forecasts of long-term normalized earnings growth,[38] plus the expected dividend yield. The equity risk premium is equal to the difference between the average DCF cost of equity for the sample and the corresponding 30-year Treasury yield for the period.

For the sample of U.S. utilities, the DCF-based risk premium test indicates an average risk premium over the 1993-2007 (2nd Qtr) period of 4.0% (Schedule 12); the corresponding average long-term government bond yield was 5.8%, approximately 75 basis points higher than the test period forecast yield on long Canada bond yields of 5.0%. I also looked at the average risk premium over the period 1998-2007 (2nd Qtr), representing the period subsequent to open access for electric utilities in the U.S.[39] The average risk premium over that period was 4.5%, with a corresponding government bond yield of 5.3%.

The data suggest that there has been an inverse relationship between the risk-free rate (as proxied by the long-term government bond yield) and utility equity risk premiums. To test the relationship between interest rates and risk premiums, a simple regression analysis between the monthly 30-year Treasury yields and the corresponding equity risk premiums over the entire

[38] The consensus forecasts are obtained from I/B/E/S, a leading provider of earnings expectations data. The data are collected from over 7,000 analysts at over 1,000 institutions worldwide, and cover companies in more than 60 countries.
[39] Open access for electric utilities was implemented via FERC Order 888 in 1997.

1993-2007 (2nd Qtr) period was conducted.[40] At the test year forecast 30-year government bond yield of 5.0%, the indicated utility equity risk premium is approximately 4.5%.

The magnitude of the spread between corporate bond yields and government bond yields is frequently used as a proxy for changes in investors' perception of risk.[41] Thus, I also tested the relationship between the spreads between long-term utility and government bond yields in conjunction with the change in the yield on long-term government bond yields.

To estimate this relationship, I performed a regression analysis over the 1993-2007 (2nd Qtr) period using the utility risk premium[42] as the dependent variable, with the corresponding long-term government bond yield and spread between long-term A-rated utility[43] and government bond yields as the two independent variables.[44] The analysis indicated that, while the utility risk premium has been negatively related to the level of government bond yields, it has been positively related to the spread between utility bond yields and government bond yields. The spread between long-term Canadian A-rated utility bonds and 30-year Canada bond yields was approximately 130 basis points at the end of August 2007, compared to the average Moody's A-rated utility/30-year Treasury spread of 139 basis points over the entire 1993-2007 (2rd Qtr) period. Using a forecast long Canada yield of 5.0% and an A-rated utility bond/long Canada spread of 130 basis points, the indicated utility risk premium is 4.3%.

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[40]

Equity Risk premium	=	7.56 – 0.606 (30-Year Treasury yield)
t-statistic	=	-11.0
R^2	=	41%

[41] Or, alternatively, willingness to take risks.
[42] Measured, as in the prior analysis, as the DCF cost of equity minus the long-term government bond yield.
[43] Based on Moody's long-term A- rated utility bond index.
[44]

Utility Risk Premium	=	4.9 - 0.41 TY + 1.12 Spread
Where,		
TY	=	30-year Treasury Yield
Spread	=	Spread between A-rated Utility Bond Yields and 30-year Treasury Yields
R^2	=	80%
t-statistics:		
Long term bond yield	=	-12.2
Utility/government bond yield spread	=	18.2

Based on both the one and two independent variable approaches, the DCF-based risk premium test results indicate a utility equity risk premium in the range of approximately 4.25-4.50%, at a long-term Canada bond yield of 5.0%.

C.5. Equity Risk Premium Test "Bare-Bones" [45] Cost of Equity

The estimated equity risk premiums for a benchmark Canadian utility based on the three methodologies are as follows:

Table 4

Risk Premium Test	Risk Premium
Risk-Adjusted Equity Market	4.25-4.50%
Historic Utility	5.0-5.50%
DCF-Based	4.25-4.50%

On balance, the three risk premium tests indicate an equity risk premium applicable to a benchmark Canadian utility of 4.25-5.25%, or approximately 4.75%. At a forecast long Canada yield of 5.0%, the "bare-bones" cost of equity is 9.25-10.25% (mid-point of 9.75%).

D. DISCOUNTED CASH FLOW TEST[46]

The discounted cash flow approach proceeds from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate that reflects the risk of those cash flows. If the price of the security is known (can be observed), and if the expected stream of cash flows can be estimated, it is possible to approximate the

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[45] "Bare-bones" means that this is the market-derived cost of equity before any adjustment to allow for financing flexibility.
[46] See Appendix E for a more detailed discussion.

investor's required return (or capitalization rate) as the rate that equates the price of the stock to the discounted value of future cash flows.

Although the DCF test, like the equity risk premium test, has flaws, it has one distinct advantage over risk premium estimates, particularly those made using the CAPM. It allows the analyst to directly estimate the utility cost of equity. In contrast, the CAPM indirectly estimates the cost of equity. The DCF model provides a widely used alternative to the CAPM; it is the principal model utilized by U.S. regulators.

There are multiple versions of the discounted cash flow model available to estimate the investor's required return. An analyst can employ a constant growth model or a multiple period model to estimate the cost of equity. The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. Similarly, a multiple period model rests on the assumption that growth rates will change over the life of the stock. In determining the DCF cost of equity for a benchmark utility, I utilized both a constant growth and a two-stage model.[47] In both cases, the discounted cash flow test was applied to a sample of low risk U.S. "pure-play" electric and gas distributors that are intended to serve as a proxy for a benchmark Canadian utility.[48]

The growth component of the DCF model is an estimate of what investors expect over the longer-term. For a regulated utility, whose growth prospects are tied to allowed returns, the estimate of growth expectations is subject to circularity because the analyst is, in some measure, attempting to project what returns the regulator will allow, and the extent to which the utilities will exceed or fall short of those returns. To mitigate that circularity, it is important to rely on a sample of proxies, rather than the subject company. (When the subject company does not have traded shares, a sample of proxies is required.)

[47] The two-stage model is a form of multiple period model; please see Appendix E for discussion of the DCF models used; the criteria for the low risk U.S. utility sample selection are described in Appendix D.
[48] Reliance on U.S. utilities was explained in the discussion of the DCF-based equity risk premium test in Chapter III.C.4.b.

Further, to the extent feasible, one should rely on estimates of longer-term growth readily available to investors, rather than superimpose on the analysis one's own view of what growth should be. Thus, in applying the DCF test, I relied solely on published forecast growth rates that are readily available to investors. The constant growth model uses the consensus of analysts' earnings growth rate forecasts as the proxy for investors' long-term growth expectations. The two-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the analysts' forecasts (which are five year projections) for the first five years, but, in the longer-term (from year 6 onward) to migrate to the expected long-run rate of nominal growth in the economy.

The results of the constant growth and two-stage DCF models indicate a required "bare-bones" return on equity of approximately 9.25-9.5% (Appendix E and Schedules 14 and 15). It is important to recognize that the 9.25-9.5% DCF cost represents the return investors expect to earn on the <u>current market value</u> of their utility common equity investments. It is not, however, the return that investors expect the utilities to earn on the book value of their common equity. *Value Line*, which publishes its projections of utility ROEs quarterly, anticipates that the return on average common equity for the sample of low risk U.S. utilities over the period 2010-2012 will be approximately 11.2-12.0% (Schedule 13).

E. ALLOWANCE FOR FINANCING FLEXIBILITY[49]

The financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. The allowance is intended to cover three distinct aspects: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the "fairness" principle.

[49] See Appendix G for a more complete discussion.

In the absence of an adjustment for financial flexibility, the application of a "bare-bones" cost of equity to the book value of equity, if earned, in theory, limits the market value of equity to its book value. The fairness principle recognizes the ability of competitive firms to maintain the real value of their assets in excess of book value and thus would not preclude utilities from achieving a degree of financial integrity that would be anticipated under competition. The market/book ratio of the S&P/TSX Composite has averaged 2.1 times over the past business cycle (1994-2006); the corresponding average market/book ratio of the S&P 500 has been 3.4 times.

At a minimum, the financing flexibility allowance should be adequate to allow a utility to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10. At this level, a utility would be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 is approximately 50 basis points.[50] As this financing flexibility adjustment is minimal, it does not fully address the comparable return standard.

The concept of a financing flexibility or flotation cost allowance has been accepted by most Canadian regulators. As a government-owned utility, OPG has not raised equity capital in the public equity markets; therefore it does not incur out-of-pocket equity financing and market pressure costs. However, both the cushion, or safety margin, for unanticipated capital market conditions and the fairness element are integral components of the cost of equity and a fair return on the book value of equity. Both should be recognized in the allowed return on equity for a regulated utility, irrespective of ownership. The Board has implicitly recognized this principle in the past (e.g., in its Transitional Rate Order (Distribution) for Hydro One, RP-1998-0001), by setting returns for the government-owned utilities that are comparable to those allowed for investor-owned utilities.

[50] Based on the DCF model; see Appendix G for calculation.

The addition of an allowance for financing flexibility of 50 basis points to the "bare-bones" return on equity estimate of 9.25-10.25% derived from both the DCF and equity risk premium tests respectively, results in an estimate of the fair return on equity of 9.75%-10.75%.

F. COMPARABLE EARNINGS TEST

The comparable earnings test provides a measure of the fair return based on the concept of opportunity cost. Specifically, the test arises from the notion that capital should not be committed to a venture unless it can earn a return commensurate with that available prospectively in alternative ventures of comparable risk. Since regulation is a surrogate for competition, the opportunity cost principle entails permitting utilities the opportunity to earn a return commensurate with the levels achievable by competitive firms facing similar risk. The comparable earnings test, which measures returns in relation to book value, is the only test that can be directly applied to the equity component of an original cost rate base without an adjustment to correct for the discrepancy between book values and current market values. Neither the equity risk premium results nor the DCF results, if left without adjustment, recognizes the discrepancy. The 50 basis point financing flexibility adjustment only minimally addresses the discrepancy.

The comparable earnings test is an implementation of the comparable earnings standard, as distinguished from the cost of attracting capital standard. The comparable earnings standard recognizes that utility costs are measured in vintaged dollars and that rates are based on accounting costs, not economic costs. In contrast, the cost of attracting capital standard relies on costs expressed in dollars of current purchasing power, i.e., a market-related cost of capital. In the absence of experienced inflation, the two concepts would be quite similar, but the impact of inflation has rendered them dissimilar and distinct.

The concept that regulation is a surrogate for competition may be interpreted to mean that the combination of an original cost rate base and a fair return should result in a value to investors commensurate with that of competitive ventures of similar risk. The fact that an original cost rate base provides a starting point for the application of a fair return does not mean that the original cost of the assets is a measure of their fair value. The concept that regulation is a surrogate for competition implies that the regulatory application of a fair return to an original cost rate base should result in a value to investors commensurate with that of similar risk competitive ventures. The comparable earnings standard, as well as the principle of fairness, suggests that, if competitive industrial firms facing a level of total risk similar to utilities are able to maintain the value of their assets considerably above book value, the return allowed to utilities should not seek to maintain the value of utility assets at book value. It is critical that the regulator recognize the comparable earnings standard when setting a just and reasonable return.

The comparable earnings test remains the only test that explicitly recognizes that, in the North American regulatory framework, the return is applied to an original cost (book value) rate base. The persistence of moderate inflation continues to create systematic deviations between book and market values. Application of a market-derived cost of capital to book value ignores that distinction. To illustrate, if the market value of an investment is $15 and the required return is 10%, the return, <u>in dollars</u>, expected by investors is $1.50. However, regulatory convention applies the market-derived return to the book value of the investment. If the book value of the investment is $10.00, application of a 10% return to the book value will result in a return, <u>in dollars</u>, of only $1.00. The application of the results of the cost of attracting capital tests, i.e., equity risk premium and discounted cash flow to the book value of equity, unless adjusted, do not make any allowance for the discrepancy between the return on market value and the corresponding fair return on book value.[51] The comparable earnings test, however, does. It applies "apples to apples", i.e., a book value-measured return is applied to a book value-measured equity investment.

[51] As previously noted, the 50 basis point financing flexibility adjustment is only a minimal recognition of the discrepancy.

The principal issues in the application of the comparable earnings test are:[52]

- ♦ The selection of a sample of industrials of reasonably comparable risk to a benchmark Canadian utility.
- ♦ The selection of an appropriate time period over which returns are to be measured in order to estimate prospective returns.
- ♦ The need for any adjustment to the "raw" comparable earnings results if the selected industrials are not of precisely equivalent risk to the benchmark utility.
- ♦ The need for a downward adjustment for the industrials' market/book ratios.

The application of the comparable earnings test first requires the selection of one or more samples of industrials of reasonably comparable risk to a benchmark Canadian utility. The selection should conform to investor perceptions of the risk characteristics of utilities, which are generally characterized by relative stability of earnings, dividends and market prices. These were the principal criteria for the selection of samples of industrial companies (from consumer-oriented industries). The criteria for selecting comparable unregulated low risk companies include industry, size, dividend history, stock and bond ratings and betas (See Appendix F).

Since the universe of Canadian industrial companies is sufficiently large to produce a representative sample of sufficient size, the focus of the comparable earnings analysis was on Canadian firms. However, a sample of U.S. companies was also used as a check on the reasonableness of the Canadian sample results. The application of the selection criteria to the Canadian universe produced a sample of 20 companies.

Next, since industrials' returns on equity tend to be cyclical, the selection of an appropriate period for measuring industrial returns must be determined. The period selected should encompass an entire business cycle, covering years of both expansion and decline. That cycle should be representative of a future normal cycle, e.g., the historic and forecast cycles should be

[52] Full discussion in Appendix F.

similar in terms of inflation and real economic growth.[53] The period 1994-2006 provides a reasonable proxy for a future business cycle, as the experienced rates of inflation and economic growth are reasonably similar to the rates projected by economists over the next business cycle. The experienced returns on equity of the sample of 20 Canadian low risk industrial companies over this period were in the approximate range of 12.75-13.25% (see Appendix F and Schedule 17).

The next step is to assess whether or not there is a need to adjust the "raw" comparable earnings results to reflect the differential risk of a benchmark Canadian utility relative to the selected industrials. The comparative risk data (including betas and stock and bond ratings) indicate, on balance, the Canadian industrials are of modestly higher risk than a benchmark utility. To recognize the industrials' higher risk, the comparable earnings test results require a downward adjustment to a range of 12.25-12.75% (mid-point of 12.50%).

Since the Canadian sample is relatively small, in large part a function of the size and make-up of the Canadian equity market, as noted above, I also selected a sample of low risk U.S. industrials to serve as a check on the reasonableness of the Canadian results. The selection criteria were virtually identical to those used for the Canadian industrial sample. The greater breadth of the U.S. market allowed the selection of a sample of 157 companies in the same stable industries used to select the Canadian industrials. The experienced returns of the U.S. industrials were in the range of 13.5-14.5% (see Schedule 19). The comparative risk data indicate that the U.S. industrials are of relatively similar risk to the Canadian industrials (see Schedule 18), and thus of slightly higher risk than a benchmark Canadian utility. When used as a check against the Canadian firms, the returns of the significantly larger U.S. sample of industrials underscore the reasonableness of the comparable earnings results for the sample of Canadian industrials.

[53] Returns on equity during earlier periods may not be comparable as the economic fundamentals that impact achievable returns (e.g., inflation) were not comparable.

The final step is to assess the need for a market/book adjustment to the comparable earnings results. The sample results would warrant such an adjustment if their market/book ratios relative to the overall market indicated an ability to exert market power. In other words, a relatively high market/book ratio would point to returns on equity that were higher than the levels achievable if market power were not present. The average market/book ratio of the sample of Canadian comparable industrial companies over the 1994-2006 period was 2.1 times, virtually identical to the market/book ratio of the S&P/TSX composite over the same period (see Appendix F). For the U.S. industrial sample, the average market/book ratio for 1994-2006 was approximately 2.7 times, compared to 3.4 times for the S&P 500. The similar to market/book ratios of the proxy samples relative to the market composites indicate no evidence of market power and thus no rationale for a downward adjustment. As a result, a fair return for a benchmark Canadian utility based on the comparable earnings test is approximately 12.5%.

G. FAIR RETURN ON EQUITY FOR A BENCHMARK CANADIAN UTILITY

The results of the three tests used to estimate a reasonable return on equity for a benchmark Canadian utility are summarized below:

Table 5

Test	"Bare-Bones" Cost of Equity	Fair Return on Equity
Equity Risk Premium	9.25-10.25%	9.75-10.75%
Discounted Cash Flow	9.25-9.5%	9.75-10.0%
Comparable Earnings	N/A	12.5%

In arriving at a reasonable return for a benchmark utility, I have given primary weight to the cost of attracting capital, as measured by both the equity risk premium and DCF tests. The "bare-bones" cost of attracting capital based on these two tests is approximately 9.25-10.0%. Including the allowance for financing flexibility, the indicated return on equity is 9.75-10.5%. However, the results of the comparable earnings test are also entitled to significant weight when setting a fair return that balances both ratepayer and shareholder interests. Based on all three test results, a fair return for a benchmark Canadian utility is approximately 10.25-10.75% (mid-point of 10.5%). A return on equity of 10.5% is applicable to OPG's regulated operations at a deemed common equity ratio sufficient to equate their total risk (business and financial) to that of the proxies used to estimate the benchmark return.

IV. DEEMED CAPITAL STRUCTURE FOR OPG REGULATED

A. PRINCIPLES

The following principles should be respected when establishing the appropriate capital structure for OPG's regulated operations:

1. The stand-alone principle.
2. Compatibility of capital structure with business risks.
3. Maintenance of creditworthiness/financial integrity.
4. Compatibility with the benchmark return on equity.

Each of these principles is defined below.

A.1. The Stand-Alone Principle

As discussed in Chapter II.B, the stand-alone principle encompasses the notion that the cost of capital incurred by the ratepayers should be equivalent to that which would be faced by each division raising capital in the public markets on the strength of its own business and financial parameters. The cost of capital should reflect neither subsidies given to, nor taken from, other activities of the firm. Application of the stand-alone principle to OPG's regulated operations means that they should be treated as if they were operating separately from the other operations of the firm.

The consolidated operations of OPG are rated by both DBRS and Standard & Poor's. DBRS rates OPG A(low) with a Stable trend and S&P rates OPG BBB+ with a Positive trend. The ratings of OPG on a purely stand-alone basis would be lower if it were not for the perceived support of the Province as shareholder. S&P, for example, has stated that OPG's rating benefits from two notches of government support.[54] In other words, in the absence of the perceived level of government support, OPG's S&P debt rating would be BBB-. Nevertheless, S&P has also stated that

> (I)t is with the potential for changing circumstances in mind that the ratings on Hydro One and OPG are more closely aligned to the underlying creditworthiness of the individual companies than their owner. Governments change, government policies change, views on ownership change, economic circumstances change, and the financial ability and willingness of the province to support its enterprises can change also.
>
> Fundamentally, it is not possible to predict the future political willingness to support a separately incorporated entity. Politics by definition is populist, expedient, and capricious, and creditors should not dismiss the likelihood of change. [55]

While DBRS concludes that the current rating is more "reflective of OPG's improved financial profile on a stand-alone basis, which has been driven by a more favourable regulatory environment," they note "that the rating on OPG over the past several years has been supported by the Province of Ontario (the Province, rated AA), OPG's sole shareholder and provider of financial support. The provincial ownership and financial support limited downward movement in OPG's rating to below the A (low) level during prior periods of weak financial performance by the Company...."[56] Although OPG does not currently borrow long-term debt in the public markets, but rather from the Ontario Electricity Financial Corporation (OEFC), the credit spreads for its funding are based on the market debt costs of regulated firms in Canada with similar or better investment grade debt ratings. As a result, ratepayers receive the benefit of a lower cost of debt than would be achievable by OPG in the absence of the perceived government support.

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[54] Standard & Poor's, *Summary: Ontario Power Generation*, April 24, 2007.
[55] Standard & Poor's, *Credit FAQ: Implied Government Support as a Rating Factor for Hydro One Inc. and Ontario Power Generation Inc.*, October 20, 2005.
[56] DBRS, *Rating Report: Ontario Power Generation Inc.*, August 3, 2006.

This benefit is provided at no cost (i.e., there is no debt fee paid to the Province for the potential financial support). The proper application of the stand-alone principle to the determination of the deemed capital structure (and return on equity) for OPG's regulated operations ignores the happenstance of ownership; the capital structure should reflect the business risks of OPG's regulated operations irrespective of the identity of the shareholder. This approach ensures that the shareholder is properly compensated for the total risk borne.

A.2. Business Risks

The capital structure should be consistent with the business risks of the specific entity for which the capital structure is being set. The business risks to which investors in a utility are exposed are those that reflect the basic characteristics of the operating environment and regulatory framework of the utility that can lead to the failure to recover a compensatory return on, and/or the return of the capital investment itself.

A.3. Maintenance of Creditworthiness and Financial Integrity

The capital structure, in conjunction with the returns allowed on the various sources of capital, should provide the basis for stand-alone investment grade debt ratings for the regulated operations. An investment grade debt rating provides the basis for access to the capital markets on reasonable terms and conditions. As a corporate entity operating with a commercial mandate to operate on a financially sustainable basis, OPG should be positioned to access the public debt markets. The regulated operations of OPG should contribute their fair share to the creditworthiness and financial integrity of Ontario Power Generation Inc., the corporate entity responsible for raising debt capital on behalf of the entire organization. The importance of investment grade debt ratings is discussed in detail in Chapter IV.C.

A.4. Compatibility with Benchmark Return

The approach I have taken applies a benchmark return on equity to a deemed equity ratio. Thus, the deemed equity ratio needs to be set at a level that, given OPG's business risks, equates the level of OPG's total risks to that of the proxy utilities used to estimate the benchmark return.

B. BUSINESS RISKS

B.1. Conceptual Considerations

Business risks have both short-term and longer-term aspects. The capital structure and fair return on equity should reflect both short- and long-term risks. Long-term risks are important because utility assets are long-lived. Because utilities are generally regulated on the basis of annual revenue requirements, there has been a tendency to downplay longer-term risks, essentially on the grounds that the regulatory framework provides the regulator an opportunity to compensate the shareholder for the longer-term risks when they are experienced. This premise may not hold. First, customer resistance may forestall the approval of higher returns when the risk materializes. Second, no regulator can bind his successors and thus guarantee that investors will be compensated for longer-term risks in the event they are incurred in the future. Third, if a risk is experienced, the incurrence of costs to address it may create cash flow constraints before appropriate rate relief can be secured.

Business risk, as defined in Chapter II.C, comprises the composite of the operating elements of the business that together determine the probability that future returns to investors will fall short of their expected and required returns. It includes the factors that expose the equity shareholders to the risk of under-recovery of the required return on, and the return of, their capital investment. Business risks include market demand, supply, physical/operating and regulatory/political risks. While different business risk categories can be identified, they are inter-related. The regulatory framework, for example, is generally designed to take account of the specific fundamental market and operating risks faced by the regulated entity.

The following sections discuss the business risks of OPG's regulated operations (or, alternatively, the prescribed assets) in the composite and the hydroelectric and nuclear operations individually.

B.2. Business Risks of the Composite Regulated Operations

B.2.a. Revenue and Market-Related Risks

Market risks for OPG are partly defined by the economy in which it operates. The Ontario economy is the largest in the country, accounting for approximately 40% of population and GDP.[57] Growth in Ontario is expected to exceed that of the country as a whole over the longer-term. The Ontario Ministry of Finance expects real GDP growth in Ontario to average approximately 2.8% from 2010 to 2019, compared to the consensus forecast for Canada as a whole of 2.6% from 2009 to 2017.[58] Strength in the economy over the longer-term is in part expected to arise as a result of a favourable demographic outlook due to sturdy international migration.[59] Challenges to the Ontario economy over the longer-term – and thus to energy demand – include the impact of the high Canadian dollar and high energy prices on global competitiveness of the export-intensive manufacturing sector, which may result in plant closures or retrenchment in key industries. Thus, while the diversity and strength of the economy are positive for the overall business risk assessment of OPG, the challenges to the manufacturing sector expose the regulated operations to some risk of lower revenues due to decreased demand, both from cyclical declines and long-term demand destruction.

[57] Ontario Financing Authority (www.ofina.on.ca)
[58] Ontario Ministry of Finance, *Toward 2025: Assessing Ontario's Long-Term Outlook,* January 2006.
[59] Consensus Economics, *Consensus Forecasts,* April, 2007.

Revenue risks for OPG's regulated operations also include the impact of weather as well as the potential impact of a provincial energy policy that actively promotes conservation and demand side management. The Ontario government has set targets for energy conservation to produce 6300 MWs of peak electricity savings by 2025 (peak demand in 2006 was 27000 MWs). Reduction in demand driven by conservation exposes the regulated assets to the risk of lower revenues.

Because the prescribed assets are primarily baseload facilities, the revenue risks associated with economic cycles, potential demand destruction and conservation are lower for OPG's regulated operations than those of a typical generator with a portfolio of baseload, mid-merit and peaking facilities.

Competitive risks with other energy sources are not significant, since electricity does not compete to any material extent with alternative energy sources, such as natural gas, due largely to the relative price of electricity. There is some competition for certain electricity uses (e.g., commercial air conditioning, water heating), but it is not considered to be a significant risk.

Counter-party risk is considered to be minor, since OPG's regulated revenue comes from the Ontario Independent Electricity System Operator (IESO), and payment defaults by market participants are first met by drawing upon prudential requirements and then through a default levy on all non-defaulting market participants.

Revenue risks are also a function of the high degree of operating leverage which is characteristic of asset intensive businesses like electricity generation. A high degree of operating leverage means that OPG's costs are largely fixed. All other things held constant, the higher the operating leverage, the higher is the business risk. When costs are largely fixed, but prices are largely consumption or energy-based, a small decline in sales can have a material impact on the firm's operating income and return on equity. OPG's payments are currently 100% energy-based, which means it must recover all of its fixed costs in a variable payment. Most utilities recover a significant proportion of their total fixed costs in a fixed customer charge, demand charge, or capacity payment. For example, the transmission utilities in Alberta collect 100% of their forecast revenue requirement in fixed monthly payments from the Alberta Electric System Operator. Gas pipelines regulated by the National Energy Board collect virtually all of their fixed costs in demand charges from shippers; electricity and gas distributors may collect up to 85% of their fixed costs in customer/capacity charges.[60] Based on the proposed payment structures for the prescribed assets (100% energy-based for hydroelectric assets and a fixed charge for nuclear assets covering 25% of forecast nuclear revenue requirement), OPG would recover approximately 20% of its total regulated costs in a fixed charge. Under this structure, the assurance of recovery of the regulated operations' fixed costs through fixed charges will be less, and the revenue risk higher, than for the typical Canadian utility.

Based on the OPG's rate application, the forecast 2009 information indicates that approximately 85% of OPG's revenue requirement other than return on equity and income taxes is comprised of expenses that are largely fixed (i.e., they do not vary directly with production). As the rate base declines over time, the dollars of return on rate base decline in absolute terms and in proportion to OPG's total fixed costs. In the absence of rate base growth (i.e., based on the existing prescribed assets, absent refurbishment), OPG's high fixed cost structure will continue to increase the sensitivity of the ROE to changes in revenues and expenses.

In contrast to electric and gas distribution utilities and vertically integrated (non-restructured) utilities, OPG does not have a defined franchise area, nor does it have an obligation to serve. The regulated generation competes in the Ontario market with OPG's unregulated generation and the generation owned by or leased by others (e.g. Bruce Power). At present, the competitive/market risks faced by OPG's regulated operations are relatively low, as the prescribed assets are primarily baseload facilities[61], with relatively low variable (marginal) costs

[60] For example, FortisAlberta collects approximately 85% of its fixed distribution costs in customer/demand charges; ATCO Electric Distribution collects approximately 65% of its fixed distribution costs in customer/demand charges.
[61] The Beck complex has some peaking capability.

of production. There are, however, other generators whose marginal costs are similarly low (e.g., Bruce Power, wind generators, Brookfield Power), which can result in OPG's regulated facilities not being dispatched for short periods in which demand is relatively low. Nevertheless, dispatch risk for the regulated assets is currently relatively low. That risk will rise as additional low marginal cost generation (which can bid below cost but receive a price specified in its PPA with the OPA) becomes available or demand drops.

With respect to the impact of market prices on revenue risk, the market wholesale price of electricity in Ontario is set on the basis of supply of and demand for electricity, with the major driving factors being load, generator availability and fuel (e.g., natural gas) prices. OPG's regulated assets do not typically set the market-clearing price, except in cases of unutilized baseload capacity.[62] Since the payments for OPG's regulated generation are expected to reflect the total costs of production, including a reasonable return on invested capital, the revenue requirement is not based on market price factors.

B.2.b. Production, Operating and Cost Recovery Risks

Production, operating and cost recovery risks include all factors that may result in OPG under-recovering a reasonable return on investment and/or a part of the investment itself due to higher than anticipated costs of production, lower than anticipated production or loss of production. These factors are largely specific to the generation technology and are discussed in the individual hydroelectric and nuclear operations sections that follow.

B.2.c. Regulatory Risks

With respect to economic regulation, regulation has the power to expose utilities to enormous risks, by disallowing costs, approving rate structures that are incompatible with the cost

[62] As additional low marginal cost generation becomes available, and the potential for unutilized baseload capacity correspondingly rises, OPG's prescribed assets will increasingly determine the market-clearing price.

structure, or allowing returns that do not conform to informed investors' perception of risk. Alternatively, regulation can provide an environment characterized by even-handedness, conducive to continued growth consistent with economic allocation of resources, and affording the utility a reasonable opportunity to achieve a fair return. Enlightened regulation will mitigate risks that are not susceptible to managerial control, and award a return that provides both (1) fair compensation for the risks that are left with management and (2) incentives to achieve (and exceed) the allowed return through continued improvement in productivity. The regulatory framework in which a utility operates is frequently viewed as the most significant aspect of risk to which investors in a utility are exposed. The financial community is very conscious of the regulatory environment, as highlighted in reports of both bond rating agencies and investment analysts.

While OPG has been subject to the provisions of Regulation 53/05 since April 2005, the introduction of active regulation by the OEB as of April 1, 2008 creates a number of uncertainties, as the "end state" of regulation is unknown. The November 30, 2006 "*Board Report: A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc.*" ultimately envisions an incentive regulation framework, but the parameters of that framework have yet to be developed, and the information necessary to create that framework can be expected to take a number of years to develop. In the interim, OPG's regulated operations will be subject to cost of service regulation. For purposes of the business risk assessment, I proceed on the assumption that OPG will be treated no differently from any other utility subject to the Board's jurisdiction: OPG will be provided a reasonable opportunity to recover its prudently incurred costs and earn a return that reasonably reflects the risks to which it is exposed.

In that context, certain requirements set out in Regulation 53/05 should be viewed as an implementation of the traditional regulatory prohibition against retroactive ratemaking. Those requirements include that:

1) OPG be allowed to recover the costs incurred with respect to the Bruce Nuclear Generating Station;

2) OPG be allowed to recover the costs and firm financial commitments incurred prior to the issuance of the Board's first rate order for the purpose of increasing the output of, refurbishing or adding operating capacity to a prescribed generation facility, if the costs and financial commitments were within the project budgets approved for that purpose by OPG's Board of Directors, and the OEB is satisfied that the costs and financial commitments were prudently incurred;

3) the Board must accept, for purposes of its first order, the values in OPG's most recently audited financial statements with respect to certain matters;

4) OPG be allowed to recover amounts recorded in the Pickering A return to service deferral account;

5) OPG be allowed to recover amounts in the variance accounts established by the regulation, subject to a determination by the OEB that the amounts were prudently incurred and accurately recorded; and,

6) OPG be allowed to recover its ONFA related costs, and to establish a deferral account for that purpose.

Going forward, OPG will be subject to the same standards of oversight with regard to recovery of costs incurred as other utilities regulated by the OEB.

As part of its payment application, OPG is applying to retain several of the deferral and variance accounts established under Regulation 53/05 that relate to future cost incurrence, but to discontinue several of the others. Specifically, OPG is proposing to retain deferral accounts for

ONFA related costs (Nuclear Liabilities Deferral Account) and costs to increase/add or refurbish its generation capacity (Capacity Increases/Additions and Refurbishments Deferral Account). OPG is also proposing to continue the variance accounts for the net revenue impact for variability in hydroelectricity production due to changes in water conditions (Water Conditions Deferral Account) and forecast ancillary service revenues (Ancillary Services Revenue Variance Accounts) . The variance account for transmission outages and restrictions will be eliminated, as will the variance accounts associated with Acts of God and unforeseen changes in nuclear technology or regulatory requirements[63], but OPG has reserved the right to do so in the future should there be material financial consequences arising from these factors. OPG is also proposing several new variance accounts, the most important of which will record the difference between actual and forecast pension/OPEB expense.[64]

The use of deferral and variance accounts can mitigate forecasting risks related to costs over which the utility has no control, but does not change the utility's fundamental risks. Moreover, the ability to create a variance or deferral account and accrue differences between forecast and actual costs does not guarantee recovery of those costs. The extent to which deferral accounts lower the forecasting risk faced by a utility and thus cost of capital is a function of the scope of the accounts and the materiality of the costs that are covered by those accounts.

All utilities have the ability to apply to the regulator for deferral accounts. The OEB has demonstrated an inclination to establish deferral accounts and recover costs accrued therein, subject to criteria of prudence, materiality, causation and uncontrollability. Therefore, OPG's

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[63] The variance accounts established for ancillary services (to be continued) and transmission outages and restrictions (to be eliminated), while they relate to revenues and costs beyond the control of management, the amounts are minor relative to the total revenue requirement and thus have little or no impact on the level of business risk.

[64] The potential variance between actual and forecast pension/OPEB expense is significant, primarily due to changes in the discount rate. A 25 basis point change in the discount rate used to establish the expense can alter expense by $50 million. OPG proposes to accumulate differences between actual and forecast expense in a variance account, but the amounts in the account would not be cleared until the cumulative balance (positive or negative) in the account reaches $100 million.

ability to recover its actual costs as a result of access to the existing deferral accounts does not result in a reduction in its risk relative to that of other utilities.

On balance, I view the regulatory risk for OPG as higher than that of the typical regulated utility in Canada and in Ontario. As the Board suggested in its November 20, 2006 report, the application of cost of service regulation to generation is a relatively unique phenomenon, with no track record upon which to gauge the outcome. The uncertainty of the "end state" is amplified by the fact that OPG will be regulated in a market environment which is a hybrid of regulation and competition, which creates additional pressure on regulated rates in a period of potentially significant cost increases (e.g., decommissioning costs, other post-retirement benefit expenses).

Further, OPG potentially faces significant capital expenditures for regulated facilities for which it may require regular access to debt markets. The requirement to refurbish existing nuclear plants, or build new nuclear or large scale hydroelectric generation facilities would entail an extended period between development, construction and putting those assets into service.

In this regard, traditional utility practice has been to exclude assets from rate base until they are used and useful and to accrue an Allowance for Funds Used During Construction (AFUDC) to recognize the financing costs incurred while the assets are being constructed. The AFUDC is capitalized and added to the cost of the assets and recovered after the assets are placed into service.[65] The exclusion of Construction Work in Progress (CWIP) from rate base is potentially a major disincentive to utilities to undertake the construction of major projects.[66] Allowing

[65] Depending on the jurisdiction, the AFUDC rate may be an interest rate or the weighted average cost of capital. In Ontario, while the OEB has previously recognized that it is appropriate to use a weighted average cost of capital (WACC) for purposes of calculating AFUDC, it has recently approved the use of a medium term interest rate to be applied to Construction Work in Progress for distribution utilities. The implication of this decision is that CWIP is 100% debt financed, a conclusion that should be taken into account in determining the allowed capital structure for rate base to ensure that the capital structure underpinning the totality of regulated assets, inclusive of CWIP, contains a reasonable balance of debt and equity.
[66] Recognition of the need to provide incentives to utilities to build needed infrastructure has led the Federal Energy Regulatory Commission to adopt a slate of incentives for transmission utilities that includes allowing CWIP in rate base.

CWIP in rate base in a period of high capital expenditures related to a fundamentally risky generation plant would help mitigate the increase in risks. The inclusion of CWIP in rate base would be viewed as mitigating risk by both debt and equity investors. My recommendation is premised on OPG being allowed to include in rate base CWIP related to specific projects where the costs are relatively large and the planning and construction period are extended, such as the Niagara Tunnel. Since OPG is not applying to include CWIP in rate base at this time, the size and duration of generation-related capital projects expose it to higher forecasting and regulatory risks than other OEB regulated utilities.

With the electricity market environment still in flux, the regulated operations of OPG remain subject to political risk. Since the initial restructuring that began in 1998 with the Energy Competition Act, there have been several interventions by the government into the operation of the electricity market. Ontario is one of the two provinces in Canada in which political intervention in the regulatory process has been a factor in the business risk assessment of utilities by the debt rating agencies (Alberta is the other). Political intervention in the industry restructuring process to shield customers from the impact of rising market prices for power was the principal reason given by the debt rating agencies for their downgrades to the debt ratings in 2003 of Ontario electric utilities. The debt rating agencies view the risk of further political intervention in the Ontario market as having declined since those debt rating reductions occurred in 2003. Nevertheless, the risk of future political intervention in the market is higher than in other Canadian jurisdictions, as there continue to be unresolved issues in an evolving Ontario electricity marketplace. With rising energy prices, the potential for future political intervention cannot be disregarded, as recent experience in the U.S. (e.g., Maryland, Illinois) demonstrates.

B.3. Business Risks of the Hydroelectric Operations

B.3.a. Revenue and Market-Related Risks

Revenue risks are partially a function of the payment structure, that is, the extent to which fixed costs are recovered in a rate that mirrors the manner in which costs are incurred. While the costs of the hydroelectric operations are largely fixed, OPG's proposed payment structure for production from its prescribed hydroelectric assets reflects a rate that is 100% energy-based. In isolation, the payment structure exposes OPG to higher revenue risks than the typical regulated company, which recovers a portion of its fixed costs in demand or customer charges.

Revenue risks also include the risk that the hydroelectric assets will not be dispatched. Dispatch risk remains low at present for the hydroelectric assets, as they are largely baseload facilities,[67] with low marginal costs. However, this risk will rise as additional low marginal cost generation becomes available. The emerging risk that OPG's prescribed assets are not dispatched and there will be unutilized baseload capacity will impact the hydroelectric facilities first.

Market prices are expected to directly impact regulated operations only through the operation of proposed hydroelectric incentive mechanism. Under the proposed Hydro Incentive Mechanism, OPG will be financially obligated to supply a given amount of energy each hour (Hourly Volume). It would receive the regulated payment for each MWh up to the Hourly Volume and the market clearing price for each MWh of energy in excess of the Hourly Volume. If OPG fails to supply the Hourly Volume for which it is financially obligated, its payments will be reduced by the difference between the amount supplied and the market price. Although the incentive mechanism and its reliance on market prices do not impact the determination of the revenue requirement (i.e., the revenue requirement is based on the total costs of providing service, not market prices), its operation can impact the recovery of the revenue requirement. While OPG's

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[67] As indicated earlier, the Beck complex has some peaking capability.

proposed regulated payments and the incentive mechanism are based on the same underlying forecast revenue requirement, the incentive mechanism has been constructed to operate on a stand-alone basis; that is, the risks/rewards of the mechanism were designed to be self-contained and as such are not incorporated into the business risk assessment of the prescribed hydroelectric assets.[68] Nevertheless, the form of the proposed incentive mechanism exposes the regulated operations to a risk that they will under-recover their revenue requirement.

B.3.b. Production, Operating and Cost Recovery Risks

The principal production risk facing the hydroelectric operations is related to the availability of water. Actual hydroelectric production can differ from long-term averages by close to 10% due to more or less than average water availability. Regulation 53/05 established a variance account to capture differences in hydroelectricity production due to differences between forecast and actual water conditions. Specifically, if the amount of available water is lower than forecast, the variance account is debited for an amount necessary to raise the total costs recovered to the level that would have been recovered had actual water levels been known; similarly the variance account is credited when actual water levels are higher than forecast. This variance account protects OPG's regulated revenues from a factor beyond management control. OPG is still at risk for differences between actual and forecast costs (e.g., shortfalls from targeted cost efficiencies) and differences between actual and forecast production for reasons other than water levels, the latter primarily arising from longer than anticipated outages and to a lesser extent from lower than expected demand (decreased demand would cause hydroelectricity production to be reduced in advance of nuclear production).

[68] The "*Board Report: A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc.*" (EB-2006-0064, November 30, 2006) ("Board Report") has indicated that the form of an incentive mechanism may be an issue. For example, the OEB will examine the current incentive mechanism including the existing threshold of 1900 MWh and the possibility of a separate price mechanism for the Beck pump generation facility. The adoption by the Board of an incentive mechanism that differs materially from that proposed by OPG could change the business risk profile of the regulated hydroelectric operations.

Given the potential differences between forecast and actual water and the resulting impacts on hydroelectric production and cost recovery, the operation of the variance account is a key risk mitigator for OPG. I have assumed the continuation of this mechanism (Water Conditions Deferral Account) as proposed by OPG for purposes of establishing an appropriate capital structure and return on equity.[69] From a relative risk perspective, the hydroelectricity variance account puts OPG on a similar footing to other utilities with significant hydroelectricity generation whose production is subject to water availability.[70]

Other forecasting risks specifically related to hydroelectricity facilities include an emerging risk related to requirements for water taking permits,[71] issues related to land claims or grievances which could result in higher than anticipated costs or interruption in production, and increased costs related to environmental issues (e.g., threatened species or fisheries authorizations).

B.3.c. <u>Regulatory Risks</u>

Chapter IV.B.2.c of this evidence discusses the regulatory environment as it impacts the composite regulated operations of OPG, including the hydroelectric operations. The key element of the regulatory framework that is unique to the hydroelectric operations is the variance account for differences between actual and forecast production due to differences between forecast and actual water conditions. As noted above, I view this variance account as a key risk mitigator, given the potential differences between forecast and actual water and the resulting impacts on hydroelectricity production and cost recovery. I have assumed the continuation of this account

[69] Going forward, this variance account may have increasing value, as water availability may become more uncertain if weather patterns become more volatile or more extreme with global climate change.
[70] In Canada, for example, Northwest Territories Power has a rate stabilization mechanism that protects against deviations between actual and normal water levels. In the U.S., Idaho Power, whose generating capacity is approximately 44% hydroelectricity-based, is allowed to recover 90% of the difference between forecast and actual purchased power and fuel costs. Puget Energy, whose generating capacity is approximately 11% hydroelectricity-based, has a power cost adjustment mechanism that provides earnings protection outside of a dead-band against various factors that can increase power costs, including water availability.
[71] Legislative changes could require permits to take water for non-consumption purposes, which could require payments for generation-related water flows and which could put limits on source water for hydroelectricity production.

for purposes of establishing an appropriate capital structure and return on equity for OPG's regulated operations.

OPG potentially faces significant capital expenditures to build new large scale hydroelectricity facilities. The requirement to build a new large scale hydroelectric generation facility would entail an extended period between development, construction and putting those assets into service. Allowing CWIP in rate base in a period of high capital expenditures would help mitigate the corresponding increase in risk. As discussed above, my recommendations are premised on the inclusion in rate base of CWIP related to specific projects where the costs are relatively large and the planning and construction period are extended, including the refurbishment of a nuclear facility or a new build. Since OPG is not applying to include CWIP in rate base at this time, the size and duration of generation-related capital projects expose it to higher forecasting and regulatory risks than other OEB regulated utilities.

B.4. Business Risks of the Nuclear Operations

B.4.a. Revenue and Market-Related Risks

As discussed earlier, revenue risks are partially a function of the payment structure, that is, the extent to which fixed costs are recovered in a rate that mirrors the manner in which costs are incurred. Except for the fuel costs, which make up a relatively small proportion of the total nuclear operations' cost structure, the costs of nuclear production are largely (over 90%) fixed. The proposed nuclear payment structure will collect 25% of OPG's forecast revenue requirement in a fixed charge. Under this structure, the assurance of recovery of the nuclear operations' fixed costs through fixed charges will still be less, and the revenue risk higher, than for the typical Canadian utility.

Revenue risks for nuclear operations include the risk that the generating plants will not be dispatched. Dispatch risk is low at present for the nuclear assets, as they are baseload facilities with low marginal costs. The risk to the nuclear operations that there will be unutilized baseload capacity will rise as additional low marginal cost generation becomes available. This is particularly problematic for nuclear generation, given the time required for the plants to ramp production up and down. No allowance for this emerging risk has been included in the forecast production.

The Board Report raises a risk that regulated revenues will be indirectly impacted by the market price, as it raises the spectre of caps on regulated payments if they exceed the market price for an extended period of time. This risk would principally impact nuclear production. Application of a cap based on market prices in the context of cost of service regulation would be an anomalous practice. Given that (1) the interim price for nuclear generation of $49.50 per MWh only included a 5% return on equity, and (2) OPG is facing potentially significant future cost increases (e.g., decommissioning costs), a cap on regulated payments tied to market prices could impair OPG's ability to earn a compensatory return.[72] The risk assessment proceeds on the assumption that the Board will not impose a cap on regulated payments tied to market prices.

B.4.b. <u>Production, Operating and Cost Recovery Risks</u>

The production/operating risks related to the nuclear assets are significantly higher than those of the hydroelectric generation facilities (and are higher than those of any other types of generation).[73] Nuclear technology is more complex than other types of generation and is subject to higher risks of unanticipated costs of repair and loss of production.

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[72] For some perspective, the weighted average Hourly Ontario Electricity Price was approximately $48.50/MWh during 2006, compared to the price of $53.38 that had been forecast for 2006 in March 2005 by Navigant Consulting in *Ontario Wholesale Electricity Market Price Forecast for the Period January 1, 2006 through December 31, 2006*, largely due to lower than anticipated load and lower than anticipated natural gas prices.

[73] According to Standard & Poor's,

> Nuclear generating assets have significant operational and technology risks. OPG operates 10 of its 12 CANDU nuclear units at its three stations. Technical challenges associated with key components of the facilities have the potential to expose the nuclear units to lengthy outages and have negatively affected operational and cash flow performance in the past. (Standard & Poor's, *Summary: Ontario Power Generation, Inc*., April 24, 2007.)

Forecasts of nuclear facility production include both planned and unplanned outages, and are based on past experience, benchmark data, levels of past and ongoing maintenance, unit reliability factors and the age and condition of individual units and thus reflect the level of production that OPG can reasonably expect to generate. The nuclear operating environment is much harsher than for fossil generation or for hydroelectric generation. As a result, the complexity and length of time for repair of nuclear plants often exceed those of hydroelectric or fossil generation. The nuclear plants may also experience deterioration or shift in physical properties that go beyond what was expected or assumed in the design of the plant. The specific circumstances of OPG entail additional risk, as the reactors reflect different stages of the CANDU design. Ongoing updates to nuclear operating standards and regulations may require modifications to the plants, particularly those with older design reactors, to ensure compliance.

While the forecast costs and production from the nuclear facilities include a provision for both planned and unplanned outages, the operating environment and the technological characteristics of OPG's nuclear generation fleet are such that the extent of required maintenance, repair or refurbishment is 1) forecast with a higher degree of uncertainty than for other types of generation, 2) can result in materially longer than anticipated outages and more frequent and longer than could be expected forced outages, 3) can result in higher than anticipated costs of repair or remediation, and 4) potentially lead to permanent loss of production either as a result of derating or a premature end of the economic life of the plant.[74]

Other production-related risks to nuclear production include weather damage and the threat of increased algae runs (which restrict cooling water intake flows). With respect to the latter, algae runs become more problematic as average temperatures rise over time. Further, as average temperatures rise, it becomes more difficult to cool the reactors. Thus, nuclear stations are more significantly affected by external conditions (e.g., cooling water availability) than fossil plants.

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[74] S&P finds that "Exposure to outages and their attendant costs is often exacerbated because nuclear outages tend to be lengthy relative to outages at other types of generation units given the complexity of nuclear reactors and the safety and regulatory issues that must be addressed before a nuclear unit is returned to service." S&P, *S&P Seeks Improved Risk - Assessment Metrics for U.S. Nuclear Power*, December 20, 2005.

While estimated unit availability and production are based on estimates that include past unit history and an understanding of the condition of the assets, the higher the capacity factor that is built into the forecasts, and the payments, the more asymmetry there is in the risk of exceeding versus falling short of forecast availability.

OPG faces significant risk of lost revenues due to longer and more frequent than anticipated outages and higher than expected costs to maintain and repair existing nuclear facilities. Every one TWh shortfall in production at a variable payment of $40 per MWh, which approximates the average variable portion of OPG's proposed nuclear payment amounts in Exhibit K1, Tab 3, Schedule 1, is equal to an approximately $40 million reduction in revenues. Since approximately 5.0% of the costs of nuclear production are variable, i.e., fuel costs (as per OPG's Exhibit I1-2-1), a $40 million reduction in revenues would reduce earnings from nuclear generation by approximately $25 million,[75] equivalent to a reduction in return on equity of approximately 0.6 percentage points relative to the total deemed equity ($4200 million) for the prescribed assets for 2008. To put this in perspective, in 2006, actual nuclear production fell 2.5 TWh below forecast. A 2.5 TWh production shortfall translates into a reduction in ROE of approximately 1.5 percentage points. It is important to note that the reduction in ROE would be higher if the proposed change in payment structure is not approved.

OPG's nuclear facilities are subject to the oversight of the Canadian Nuclear Safety Commission (CNSC), whose mandate is to protect the health and safety of persons and the environment, and to ensure national security from risks associated with the use of nuclear energy and nuclear material. The CNSC is responsible for licensing nuclear facilities during each of five phases in a nuclear plant's life cycle, site preparation, construction, operation, decommissioning and abandonment. In fulfilling its mandate, the CNSC has the ability to impose conditions of licenses, including, among other things, increased security requirements – which have become

[75] Equal to a reduction in revenue of $40 million less $2.0 million in variable costs, equivalent to $25 million in after-tax earnings at a 34% tax rate.

significantly more stringent since 9/11 – as well as increased safety and health standards.[76] Compliance with all security and health and safety regulations as well as license conditions is required in order for the nuclear facilities to continue to operate. OPG may incur significant operating and capital costs (as well as face curtailment of production and potentially permanent shutdown) to comply with such CNSC regulations and license conditions. Regarding environmental requirements, particularly with respect to discharges to the environment, and handling, use, storage, disposal and clean-up of hazardous substances, as well as the decommissioning of nuclear stations at the end of their useful lives, OPG also faces significant operating and capital costs. To the extent that nuclear production is adversely impacted by changes in legislation or regulations related to CNSC compliance or compliance with any other applicable laws, OPG is at risk, with the proviso that it retains the right to request a deferral account to recover related costs if they result in a material financial impact.[77]

Changing demographics, specifically an aging workforce, also create cost and production risks for all the regulated operations, but this issue is particularly pronounced for nuclear operations. Both availability and cost of nuclear-skilled employees are a concern, as the retirement of a large percentage of the skilled workforce becomes increasingly imminent. Bruce Power competes for available skilled personnel; training cycles are lengthy and costly. Similar to other employers, over 25% of OPG's workforce is eligible for retirement within the next 10 years.[78]

While the variable costs of nuclear production are not as significant as those of fossil generation, they are not immaterial. Market prices for uranium increased almost 200% over the period 2004-2006 due to a shortage in worldwide mine production and a drawdown of inventory. Speculation in uranium markets that as many as 168 nuclear plants could be built globally by 2020[79] drove the price from under $20 per pound in 2004 to over $70 per pound at the end of 2006. Since the

[76] Since 9/11, the threat of terrorism has emerged as an important risk factor for nuclear generation facilities.
[77] The proposal to seek a deferral account if related costs result in a material financial impact takes the place of the deferral account for unforeseen changes in technology or regulatory requirements established by Regulation 53/05.
[78] Statistics indicate that less than 45% of all nuclear engineers in the U.S. employed in 2004 would still be working in 2008.
[79] Melbye, Scott (Cameco), *Presentation to the World Nuclear Association Annual Symposium*, 2006.

beginning of 2007, market prices have continued to show high volatility with world prices reaching as high as $136 per pound (U.S.) from a low of $75 per pound (U.S.). Delays in bringing on new production could lead to even higher market prices. In addition, OPG's exposure to market prices for future years has increased due to a larger proportion of supply contracts that contain pricing indexed to market indicators at the time of delivery, a growing trend in the industry and a function of a strong sellers' market. For example, over 50% of the deliveries in 2009 are priced based on world prices at the time of delivery. Historically, a significant proportion of supply contracts were base price contracts with CPI or similar forms of escalation. This had resulted in considerably lower uncertainty in forecasting fuel expense than will be the case for the next several years. Higher uranium prices have already increased OPG forecast fuel expense in 2009 by almost 140% relative to 2004; continued increases in uranium prices could push the fuel expense even higher. As a result, regulated payments may not cover unanticipated uranium price increases. Given the significant volatility in uranium prices, which is not predictable and beyond management control, OPG is requesting a variance account to record variances between forecast and actual uranium costs. The proposed variance account would cover the preponderance of OPG's fuel price risk.

With respect to decommissioning and used fuel risks, OPG is responsible for the decommissioning of its nuclear stations, including the leased Bruce facilities[80], and for the management and disposal of used fuel from those plants. The Ontario Nuclear Funds Agreement (ONFA) between the Government of Ontario and OPG provides for segregated Decommissioning and Used Fuel Funds, and requires contributions to those funds, limits OPG's risk with respect to long-term used fuel management, and requires the Province to provide financial guarantees to CNSC that there will be funds available to discharge the used fuel and decommissioning liabilities.[81] Pursuant to ONFA, OPG's liability with respect to the management and disposal of used fuel is limited to approximately $6 billion based on the present value of the obligation in 1999 (approximately $9.1 billion in 2007 dollars). The Province and

[80] Bruce Power makes payments to OPG that cover decommissioning and waste management funding.
[81] The Provincial guarantee on unfunded liabilities was required by the CNSC to satisfy licensing requirements.

OPG have agreed to share cost increases associated with high level nuclear waste disposal up to a maximum of 2.23 million fuel bundles. In light of plans to refurbish and extend the lives of existing nuclear plants (including the refurbishment of Bruce A), current projections of high level nuclear waste now exceed 2.23 million fuel bundles. OPG assumes the liability for the additional waste and the related cost recovery risk. In contrast, the liability for used fuel in the U.S. is the responsibility of the Department of Energy; utilities with nuclear facilities pay a per kWh charge based on production to the government for assuming the disposal obligation. OPG bears the risk and liability for decommissioning cost estimate increases and fund earnings. At the end of 2006, based on the 2006 Reference Plan[82] for decommissioning, the Decommissioning Fund was fully funded. The rate of return on the Used Fuel Fund is guaranteed by the provincial government. At the end of 2006, the unfunded liability related to used fuel was approximately $2.4 billion.

While the decommissioning and used fuel liabilities are mitigated by funding them over time, the estimates are subject to change (e.g., changes in life cycle costs) each time the Reference Plan is revised (as required by legislation or every five years, whichever is earlier, or when there is a material change). A significant increase in the estimate of the liability could have a significant negative impact on OPG's financial condition. With respect to waste storage, although an options study for the disposal of high level waste has been submitted to the federal government, the choice of alternative could have a significant impact on the estimated liability. Risks associated with nuclear waste storage include financial impacts of sitting the geological repository and concerns in communities of interest. Licensing of the repository requires community support, which could deteriorate and result in protracted and costly processes. Similar issues exist with respect to the storage of low and intermediate level waste. The government has recently elevated the environmental assessment of OPG's proposed deep geological depository within the Bruce Nuclear site to a panel, which could result in material schedule delays and costs.

[82] The Reference Plan details the estimated costs of, and manner in which, the liabilities are to be discharged. ONFA requires periodic re-estimation of the decommissioning and used fuel obligations. The 2006 Reference plan raised OPG's liability by approximately $1.4 billion.

While Regulation 53/05 mitigates the risks to OPG as it requires that the OEB ensure that OPG recovers its costs related to ONFA, increased cash requirements for funding or a reduction in the time period over which those costs must be recovered could result in material pressures on the regulated payments.

Further, as time passes, the obligations to discharge the liabilities increase as the period over which the liability has been discounted to present value grows shorter. The potential ultimate result is that the size of the liability will eventually surpass the liabilities/net worth associated with OPG's actual operations. As regulated facilities are decommissioned, there is increasingly less production over which to recover future changes in the liabilities. The larger the liability relative to the actual operations of OPG, the greater is the impact of the volatility in the returns of the decommissioning fund on the overall volatility of OPG's earnings. Extension of the life of the nuclear facilities through refurbishment shifts the liability to a later time period, reducing the present value of the decommissioning liability. However, life extension also increases liabilities related to used fuel and waste management costs. In addition, since the assumption underlying decommissioning is that the reactors will be in safe storage for 30 years after the end of their useful life, and that dismantlement will take a further 10 years, there is a significant risk that the costs to service the liability will have changed, the decommissioning funds will not perform as was expected, and if they do not, that there will be no viable means to recover the deficit through regulated operations.

OPG is proposing to discontinue the variance account established under Regulation 53/05 for changes in nuclear electricity production due to unforeseen changes to the law or to unforeseen technological changes. As of the end of December 2006, OPG had recorded no costs in this variance account. However, the relevant costs – which I interpret as exceptional events or discoveries that are outside of past experience – could be significant. To the extent that unanticipated costs are incurred due to unforeseen technological changes, OPG retains the ability to seek deferral of those costs for future recovery. Nevertheless, even if OPG seeks a deferral account in future, there is no guarantee that OPG will be allowed to recover 100% of the incurred costs.

B.4.c. Regulatory Risks

Chapter IV.B.2.c. discusses the regulatory environment as it impacts the composite regulated operations of OPG, including the nuclear operations. The key elements of the regulatory framework as they relate specifically to nuclear operations are discussed below.

Regulation 53/05 established several deferral and variance accounts for the nuclear operations. These included deferral and variance accounts for:

(1) non-capital costs associated with the return to service of Pickering A nuclear generating station units (PARTS Deferral Account);
(2) costs incurred prior to the Board's first rate order to refurbish, increase or add generation capacity or to develop new nuclear capacity (Increased Capacity/Output and Refurbishment Deferral Account);
(3) transmission outages and restrictions; and
(4) ONFA related costs (Nuclear Liabilities Deferral Account); and
(5) unforeseen changes in nuclear technology or regulatory requirements.

OPG is proposing to recover amounts accumulated in the PARTS deferral account over a period of 15 years; the only additional costs that will be added to this account are carrying costs. The costs accumulated in the Increased Capacity/Output and Refurbishment Deferral and the Nuclear Liabilites Deferral Accounts as of December 31, 2007 are forecast to be recovered in regulated payments by the end of 2010. As indicated above, OPG is proposing to eliminate the variance accounts for transmission outages and restrictions, Acts of God and unforeseen changes in nuclear technology or regulatory requirements (with the proviso that OPG may apply for accounts in the future should the related costs result in a material financial impact).

OPG faces significant capital expenditures for refurbishment of existing or to build new regulated nuclear facilities.[83] The undertaking of the refurbishment of existing nuclear unit or construction of a new nuclear plant would raise the risks to which the utility is exposed. With respect to new nuclear plant construction, S&P is of the view that, despite the recent excellent performance of nuclear plants, historic risks will persist throughout a new plant's life cycle. These risks include cost growth, design and scope changes, permitting delays, public opposition, regulatory changes, latent technical defects, and uncertain decommissioning costs. All else being equal, S&P has concluded, an electric utility with nuclear exposure has weaker credit than one without.[84]

The requirement to refurbish existing nuclear plants, or build new nuclear generation facilities would entail an extended period between development, construction and putting those assets into service. Allowing CWIP in rate base in a period of high capital expenditures related to a fundamentally risky nuclear generation plant would help mitigate the increase in risks. As discussed above, my recommendations are premised on the inclusion in rate base of CWIP related to specific projects where the costs are relatively large and the planning and construction period are extended, including the refurbishment of a nuclear facility or a new build.

B.5. Relative Business Risks of OPG's Regulated Operations

With respect to relative business risk, OPG's regulated operations face significantly higher business risks than the typical Canadian utility and the typical vertically integrated electric utility in Canada or the U.S., for the following reasons:

a. As a generation-only business, OPG's regulated operations have no low risk monopoly "wires" or distribution "pipes" operations. Generation is inherently subject to higher

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[83] S&P has indicated that the "sheer amount of capital necessary to bring a new [nuclear] plant on line is daunting." S&P, *U.S. Is Looking at a Paced Reemergence of the Nuclear Power Option*, June 26, 2006.
[84] S&P, *Time for a New Start for U.S. Nuclear Energy?*, June 4, 2003.

market/competitive risks than "wires" or distribution "pipes", for which the probability of duplication of facilities is virtually nil. Generation is also subject to higher operating and production risks than "wires" or "pipes" operations.

b. The existing nuclear plants are subject to significantly higher production/operating risks than other types of generation.

c. While the risk-sharing of used fuel obligations with the government caps OPG's nuclear liability and the Nuclear Liabilites Deferral Account for ONFA costs mitigates the risks related to the nuclear liabilities, the long-run risks remain higher for OPG than for utilities with either no nuclear exposure, exposure tempered by the smaller size of nuclear operations relative to total operations, or where the government assumes the risk for a fee (as is the case in the U.S. for used fuel).

d. Regulatory risks are relatively high; there remains a risk of further political intervention that could alter OPG's ability to recover a reasonable return on (or return of) the invested capital; and

e. Potentially high levels of capital expenditures for refurbishment and new plant construction expose OPG to significant cost recovery risks.

C. IMPORTANCE OF INVESTMENT GRADE DEBT RATINGS

In contrast to unregulated companies, public utilities have obligations that require them to raise capital "on demand". Although OPG's regulated operations are not governed by the traditional obligation to serve, its mandate includes continuous improvement of its nuclear generation fleet, including refurbishment of older units, and expansion, development and improvement of its hydroelectric generating capacity. In August 2007, the Ontario Power Authority (OPA) delivered to the Ontario Ministry of Energy its proposed 20-year plan for the Province's electricity system. The plan outlined by OPA (subject to government approval) has been estimated to cost approximately $60 billion. In response to the OPA's initial recommendations (December 2005's *Supply Mix Advice and Recommendation Report*), OPG was directed by the government to begin an assessment of the refurbishment of existing nuclear units and the construction of new units. The success and cost of implementing the plan will depend in part on the ability of OPG and other generators to raise funds when required and on reasonable terms and conditions. If OPG is to be able to achieve a sustainable financial model as envisioned under the Memorandum of Agreement between OPG and the Province of Ontario, it needs to be able to access funds from the public markets for refurbishment and expansion.

In my opinion, to ensure access to the public markets, the capital structure for OPG's regulated operations should be sufficient to achieve debt ratings on a stand-alone basis in the A category. While debt ratings of BBB- or better are considered investment grade, debt ratings in the A category provide assurance that a utility will be able to access the debt markets as required on reasonable terms and conditions over the full interest rate or business cycle. If OPG is directed to refurbish or build new generating facilities, it will not have the flexibility to defer financing that an unregulated firm has.

Generation assets are long-lived. The life span of a nuclear generation facility is expected to be approximately 40 years; hydroelectric generation facilities can operate for periods in excess of 100 years. With long-lived assets, OPG needs to be able to access the long-term debt markets consistently. Financing long-term assets with short-term debt creates a mismatch between recovery of the investment in regulated payments and the return to investors of the capital committed, and exposes the utility to higher refinancing risk. Debt ratings in the A category will provide better assurance of predictable access to the long-term debt markets on reasonable terms and conditions than would BBB ratings.

Utilities with ratings in the BBB category not only will have to pay more for debt than A rated utilities, but they may have more onerous conditions attached to debt issues. In recent years, the spread between long-term BBB rated utility debt and A rated utility debt in Canada has been as high as 175 basis points.[85] In the U.S. over the past five years, the spread between A and Baa long-term utility bonds has been as high as 85 basis points. Of particular concern would be that a BBB rated utility would, at times, be completely shut out of the long-term (30-year) debt market.[86]

A utility with split ratings (that is, one debt rating agency rates the company's debt in the A category and another debt rating agency rates it in the BBB category) could face a materially higher cost of debt than a utility with both ratings in the A category. Debt investors are likely to take the lowest rating into account when pricing an issue. To illustrate, the credit spreads for new 30-year bond issues for Canadian utilities with split ratings have been approximately 35 basis points higher than for Canadian utilities for which all debt ratings are in the A category. Within the past five years, the spread differentials have been as high as approximately 65 basis points.

The public market for BBB rated debt remains more limited in Canada than in the U.S. Many institutions, who are major purchasers of corporate debt issues, either may not purchase BBB rated debt or have limitations on the proportion of BBB rated debt that they can hold in their portfolio. If an issuer's debt is downgraded further, into a non-investment grade category, the institution may have to dispose of its holdings in those securities. To illustrate, the NEB reported in its August 2005 *Canadian Hydrocarbon Transportation System Report* that Canadian bonds are an important revenue source to pension funds and other institutional investors, and a downgrade could require institutional holders to sell a large percentage of their bonds at discounted prices.[87]

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[85] Based on a comparison between the indicated spreads for TransAlta Corporation and Canadian utilities whose debt ratings are all in the A category.

[86] FortisBC, for example, rated at the time Baa3 by Moody's and BBB(high) by DBRS, had a difficult time during late 2004 and early 2005 accessing the 30-year debt market, despite the fact that the debt markets at the time were some of the most robust that had been experienced in Canada for years.

[87] More generally, the pension funds had indicated to the NEB that the basic financial parameters (allowed return on equity and deemed capital structure) in the Board's regulatory scheme should be improved.

D. DEBT RATINGS OF OPG

Ontario Power Generation Inc. is the entity that raises debt on behalf of the regulated operations and whose debt is rated. In 2006, the regulated operations of OPG accounted for approximately 60% of the company's total revenues and total generation. Thus, the views of the debt rating agencies with respect to OPG may provide some useful information regarding an appropriate stand-alone capital structure for the regulated operations.

D.1. DBRS

DBRS, which rates OPG's unsecured debt as A(low)[88], considers the key strengths of OPG as they relate to regulated operations to be:

a) Shareholder support;
b) Dominant market position;
c) More favourable interim regulatory framework relative to previous framework;
d) Nuclear waste management liabilities limited due to agreement with the Province.

The challenges related to regulated operations, in DBRS' view include:

a) Interim regulatory framework less favourable than in other North American jurisdictions;
b) Higher operating and financial risks associated with nuclear generation equipment;
c) Political intervention;
d) Significant capital program anticipated.

The sole challenge listed by DBRS that is unique to the unregulated operations is fuel cost risk associated with coal generation. Thus, it would be reasonable to conclude that DBRS views the

[88] DBRS, *Rating Report Ontario Power Generation Inc.*, August 3, 2006.

regulated operations as facing no less business risk than the unregulated operations. As such, DBRS' evaluation of the consolidated financial metrics and its resulting debt rating decision can be viewed as applicable to the regulated operations on a stand-alone basis.

DBRS notes that while OPG's cash flow-to-debt and interest coverage ratios have improved significantly and are strong relative to peers' (cash flow-to-debt ratio of 21.1% and fixed charge coverage of 4.55X in 2005, compared to 7.7% and 0.7X in 2004), the debt rating is limited by uncertainties with respect to closure of coal generation facilities, nuclear refurbishment, new nuclear build and the direction of regulation beyond 2008. The rating agency also referred to the fact that "OPG's regulated rates are based on an ROE of 5%, which is low in comparison to what the majority of other regulated generation companies receive in other jurisdictions in North America", and is lower than the ROEs of regulated transmission and distribution in Ontario, both of which have a lower business risk profile than generation. DBRS commented that regulated vertically integrated utilities in the U.S. have deemed capital structures ranging from 35% common equity to 55% common equity and have an approved ROE ranging from 9.75% to 13.5%. According to DBRS, a comparable entity to OPG (that is, one without stable transmission and distribution operations), according to DBRS, would be near the top of both ranges. DBRS concluded that if long-term certainty develops with respect to uncertainties related to local plant closures, nuclear refurbishment and new build, regulation beyond 2008, the level of allowed returns, and if financial ratios remain strong, it may consider a positive rating action.

The A(low) rating currently accorded OPG's consolidated operations, and which, as noted in IV.A.1, as of August 2006, was more "reflective of OPG's improved financial profile on a stand-alone basis" reflects a 2005 common equity ratio of close to 60%, a return on equity of 11.7% and the coverage ratios cited above.

D.2. Standard & Poor's

As noted above, Standard & Poor's rating for OPG of BBB+ reflects a two notch enhancement due to its relationship with its shareholder, the Province of Ontario. S&P views OPG's principal credit strengths as: [89]

a. Government ownership and implied financial support;
b. Fixed price for output from baseload nuclear and hydroelectric assets;
c. Diversified portfolio of generating assets; and
d. Strong cost-competitive position in its primary market.

Partially offsetting the credit strengths are:

a. Operational and technology risk associated with nuclear assets;
b. Non-regulated cash flow constraints related to unregulated operations due to a government-imposed revenue cap;
c. Volume risks on unregulated assets; and
d. An intermediate financial profile.

S&P's assessment of OPG's credit strengths and weaknesses suggests that it views the regulated operations as facing no less business risk than the unregulated operations, given its focus on the operational and technology risk of the nuclear facilities. Consequently, the recent consolidated financial parameters should be viewed as reflective of the level consistent with a stand-alone rating for the regulated operations in the BBB category.

[89] Standard & Poor's, *Summary: Ontario Power Generation*, April 24, 2007.

S&P reported a 2006 debt/capital ratio of 55.6% versus 63.9% in 2005[90], reflecting its 2006 adoption in Canada of a measurement methodology that makes analytical adjustments to amounts reported in companies' financial statements and treats items such as unfunded OPEBs, pension fund deficits and operating leases as debt for purposes of calculating capital structure ratios.[91] The 2006 and 2005 Adjusted Funds from Operations Interest Coverage ratios were 3.7X and 4.9X respectively; the corresponding Adjusted Funds from Operations to Total Debt ratios were 10.6% and 14%.[92] S&P's expectation is that the financial profile will remain relatively stable in 2007 absent any material changes to financial policies or capital structure. S&P maintains a positive outlook on the rating, indicating that it:

> reflects an improved pricing framework and regulatory environment. The rating will likely move a notch higher if OPG can manage its expenses and operational performance within the bounds of its current license agreement and maintain its satisfactory financial profile in 2007 with a similar outlook for 2008 and beyond. For the rating to move a notch higher, there will also have to be an expectation of continued relative stability in both Ontario's electricity policy and regulatory framework and a clear financial policy for the company. The outlook could be revised to stable or negative as a result of a sustained period of significantly lower-than-expected electricity production due to operational or technological challenges at the company's nuclear facilities, or higher operating expense due to poor hydrology and higher prices for coal, with no related increase to the revenue cap. As the shareholder relationship evolves in the long term, there could be a change to the degree of support factored into the rating.

Based on both debt rating agency reports, the current debt ratings for the consolidated operations of OPG are based on common equity ratios, as measured by external debt and equity, in the range of 55-60%. To achieve and maintain similar stand-alone investment grade debt ratings, the deemed common equity ratio for the regulated operations would need to be in a similar range.

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[90] Standard & Poor's, *CreditStats: Electric Utilities – Canada*, September 10, 2007. Based on the methodology used by S&P prior to adopting analytic adjustments for these items, the 2005 debt ratio, based solely on debt and equity, would have been reported by S&P as 44%.

[91] In its December 2005 report for OPG, S&P reported the 2004 debt/capital ratio at 42.7% based on reported amounts of debt and equity; in the September 2006 and 2007 *CreditStats*, with S&P's analytic adjustments, it was reported to be 56.5%.

[92] Standard & Poor's, *Summary: Ontario Power Generation*, April 24, 2007.

E. FINANCIAL METRIC GUIDELINES[93]

Of the three bond rating agencies that rate Canadian utility bonds (as well as the debt of utilities globally), Standard & Poor's has published the most detailed matrix of quantitative guidelines for different debt ratings.[94] S&P assigns to utilities a business risk score in a range of "1" to "10", where "1" indicates the lowest level of business risk, and "10" the highest. For a given business risk score and a particular debt rating, S&P provides a guideline range for debt ratios, Funds from Operations Interest Coverage, and Funds from Operations To Total Debt. While the guidelines are not applied mechanically, they do represent one objective basis for evaluating an appropriate stand-alone capital structure for OPG's regulated operations.

The key qualitative factors that S&P evaluates in arriving at a business risk score for regulated companies, including generation, distribution, transmission and vertically integrated companies, include regulation, markets, operations, competitiveness and management. S&P considers regulation to be a critical aspect of utilities' creditworthiness. Vertically integrated utilities generally have business profile scores of "5"-"6"[95]; generating companies have scores in the "7"-"10" range, with the level dependent upon the extent of the regulatory umbrella.[96] The analysis of the vertically integrated utilities as it regards operations is focused on the generation facilities. Specifically,

> [t]he status of utility plant investment is reviewed with regard to generating station availability, efficiency, and utilization, as well as for compliance with existing and potential environmental and other regulatory standards. The record of plant outages, system losses, equivalent availability, load factors, heat rates, and capacity factors are examined. Important considerations include the projected capital improvements and plant

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[93] See Appendix H for complete quantitative guidelines.
[94] DBRS has published guidelines that do not distinguish by either business risk or investment-grade rating category.
[95] Standard & Poor's, *Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers*, September 14, 2006.
[96] Standard & Poor's, *Rating Methodology for Global Power Utilities*, August 30, 1999

> additions necessary to provide high-quality, reliable service. The generation condition of the assets and how well such assets are maintained are also important.[97]
>
> Similarly, utilities that rely on nuclear generation receive an elevated degree of attention due to the scale, technical complexity, and politically sensitive nature of nuclear facilities. Indeed, the sound operation of nuclear units can define a utility's operational risk profile and its ability to achieve projected financial results.[98]

The average business profile score for Canadian utilities has been "3"; the majority of these are largely "wires" or "pipes" companies whose business risks are not comparable to those of OPG's regulated operations. Among the Canadian companies that have been assigned business profile scores is one vertically-integrated utility, Nova Scotia Power, which was assigned a score of "4" and TransAlta Corporation, assigned a "6". OPG's regulated operations, as solely generation, are riskier than Nova Scotia Power, whose operations include lower risk wires operations and no nuclear generation. In comparison to TransAlta Corporation, some of whose generating assets are subject to cost-of-service type Power Purchase Arrangements (approximately 45% of operating income) and none of which are nuclear, OPG's regulated operations would face no less business risk. On balance, it is likely that OPG's regulated operations would, on a stand-alone basis, be assigned a business profile score of "6".

S&P's guidelines for an A debt rating and a business risk score of "6" are as follows:

Table 6

Total Debt/Total Capital (%)	40-48
FFO Interest Coverage (x)	4.2-5.2
FFO/Average Total Debt (%)	28-35

Source: Standard & Poor's, *Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers*", September 14, 2006.

[97] Standard & Poor's, *Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers*, September 14, 2006, p. 4.
[98] *Ibid.*, p. 4.

The guidelines for business risk profile scores of "6" indicate that a common equity ratio in the range of 52% to 60% is warranted for an A rating.

Moody's also has published quantitative guidelines. While OPG does not currently have a Moody's rating, there are a large number of Canadian electric, gas and pipeline companies that are rated by Moody's, including Hydro One. Thus Moody's guidelines are applicable to those companies and will play a role in the establishment of capital structures that will be adequate to maintain investment grade debt ratings. OPG's financial parameters will be compared against its peers', whose financial parameters will be judged against Moody's guidelines. Moody's guidelines for an A rating for a regulated company of "medium risk" are:

Table 7

FFO Interest Coverage (x)	3.5-6.0
FFO/Debt (%)	22-30
Retained Cash Flow/Debt (%)	13-25
Debt/Capital (%)	40-60

With only generation operations, of which close to half (as measured by assets) are nuclear generation, OPG's regulated operations would likely be viewed, on a stand-alone basis[99], as falling in the upper end of the risk spectrum, thus warranting a debt ratio in the lower end of the range for "medium risk" utilities. Hence, based on Moody's guidelines, a reasonable deemed

[99] Moody's actual ratings for publicly-owned utilities, in contrast to the approach of DBRS and S&P, reflect a methodology specific to government-related issuers. Its ratings for Hydro One, for example, explicitly consider the high degree of dependency between Hydro One and the local economy, Hydro One's operating and financial proximity to the government, and the support of the province as sole shareholder. In the absence of the implied government support, Moody's rating for Hydro One would be two notches lower than its Aa3 rating, that is, on a stand-alone basis, it would be rated A. According to its December 2005 report, Moody's considers Hydro One to have a credit risk of "3" on a scale of "1" to "6". OPG's regulated operations would likely have a materially higher credit risk, and a lower rating based on Moody's government-related methodology than Hydro One. Consistent with the differences between the other rating agencies' ratings for Hydro One and OPG, given the relationships between OPG and the provincial government, the most likely Moody's rating for OPG would be A.

common equity ratio for OPG's regulated operations compatible with a stand-alone A rating would be in the range of 50-60%.

The common equity component alone does not determine the debt rating. Other financial metrics, along with qualitative factors, are also taken into account by debt rating agencies. Thus, for example, if a utility is able to achieve adequate ratios such as FFO Interest Coverage and FFO/Debt ratios despite a debt ratio that is higher than indicated by guidelines (as a result of the combination of ROE, cost of debt and cash flows from depreciation), it still may be able to achieve an A rating. Consequently, S&P's guideline range for the debt ratio is an important indicator of an appropriate capital structure for OPG's regulated operations, but other financial metrics need to be taken into account. An analysis of stand-alone "notional"[100] coverage ratios at the benchmark return on equity of 10.5% and a common equity ratio of 57.5%, in the absence of experiencing risks that cause the actual performance of the regulated operations to fall short of expected levels, the principal cash flow metrics (FFO interest coverage and FFO to total debt) for the regulated operations would be expected to be sufficient to achieve and maintain stand-alone debt ratings in the A category.

F. CAPITAL STRUCTURES OF PEERS

The actual capital structures of OPG's peers, which underpin those utilities' debt ratings, may also provide some insight into an appropriate stand-alone capital structure for an A rating. Since there are no other regulated generation companies in North America, the closest peers for OPG's regulated operations would be, in Canada, TransAlta Utilities and TransAlta Corporation, and in the U.S., electric utilities with S&P business profile scores of "6".

[100] The debt rating agencies do not calculate ratios for individual divisions of a company; they look at the ratios of the entity that raises capital. The notional ratios were estimated solely to test the impact of the combination of hypothetical capital structure and return on equity on the ability of the regulated operations to attract capital and maintain their creditworthiness on a stand-alone basis.

TransAlta Corporation is rated BBB by both DBRS and S&P. TransAlta Utilities, the subsidiary of TransAlta Corporation that holds the PPAs for the "heritage" Alberta generation, is rated A(low) by DBRS and BBB+ by S&P. The debt ratio for TransAlta Corporation, as measured by DBRS, has averaged 47.9% from 2003-2005; the corresponding debt ratio for TransAlta Utilities has averaged 52.3%. The average ratios as measured by S&P for 2004-2006 were 53.2% for TransAlta Corporation and 21.1% for TransAlta Utilities. The differences in the measurement of the debt ratios for TransAlta Utilities by the two debt rating agencies relates primarily to the treatment of preferred securities and preferred shares; DBRS treats TransAlta Utilities' inter-company preferred securities as 50% debt and the perpetual preferred shares as 30% debt, while S&P treats both the preferred securities and shares as equity.[101] The large proportion of TransAlta Utilities' capital structure that is made up of "hybrid" preferred securities makes it difficult to draw definitive conclusions regarding a reasonable deemed debt/common equity capital structure for OPG. Moreover, since the ratings of TransAlta Utilities are split (A(low) by DBRS and BBB+ by S&P) and the ratings of TransAlta Corporation are both in the BBB category, they provide some insight into what would be warranted for a BBB rating, but not for an A rating. For a BBB rating, the TransAlta capital structures are indicative of a common equity ratio (based solely on a debt/equity split) of approximately 50% for a generating company.

With respect to U.S. companies, there are no A rated electric utilities with business profile scores of "6". The following table summarizes the debt ratios and other corresponding financial metrics for the universe of electric utilities with rated debt.

[101] Over 50% of TransAlta Utilities' 2005 total capital, when defined as debt, preferred securities and common equity, was preferred securities.

Table 8

Group	S&P Business Profile	2005 Debt Ratio [1/] (%)	S&P Credit Stats: 2005 Debt Ratio (%)	Average 2003-2005: Debt Ratio (%)	EBIT Coverage (X)	FFO/Debt (%)	FFO Coverage (X)	Average ROE 2003-2005 (%)
	(Medians)							
All A Rated	4	51.6	55.9	56.6	3.7	21.8	4.8	12.2
All BBB Rated	5	51.8	56.8	57.2	2.8	19.5	4.1	10.5
BBB Business Profile 1-4	4	55.6	57.6	55.9	2.7	18.7	3.7	11.1
BBB Business Profile 5	5	51.0	55.4	56.1	2.7	20.9	4.0	10.6
BBB Business Profile 6	6	51.2	57.3	59.0	2.7	18.7	4.2	10.5
BBB Business Profile 7	7	54.7	59.3	61.5	3.5	20.6	4.3	13.7
BBB Business Profile 7-10	8	49.0	56.0	56.6	3.5	20.9	4.1	12.4
ENTIRE SAMPLE	5	51.7	56.6	56.8	2.9	20.7	4.2	10.9

[1/] Sum of long-and short-term debt divided by sum of long- and short-term debt, common equity and preferred stock.
Source: Schedule 27.

The table indicates that the typical debt ratio is approximately 55% (45% equity ratio) irrespective of debt rating category. However, the earned returns on equity for the utilities, at those capital structures, have been approximately 11% for the industry as a whole, 12% for the A rated utilities and approximately 12% for the highest risk companies. The resulting FFO Coverage ratios have been approximately 5 times for the A rated utilities (which are of lower business risk than OPG), and 4.2 times for the BBB rated companies with a "6" business profile score. FFO/Debt ratios are approximately 22% for the low risk A rated utilities and approximately 20% for BBB rated utilities with a "6" business profile score. The results suggest that the industry average is an approximately 45% common equity ratio. However, the equity ratio cannot be considered independently of the ROEs that have been key to the achievement of the utilities' financial metrics. As indicated above, the achievement of the referenced coverage ratios was dependent on earned returns on equity in the 11-12% range. In deriving an appropriate common equity ratio for OPG at the proposed benchmark return on equity of 10.5%, which is premised on equating the total risks of OPG's regulated operations to those of low business risk utilities rated in the A category, the deemed equity ratio will need to be higher than the industry average of 45%. The alternative is to set the capital structure at the industry standard, and to recognize OPG's higher business risks relative to the benchmark in the common equity return. Chapter IV.G following analyzes the trade-off between the equity ratio and the return on equity.

G. CAPITAL STRUCTURE FOR OPG AT BENCHMARK RETURN[102]

In contrast to OPG's regulated operations, which are 100% generation, the individual utilities used to derive the benchmark return on equity are largely "wires" or "pipes" companies. Of the seven individual Canadian utilities with publicly-traded stock[103], and for which betas were calculated, only three (Canadian Utilities, Emera and TransCanada) have any material generation activities. Of these three, only one has any nuclear generation; TransCanada has a 47.9% ownership stake in Bruce Power. The U.S. companies used to derive the benchmark return are also largely low risk wires and pipes utilities. Of the 13 utilities in the benchmark U.S. utility sample, only 5 are integrated electric utilities. The sample's asset mix includes approximately 2.5% generation based on the median and 15.0% generation based on the average. The average business profile score of the U.S. benchmark sample is "3", compared to the typical generation business profile score of "7" to "10". The business profile scores that have been assigned to Canadian utilities by S&P have averaged "3"; only two electricity firms, Emera/NSPI ("4") and TransAlta Corporation ("6") have been assigned scores higher than "3".

OPG's regulated operations, 100% of which are generation, and approximately 45% of whose regulated assets (65% of regulated generation capacity) are nuclear generation, are of significantly higher risk than the utilities used to establish the benchmark return. As discussed in Chapter III.A, the benchmark return is applicable to a typical, or average risk, Canadian utility. For the benchmark return to be applicable to OPG's regulated operations, the deemed capital structure must be estimated that would equate OPG's total (business plus financial) risks to those

[102] A complete discussion of the methodology applied in this section is provided in Appendix I.
[103] The seven utilities referenced are: Canadian Utilities, Emera, Enbridge, Fortis, Pacific Northern Gas, Terasen Inc. (stock has not been publicly-traded since its purchase by Kinder Morgan in November 2005), and TransCanada PipeLines.

of the utilities used to derive the benchmark return. The benchmark return would be applicable to a utility which, given its business risk and capital structure, would be able to achieve debt ratings in the A category.

In order to estimate the common equity ratio for OPG that would permit the application of the benchmark return to its regulated operations, I selected a sample of vertically integrated utility companies with significant generation operations in order to estimate the incremental cost of equity for regulated generation company like OPG. The incremental cost of equity for the "high generation" sample can then be translated into the common equity differential required to equate OPG's total business and financial risk to that of an average risk benchmark Canadian utility. At the identified common equity ratio, the benchmark utility return on equity will be applicable to OPG. For purposes of establishing the incremental cost of equity and the common equity differential, the sample of low risk U.S. electric and gas utilities (similar in risk to an average risk Canadian utility) served as the benchmark against which the selected sample of "high generation" U.S. utilities was compared.

The principal criteria for selection of the "high generation" sample included (1) an investment grade debt rating and (2) generation assets accounting for no less than one-third of total assets.[104] The selected sample includes 21 utilities with an average S&P debt rating of BBB (Moody's rating of Baa2), and an average proportion of generation to total assets of 48%. Sixteen of the 21 utilities have nuclear generation.[105]

The comparative S&P business profile scores, debt ratings, betas and common equity ratios of the high generation and benchmark low risk utility samples are provided in the table below.

[104] Criteria for selection of the "high generation" utilities are set out in Appendix I.
[105] The selected utilities are listed on Schedule 28.

Table 9

	***Value Line* Beta**	**Research Insight Beta**	**Average of *Value Line* and Research Insight Betas**	**S&P Business Profile**	**S&P Debt Rating**	**Moody's**	**Common Equity Ratio (2006)**
Benchmark Utility Sample							
Mean	0.86	0.59	0.73	3	A	A2	44.9%
Median	0.85	0.60	0.73	3	A	A3	44.6%
Weighted Average	0.80	0.53	0.67	4	A	A2	43.5%
High Generation Utility Sample							
Mean	0.93	0.77	0.85	6	BBB	Baa2	44.8%
Median	0.95	0.81	0.88	6	BBB	Baa2	45.8%
Weighted Average	0.93	0.68	0.81	6	BBB+	Baa1	43.0%

Source: Schedules 13 and 28.

The betas in the table are investment risk or levered betas. Investment risk betas are a function of both business and financial risks. When the financial risks of the sample companies (capital structures) are materially different, the business and financial risk components of the investment risk betas need to be segregated to determine how much of the risk differential between the samples is due to differences in business risk and how much is due to differences in financial risk. In the case of the high generation and benchmark utility samples, the capital structure ratios are very similar. Hence, the differences in the investment risk betas of the samples can be attributed to differences in business risk. The conclusion that the principal risk difference is related to business risk is supported by the difference in the S&P business risk profile scores between the two samples; "3" for the benchmark sample and "6" for the high generation sample.

Based on the average of the *Value Line* and Research Insight adjusted betas, the beta for the high generation sample is approximately 0.84 versus 0.71 for the benchmark sample. Using my estimated 6.5% market risk premium, the difference in equity return requirement between a high generation utility and the benchmark is close to 1.0 percentage point ((0.84-0.71) X 6.5%= 0.85%). As both samples have similar common equity ratios (approximately 45%), the approximately 1.0% differential in return requirement is applicable to a higher business risk utility at a 45% common equity ratio. Since the high generation sample contains significant wires operations (43.7% of assets on average), this differential equity return requirement should be viewed as the minimum difference required for a generation-only company with a common equity ratio of 45%.

The high generation sample was then used to derive a generation-only beta using the residual beta model (See Appendix I for theoretical basis). The residual beta model is based on the premise that the beta for the company is a weighted average of the betas of the individual betas of the different divisions of the company. If the beta for the company is known, and the betas for all but one of the divisions can be separately estimated, the beta for the remaining division can be derived by disaggregating the beta for the company as a whole. The residual generation-only beta was estimated using the following equation:

$$\beta_{HighGx} = \beta_{Gx} \text{ x } \%Assets_{Gx} + \beta_{Pure\ Wires} \text{ x } \%Assets_{Wires} + \beta_{Other} \text{ x } \%Assets_{Other}$$

The beta for the “wires” operations of the high generation sample was estimated from a sample of utilities with primarily “wires” operations. The selection of the “wires” sample is described in Appendix I. The beta of pure wires was estimated at 0.70; the beta for the “other operations” which account for 8.0% of the assets of the high generation sample was assumed to be 1.0, equal to the beta for the market as a whole (or, alternatively, of an average risk stock). The common equity ratio of the “wires” sample, at 43.7%, is virtually identical to the common equity ratio for the high generation sample. Thus, since the average common equity ratio of the “wires” sample is identical to that of the “high generation” sample, differences in beta between the two samples can be attributed to differences in business risk (i.e., there is no need to segregate the investment risk betas of the "wires" sample into business and financial risks components). Using the formula and betas above, the derived beta for generation-only was estimated at 0.94. The difference in the equity return requirement between generation and a benchmark utility can then be estimated as approximately 1.5%, calculated as the difference in betas multiplied times the market risk premium ((0.94-0.71) X 6.5% = 1.5%). As with the estimation of the return requirement differential based on the high generation sample compared to the benchmark sample, the 1.5% applies to a generation-only company with a similar common equity ratio, that is, 45%.

Because OPG's regulated operations are 100% generation, the incremental equity returns at a 45% equity ratio are at the upper end of the range, i.e. in the range of approximately 1.25% to 1.50%. This incremental equity return was then used to develop the range of equity ratios for OPG's regulated operations that would be required to equate the fair return for OPG's regulated operations to the benchmark return of 10.5%. The quantification of the common equity ratio range was based on the application of two capital structure theories.

Theory 1 posits that income taxes and the deductibility of interest for corporate income tax purposes have no impact on the cost of capital. Under this theory, the overall cost of capital stays constant when the capital structure changes, although the costs of the debt and equity components change (i.e., the cost of equity rises when the equity ratio declines). Theory 2 posits that income taxes and the corporate deductibility of interest expense cause the overall cost of capital to continually decline as the equity ratio declines and the debt ratio increases. The actual impact on the cost of capital most likely lies in between the results of the two theories; income taxes and the deductibility of interest do tend to decrease the cost of capital (as the income trust market has demonstrated), but as the debt ratio rises, there are increasing costs in terms of loss of financing flexibility and potential bankruptcy. Moreover, in the case of regulated companies, the benefit of the tax deductibility of interest is to the benefit of ratepayers, while in the unregulated sector, the benefit goes to the shareholder. Since both theories have merit, both were applied to estimate the impact of a change in return on equity on capital structure.

The table below indicates that, based on both theories, the range of common equity ratios required to equate the return on equity for OPG's regulated operations to the benchmark return of 10.5% is in the range of 55-60%.

Table 10

	Common Equity Ratio		
	55%	**57.5%**	**60%**
Theory 1	10.5%	10.2%	10.0%
Theory 2	11.0%	10.8%	10.6%
Average	10.75%	10.5%	10.3%

Source: Appendix I and Schedule 31.

H. RECOMMENDED CAPITAL STRUCTURE AND FAIR RETURN

Based on (1) my analysis of the OPG's business risks, (2) the debt rating agencies' quantitative guidelines for specific debt ratings, (3) OPG's own debt ratings and its financial metrics, (4) the financial metrics of the electricity industry (including equity ratios), and (5) the incremental cost of equity for regulated generation relative to that of integrated utilities, the deemed common equity ratio for OPG's regulated operations should be set within a range of 55-60% (mid-point of 57.5%). A 57.5% common equity ratio would, in my opinion, be adequate to allow OPG's regulated operations to achieve a stand-alone debt rating in the A category. On the basis of the combined business and financial risks, OPG's regulated operations would then be of approximately equivalent total risk to a benchmark utility. At a 55-60% deemed common equity ratio, the fair return for OPG's regulated operations is equal to the benchmark return on equity of 10.5%.

I. IMPLIED CAPITAL STRUCTURE OF OPG'S UNREGULATED OPERATIONS

The objective of adherence to the stand-alone principle for purposes of determining the deemed capital structure and return on equity is to ensure that ratepayers are bearing a cost of capital that represents the risks of the regulated activities of the firm, not the risks of the consolidated operations. An element of the application of the stand-alone principle is ensuring that the regulated operations are not subsidizing unregulated operations. A cross-subsidy can be said to exist if the regulated operations are bearing costs that are the responsibility of the unregulated operations.

Since the proposed deemed common equity ratio for the regulated operations of 57.5% is lower than OPG's 2006 consolidated equity ratio as reflected in OPG's audited financial statements, assuming the consolidated equity ratios were maintained, the implied unregulated operations' common equity ratio is higher than the proposed deemed ratio for regulated operations. Further, the profitability of the consolidated operations and the individual business segments since the implementation of the Electric Restructuring Act 2004 indicate that the unregulated segment has been largely responsible for the improved financial position of OPG. As reported by DBRS, the return on equity for the consolidated operations was 11.7% in 2005 compared to the ROE of 5.0% on the prescribed assets. The unregulated operations, which account for approximately one-third of the assets, contributed over 50% of the operating income in both 2005 and 2006 as per OPG's audited financial statements.

Given that the unregulated operations – which are comprised largely of coal, oil/gas, hydro and wind generation – add to the diversification of OPG's overall portfolio of generation, contribute more than 50% of the operating income of the operations (even with a revenue cap in place), and have an implied common equity ratio slightly higher than that proposed for the regulated operations, there is no basis for any concern that, with a deemed common equity ratio of 57.5%, the regulated operations would be subsidizing the unregulated operations.

V. CAPITAL MARKET VIEWS ON FAIR RETURN/CAPITAL STRUCTURE

A. IMPLICATIONS OF GLOBALIZATION OF CAPITAL MARKETS

With the potential for refurbishment of existing nuclear units and construction of new nuclear units, OPG could be facing unprecedented capital expenditures for regulated generation over the next 20 years. As noted earlier, OPA has estimated that the plan to ensure the reliability of the Ontario's electricity supply could cost approximately $60 billion, of which approximately $26 billion could be for refurbishment of existing nuclear units and construction of new units.[106] OPG would not be alone in facing large capital expenditures. In its 2003 *World Energy Investment Outlook*, the International Energy Agency estimated that over $1.5 trillion in investment would be required by the electricity industry in North America. OPG will thus be competing for capital in a market that may be characterized by an unprecedented requirement for debt capital by a single industry. To compete successfully in the public debt markets, that is, to be able to attract capital on flexible terms and conditions, OPG will require financial metrics that are compatible with its peers on a risk-adjusted basis. Its peers are increasingly global, not solely Canadian.

Globalization of the capital markets has been a gradual phenomenon, as information barriers and transactions costs have declined, and financial reporting has become more standardized. The repeal of the Foreign Property Rule (FPR) in Canada in August 2005 has eliminated a further barrier, effectively releasing investment that was previously captive. Comparisons among companies across boundaries have become increasingly common. For example, S&P's peer

[106] The forecast costs for nuclear refurbishment and new build are not specific to OPG.

comparison for OPG includes two Canadian companies (TransAlta and Emera) and a U.S. company, Exelon.[107] With investors more willing to invest capital across international boundaries, a regulated company's ability to offer a return that is compensatory with its risk and comparable to its peers' becomes an increasingly imperative objective.

In the U.S., the average return on equity allowed for electric utilities by state regulators from the beginning of 2003 to the end of the second quarter of 2007, during which the long-term U.S. Treasury bond yield averaged 4.9% – virtually identical to the forecast 2008 5.0% long Canada yield – was 10.6% on a common equity ratio of 47.7%. The approved returns and capital structures are for both "wires" only (transmission/distribution companies) and vertically integrated companies, both of which would be less risky than OPG, whose regulated operations are generation-only. At the U.S. federal level, the Federal Energy Regulatory Commission (FERC) sets returns and capital structures for electricity transmission, for which the recent allowed "baseline" returns on equity have been in the range of 10.8%-12.4% on equity ratios in the 50-60% range. Baseline returns are exclusive of incentives. Since generation is riskier than transmission, the FERC returns would be supportive of returns in excess of 11-12%.[108]

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[107] TransAlta's peers are PPL Corp and Constellation Energy, both U.S. companies.

[108] The Conference Board of Canada has pointed out the importance of competitive returns for transmission in Canada. In its May 2004 Briefing entitled, "*Electricity Restructuring: Opening Power Markets*", the Conference Board stated,

> Investors are discouraged by limitations on the regulated cost recovery for transmission upgrading. Transmission companies are simply not seeing favourable risk/return ratios on their investments, and know that they can realize better returns in the United States, where regulated rates of return are much higher. Rates of return to Canadian firms for transmission projects are around 9 to 10 per cent, well below the 13 to 14 per cent available to U.S. companies. These lower rates discourage investment in Canadian utilities. Moreover, investors are additionally deterred by the fact that existing cost-of-service rates do not reflect the economic value of the transmission grid.

That conclusion would be no less true for regulated generation.

B. VIEWS OF CANADIAN DEBT RATING AGENCIES

As indicated in Chapter III.D, debt rating agencies and debt investors look at a variety of quantitative financial measures in assessing the financial strength of a regulated company. For a regulated utility, the ability to achieve strong financial metrics arises not only from the equity component, but also the return allowed on that equity component and the rate of depreciation. Both DBRS and S&P have consistently commented on the highly levered nature of Canadian utilities and the low allowed common equity returns relative to their global peers, particularly those in the U.S.

DBRS has noted that it would like to see both the deemed common equity ratios and allowed returns increased to levels more consistent with U.S. returns. [109]

In December 2004, subsequent to the AEUB's Generic Cost of Capital Decision (2004-052, dated July 2004), DBRS referred to the low deemed equity and returns as a "challenge" for the ATCO Utilities. The DBRS report for ATCO Ltd. stated,

> While ATCO's diversified operations, coupled with the Company's prudent management approach, provide a level of earnings stability, additional challenges over the medium term include the relatively low approved returns on equity (ROE) and deemed equity for the regulated businesses, continuing regulatory risk and lag and ATCO's merchant power exposure in Alberta.

Additional recent DBRS reports citing the challenge of low approved returns on equity have been published for other Alberta utilities, i.e., AltaLink (November 2004), and FortisAlberta (September 2004).

As previously noted, IV.D.1, DBRS has commented with specific reference to OPG, that regulated vertically integrated utilities in the U.S. have deemed capital structures ranging from

[109] DBRS, *The Rating Process and the Cost of Capital for Utilities: Five Reasons Why Canadian Utilities have Lower Ratios and Five Changes to Regulation Which Should be Introduced in Canada*, May 2003.

35% common equity to 55% common equity and have an approved ROE ranging from 9.75% to 13.5%. A comparable entity to OPG (that is, one without stable transmission and distribution operations), according to DBRS, would be near the top of both ranges.

With respect to Standard & Poor's, in early March 2003, the debt rating agency announced that it was re-evaluating its prior justification of the strong investment grade ratings of Canadian utilities (i.e., the nature of Canadian regulation).

S&P noted that Canadian utilities are among the most highly levered utilities in their global ratings universe, and that the highly leveraged financial profiles generally stem from regulatory directives. Subsequent to that announcement, S&P has commented on the low equity ratios and allowed returns of specific Canadian utilities.

For example, like DBRS, S&P has made references to the low level of equity ratios allowed in the EUB's Generic Cost of Capital decision for other Alberta utilities. Subsequent to the EUB decision, S&P commented on the thin equity layers allowed the ATCO group of utilities, stating,

> The regulatory regime, although comparable with other provinces in Canada, typically approves less generous returns on thinner equity layers than those approved for ATCO's global peers. Approved returns for ATCO's regulated businesses are 9.6% on equity layers varying from 33%-43% of total capital. (S&P, *Research Update: ATCO Group of Companies 'A' Ratings Affirmed; Outlook Stable*, November 9, 2004.)

In a relatively recent report for AltaLink (rated A-), S&P stated,

> Like many regulated utilities in Canada, AltaLink's average financial profile is constrained by a comparatively low approved ROE (8.93% in 2006) on a thin deemed equity base of 35%. (S&P, *Research Summary: AltaLink*, June 5, 2006)

In its report for Union Gas issued subsequent to the utility's 2006 settlement in which the allowed common equity ratio was raised to 36%, the two weaknesses referred to by S&P were the high leverage associated with company's regulated capital structure and the relatively low allowed ROE compared with global peers (S&P, *Research: Union Gas*, August 24, 2006).

In general, S&P considers that Canadian utility financial polices tend to be aggressive with leverage, and regulators parsimonious with returns.[110] As noted above, the "aggressive leverage" is largely a result of regulatory directives.

C. VIEWS OF EQUITY ANALYSTS

Canadian equity analysts rarely comment on the level of allowed returns and capital structures of regulated companies. However, there have been some notable exceptions. As long ago as December 2001, CIBC World Markets Report entitled "*Pipelines and Utilities: Time to Lighten Up*", stated, in reference to the then recent formulaic reduction in Newfoundland Power's allowed return (from 9.59% to 9.05% year over year):

> The magnitude of the reduction in the case of Newfoundland Power illustrates the flaw in using a brief snapshot of existing rates rather than a forecast of rates that are expected to persist during the upcoming year. More importantly, however, it shows the shortcoming of the formula approach itself. Mechanically tying allowed returns on equity to long bond yields is an approach that is simple for regulators to apply; however, in recent years, with a steady decline in bond yields, it has produced-allowed returns that are out of sync with the cost of capital, and returns that are being achieved with comparable nonregulated companies or regulated returns that are achievable in the U.S.

At the time of the report, the allowed returns for Canadian utilities were approximately 9.6%, compared to just over 11% for U.S. utilities.

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[110] Standard & Poor's, *Industry Report Card: Regulatory Rulings, M&A, and Fuel Cost Recovery Dominate Global Utilities Credit Environment*, November 21, 2006.

In the NEB's August 2005 *Canadian Hydrocarbon Transportation System* report, as noted above, pension funds had indicated to the Board that the basic financial parameters (allowed return on equity and deemed capital structure) in its regulatory scheme should be improved. In its 2006 report of the same name, the NEB reported that a number of analysts felt that the ROE generated by the NEB formula and by other Canadian regulators' formulas "were a little too low" and not supportive of dividend growth or credit metrics. A number of analysts commented that where they have "Buy" recommendations on utility stocks, the recommendations tend to reflect the prospects of the unregulated operations.[111] Analysts also commented that companies have reduced costs and taken other steps to improve profitability and dividend growth for several years, and wondered how long that could continue. The 2007 Report expressed similar views. Some parties expressed concern that the stand-alone pipelines might have difficulty attracting capital given low ROEs. Others felt the regulated entities would be able to attract capital, but that the terms under which they did so would be more costly than for the consolidated entity. In addition, the report stated that,

> Many analysts expressed support for a formulaic approach to determining ROEs because of the transparency, stability and predictability that this method provides. However, a number expressed the view that the ROE resulting from the formula was too low, and contend that they are much lower than regulated ROEs in the U.S. and U.K. While views ranged widely on this issue, some felt that the typically lower ROEs in Canada were not justified by the differences in risk for Canadian companies compared to FERC-regulated pipelines. Some parties suggested it was time for the Board to revisit the ROE Formula.

The most recent analyst commentary on the level of allowed ROEs in Canada expresses the view that the current level of allowed ROEs, expected to be approximately 8.6% in 2007, is now confiscatory. Specifically, in *Pipelines/Gas & Electric Utilities,* dated December 7, 2006, Karen Taylor, equity analyst for BMO Capital Markets, concluded:

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[111] In many cases, the ROEs achieved by the entity whose shares are traded have been materially higher than the ROEs allowed under the formulas. The allowed ROE generated by the NEB formula averaged 9.6% over the period 2002 to 2005; the ROE reported for TransCanada Pipelines Ltd by DBRS over that same period was 12.7%. For Terasen Gas, its allowed ROE averaged 9.2%; Terasen Inc.'s ROE (as reported by DBRS) averaged 11.1%. DBRS reported an average ROE of 13.0% for Canadian Utilities Ltd., compared to its regulated subsidiaries' allowed ROEs of approximately 9.6%.

We believe that regulators have consistently refused to give weight to a number of arguments that would result in higher allowed returns, solely on the basis that to do so would result in higher customer rates.

- The North American capital markets are increasingly integrated and investors have the ability to invest in utility assets north and south of the border.
- There is merit incorporating U.S. market metrics into the analysis and that the Canadian benchmark equity portfolio (the S&P/TSX) may not meet the theoretical requirement for a diversified market portfolio.
- The returns on comparable investments with similar risk, whether they be Canadian or U.S. examples, should be considered.
- The allowed return on equity and deemed equity must satisfy all aspects of the Fair Return Standard and that no part of the Standard has priority. ….
- No pipeline or energy utility in our regulated coverage universe has issued equity in the last five years to fund, on an unlevered basis, a dollar-for-dollar equity investment in utility rate base. Continued assertions by regulators that utilities have adequate access to capital are not credible with respect to the equity component, as access to equity has not been tested over the ensuing period. ….
- Continued investment in utility rate base by the owners of utilities is not an acquiescence that the allowed return on equity is appropriate and that investment may relate to other obligations including the utility's obligation to be the supplier or supply of last resort and fulfill the obligation to serve, maintain the safe and reliable operation of the utility, and may be fulfilling specific conditions of its operating licence. ….
- A failure by utility companies to annually litigate the allowed return on equity "formula" does not constitute acceptance of the adequacy of the allowed return. Rather, we believe that the lack of annual litigation reflects the cost of the process, the time required to pursue litigation that detracts from management's ability to focus on the efficient operation of the business and the potential damage to important utility regulatory and customer relationships. ….
- The evidenciary standard is too high and almost impossible to meet. Moreover, we believe that notwithstanding decisions from the Supreme Court that stipulate otherwise, utility regulators continue to rely heavily on their quasi-judicial and expert status to impose a bare-bones return on equity and drive down the deemed capital structure of the utility in order to protect customers from prices, without the fear of reconsideration upon appeal. Regulators must establish the cost of equity and deemed equity not because they are experts in this regard, but in order to establish just and reasonable rates. The regulator is not permitted to consider the effects

> on customers in the determination of the allowed ROE and capital structure, and we do not believe that the regulator is permitted to factor in other policy objectives into its determination of the allowed return on equity; i.e., we do not believe that the regulator is permitted to reduce the allowed return on equity and/or deemed equity for small utility companies in other to encourage consolidation or any other specific policy objective. We believe in these situations, that the inclusion of these other factors in the assessment of cost of equity and designation of deemed equity, unlawfully transfers value to utility ratepayers from its legitimate owner, the utility shareholders.

In sum, the returns available to comparable U.S. utilities are materially higher than the returns that are allowed to Canadian utilities, the returns allowed for Canadian utilities are generally regarded as too low, and the returns that investors expect and are achieving from the traded entities in Canada are considerably higher than the returns that have been allowed by regulators. These factors are legitimate considerations to be taken into account in setting a fair and reasonable return for OPG's regulated operations.

VI. AUTOMATIC ADJUSTMENT MECHANISM

The key purpose of automatic adjustment mechanisms for return on equity (ROE) is to avoid annual reviews of the allowed return on equity. The appropriate return on equity is unobservable (in contrast to the cost of debt) and is subject to a wide difference of opinion. Testimony on the fair return is typically technical and lengthy, and often quite similar from year to year. Considerable time, effort and money are spent on testimony preparation, information requests, and cross-examination. An automatic adjustment mechanism is a means of avoiding annual ROE reviews, while providing timely changes in the allowed return on equity. Since OPG is likely to face a number of limited issue hearings over the next several years, with ROE assigned to the first, the consideration of an automatic adjustment mechanism is particularly germane. The ROE can be set in the first proceeding, with no further need to address the issue throughout the remaining limited issues proceeding.

An automatic adjustment mechanism for ROE is relied upon in six different regulatory jurisdictions in Canada. The OEB first introduced an automatic adjustment mechanism in 1997 for the natural gas utilities; it approved automatic adjustment mechanisms for Hydro One and the electricity distributors in 1998 and 1999 respectively. The Board's automatic adjustment mechanism for the gas distributors was reviewed in detail in 2003 and reconfirmed in early 2004. In its *Report to the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, issued December 20, 2006, the Board has retained the existing automatic adjustment mechanism for the electricity distributors as part of its guidelines for setting rates for 2007-2009.

The automatic adjustment mechanisms currently operating in Canada are all quite similar. The point of departure for the implementation of each of the automatic adjustment mechanisms was the determination of a “base” or initial ROE and its two component parts, the risk-free rate and the equity risk premium. The adjustment mechanism itself specifies how changes from the base ROE are to be calculated for subsequent years. The two major components of the adjustment mechanism are the measurement of the risk-free rate and the formula to be used to adjust the ROE from one year to the next. The yield on the benchmark long-term (30-year) Government of Canada bond is used as the proxy for the risk-free rate.

The methodology used by the OEB has two components, the “initial setup” and the “adjustment mechanism”. The “initial setup” has two steps: (1) establish the forecast of the long-term Canada yield for the test year and (2) establish the implied risk premium. The “adjustment mechanism” also has two steps: (1) establish the forecast long Canada rate and (2) apply the adjustment factor. The adjustment factor was specified in the Guidelines at 0.75. The adjustment factor of 0.75 means that the allowed ROE changes by 75% of the change in the forecast long-term Government of Canada bond yield. The same 75% adjustment mechanism is used by four of the other five regulators that rely on automatic adjustment mechanisms.

The key advantages of an automatic adjustment mechanism are as follows:

1. It reduces the regulatory burden imposed by the annual determination of ROEs.

2. It results in increased predictability of the allowed returns;

3. It avoids any potential arbitrariness of the outcome.

The principal disadvantages include:

1. There are constraints placed on the regulator’s flexibility in setting the allowed return to address issues such as financing flexibility requirements;

2. If the base return is inadequate or excessive, the operation of the formula could potentially compound problems with the initial ROE;

3. If the formula adopted does not appropriately track changes in the cost of equity, subsequent allowed ROEs may not be representative of a fair return, and potentially, an impairment of financing flexibility.

4. There is a potential for more volatility in the regulated payments if the ROE changes materially from year-to-year than if the ROE remains unchanged for an extended period.

5. Some parties believe that the use of an automatic adjustment formula based on changes in the risk-free rate requires that the base ROE be determined solely on the basis of the equity risk premium test.

If there are sufficient safeguards in place that permit the formula to be revisited or that permit the utility to seek relief in circumstances of financial distress, the principal disadvantages of an automatic adjustment formula can be overcome. Moreover, financial flexibility concerns can be addressed through a change in the deemed capital structure. While DBRS has called the sensitivity of Canadian utilities' earnings to interest rates a "Challenge", the experienced year-to-year changes in formula-driven ROEs do not individually have a major negative impact on interest coverage. However, a steady decline in ROEs over a number of years will have (and has had) a cumulative impact, largely because the embedded cost of debt declines more slowly than allowed ROEs.

With respect to any concerns that the automatic adjustment mechanism sacrifices the contribution of tests other than the equity risk premium test, that concern is misplaced. The reliance on an interest rate to adjust the ROE from year to year, does not exclude, for purposes of setting the initial return, reliance on tests whose formulation does not include an interest rate. In this regard, I note that the BCUC and the AEUB, when setting the base return in their recent "generic" cost of capital decisions (2006 and 2004 respectively), looked at all of the tests and market information on their own merits, not whether they were based on the same parameters as the proposed automatic adjustment formula.

I recommend the adoption of an automatic adjustment formula for OPG, recognizing that a key to its success is the Board's adoption of a reasonable initial return.[112] With respect to the specifics of the adjustment mechanism, the Board's existing formula for subsequent changes in ROE, that is, a 75 basis point change in ROE for every one percentage point change in the forecast 30-year Canada bond yields, remains a reasonable approximation of the relationship between cost of equity and interest rates. However, OPG should retain the right to seek a review of the formula if there is evidence that the formula itself is not producing returns that will allow OPG to attract capital on reasonable terms (e.g., a threat of a downgrade to non-investment grade, assuming that threat can be tied, at least in part, to regulated operations).

As a further protection, I recommend that the formula should be reviewed if forecast long Canada bond yields fall below 3.0% or exceed 8.0%. Long Canada yields outside of the range of 3.0%-8.0% may indicate a materially altered relationship between long Canada bond yields and the utility cost of equity. The specification of 3.0% as the bottom end of the range recognizes there has been no experience with long-term Canada yields near this level since the early 1950s. With respect to the upper end of the range, if long Canada bond yields were to reach 8.0%, the real cost of capital or inflation would be materially higher than that which is currently anticipated. Both circumstances would warrant a review of the validity of the formula.

[112] The importance of the internal consistency between the initial return and the automatic adjustment formula must be underscored. It would be unreasonable for the Board to allow a return on equity that implicitly assumes that the cost of equity has declined by 100% of the decline in interest rates since the persistent downward trend began in 1995, but then impose a formula that only increases the allowed return by 75% of future increases in interest rates.

APPENDICES
TO

Capital Structure and Fair Return on Equity

Prepared for

ONTARIO POWER GENERATION

Prepared by

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.

November 2007

APPENDICES

APPENDIX A

DEEMED VERSUS ACTUAL CAPITAL STRUCTURE

DEFINITION OF DEEMED CAPITAL STRUCTURE

The term deemed, or hypothetical, capital structure, simply refers to imputing, for ratemaking purposes, a capital structure that is different from the capital structure that is reported on the utility's financial statements or forecast to be reported on the financial statements during the test period. The most common method of applying the deemed capital structure construct is to:

1. estimate the rate base;

2. apply to the rate base a pre-determined percentage of common equity;

3. attribute to the regulated operations actual outstanding and forecast issues of long-term debt and preferred shares; and

4. to the extent that the rate base and the sum of the deemed common equity and the available actual long-term debt and equity do not match, balance the rate base and capital structure with a "plug", either debt (if rate base is greater than capitalization) or notional investments (if capitalization is greater than rate base).

HISTORY OF DEEMED CAPITAL STRUCTURE IN CANADA

Deemed capital structures have been used in Canada since at least 1978. The Ontario Energy Board has relied on deemed capital structures for the local gas distribution utilities it regulates since at least 1981.[113] The use of deemed capital structures arose in the context of applying what has been referred to as the stand-alone principle. Adherence to the stand-alone principle requires setting a capital structure and cost of capital that reflect the risks of the regulated utility as a stand-alone entity, not those of the legal entity within which the regulated utility resides.[114] The perceived need for reliance on deemed capital structures was primarily the result of the extent to which regulated companies were diversified into operations whose risks were significantly different from those of their regulated operations. The consolidated capital structure and cost of capital were thus viewed as not representative of the capital structures the regulated entity would maintain on a stand-alone basis or of the cost of capital the regulated entity would face on a stand-alone basis. The stand-alone capital structure and return on rate base were intended to

[113] In EBRO 376-I & II (January 30, 1981), the OEB approved a stand-alone capital structure for Consumers Gas (now Enbridge Gas Distribution).

[114] The Alberta Energy and Utilities Board (EUB) described the stand-alone principle as follows:

> This first application of the stand-alone principle is designed to remove the effects of diversification by utilities into non-regulated activities. <u>Using the stand-alone principle in this case, a utility is regulated as if the provision of the regulated service were the only activity in which the company is engaged.</u> This application of the principle ensures that the revenue requirement of regulated utility operations is not influenced up or down by the operations of a parent or 'sister' company. <u>Thus the cost (or revenue requirement) of providing utility service reflects only the expenses, capital costs, risks and required returns associated with the provision of the regulated service.</u> (emphasis added) (Decision 2001-92, December 12, 2001, pp. 24-25).

protect the ratepayers from the impacts of the consolidated companies' non-regulated operations.[115]

While the deemed capital structure construct was initially applied in situations where there were significant non-regulated operations co-mingled with the regulated operations (in the same corporate entity), it has become the standard Canadian approach, even in situations where the regulated entity is for all intents and purposes a "pure play" utility. This is the case for natural gas and electricity distribution utilities in Ontario. I am aware of no utility in Canada with significant non-regulated operations whose ratemaking capital structure is based on its actual capital structure.

In the North American context, the wide-spread use of a deemed capital structure is primarily a Canadian phenomenon.[116] Its use in the United States has generally been limited to circumstances in which the utility's actual common equity ratio is determined to be well above the level maintained by its peers.

RELATIONSHIP BETWEEN CAPITAL STRUCTURE AND RETURN ON EQUITY

The basic principle that underpins the determination of the stand-alone cost of capital is that the opportunity cost of capital to a firm, or division of a firm, is a function of its business risks. The financing of the assets with a combination of debt and equity can lower the overall (weighted average) cost of capital, since debt is less expensive than equity, and interest expense is deductible for corporate income tax purposes. However, too much debt will increase the

[115] The stand-alone principle has also been applied to other types of costs, including income taxes and OM&A.
[116] The approach used to set the cost of capital for utilities in the UK is also based on a deemed capital structure.

weighted average cost of capital, as the costs of financial distress will outweigh the benefits of additional debt. Two other factors offset some of the advantage of using debt in the capital structure. The first factor is the impact of personal income taxes on interest income. While interest expense is deductible at the corporate level, the corresponding interest income is taxable to individual investors at higher rates than on equity income (dividends and capital gains). Second, in the case of regulated utilities, the benefits of the tax deductibility of interest expense flow to ratepayers, not shareholders, as the revenue requirement is reduced to reflect the lower corporate income tax expense.

In theory, there exists an optimal capital structure, i.e., one that minimizes the overall cost of capital. For tax-paying utilities, the ability to deduct interest expense for tax purposes creates a compelling incentive to pinpoint an optimal capital structure. However, it is not possible to pin-point the optimal capital structure. In practice, there exists a range of capital structures over which the average cost of capital does not change materially. Within this range, an increase in the debt ratio will result in an increase in both the cost of debt and the cost of equity, but the overall cost of capital will not change measurably. Despite wide-spread agreement in the academic community (as well as among practitioners) that the optimal capital structure can not be precisely identified, the use of a deemed capital structure for ratemaking purpose is effectively based on the premise that it can be estimated within a relatively narrow range.

There is agreement, however, that as a general proposition, companies with less business risk can safely assume more debt than those with higher business risk without impairing their ability to access the capital markets on reasonable terms and conditions. In principle, higher business risk can be "offset" by maintaining or imputing a higher common equity ratio, so that two utilities with different levels of business risk and different capital structures would face similar costs of debt and equity.

ESTIMATING CAPITAL STRUCTURES AND RETURNS ON EQUITY: REGULATORY APPROACHES

There are effectively two approaches that have been used by Canadian regulators to determine the deemed capital structure and corresponding return on equity. The first has been to assess the "subject" utility's business risks, then establish a capital structure that (a) is compatible with its business risks; (b) would permit it to achieve a stand-alone investment grade debt rating; and (c) would approximately equate the level of the specific utility's total (business and financial) risk to that of the proxies (or benchmarks) used to estimate the cost of equity. This approach permits the application of the proxy firms' cost of equity to the subject utility without any adjustment to the "benchmark" return on equity.

The second approach entails establishing a deemed capital structure that is reasonable, but does not necessarily equate its total risks to those of a "benchmark." Using the adopted equity ratio, the utility's level of total risk (business plus financial) is then compared against that faced by the proxy firms that were used to estimate the equity return requirement. If the total risk of the proxies is higher or lower than that of the subject utility, an adjustment (typically a premium) to their cost of equity is made when setting the subject utility's allowed return on equity.

This second approach, that is varying both capital structures and risk premiums, is equally as valid as the first approach as long as the combination of allowed capital structure and equity risk premium for a particular utility reasonably compensates for its business risk relative to that of its peers. Both of these approaches have been adopted by Canadian regulators.

The National Energy Board adopted the first approach when it established its automatic adjustment mechanism for a number of oil and gas pipelines in its 1995 Multi-Pipeline Cost of Capital Decision. Each individual pipeline was deemed a common equity ratio that was intended to compensate for its business risk relative to the other pipelines, so that a single "benchmark" return on equity could be applied across all of the pipelines. In the years since the multi-pipeline return on equity was adopted, the NEB has changed the allowed capital structure, rather than the allowed return, to recognize changes in business risk. Thus, TransCanada PipeLine's allowed common equity ratio has risen from 30% in 1995 to 33% in 2002 and 36% in 2005,[117] but the ROE has continued to be determined annually using the automatic adjustment mechanism adopted in 1995.

The same approach was adopted by the EUB in Decision 2004-052 (July 2, 2004). In that decision, the EUB set different capital structures for eleven electric and gas distribution and transmission entities, based on their different business risk profiles, and then established a common "benchmark" return on equity to be applied to each of the utilities under its jurisdiction. The EUB's decision established allowed common equity ratios ranging from 33% for electric transmission to 43% for a relatively risky gas pipeline. In the middle of the business risk range were the major electricity and gas distributors with allowed common equity ratios of 37% and 38%, respectively.

In contrast to the NEB and EUB approach, the British Columbia Utilities Commission (BCUC) has allowed for both different capital structures and different equity risk premiums among the various utilities it regulates. In every year since 1994, the BCUC has determined a benchmark

[117] Deemed at 40% by Negotiated Settlement for 2007-2011, approved by the NEB in May 2007.

low risk utility return on equity using an automatic adjustment formula (which has been amended several times) and has designated Terasen Gas as the benchmark low risk utility. Each of the utilities regulated by the BCUC has its own unique deemed capital structure and allowed equity risk premium (expressed as a premium to the low risk benchmark utility equity risk premium). The company-specific capital structures and equity risk premiums (relative to the benchmark) can be reviewed during the individual utility's company-specific revenue requirement proceedings. Theoretically, the combination of capital structure and return on equity for each utility should reasonably compensate it for its business risk relative to that of its peers.

The Régie de l'Energie de Québec has also used a combination of deemed capital structures and returns on equity. The two gas utilities and the transmission and distribution operations of Hydro Québec all were allowed different capital structures and equity risk premiums.

In Ontario, both approaches have been used. The two large gas distributors (Enbridge Gas and Union Gas) historically have been allowed the same deemed common equity ratio, but Union is allowed a somewhat higher risk premium. Natural Resource Gas (NRG), a very small gas utility, had, between 1997 and 2006, been allowed a higher common equity ratio than Enbridge and Union, with a common equity return equal to that of Enbridge. When NRG refinanced its capital structure in 2006, the OEB reduced NRG's deemed equity ratio to a level close to the actual level, and increased its equity risk premium (above that of Enbridge Gas).

For the electricity distributors, in 2000, the OEB established different deemed capital structures for different tiers of utilities, based on size, where size was used as a proxy for differences in business risk. The same equity return was then applied to all the individual utilities. In the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (*Report*), issued December 20, 2006, the Board has issued new guidelines which use the same deemed capital structure for all the electricity LDCs (60% debt/40% equity as well as the same ROE). The *Report* does not reflect any change in the principle that the capital structure (or return on equity) should reflect the utilities' relative risk. Rather, the *Report* reflects the conclusion that size no longer represents an accurate proxy for risk. The 40% equity ratio adopted in the *Report* represents Board Staff's proposal, which took into account the allowed common equity ratios for the gas utilities and the conclusion that a thicker common equity ratio is warranted for the electricity distributors. The rationale for this conclusion was that the risks of the gas utility business have been examined thoroughly through the regulatory process, unlike the electricity distribution industry, and that the electricity distribution industry requires significant investment in infrastructure, which imposes additional risks on the electricity distributors relative to the gas utilities.

ACTUAL vs. DEEMED CAPITAL STRUCTURE: PROS AND CONS

The advantages of using an actual capital structure are that:

1. it leaves the choice of capital structure to management, whose expertise in financial matters is superior to that of the regulator;

2. it allows, in principle, the actual capital costs of the utility to be recovered;

3. it recognizes that there is no widely agreed-upon measurement of the optimal capital structure; and

4. it recognizes that the factors such as the lumpiness of capital expenditures may not permit the utility to manage its actual capital structure to the ratios that would otherwise be deemed.

The principal advantages of a deemed capital structure are:

1. its use is compatible with basic finance theory that the opportunity cost of capital reflects the use of funds, that is the risk of the enterprise in which funds are invested, not the overall cost of funds to the entity that raises the capital;

2. it ensures that the ratepayer is protected from the riskier operations of a parent company; and,

3. it will result in more stable rates than using an actual capital structure that might change materially from year to year.

ISSUES IN SELECTING THE DEEMED CAPITAL STRUCTURE FOR REGULATED OPERATIONS

The selection of the appropriate deemed capital structure for regulated operations is based in large part on an assessment of the stand-alone business risks of those operations and on the resulting stand-alone financial metrics for those operations. The latter is to ensure that the regulated operations could, on a stand-alone basis, access the capital markets on reasonable terms and conditions without being subsidized by the unregulated operations.

If the deemed capital structure is to be in place for multiple years without review, e.g., during a PBR term, the proposed deemed ratio should be sustainable over that period. This is not usually an issue for an investor-owned utility that can seek equity infusions from its parent during that period to maintain the actual equity ratio close to the deemed level, but may be an issue for a publicly-owned utility facing material capital expenditures but access to equity only through management of dividend payments.

For an enterprise with both utility and non-utility operations, the utility may be required to demonstrate that the deemed equity ratio for the utility operations is not subsidizing the non-utility operations. To illustrate, assume a company which has 50% of its assets in utility and non-utility operations respectively. The consolidated common equity ratio of the company is 45%. A reasonable deemed common equity ratio for the utility operations is determined to be 50%. If the deemed equity ratio for the utility operations were indeed set at 50%, the implied common equity ratio of the non-utility operations would be only 40%.[118] Thus, unless there were evidence that the returns being earned by the non-utility operations were at a level that was compatible with the 40% implied equity ratio, an inference might be drawn that, at a 50% deemed equity ratio, the regulated operations (and ratepayers) are subsidizing the unregulated operations. It is important to ensure that the proposed deemed capital structure avoids potential cross-subsidization.

[118]The calculation is as follows:

$$\text{40\% non-utility equity ratio} = \frac{\text{45\% corporate equity ratio} - \text{(50\% utility assets x 50\% utility equity ratio)}}{\text{50\% non-utility assets}}$$

IMPLEMENTATION OF A DEEMED CAPITAL STRUCTURE

The use of a deemed capital structure requires matching the capital structure to the rate base. The rate base, in principle, in its entirety is intended to be a representation of the amount of investor-supplied capital required to provide utility service. Ratepayer provided funds that are used to finance utility assets represent no cost capital. No cost capital (e.g., deferred taxes) should be deducted from rate base (or included in capital structure at a 0% cost rate).

To the extent that there are no specific debt issues that can be separately identified with the unregulated operations, actual long-term debt can be attributed to the deemed capital structure to the extent required to bring the rate base and deemed capital structure into balance. If the deemed equity and allocation to the utility capital structure of 100% of the actual long-term debt available does not equate rate base and capital structure, i.e., capital structure remains lower than rate base, the remaining gap is "plugged" by deeming sufficient debt to create a balance between the two.[119] The choice of short-term or long-term debt as the "plug" should be based on the nature of the shortfall between the two.[120] If, for example, the difference is primarily attributable to differences in the way working capital is estimated for regulatory purposes (lead/lag study) versus financial statement purposes, reflecting seasonal usage of short-term debt, the plug should attract a short-term debt cost. If, however, the difference were attributable to deeming a lower common equity ratio than the actual equity available, the "plug" should reflect the long-term nature of the assets and thus be deemed as, and costed at, a long-term debt rate.

[119] In its *Report* for the electricity distributors, the Board has fixed the short-term debt proportion at 4% of rate base. A cap on the short-term debt would require any additional "plug" that is required to equate rate base and capital structure to be deemed as long-term debt.

[120] In certain cases, where actual equity exceeds the deemed level, the "plug" is a reduction to capitalization. The cost rate on the "plug" has typically been deemed at a cost that reflects the rate achievable if the excess capitalization had been invested.

APPENDIX B

THE CAPITAL ATTRACTION AND COMPARABLE EARNINGS STANDARDS

Two standards for a fair return have arisen from the legal precedents for establishing a fair return, the capital attraction and comparable earnings standard. The principal Court cases in Canada and the U.S. establishing the standards include *Northwestern Utilities Ltd.* v. *Edmonton (City)*, [1929] S.C.R. 186; *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679, 692 (1923)*; and, *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591 (1944))*.

In *Northwestern*, Mr. Justice Lamont stated

> The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.

In *Bluefield*, the criteria for a fair return were described as follows:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be

> reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

In *Hope*, Justice Douglas stated,

> By that standard the return on equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

The fact that the allowed return is applied to an original cost rate base is key to distinguishing between the capital attraction and comparable earnings standards. The base to which the return is applied determines the dollar earnings stream to the utility, which, in turn, generates the return to the shareholder (dividends plus capital appreciation). In the early years of rate of return regulation in North America, there was considerable debate over how to measure the investment base. The controversy arose from the objective that the price for a public utility service should allow a fair return on the fair value of the capital invested in the business. The debate focused on what constituted fair value: Was it historic cost, reproduction cost, or market value? Ultimately, *Hope* opted for the "reasonableness of the end result" rather than the specification of a particular method of rate base determination. The use of a historic cost rate base became the norm because it provided an objective, measurable point of departure to which the return would be applied. There is no prescription, however, that the historic cost rate base itself constitutes the "fair value" of the investment.

Nevertheless, regulators' application of a capital market-derived "cost of attracting capital" to a historic rate base in principle will result in the market value of the investment trending toward the historic cost based on the erroneous assumption that this equates to "fair value". The "fair value equals original cost" result arises from the way "cost" has typically been interpreted and applied in determining other cost elements in the regulation of North American utilities. For most utilities, rates are set on the basis of book costs; that concept has been applied to the cost of debt and depreciation expense, as well as to all operating and maintenance expenses.

For economists, the theoretically appropriate definition of cost is marginal or incremental cost. For regulated utilities historic costs have been substituted for marginal or incremental costs for two reasons: first, as a practical matter, long-run incremental costs are difficult to measure; second, for the capital intensive utility industries, pricing on the basis of short-run marginal costs would not cover total costs incurred.

The determination of the return on common equity for regulated companies has traditionally been a "hybrid" concept. The cost of equity is a forward-looking measure of the equity investors' required return. It is, therefore, an incremental cost concept. The required equity return is not, however, applied to a similarly determined rate base (that is, current cost). It is applied to an original cost rate base. When there is a significant difference between the historic original cost rate base and the corresponding current cost of the investment, application of a current cost of attracting capital to an original cost rate base produces an earnings stream that is significantly lower than that which is implied by the application of that same cost rate to market value. The divergence between the earnings stream implied by the application of the return to book value rather than market value is magnified as a result of the long lives of utility assets.

The current cost of attracting capital is measured by reference to market values. The discounted cash flow test, for example, measures the return that investors require on the market value of the equity. For a utility regulated on the basis of original cost book value, the current cost of attracting equity capital is only equivalent to the return investors require on book value when the market value of the common stock is equal to its book value. As the market value of the equity of regulated utilities increases above its book value, the application of a market-value derived cost of equity to the book value of that equity increasingly understates investors' return requirements (in dollar terms).

Some would argue that the market value of utility shares should be equal to book value. However, economic principles do not support that conclusion. A basic economic principle establishes the expected relationship between market value and replacement cost which provides support for market prices in excess of original cost book value. That economic principle holds that, in the longer-run, in the aggregate for an industry, market value should equal replacement cost of the assets. The principle is based on the notion that, if the market value of firms exceeds the replacement cost of the productive capacity, there is an incentive to establish new firms. The existence of additional firms would lower prices of goods and services, lower profits and thus reduce market values of all the firms in the industry. In the opposite circumstance, there is an incentive to disinvest, i.e., to not replace depreciated assets. The disappearance of firms would push up prices of goods and services; raise the profits of the remaining firms, thereby raising the market values of the remaining firms. In equilibrium, market value should equal replacement cost. In the presence of inflation, even at moderate levels, absent significant technological advances, replacement cost should exceed the original cost book value of assets. Consequently, the market value of utility shares should be expected to exceed their book value.

Therefore, when the allowed return on original cost book value is set, a market-derived cost of attracting capital must be converted to a fair and reasonable return on book equity. The conversion of a market-derived cost of capital to a fair return on book value ensures that the stream of dollar earnings on book value equates to the investors' dollar return requirements on market value.

APPENDIX C

RISK-ADJUSTED EQUITY MARKET RISK PREMIUM TEST

CONCEPTUAL UNDERPINNINGS OF THE CAPITAL ASSET PRICING MODEL

The Capital Asset Pricing Model (CAPM) is a theoretical, formal model of the equity risk premium test which posits that the investor requires a return on a security equal to:

$$\mathbf{R_F} \quad + \quad \boldsymbol{\beta}(\mathbf{R_M} - \mathbf{R_F}),$$

Where:

$\mathbf{R_F}$	=	risk-free rate
$\boldsymbol{\beta}$	=	covariability of the security with the market (M)
$\mathbf{R_M}$	=	return on the market.

The model is based on restrictive assumptions, including:

1. Perfect, or efficient, markets exist where,

    a. each investor assumes he has no effect on security prices;
    b. there are no taxes or transaction costs;
    c. all assets are publicly traded and perfectly divisible;
    d. there are no constraints on short-sales; and,

e. the same risk-free rate applies to both borrowing and lending.

2. Investors are identical with respect to their holding period, their expectations and the fact that all choices are made on the basis of risk and return.

The CAPM relies on the premise that an investor requires compensation for non-diversifiable risks only. Non-diversifiable risks are those risks that are related to overall market factors (e.g., interest rate changes, economic growth). Company-specific risks, according to the CAPM, can be diversified away by investing in a portfolio of securities whose expected returns are not perfectly correlated. Therefore, a shareholder requires no compensation to bear company-specific risks.

In the CAPM, non-diversifiable risk is captured in the beta, which, in principle, is a forward-looking (expectational) measure of the volatility of a particular stock or portfolio of stocks, relative to the market. Specifically, the beta is equal to:

$$\frac{\text{Covariance}\ (R_E, R_M)}{\text{Variance}\ (R_M)}$$

The variance of the market return is intended to capture the uncertainty related to economic events as they impact the market as a whole. The covariance between the return on a particular stock and that of the market reflects how responsive the required return on an individual security is to changes in events that also change the required return on the market.

RISK-FREE RATE

1. The theoretical CAPM assumes that the risk-free rate is uncorrelated with the return on the market. In other words, the assumption is that there is no relationship between the risk-free rate and the equity market return (i.e., the risk-free rate has a zero beta). However, the application of the model typically assumes that the return on the market is highly correlated with the risk-free rate, that is, that the equity market return and the risk-free rate move in tandem.

2. The theoretical CAPM calls for using a risk-free rate, whereas the typical application of the model in the regulatory context employs a long-term government bond yield as a proxy for the risk-free rate. Long-term government bond yields may reflect various factors that render them problematic as an estimate of the "true" risk-free rate, including:

    a. The yield on long-term government bonds reflects the impact of monetary and fiscal policy; e.g., the potential existence of a scarcity premium. The Canadian federal government has been in a surplus position for nine years, which has reduced its financing requirements. However, the demand for long-term government securities by institutions (e.g., pension funds) that match assets and liabilities has not declined. The pension funds, which are key purchasers of long-term government bonds, are typically buy and hold investors, which means that the government bonds in their portfolios do not trade. Thus, there is the potential not only for a scarcity premium in prices due to the demand for long-term government bonds, but also potential illiquidity in the market.

b. Yields on long-term government bonds may reflect shifting degrees of investors' risk aversion; e.g., "flight to quality". An increase in the equity risk premium arising from a reduction in bond yields due to a "flight to quality" is not likely to be captured in the typical application of the CAPM which focuses on a long-term average market risk premium.

c. Long-term government bond yields are not risk-free; they are subject to interest rate risk. The size of the equity market risk premium at a given point in time depends in part on how risky long-term government bond yields are relative to the overall equity market. The need to capture and measure changes in the risk of the so-called risk-free security introduces a further complication in the application of the CAPM.

EQUITY MARKET RISK PREMIUM

1. Equity Risk Premium and Historic Data

The equity market risk premium is typically measured largely by reference to historic data. Adjustments are then made to capture (a) changes that have occurred in the underlying markets over time, or (b) perceived differences between what investors actually achieved and what they may have expected on an *ex ante* basis. There are a wide range of views on what constitutes an appropriate period for estimating the historic risk premium, on what constitutes the appropriate averaging technique, and on whether various time-specific or country-specific outcomes diminish the reliability of history as a predictor of the future (expected) risk premium. In summary, the link between the historic and the expected risk premium is subject to considerable judgment.

2. Factors specific to the Canadian historic risk premium data are problematic.

a. The Canadian equity market has undergone significant structural changes over the periods typically used to measure historic risk premiums. The historic market returns reflect in considerable measure a resource-based economy. At the end of 1980, no less than 46% of the market value of the TSE 300 was resource-based stocks.[121] By comparison, at the end of 2000, the resource-based percentage of the S&P/TSX Composite had declined to 18.4%. The influence of technology-intensive and service-related sectors on the index, in comparison had risen markedly. In particular, financial services had become a key sector of the equity composite. Table C-1, which compares the year-end 1980 and 2000 market weightings of the financial services and technology sectors, highlights the changes that occurred between 1980 and 2000.

[121] As measured by the oil and gas, gold and precious minerals, metals/minerals, and pulp and paper products sectors. Excludes "the conglomerates sector", which also contained stocks with significant commodity exposure.

Table C-1

	1980	2000
Biotechnology/ Health Care/ Pharmaceuticals	0.0%	2.8
Information Technology	0.9%	24.1
Telecommunication Services	4.8%	6.5
Media & Entertainment	0.6%	4.1
Financial Services	13.5%	24.1
	19.8%	61.1

Source: *TSE Review*, December 1980 and December 2000.

By the end of August 2007, with the run-up in commodity prices since mid-2004, (and, to a lesser extent, with the implosion of the information technology sector in 2001), the resource-based sectors (comprised of the Energy sector and the largely mining-based Materials sector) once again have become a dominant component of the equity market, accounting for 43.5% of the total market value of the S&P/TSX Composite, with financial services second. With almost 75% of the S&P/TSX Composite's market value in three sectors, the Energy sector at 27% of the total market value of the Composite, the Financial sector at 31% and Materials at 17%, the Canadian market has, to some extent, had characteristics of market sectors, rather than of a diversified portfolio.

By comparison, the U.S. market is significantly more balanced among industry sectors. A comparison of market weights in Canada and the U.S. of the major sectors at August 31, 2007 demonstrates the difference.

Table C-2

Sector	Canada S&P/TSX Composite	U.S. S&P 500
Consumer Discretionary	5.2%	9.8%
Consumer Staples	2.6%	9.5%
Energy	27.0%	11.1%
Financials	30.7%	20.1%
Health Care	0.6%	11.7%
Industrials	5.7%	11.4%
Information Technology	4.3%	16.3%
Materials	16.6%	3.1%
Telecommunication Services	5.8%	3.7%
Utilities	1.5%	3.4%

Source: *TSX Review* August 2007 and Standardandpoors.com.

b. Even within the remaining 25% of the Canadian market (the non-resource and non-financial sectors), there are various sectors of the economy that are relatively underrepresented, e.g., pharmaceuticals, retailing and health care.

c. The historic average achieved returns of the TSE 300 Index have been significantly affected by the relatively mediocre performance of commodity-linked securities over the long-term. From 1956-2003 (the longest period for which consistent data exist for the individual TSE 300 sub-indices), the average returns of the commodity-based sectors were exceeded by the returns of virtually every other sector of the TSE 300.[122] Because the long-term returns of the various sectors are inconsistent with their relative risk, the achieved returns for the market composite may not accurately reflect what investors had expected.

d. In 2005, the S&P/TSX Composite underwent a significant change with the inclusion of income trusts. Income trusts, which just five years ago, had a market capitalization of approximately $20 billion, had a market capitalization of approximately $189 billion at the end of 2006, accounting for approximately 9% of the total market value of the TSX. Despite the change to the income tax treatment of income trusts announced in October 2006, income trusts significantly outperformed the "conventional" equity markets during the period for which income trust market data are readily available. The annual total return for the S&P/TSX Capped Income Trust Index over the 1998-2006 period averaged 16.4%, compared to 9.4% for the S&P/TSX Composite Index. The exclusion of income trust returns from the S&P/TSX Composite Index prior to 2005 means that the measured equity returns using the Composite Index understate the actual equity market returns achieved by Canadian investors.

[122] The average (compound, or geometric) returns of the commodity-based sectors were as follows:

Metals/Minerals	7.8%
Gold	9.5%
Oil and Gas	9.5%
Paper/Forest	7.1%

By comparison, the corresponding simple average of the remaining sectors' returns over the same period was 10.3%.

e. The TSE 300 Index has been criticized for its lack of liquidity and for the quality and size of the stocks it has contained. In a speech in early 2002, Joseph Oliver, President and CEO of the Investment Dealers Association of Canada stated,

> Over the last 25 years, the TSE 300 has steadily declined as a relevant benchmark index. Part of the problem relates to the illiquidity of the smaller component companies and part to the departure of larger companies that were merged or acquired. Over the last two years, 120 Canadian companies have been deleted from the TSE 300.
>
> When a company disappears from a US index due to a merger or acquisition, that doesn't affect the U.S. market's liquidity. An ample supply of large cap, liquid U.S. companies can take its place. In Canada, when a company merges or is acquired by another company, it leaves the index and is replaced by a smaller, less liquid Canadian company. We have seen this over the last two years, -- notably in the energy sector. Over the next few years, we are likely to see it in financial services, where further consolidation is inevitable. Over time, Canada's senior index has become less diversified, with more smaller component companies. As a result, as many as 75 of the TSE 300 will not qualify for inclusion in the new S&P/TSE Composite Index.

When the TSE 300 was overhauled (becoming the S&P/TSX Composite in May 2002), 275 companies were initially included, instead of the previous 300.[123] At December 31, 2005 there were 278 companies in the Composite, including the recently added income trusts.

f. The performance of the Canadian equity market as the "market portfolio" has been unduly influenced by a small number of companies. In mid-2000, before the

[123] The overhaul of the composite index, which included more stringent criteria for inclusion, did not require that a specific number of companies be included in the index.

debacle in Nortel Networks' stock value, Nortel shares alone accounted for 34.6% of the total market value of the TSE 300. To put this in perspective, the largest stock in the S&P 500 at that time (General Electric) accounted for only 4% of the S&P 500's total market value. The undue influence of a small number of stocks requires caution in drawing conclusions from the history of the TSE 300 regarding the forward-looking market risk premium.

g. The returns in the Canadian market have historically been negatively impacted by the existence of restrictions on the foreign content of assets held in pension plans and tax deferred savings plans such as Registered Retirement Savings Plans (RRSPs). In 1957, when tax deferred savings plans were first established, no more than 10% of the income in pension plans or RRSPs could come from foreign sources. The Foreign Property Rule was instated in 1971 and limited foreign content to 10% of the book value of assets in the funds. The limit was raised to 20% in 2% increments between 1990 and 1994.

In 1999, the Investment Funds Institute of Canada (IFIC) estimated that raising the cap to 20% had increased returns by 1% and that a 30% limit would increase returns a further 0.5%.[124] The limit was raised to 30% in 5% increments between 2000 and 2001. In 2002, the Pension Investment Association of Canada (PIAC) and the Association of Canadian Pension Management (ACPM) published a report entitled *The Foreign Property Rule: A Cost-Benefit Analysis*,[125] which

[124] *Paving the Way for Change to RRSP Foreign Content Rules*, Tom Hockin, President and CEO IFIC, January 31, 2000.

[125] David Burgess and Joel Fried, *The Foreign Property Rule: A Cost-Benefit Analysis*, The University of Western Ontario, November 2002.

supported the removal of the cap.[126] The *Globe and Mail* reported that the removal of the foreign content cap is expected to "have the broadest long-term impact of any personal finance measure in the budget. Global stock markets, accessible to any investor through global equity mutual funds, have historically made higher returns than the Canadian market, which only accounts for just over 2 per cent of the world's stock market value."[127] The Foreign Property Rule was finally eliminated in August 2005 effective January 1, 2005.

h. The achieved equity market risk premiums in Canada have been squeezed by the performance of the government bond market. The radical change in Canada's fiscal performance over the past decade has contributed to a steady decline in interest rates and concomitant increases in total bond returns. The prevailing low level of interest rates relative to the historic total returns on bonds indicates that the historic returns on long-term Government of Canada bonds overstate likely future bond returns. Consequently the historic equity risk premium understates the future risk premium.

[126] The IFIC's report *Year 2002 in Review* stated,

> During the period of 1991-1998, the percentage of sales in equity mutual funds that were comprised of non-domestic equities has hovered around the 41-58% range. This has significantly increased in 1999 and onwards. While performance in the markets is the major factor affecting such an increase, these figures can also be attributed to increases in foreign content limits in registered retirement savings plans as well as increased interest and availability of foreign clone funds.

[127] Rob Carrick, *Finance: Your Bottom Line*, Globeandmail.com, February 23, 2005.

3. Use of Arithmetic Averages to Estimate the Equity Market Risk Premium

a. Rationale for the Use of Arithmetic Averages

In Robert F. Bruner, Kenneth M. Eades, Robert S. Harris, and Robert C. Higgins, "Best Practices in Estimating the Cost of Capital: Survey and Synthesis", *Financial Practice and Education*, Spring/Summer 1998, pp. 13-28, the authors found that 71% of the texts and tradebooks in their survey supported use of an arithmetic mean for estimation of the cost of equity. One such textbook, Richard A. Brealey and Stewart C. Myers, *Principles of Corporate Finance,* Boston: Irwin McGraw Hill, 2000 (p. 157), states, "Moral: If the cost of capital is estimated from historical returns or risk premiums, use arithmetic averages, not compound annual rates of return."

The appropriateness of using arithmetic averages, as opposed to geometric averages, for this purpose is succinctly explained in Ibbotson Associates; *Stocks, Bonds, Bills and Inflation*, *1998 Yearbook*, pp. 157-159:

> The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values . . . in the investment markets, where returns are described by a probability distribution, the arithmetic mean is the measure that accounts for uncertainty, and is the appropriate one for estimating discount rates and the cost of capital.[128]

[128] An illustration from Ibbotson Associates demonstrating why the arithmetic average is more appropriate than the geometric average for estimating the expected risk premium is presented in Figure C-1.

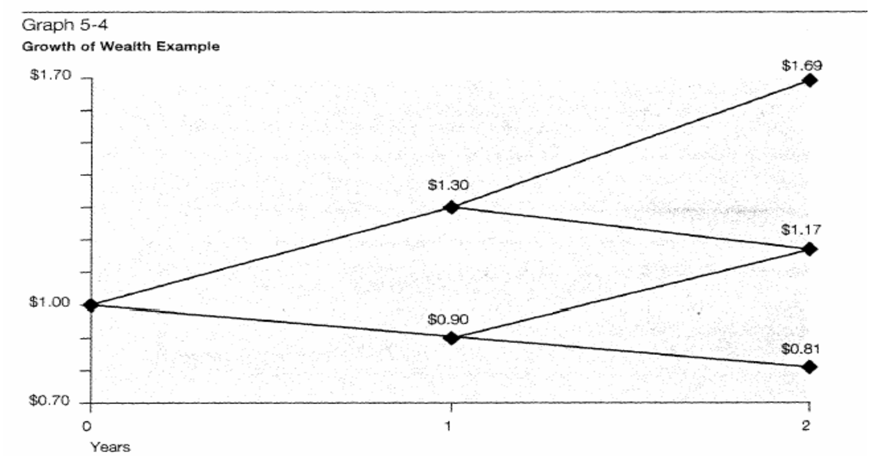
Triumph of the Optimists: 101 Years of Global Investment Returns by Elroy Dimson, Paul Marsh and Mike Staunton, Princeton: Princeton University Press, 2002 (p. 182), stated,

> The arithmetic mean of a sequence of different returns is always larger than the geometric mean. To see this, consider equally likely returns of +25 and –20 percent. Their arithmetic mean is 2½ percent, since (25 – 20)/2 = 2½. Their geometric mean is zero, since (1 + 25/100) x (1 – 20/100) – 1 = 0. But which mean is the right one for discounting risky expected future cash flows? For forward-looking decisions, the arithmetic mean is the appropriate measure.
>
> To verify that the arithmetic mean is the correct choice, we can use the 2½ percent required return to value the investment we just described. A $1 stake would offer equal probabilities of receiving back $1.25 or $0.80. To value this, we discount the cash flows at the arithmetic mean rate of 2½ percent. The present values are respectively $1.25/1.025 = $1.22 and $0.80/1.025 = $0.78, each with equal probability, so the value is $1.22 x ½ + $0.80 x ½ = $1.00. If there were a sequence of equally likely returns of +25 and –20 percent, the geometric mean return will eventually converge on zero. The 2½ percent forward-looking arithmetic mean is required to compensate for the year-to-year volatility of returns.

b. Illustration of Why Arithmetic Average Should be Used

In Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: Valuation Edition, 2005,* the following discussion was included:

> To illustrate how the arithmetic mean is more appropriate than the geometric mean in discounting cash flows, suppose the expected return on a stock is 10 percent per year with a standard deviation of 20 percent. Also assume that only two outcomes are possible each year — +30 percent and -10 percent (i.e., the mean plus or minus one standard deviation). The probability of occurrence for each outcome is equal. The growth of wealth over a two-year period is illustrated in Graph 5-4.



The most common outcome of $1.17 is given by the geometric mean of 8.2 percent. Compounding the possible outcomes as follows derives the geometric mean:

$$[(1+0.30)x(1-0.10)]^{½} - 1 = 0.082$$

However, the expected value is predicted by compounding the arithmetic, not the geometric, mean. To illustrate this, we need to look at the probability-weighted average of all possible outcomes:

	(0.25 x $1.69)	=	$0.4225
+	(0.50 x $1.17)	=	$0.5850
+	(0.25 x $0.81)	=	$0.2025
	Total		$1.2100

Therefore, \$1.21 is the probability-weighted expected value. The rate that must be compounded to achieve the terminal value of \$1.21 after 2 years is 10 percent, the arithmetic mean.

$$\$1 \text{ x } (1+0.10)^2 = \$1.21$$

The geometric mean, when compounded, results in the median of the distribution:

$$\$1 \text{ x } (1+0.0.082)^2 = \$1.17$$

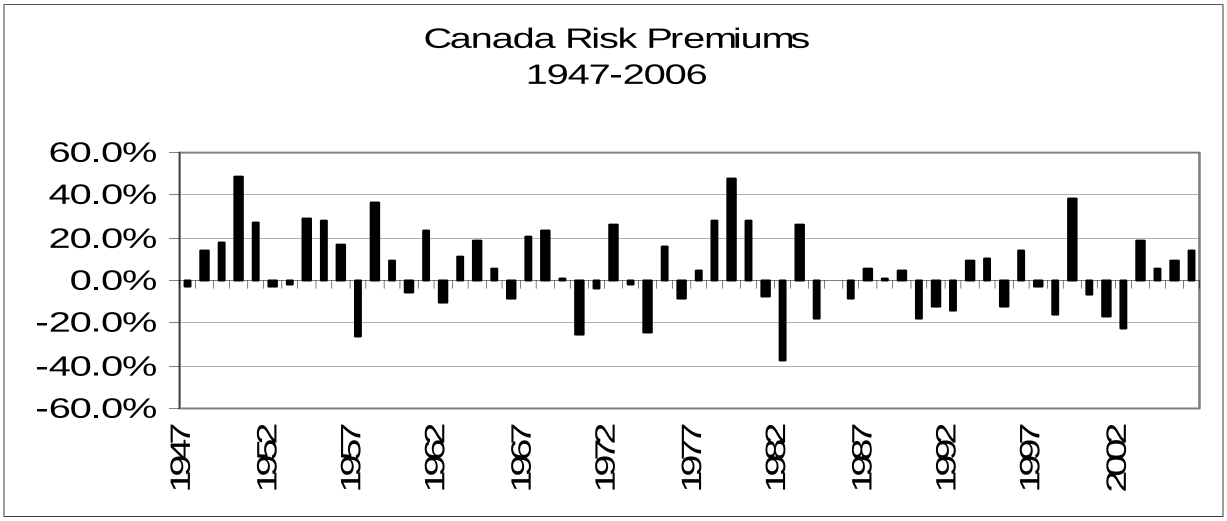
The arithmetic mean equates the expected future value with the present value; it is therefore the appropriate discount rate.

c. Randomness of Annual Equity Market Risk Premiums

The use of arithmetic averages is premised on the unpredictability of future risk premiums. The following figures illustrate the uncertainty in the future risk premiums by reference to the historic annual risk premiums. The figures for both Canada and the U.S. suggest that each year's actual risk premium has been random, that is, not serially correlated with the preceding year's risk premium.[129]

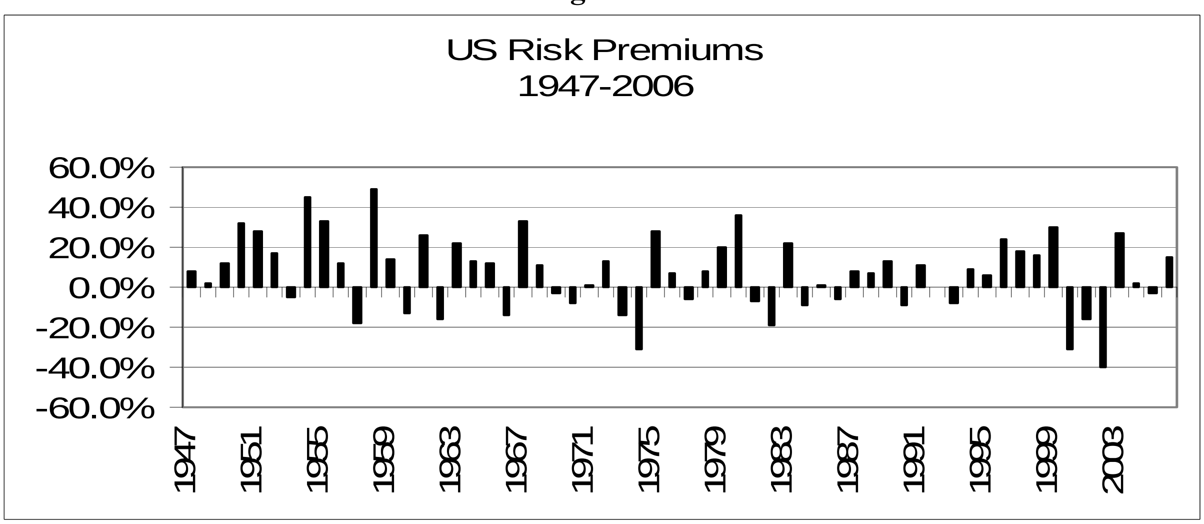
[129] A test for serial correlation between the year-to-year equity risk premiums shows that the serial correlation between the current year's risk premium and that of the prior year for the period 1947-2006 is 0.06 for Canada and −0.05 for the U.S. If the current year's risk premium were predictable based on the prior year's risk premium, the serial correlation would be close to positive or negative 1.0.

Figure C-1



Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics, 1924-2006*.

Figure C-2



Source: Ibbotson Associates, *Stocks, Bonds, Bills & Inflation, 2007 Yearbook*.

FUTURE vs. HISTORIC RISK PREMIUMS

1. Analysis of Trends in Canadian and U.S. Stock and Bond Returns

Table C-3 on the following page compares the historic Canadian and U.S. stock returns, bond returns, and equity risk premiums, over 10-year periods.

Table C-3

Time Period	Stock Returns		Bond Returns		Risk Premiums	
	Canada	U.S.	Canada	U.S.	Canada	U.S.
1947-1956	18.9%	19.4%	1.4%	0.8%	17.5%	18.5%
1957-1966	8.3%	10.5%	2.9%	3.0%	5.4%	7.5%
1967-1976	7.5%	8.4%	5.1%	4.6%	2.4%	3.8%
1977-1986	17.8%	14.6%	11.4%	10.7%	6.4%	3.9%
1987-1996	10.9%	16.0%	12.1%	10.0%	-1.2%	6.1%
1997-2006	11.0%	10.0%	8.7%	8.2%	2.3%	1.8%

Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics, 1924-2006* and Ibbotson Associates, *Stocks, Bonds, Bills & Inflation, 2007 Yearbook*.

The decade-by-decade averages suggest that there has been no upward or downward trend in the stock returns. By comparison, the bond returns generally exhibit an increase over time. The pattern in the bond returns results from:

- low bond returns in the 1950s-1970s, as rising interest rates produced capital losses on bonds;

- high bond returns in the 1980s, corresponding to the high rates of inflation, which pushed up bond yields; and,

- high bond returns in the 1990s and first half of the 2000s, reflecting the decline in interest rates and resulting capital appreciation of bonds, leading to total returns well in excess of the yields.[130]

A similar conclusion regarding trends in the risk premium can be drawn from an analysis of rolling and cumulative averages of Canadian and U.S. stock and bond returns. The following averages were calculated for this analysis:

- Twenty-five year rolling arithmetic averages of Canadian and U.S. equity and long-term government bond returns (1947-2006).

- A series of cumulative average equity and bond returns for Canada and the U.S. The first average starts in 1947, covering 25 years (1947-1971). The second average incorporates 26 years, etc. The final average encompasses the full 1947-2006 period.

- A second series of cumulative average returns, where the first average includes the most recent 25 year period (1982-2006); each subsequent average includes an additional prior year.

[130] The bond yield is, in fact, an estimate of the expected return.

The following table summarizes the resulting averages for the equity market returns.[131] The summary of the various averages indicates that the historic equity market returns have not exhibited a secular upward or downward trend, but are within the following ranges:

Table C-4

	Canada	U.S.
25-Year Rolling Averages:		
Range	9.6-14.5%	9.4-18.0%
Average of Averages	11.8%	12.5%
± 1 standard deviation	10.7-12.8%	10.4-14.6%
Increasing Averages (1947+):		
Range	11.4-13.6%	11.5-14.6%
Average of Averages	12.6%	13.1%
± 1 standard deviation	12.0-13.1%	12.4-13.8%
Increasing Averages (2005+):		
Range	10.8-13.3%	11.6-14.6%
Average of Averages	11.9%	12.8%
± 1 standard deviation	11.3-12.6%	11.9-13.7%

Source: Schedule 4.

The analysis also shows achieved total bond returns have experienced an upward trend, similar to that identified in the decade-by-decade returns described earlier. That trend is unlikely to continue, as recent low levels of interest rates limit future capital gains; it is more likely, in an environment of rising interest rates that bonds would experience capital losses, and the achieved risk premiums will rise.

[131] All of the averages appear on Schedule 4.

Given the absence of any upward or downward trend in the historic equity market returns, a reasonable expected value of the future equity market return is a range of 11.5-12.5%, based on both the Canadian and U.S. equity market returns. Based on the 2008 forecast for long Canada bond yields of 5.0%[132], and an expected equity market return of 11.5-12.5%, the indicated market risk premium would be in the range of 6.5-7.5%, or approximately 7.0%. Based on the longer-term forecast for long Canada bond yields of approximately 5.25%,[133] the indicated market risk premium is 6.25-7.25%.

2. Trends in Price/Earnings Ratios

Several studies of historic and equity risk premiums conclude that past equity markets are unsustainable, since they were achieved through an increase in price/earnings ratios that cannot be perpetuated.

With respect to the U.S. equity market, the preponderance of the increase in price/earnings ratios occurred during the 1990s. The P/E ratio[134] of the S&P 500 averaged 14 times from 1926-1989, with no discernible upward trend.[135] From 14.7 in 1989, the P/E ratio rose to a high of 32.3 in 1998, and averaged 23 from 1990-2000. At the height of the equity market (1998 to mid-2000), frequently described as a "speculative bubble", investors believed the only risk they faced was not being in the equity market. In mid-2000, the bubble burst, as the U.S. economy began to lose steam. The events of September 11, 2001, the threat of war, the loss of credibility on Wall

[132] Based on the August 2007 *Consensus Forecast*.
[133] The 2008 forecast is, as previously noted, 5.0%. Consensus Economics, *Consensus Forecasts*, April 2007 anticipates the 10-year Canada bond yield to average approximately 5.0% from 2009 to 2017. Adding a spread of approximately 10 (as of August 2007) to 30 (historic average) basis points to the 5.0% forecast results in a 30-year Canada bond yield forecast of close to 5.25%.
[134] Coincident price and earnings.
[135] The average from 1947-1989 was 13.3 times.

Street, accounting misrepresentations and outright fraud, led to a loss of confidence in the market and a sense of pessimism about the equity market. These events led to a heightened appreciation of the inherent risk of investing in the equity market, all of which translated into a "bearish" outlook for the U.S. equity market and sent retail investors to the sidelines.[136] Nevertheless, the P/E ratio for the S&P 500 remains above the average for 1947-1989, but within the historic range.[137]

To assess the impact of rising P/E ratios on achieved returns, I analyzed the equity returns of the S&P 500 achieved between 1947 and 1990, that is, prior to the observed upward trend in P/E ratios. The analysis indicates that the achieved equity returns for the S&P 500 averaged 12.3% (geometric average) to 13.5% (arithmetic average) from 1947-1989. The corresponding returns from 1947-2006 were 11.9% (geometric average) to 13.2% (arithmetic average). Hence, despite the increase in P/E ratios experienced during the 1990s, the average equity market returns were actually <u>lower</u> over the entire 1947-2006 period than over the 1947-1989 period. Stated differently, the increase in P/E ratios during the 1990s has not resulted in a higher and unsustainable level of equity market returns. Consequently, based on history, an expected value for the U.S. equity market return equal to the historic levels of 12.0-13.0% is not unreasonable. Relative to the consensus forecast yield for 30-year Treasury bonds for 2007 and for the longer term of approximately 5.3%,[138] the risk premium would be approximately 6.75-7.75%.

My review of Canadian equity returns over the same period indicates similar results. The 1947-1989 returns for the Canadian equity market were 11.9% (geometric average) to 13.1%

[136] Lowered expectations for the equity market have led investors to focus elsewhere for superior risk/reward opportunities, e.g., real estate, and private equity, suggesting the possibility that recent expectations for the public equity market may be out-of-line with return requirements. Investors' experiences during the equity market "bust" have been a key factor in explaining the recent burgeoning of the income trust market in Canada.
[137] At the end of August 2007, the S&P 500 P/E ratio was 17.3.
[138] For 2008-2017; Blue Chip *Financial Forecasts*, August 1, 2007 and June 1, 2007.

(arithmetic average), very similar to the U.S. returns, and higher than the average of the 1947-2006 returns. In relation to the 2008 and long-term forecasts of the 30-year Canada bond yield, 5.0% and 5.25% respectively, and an expected value of the Canadian equity market returns in the range of 12.0-13.0%, the expected value for the equity risk premium would be in the range of approximately 7.0-7.75%.

The analysis of stock and bond returns in Canada and the U.S. over the 1947-2006 period reveals no upward or downward trend in market equity returns. Nevertheless, the achieved risk premiums have declined. The arithmetic average achieved risk premium in Canada from 1947-1989 was 7.6%; in the U.S., it was 8.5%. By comparison, the corresponding 1947-2006 risk premiums were 5.5% and 6.9% respectively. An analysis of the data shows that high bond returns over the period 1990-2006 are the principal reason for the decline in experienced risk premiums, not a downward trend in stock returns. The average bond return from 1990-2006 was 10.6%, compared to the corresponding average yield on long-term Canada bonds of 6.8%.

Over the entire 1947-2006 period, the average return (income plus capital appreciation) on long Canada bonds was approximately 7.0%. With interest rates currently at historically low levels (approximately 4.5% at the end of August 2007), and more likely to increase rather than decrease further, the 1947-2006 average bond return of approximately 7.0% overstates the forward-looking expectation of bond returns, as embedded in both current yields and long-term forecasts. The current low level of long-Canada yields limits the possibility of future capital gains, which arise from a decline in interest rates. Thus, a reasonable expected value of the long Canada bond return is the forecast long Canada yield, rather than the historic average.

RELATIVE RISK ADJUSTMENT

1. Beta

Impediments to reliance on beta as the sole relative risk measure, as the CAPM indicates, include:

a. The assumption that all risk for which investors require compensation can be captured and expressed in a single risk variable;

b. The only risk for which investors expect compensation is non-diversifiable equity market risk; no other risk is considered (and priced) by investors; and,

c. The assumption that the observed calculated betas (which are simply a calculation of how closely a stock's or portfolio's price changes have mirrored those of the overall equity market)[139] are a good measure of the relative return requirement.

d. Use of beta as the relative risk adjustment allows for the conclusion that the cost of equity capital for a firm can be lower than the risk-free rate, since stocks that have moved counter to the rest of the equity market could be expected to have

[139] The beta is equal to:

$$\frac{\text{Covariance}\ (R_E, R_M)}{\text{Variance}\ (R_M)}$$

Betas are typically calculated by reference to historical relative volatility using simple regression analysis of the change in the market portfolio return and the corresponding change in an individual stock or portfolio of stock returns.

betas that are negative. Gold stocks, for example, which are regarded as a quintessential counter-cyclical investment, could reasonably be expected to exhibit negative betas. In that case, the CAPM would posit that the cost of equity capital for a gold mining firm would be less than the risk-free rate, despite the fact that, on a total risk basis, the company's stock could be very volatile.

The body of evidence on CAPM leads to the conclusion that, while betas do measure relative volatility, the proportionate relationship between beta and return posited by the CAPM has not been established. A summary of various studies, published in a guide for practitioners, concluded,

> Empirical tests of the CAPM have, in retrospect, produced results that are often at odds with the theory itself. Much of the failure to find empirical support for the CAPM is due to our lack of ex ante, expectational data. This, combined with our inability to observe or properly measure the return on the true, complete, market portfolio, has contributed to the body of conflicting evidence about the validity of the CAPM. It is also possible that the CAPM does not describe investors' behavior in the marketplace.
>
> Theoretically and empirically, one of the most troubling problems for academics and money managers has been that the CAPM's single source of risk is the market. They believe that the market is not the only factor that is important in determining the return an asset is expected to earn. (Diana R. Harrington, *Modern Portfolio Theory, The Capital Asset Pricing Model & Arbitrage Pricing Theory: A User's Guide*, Second Edition, Prentice-Hall, Inc., 1987, page 188.)

Fama and French in "The CAPM: Theory and Evidence", *Journal of Economic Perspectives*, Volume 18, Number 3 (Summer 2004), pp. 25-26:

> The attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor – poor enough to invalidate the way it is used in applications. The CAPM's empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model. For example, the CAPM says that the risk of a stock should be measured relative to a comprehensive 'market portfolio' that in principle can include not just traded financial assets, but also consumer durables, real estate and human capital. Even if we take a narrow view of the model and limit its purview to traded financial assets, is it legitimate to limit further the market portfolio to U.S. common stocks (a typical choice), or should the market be expanded to include bonds, and other financial assets, perhaps around the world? In the end, we argue that whether the model's problems reflect weaknesses in the theory or in its empirical implementation, the failure of the CAPM in empirical tests implies that most applications of the model are invalid.

Fama and French have developed an alternative model which incorporates two additional explanatory factors in an attempt to overcome the problems inherent in the single variable CAPM.[140]

To quote Burton Malkiel in *A Random Walk Down Wall Street*, New York: W. W. Norton & Co., 2003:

> Beta, the risk measure from the capital-asset pricing model, looks nice on the surface. It is a simple, easy-to-understand measure of market sensitivity. Alas, beta also has its warts. The actual relationship between beta and rate of return has not corresponded to the relationship predicted in theory during long periods of the twentieth century. Moreover, betas for individual stocks are not stable from period to period, and they are

[140] The additional factors are size and book to market.

> very sensitive to the particular market proxy against which they are measured.
>
> I have argued here that no single measure is likely to capture adequately the variety of systematic risk influences on individual stocks and portfolios. Returns are probably sensitive to general market swings, to changes in interest and inflation rates, to changes in national income, and, undoubtedly, to other economic factors such as exchange rates. And if the best single risk estimate were to be chosen, the traditional beta measure is unlikely to be everyone's first choice. The mystical perfect risk measure is still beyond our grasp. (page 240)

One of the key developers of the Arbitrage Pricing Model, Dr. Stephen Ross, has stated,

> Beta is not very useful for determining the expected return on a stock, and it actually has nothing to say about the CAPM. For many years, we have been under the illusion that the CAPM is the same as finding that beta and expected returns are related to each other. That is true as a theoretical and philosophical tautology, but pragmatically, they are miles apart.[141]

2. Relationship between Beta and Return in the Canadian Equity Market

To test the actual relationship between beta and return in a Canadian context, the betas (using monthly total return data) were calculated for various periods for each of the 15 major sub-indices of the "old" TSE 300 as were the corresponding actual geometric average total returns. Simple regressions of the betas on the achieved market returns were then conducted to determine if there was indeed the expected positive relationship. The regressions covered (a) 1956-2003, the longest period for which data for the TSE 300 and its sub-index components are available;

[141] Dr. Stephen A. Ross, "Is Beta Useful?" *The CAPM Controversy: Policy and Strategy Implications for Investment Management*, AIMR, 1993.

(b) 1956-1997, which eliminates the major effects of the "technology bubble", and (c) all potential non-overlapping 10-year periods from 2003 backwards.

The analysis showed the following:

Table C-5

Returns Measured Over:	Coefficient on Beta	R^2
1956-2003	-.088	47%
1956-1997	-.082	44%
1964-1973	-.020	1%
1974-1983	-.008	1%
1984-1993	-.056	11%
1994-2003	-.053	9%

Source: Schedule 6, page 1 of 2.

The analysis suggests that, over the longer term, the relationship between beta and return has been negative, rather than the positive relationship posited by the CAPM. For example, as indicated in Table C-5 above, for the period 1956-2003, the R^2 of 47% means that the betas explained 47% of the variation in returns among the key sectors of the TSE 300 index. However, since the coefficient on the beta was negative, this means that the higher beta companies actually earned lower returns than the low beta companies.

A series of regressions was also performed on the 10 major sectors of the S&P/TSX Composite. These regressions covered (a) 1988-2006, the longest period for which data for the new

Composite and its sector components are available; (b) 1988-1997,[142] and (c) the most recent 10-year period ending 2006.

That analysis showed the following:

Table C-6

Returns Measured Over:	Coefficient on Beta	R^2
1988-2006	-.043	23%
1988-1997	-.017	1%
1996-2006	-.098	45%

Source: Schedule 6, page 2 of 2.

These analyses indicate that, historically, the relationship between beta and return in the Canadian equity market has been the reverse (higher beta = lower return) than the posited relationship.

3. Impact of Interest Sensitivity of Utility Shares on Relative Risk Adjustment

The single equity beta does not capture the interest sensitivity of utility shares. The following analysis demonstrates how explicitly incorporating interest sensitivity impacts the relative risk assessment.

[142] The use of this sub-period was intended to ensure elimination of the impacts of any anomalous market behavior during the technology "bubble and bust", which occurred mainly from 1999 through mid-2002.

A regression of the monthly returns on the TSE Gas/Electric Index against the TSE 300 over the period 1970-August 1999[143] shows the following:

$$\text{Monthly TSE Gas/Electric Return} = 0.0054 + 0.58 \left\{ \text{Monthly TSE 300 Return} \right\}$$

$$\text{t-statistic} = 16.5$$

$$R^2 = 43.3\%$$

The relationship quantified in the above equation suggests a relative risk adjustment of close to 0.60. However, the R^2, which measures how much of the variability in utility stock prices is explained by volatility in the equity market as a whole, is only 43%. That means 57% of the volatility remains unexplained.

When the analysis is expanded to include Government of Canada bond returns, the following regression is produced:

$$\text{Monthly TSE Gas/Electric Return} = 0.0018 + 0.48 \left\{ \text{Monthly TSE 300 Return} \right\} + .52 \left\{ \text{Monthly Long Canada Bond Return} \right\}$$

$$\text{t-statistics} = 14.5 \qquad 9.5$$

$$R^2 = 55.0\%$$

When interest rates (as proxied by government bond returns) are added as a further explanatory variable, more of the observed volatility in utility stock prices is explained (55% versus 43%).

The second regression equation suggests that utility shares have had approximately 50% of the volatility of the equity market as well as approximately 50% of the volatility of the bond market,

[143] Excludes the anomalous market "bubble and bust"/"Nortel effect" period.

consistent with utility common stocks' interest sensitivity. Using an expected equity market return of 11.5%, and a long Canada bond return equal to the 2008 forecast 30-year Canada yield of 5.0%, the equation indicates an expected utility return of 10.4%. When the 10.4% utility return is expressed as an equity risk premium relative to the 5.0% long Canada yield, the indicated relative risk adjustment is close to 83%.[144]

144 $\frac{10.4\% - 5.0\%}{11.5\% - 5.0\%} = .83$

APPENDIX D

DCF-BASED RISK PREMIUM TEST

SELECTION OF LOW RISK BENCHMARK UTILITIES

For the estimation of the benchmark return, a sample of low risk U.S. utilities was selected, comprised of all electric utilities and gas distributors satisfying the following criteria:

1. Classified by *Value Line* as an electric utility or a gas distributor;

2. Standard & Poor's business risk profile score of "5" or less;

3. Standard & Poor's debt rating of A- or higher;

4. Not presently being acquired; and,

5. Consistent history of analysts' forecasts.

The 13 utilities that met these criteria are listed on Schedule 13.

CONSTRUCTION OF THE DCF-BASED EQUITY RISK PREMIUM TEST

The constant growth DCF model was used to construct a monthly series of expected utility returns for each of the 13 utilities in the sample over the period 1993-2007 (2nd Qtr).[145] The monthly DCF cost for each utility was estimated as the sum of the utilities' I/B/E/S mean earnings growth forecast (published monthly) **(g)** and the corresponding expected monthly dividend yield **(DY_e)**. The dividend yield **(DY)** was calculated as the most recent quarterly dividend paid, annualized, divided by the monthly closing price. The expected dividend yield was then calculated by adjusting the monthly dividend yield for the I/B/E/S median earnings growth forecast **(DY_e=DY*(1+g))**. The individual utilities' monthly DCF estimates **(DY_e + g)** were then averaged to produce a time series of monthly DCF estimates **(DCFs)** for the sample. The monthly equity risk premium **(ERP)** for the sample was calculated by subtracting the corresponding 30-year Treasury yield **(TY)** from the average DCF cost of equity **(ERPs=DCFs–TY)** (Schedule 12). The monthly sample average ERPs were used to estimate the regression equations found in Chapter III.C.b.4 of the testimony.

[145] Subsequent to Open Access for natural gas transmission implemented via FERC Order 636.

APPENDIX E

DISCOUNTED CASH FLOW TEST

DCF MODELS

Constant Growth Model

The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. The assumption that investors expect a stock to grow at a constant rate over the long-term is most applicable to stocks in mature industries.

Growth rates in these industries will vary from year to year and over the business cycle, but will tend to deviate around a long-term expected value. As a pragmatic matter, the application of a constant growth model is compatible with the likelihood that investors do not forecast beyond five years. Hence, in that context the current market price and dividend yield would not explicitly anticipate any changes in the outlook for growth.

The constant growth model is expressed as follows:

$$\text{Cost of Equity } \mathbf{(k)} = \frac{\mathbf{D_1}}{\mathbf{P_o}} + \mathbf{g},$$

where,

$\mathbf{D_1}$ = next expected dividend[146]
$\mathbf{P_o}$ = current price
$\mathbf{g}$ = constant growth rate

[146] Alternatively expressed as D_o (1 + g), where D_o is the most recently paid dividend.

This model, as set forth above, reflects a simplification of reality. First, it is based on the notion that investors expect all cash flows to be derived through dividends. Second, the underlying premise is that dividends, earnings, and price all grow at the same rate. However, it is likely that, in the near-term, investors expect growth in dividends to be lower than growth in earnings.

The model can be adapted to account for the potential disparity between earnings and dividend growth by recognizing that all investor returns must ultimately come from earnings. Hence, focusing on investor expectations of earnings growth will encompass all of the sources of investor returns (e.g., dividends and retained earnings).

Two-Stage Model

The two-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the company-specific growth rates for the near-term (Stage 1 Growth), but, in the longer-term (from Year 6 onward) to migrate to the expected long-run rate of growth in the economy (GDP Growth). All industries go through various stages in their life cycle. Utilities are considered to be the quintessential mature industry. Mature industries are those whose growth parallels that of the overall economy.

The use of forecast GDP growth as the long-term growth component is a widely utilized approach. For example, the Merrill Lynch discounted cash flow model for valuation utilizes nominal GDP growth as a proxy for long-term growth expectations. The Federal Energy Regulatory Commission relies on GDP growth to estimate expected long-term nominal GDP growth in its standard DCF models for gas and oil pipelines.

Using the two-stage DCF model, the DCF cost of equity is estimated as the internal rate of return that causes the price of the stock to equal the present value of all future cash flows to the investor.

The cash flow per share in Year 1 is equal to:

Last Paid Annualized Dividend x (1 + Stage 1 Growth)

For Years 2 through 5, cash flow is defined as:

Cash Flow $_{t-1}$ x (1 + Stage 1 Growth)

Cash flows from Year 6 onward are estimated as:

Cash Flow $_{t-1}$ x (1 + GDP Growth)

SELECTION OF PROXY BENCHMARK UTILITIES

The same sample of benchmark utilities was used as for the DCF-based risk premium test. The selection criteria for these low risk utilities are described in Appendix D.

INVESTOR GROWTH EXPECTATIONS

The application of the constant growth model relies principally on the consensus of investment analysts' forecasts of long-term earnings growth compiled by I/B/E/S. The application of the two-stage model relies upon the I/B/E/S consensus earnings forecasts as the estimate of investor growth expectations during Stage 1. The expected nominal long-run rate of growth in the economy (GDP) is based on the consensus of economists' long-term forecasts (published twice annually) found in *Blue Chip Economic Indicators* (March 10, 2007). The consensus forecast rate of growth in the long-term (2009-2018) is 5.1%.

Empirical studies that conclude that investment analysts' growth forecasts serve as a better surrogate for investors expectations than historic growth rates include: Lawrence D. Brown and Michael S. Rozeff, "The Superiority of Analyst Forecasts as Measures of Expectations: Evidence from Earnings", *The Journal of Finance*, Vol. XXXIII, No. 1, March 1978; Dov Fried and Dan Givoly, "Financial Analysts Forecasts of Earnings, A Better Surrogate for Market Expectations", *Journal of Accounting and Economics,* Vol. 4 (1982); R. Charles Moyer, Robert E. Chatfield, Gary D. Kelley, "The Accuracy of Long-Term Earnings Forecasts in the Electric Utility Industry", *International Journal of Forecasting* Vol. I (1985); Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return", *Financial Management*, Spring 1986, and, James H. Vander Weide and William T. Carleton, "Investor Growth Expectations: Analysts vs. History", *The Journal of Portfolio Management*, Spring 1988; David Gordon, Myron Gordon and Lawrence Gould, "Choice Among Methods of Estimating Share Yield," *The Journal of Portfolio Management*, Spring 1989.

The Vander Weide and Carleton study cited

> found overwhelming evidence that the consensus analysts' forecast of future growth is superior to historically oriented growth measures in predicting the firm's stock price [and that these results] also are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions.

The Gordon, Gordon and Gould study concluded,

> …the superior performance by KFRG [forecasts of [earnings] growth by securities analysts] should come as no surprise. All four estimates [securities analysts' forecasts plus past growth in earnings and dividends and historic retention growth rates] rely upon past data, but in the case of KFRG a larger body of past data is used, filtered through a group of security analysts who adjust for abnormalities that are not considered relevant for future growth.

In the application of the DCF test, the reliability of the earnings growth forecasts as a measure of investor expectations has been questioned by some Canadian regulators. The issue of reliability arises because of the documented optimism of analysts' forecasts historically. However, as long as investors have believed the forecasts, and have priced the securities accordingly, the resulting DCF costs of equity are an unbiased estimate of investors' expected returns. That proposition can be tested indirectly. For the sample of low risk utilities used in the DCF test (as well as the DCF-based equity risk premium test to estimate the benchmark return on equity), the average expected long-term growth rate, as estimated using analysts' forecasts, for the entire 1993-2007 (2nd Qtr) period of analysis was 4.7%. That growth rate is lower than the expected long-term nominal growth in the economy as a whole over the same period.[147] An expected growth rate that is close to that of the economy as a whole would not be out-of-line with the level of growth investors could reasonably expect in the relatively mature utility industries over the longer-term.

[147] The average expected long-term nominal rate of growth in the U.S. economy, based on consensus forecasts (Blue Chip *Economic Indicators*, March editions, 1993-2007), has been 5.3% over the same period covered by the DCF-based equity risk premium test.

APPLICATION OF THE DCF MODELS

Constant Growth Model

The constant growth DCF model was applied to the sample of U.S. low risk gas and electric utilities using the following inputs to calculate the dividend yield:

1. the most recent annualized dividend paid as of July 31, 2007 as D_o; and,
2. the average of the daily close prices for the period July 16 to August 15, 2007 as P_o.

For the expected growth rates, the July 2007 I/B/E/S consensus (mean) earnings growth forecasts were used to estimate "g" in the growth component for each utility and to adjust the current dividend yield to the expected dividend yield. The DCF estimates of the cost of equity for the benchmark sample based on the constant growth model were approximately 9.3% (See Schedule 14).

Two-Stage Model

The two-stage model relies on the I/B/E/S consensus of analysts' earnings forecasts for the first five years (Stage 1), and forecast growth in the economy thereafter (Stage 2). The consensus long-run (2009-2018) expected nominal rate of growth in GDP, as noted above, is 5.1%.

The two-stage DCF model estimates of the cost of equity for the benchmark low risk U.S. utility sample (Schedule 15) are as follows:

Mean	9.4%
Median	9.5%

Results of the Constant Growth and Two-Stage Models

The results of the two models indicate a required “bare-bones” return on equity of approximately 9.25% (constant growth model) to 9.5% (two-stage model).

APPENDIX F

COMPARABLE EARNINGS TEST

SELECTION OF CANADIAN INDUSTRIALS

The selection process starts with the recognition that industrials generally are exposed to higher business risk, but lower financial risk, than a benchmark Canadian utility. The selection of industrials focuses on total investment risk, i.e., the combined business and financial risks. The comparable earnings test is based on the premise that industrials' higher business risks are offset by a more conservative capital structure, i.e., higher equity ratios, thus permitting selection of industrial samples of reasonably comparable investment risk to a benchmark Canadian utility.

As a point of departure, the selection was limited to industries that are characterized by relatively stable demand characteristics, as well as consistent dividend payments and relatively low earnings and share price volatility. The initial universe consisted of all firms on the TSX in Global Industry Classification Standard (GICS) sectors 20-30. The sectors represented by the GICS codes in this range are: Industrials, Consumer Discretionary and Consumer Staples.[148] The resulting universe contained 479 firms. From this group of 479 companies, all firms with missing book equity or negative common equity during the period 1994-2006 as well as 2006 equity below $50 million were removed (76 companies remaining). Next, all companies that paid no dividends in any year 2001-2006 were removed (46 companies remaining). To remove small and/or thinly traded companies, all companies that traded fewer than 125,000 shares in

[148] Included in these sectors are major industries such as: Food Retail, Food Distributors, Tobacco, Packaged Foods, Soft Drinks, Distillers, Household Appliances, Aerospace and Defense, Electrical Components & Equipment, Industrial Machinery, Publishing & Printing, Department Stores, and General Merchandise.

2006 were eliminated, as were those companies with fewer than five years of market data available (leaving 43 companies). To ensure that relatively low risk unregulated companies were selected, all companies with five-year "raw" betas ending December 2006 over 1.0 were removed. The resulting group contained 40 companies.[149] Next, those companies whose 1994-2006 returns fall outside ± 1 standard deviation from the average were removed to eliminate companies whose earnings have been chronically depressed or which have been extraordinarily profitable (30 companies remaining). Finally, those companies whose stock was ranked "Higher Risk" or "Speculative" by the Canadian Business Service (CBS),[150] whose debt is rated non-investment grade i.e., BB+ or below by either DBRS or Standard & Poor's, or for which none of the agencies report a rating, were eliminated. The final sample of low risk Canadian industrials is comprised of 20 companies (Schedule 16).

TIME PERIOD FOR MEASURING RETURNS

Since industrials' returns on equity tend to be cyclical, the appropriate period for measuring industrial returns should encompass an entire business cycle, covering years of both expansion and decline. The cycle should be representative of a future normal cycle, e.g., relatively similar in terms of inflation and real economic growth. The period 1994-2006 encompasses both years of economic expansion and contraction. Over the period 1994-2006, the experienced returns on equity of the sample of 20 industrials were as follows.

[149] SNC-Lavalin was removed due to its purchase of regulated electric transmission assets in Alberta; Canadian Pacific Railway was also eliminated due to its reorganization in 2000, which rendered its historic data series inconsistent; Canadian National Railway was removed as it was controlled by the Federal Government through November 1995; Foremost Income Fund and North West Co. Fund, were removed because they are income trusts.
[150] Canadian Business Service (CBS) ranks stocks "Very Conservative", "Conservative", "Average", "Higher Risk", or "Speculative".

Table F-1

Returns on Average Common Equity for Low Risk Canadian Industrials (1994-2006)	
Average	13.3%
Median	12.8%
Average of annual medians	13.3%

Source: Schedule 17.

Based on these data, the returns are in the approximate range of 12.75-13.25%.

The average nominal economic growth for Canada during the 1994-2006 business cycle was 5.4%, compared to the consensus forecast for real growth of 2.7%, and for inflation (CPI) of 2.0% for the period (2008-2017)[151], which suggests nominal long-term GDP growth of approximately 4.75%. While nominal growth is expected to be moderately lower relative to the past business cycle, the experienced returns on book equity, absent extraordinary events, provide a reasonable proxy for the future.

[151] Consensus Economics, *Consensus Forecasts*, April 2007.

RELATIVE RISK COMPARISON

With respect to the investment risk of the Canadian industrials relative to a benchmark Canadian utility, comparisons of the various risk measures indicate that they are in a similar risk class. The median CBS stock rating for the industrials is “Conservative”, compared to the median of “Very Conservative” for the investor-owned Canadian utilities with publicly-traded stock. The median S&P and DBRS debt ratings for the industrials are BBB+ and BBB(high) respectively, compared to Canadian utilities’ median ratings of A- and A (See Schedules 16 and 26). The median adjusted beta for the industrials was 0.62 for the five year period ending December 2006 (see Schedule 16), compared to the adjusted betas for Canadian utilities over the same time period of approximately 0.50-0.55. (Schedule 8)

The estimate of a normal cycle average level of returns for low risk Canadian industrials is in the approximate range of 12.75-13.5%. The comparative risk data indicate, on balance, the Canadian industrials are somewhat riskier than a benchmark utility. The somewhat higher risk of the industrials relative to a benchmark utility requires a modest downward adjustment to the industrials’ 12.75-13.25% average ROE to a range of 12.25-12.75% (mid-point of 12.5%).

SELECTION OF U.S. INDUSTRIALS

The U.S. industrials were selected using similar criteria to the selection of Canadian industrials. The initial universe consisted of all firms actively traded in the U.S. from S&P's Compustat database in Global Industry Classification Standard (GICS) sectors 20-30. The sectors represented by the GICS codes in this range are: Industrials, Consumer Discretionary and Consumer Staples.[152] The resulting universe contained 2,643 firms. All non-U.S. companies were then removed, leaving 2,353. From this group of 2,353 companies, all firms with missing or negative common equity during the period 1994-2006 or with 2006 common equity less than $50 million were removed (681 companies remaining). To remove thinly traded companies, all companies that traded fewer than 125,000 shares in 2006 were eliminated (leaving 658 companies). Next, all companies that paid no dividends in any year 2001-2006 were removed (310 companies remaining). To ensure that low risk companies were selected, all companies with five year "raw" betas ending December 2006 over 1.0 were removed (leaving 221 companies). Next, those companies whose 1994-2006 returns were greater than ± 1 standard deviation from the average were removed to eliminate companies whose earnings have been chronically depressed or which have been extraordinarily profitable (leaving 182 companies). Finally, those companies whose debt is rated non-investment grade i.e., BB+ or below by Standard & Poor's, or for which the *Value Line* Safety Rank was equal to "4" or "5",[153] were eliminated. The final sample of low risk U.S. industrials is comprised of 157 companies

[152] Included in these sectors are major industries such as: Food Retail, Food Distributors, Tobacco, Packaged Foods, Soft Drinks, Distillers, Household Appliances, Aerospace and Defense, Electrical Components & Equipment, Industrial Machinery, Publishing & Printing, Department Stores, and General Merchandise.

[153] *Value Line*'s Safety Rank is a measurement of potential risk associated with individual common stocks. The Safety Rank is computed by averaging two other *Value Line* indexes – the Price Stability Index and the Financial Strength Rank. Safety Ranks range from "1" (highest) to "5" (lowest).

(Schedule 18). The returns for the sample of U.S. industrials are summarized in Table F-2 following.

Table F-2

Returns on Average Common Equity for Low Risk U.S. Industrials (1994-2006)	
Average	14.6%
Median	13.6%
Average of annual medians	14.5%

Source: Schedule 19.

Based on these data, the returns are in the approximate range of 13.5-14.5%.

Comparisons of the U.S. industrials' and utilities' risk measures indicate that the U.S industrials are of somewhat higher risk than the utilities. The median and mean *Value Line* Safety Ranks for the U.S. industrials are both "3", compared to the Safety Rank of "2" for TransCanada Corporation, the one regulated Canadian company with *Value Line* rankings.[154] The industrials' median and mean S&P debt ratings are BBB+ and A-, respectively, compared to the major Canadian utilities' S&P median and mean ratings of A- and to the benchmark low risk U.S. utilities' median and mean S&P debt ratings of A (see Schedules 13, 18 and 26). The most

[154] The mean and median Safety Ranks for the proxy sample of U.S. electric and gas utilities used to perform the DCF-based equity risk premium and discounted cash flow tests are "2" and "1" respectively; See Schedule 13.

recent median *Value Line* beta for the U.S. industrials was 0.95 (see Schedule 18), compared to the similarly calculated beta of 0.85 of the benchmark low risk U.S. utilities. A downward adjustment to the U.S industrial returns for the difference in betas indicates a risk-adjusted return of approximately 13.0%. The returns for the U.S. industrials as adjusted for relative risk then supports the reasonableness of the comparable earnings results as applied to the Canadian industrials.

The returns for the relatively low risk competitive U.S. firms confirm that the results of the comparable earnings test applied to unregulated Canadian firms are reasonable.

MARKET/BOOK RATIOS

Prior to its adoption of an automatic adjustment mechanism for ROE,[155] the OEB gave weight to the comparable earnings test "incorporating a market/book ratio adjustment".[156] In arriving at its recent decision for Terasen Gas (March 2006), the British Columbia Utilities Commission stated that it did not believe comparable earnings had outlived its usefulness, and that it may yet play a role in future ROE hearings. Nevertheless, the BCUC concluded that there was insufficient evidence before it regarding whether or not a market/book ratio adjustment was merited and, if so, how it might be accomplished.

[155] The OEB initially adopted an automatic adjustment mechanism for the natural gas distributors in March 1997.
[156] For example, in EBRO 470 (April 1991) for Union Gas.

The rationale for a market/book ratio adjustment to the comparable earnings test results has arisen on two grounds:

1. The market/book ratio of utility common shares should be approximately 1.0 times, i.e., that the fair market value of utility shares is equal to their book value.

2. Market/book ratios of unregulated firms well in excess of 1.0 times is evidence that the companies are earning returns in excess of their cost of capital, and thus are exerting market power.

With respect to the notion that the market/book ratio of utility shares should be approximately 1.0 times, that conclusion is incompatible with the standard of comparable returns. The comparable returns standard requires that a utility have the opportunity to earn a return commensurate with returns on investments in other enterprises having corresponding risks.

Regulation is intended to be a surrogate for competition. If unregulated competitive enterprises of corresponding risks to utilities are able to maintain market/book ratios in excess of 1.0, it would be patently contrary to the to the objective of regulation and to the comparable earnings standard to reduce the returns of unregulated comparable firms in order to target a particular market/book ratio for a utility.

With respect to the second rationale, the question that needs to be addressed is whether the market/book ratios of the sample of comparable unregulated companies are evidence of market power.

To address this question, the first issue is whether the market/book ratios of competitive companies should, in principle, trend toward 1.0. Regulation is intended to be a surrogate for competition. The competitive model indicates that equity market values tend to gravitate toward the replacement cost of the underlying assets. This is due to the economic proposition that, if the discounted present value of expected returns (market value) exceeds the cost of adding capacity, firms will expand until an equilibrium is reached, i.e., when the market value equals the replacement cost of the productive capacity of the assets.

The ratio of market value to replacement cost is called the "Q Ratio", a term coined by the Nobel Prize winning economist James Tobin in the late 1960s.[157] Essentially, the economic theory is that the market value of assets in the aggregate should equate to their replacement cost, that is, the "Q Ratio" (market value/replacement cost) should trend toward 1.0.

The "Q Ratio" has since gained stature as an investment tool,[158] whose importance was underscored in a March 2002 *New York Times* article which stated, referring to Tobin's obituaries:

[157] The general idea had been expressed decades earlier by the economist John Keynes.
[158] The Federal Reserve Board tracks the "Q Ratio" of the U.S. equity market. It was the level of the "Q Ratio", along with the price/dividend ratio, that led Fed Chairman Alan Greenspan to warn of a speculative bubble in the equity market as early as 1996.

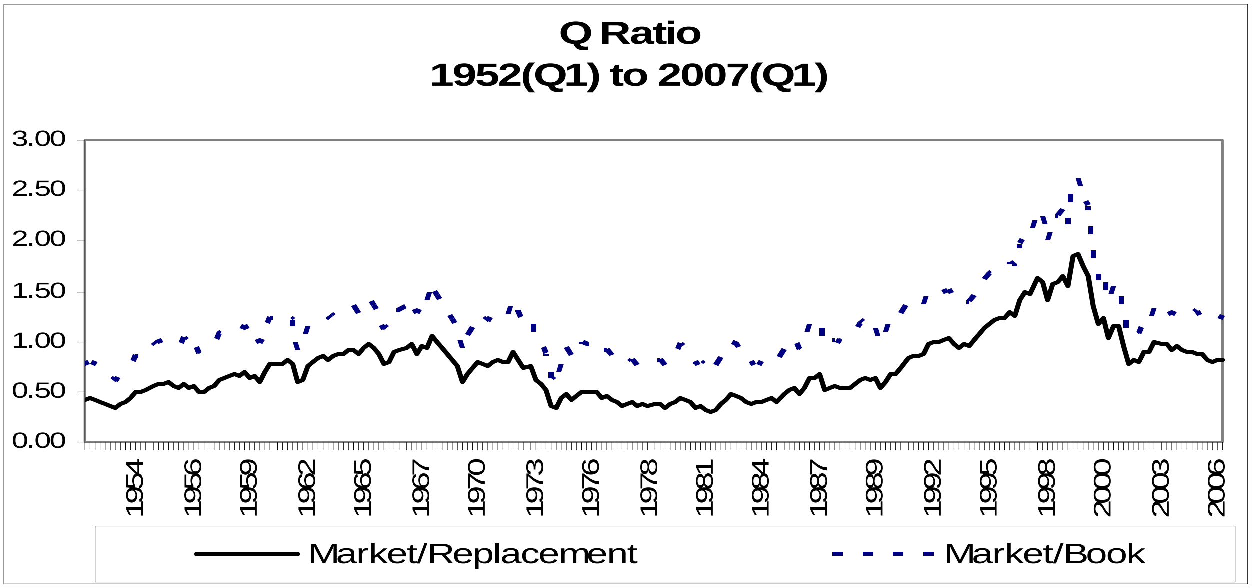
> Great emphasis was placed on how revolutionary his insights were three, four or five decades ago. Yet most were relatively silent on how those insights can lead us to be more successful investors today. It is a shame. Investors greatly handicap themselves if they ignore Dr. Tobin's work.
>
> Consider Tobin's Q, the ratio for which Dr. Tobin, at least at one time, was most famous among investors. This is the ratio of a company's total market capitalization to the replacement value of that company's total assets. <u>While the Q ratio – as Tobin's Q is often called – is conceptually similar to the price-to-book ratio, it avoids the myriad accounting difficulties associated with book value. For example, while book value carries assets at depreciated original cost, replacement value focuses on how much it would cost to buy those assets today</u>. [emphasis added]

Absent inflation and technological change, the market value and replacement cost of firms operating in a competitive environment would tend to equal their book value or cost. However, the fact that inflation has occurred, and continues to occur, renders that relationship invalid. With inflation, under competition, the market value of a firm trends toward the current cost of its assets. The book value of the assets, in contrast, reflects the historic depreciated cost of the assets. Since there have been moderate to relatively high levels of inflation over the past twenty-five years, it is reasonable to expect market values to exceed the book value of those assets.

As indicated in Figure F-1 below, market/replacement cost ratios, as derived from the flow of funds accounts, have been systematically lower than the market to original cost ratios. For the U.S., the market/replacement cost ratio for corporations[159] has averaged approximately 60% lower than the market/book ratio.

[159] Based on non-farm, non-financial corporate businesses.

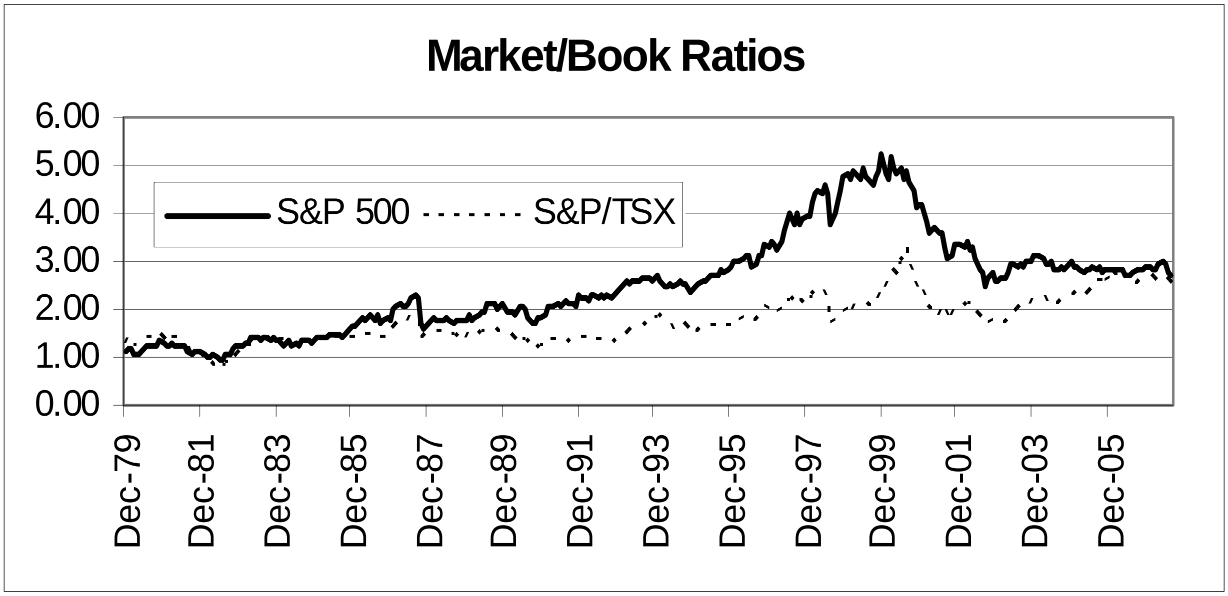
Figure F-1



Source: US Federal Reserve Flow of Funds (B102).

To test the potential for market power in the achieved returns of the two samples of low risk unregulated firms used in the comparable earnings test, their market/book ratios were compared to those of the respective Canadian and U.S. market composites. The figure below tracks the market/book values for the S&P/TSX Composite and the S&P 500 from 1980-2006.

Figure F-2



Source: RBC Capital Markets Quantitative Research

The data from which the table was created indicate that the market/book ratio for the overall Canadian equity market has averaged approximately 1.7 times from 1980-2006, and approximately 2.1 times from 1994-2006, the period over which the comparable earnings test was conducted. Based on twenty-five years of data, the market/book ratio for the Canadian equity market has varied around an average of close to 1.7 times, not 1.0 times. Over the period 1994-2006 the market/book ratio for the sample of comparable Canadian unregulated companies averaged 2.1 times, equal to the average for the S&P/TSX Composite. For the S&P 500, the market/book ratios were approximately 2.5 and 3.4 times, respectively, over the same two periods. For the sample of low risk U.S. unregulated firms, the average market/book ratio was 2.7 times from 1994-2006. The similar to lower average market/book ratios of the low risk samples relative to the overall equity market composites permit the inference that the sample average returns are not characterized by market power.

In summary, the comparable earnings results do not warrant an adjustment for market/book ratios.

APPENDIX G

FINANCING FLEXIBILITY ADJUSTMENT

An adjustment to the equity risk premium and discounted cash flow test results for financing flexibility is required because the measurement of the return requirement based on market data results in a "bare-bones" cost. It is “bare-bones” in the sense that, theoretically, if this return is applied to (and earned on) the book equity of the rate base (assuming the expected return corresponds to the approved return), the market value of the utility would be kept close to book value.

The financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. The allowance is intended to cover three distinct aspects: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the "fairness" principle. Fairness dictates that regulation should not seek to keep the market value of a utility stock close to book value when industrials of comparable investment risk have been able to consistently maintain the real value of their assets considerably above book value.

The financing flexibility allowance recognizes that return regulation remains, fundamentally, a surrogate for competition. Competitive industrials of reasonably similar risk to utilities have consistently been able to maintain the real value of their assets significantly in excess of book value, consistent with the proposition that, under competition, market value will tend to equal the replacement cost, not the book value, of assets.

Utility return regulation should not seek to target the market/book ratios achieved by such industrials, but, at the same time, it should not preclude utilities from achieving a level of financial integrity that gives some recognition to the longer run tendency for the market value of industrials to equate to the replacement cost of their productive capacity. This is warranted not only on grounds of fairness, but also on economic grounds, to avoid misallocation of capital resources. To ignore these principles in determining an appropriate financing flexibility allowance is to ignore the basic premise of regulation. The adjustment for financing flexibility recognizes that the market return derived from the equity risk premium test needs to be translated into a return that is fair and reasonable when applied to book value.

This premise was recognized by the Independent Assessment Team (IAT), retained by the Alberta Department of Resource Development to determine the cost parameters for the Power Purchase Arrangement (PPAs) for existing regulated generating plants, concluded in its 1999 report, regarding flotation costs,

> This is sometimes associated with flotation costs but is more properly regarded as providing a financial cushion which is particularly applicable given the use of historic cost book values in traditional rate of return regulation in Canada. No such adjustment has ever been made in UK utility regulation cases which tend to use market values or current cost values.[160]

The Report of the IAT was accepted by the Alberta Energy and Utilities Board in Decision U99113 (December 1999).

Further, the financing flexibility allowance should also recognize that both the equity risk premium and DCF cost of equity estimates are derived from market values of equity capital. The

[160] *Independent Assessment Team Power Purchase Arrangement Report*, July 1999, page XLV, footnote 99.

cost of capital reflects the market value of the firms' capital, both debt and equity. The market value capital structures may be quite different from the book value capital structures. When the market value common equity ratio is higher (lower) than the book value common equity ratio, the market is attributing less (more) financial risk to the firm than is "on the books" as measured by the book value capital structure. Higher financial risk leads to a higher cost of common equity, all other things equal.

To put this concept in common sense terms, assume that I purchased my home 10 years ago for \$100,000. My home is currently worth \$250,000. If I were applying for a loan, the bank would consider my net worth (equity) to be \$150,000, not the "book value" of my home, which reflects the original purchase price less the mortgage loan amount. It is the market value of my home that determines my financial risk to the bank, not the original purchase price. The same principle applies when the cost of common equity is estimated. The book value of the common equity shares is not the relevant measure of financial risk to equity investors; it is their market value, that is, the value at which the shares could be sold.

Regulatory convention applies the allowed equity return to a book value capital structure. When the market value equity ratios of the proxy utilities are well in excess of their book value common equity ratios, application of an unadjusted market-derived cost of equity to the book value capital structure fails to recognize the higher financial risk and the higher cost of equity implied by the book value capital structures.

Two approaches can be used to quantify the range of the impact of a change in financial risk on the cost of equity. The first approach is based on the theory that the overall cost of capital does not change materially over a relatively broad range of capital structures. The second approach is based on the theoretical model which assumes that the overall cost of capital declines as the debt ratio rises due to the income tax shield on interest expense.[161]

Schedules 20 and 22 provide the formulas and inputs for estimating the change in the cost of equity under each of the two approaches. The schedules show that a recognition of the difference in financial risk between the market value and book value capital structures of the publicly-traded Canadian utilities and the low risk U.S. utilities results in an increase in the cost of equity in the range of 0.85 to 2.05 percentage points. A minimal recognition of the higher financial risk in the book value capital structures supports a financing flexibility adjustment of no less than 50 basis points.

At a minimum, the financing flexibility allowance should be adequate to allow a utility to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10. At this level, a utility will be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 is approximately 50 basis points.[162]

[161] The second approach does not account for any of the factors that offset the corporate income tax advantage of debt, including the costs of bankruptcy/loss of financing flexibility, the impact of personal income taxes on the attractiveness of issuing debt, or the flow-through of the benefits of interest expense deductibility to ratepayers. Thus, the results of applying the second approach will over-estimate the impact of leverage on the overall cost of capital and understate the impact of increasing financial leverage on the cost of equity.

[162] The financing flexibility allowance is estimated using the following formula developed from the discounted cash flow formula:

$$\text{Return on Book Equity} = \frac{\text{Market/Book Ratio x “bare-bones” Cost of Equity}}{1 + [\text{retention rate (M/B} - 1.0)]}$$

For a market/book ratio of 1.075 (mid-point of 1.05 and 1.10), assuming a dividend payout ratio of 65% and a cost of equity of 10.0%, the indicated ROE is:

The concept of a financing flexibility or flotation cost allowance has been accepted by most Canadian regulators. As a government-owned utility, OPG does not raise capital in the public equity markets; therefore it would not incur out-of-pocket equity financing and market pressure costs. However, both the cushion, or safety margin, for unanticipated capital market conditions and the fairness element are integral components of the cost of equity and a fair return on the book value of equity. Both should be recognized in the allowed return on equity for a regulated utility, irrespective of ownership.

OPG operates as a commercial entity. As such, the utility should be financed with a capital structure that, similar to investor-owned utilities, reflects its business risks and, in principle, would allow it to access the capital markets on reasonable terms and conditions on a stand-alone basis. An investor-owned utility can access the public equity markets to finance its "normal" capital program, as well as any extraordinary needs, and to maintain a balanced capital structure. OPG's access to equity is largely through retained earnings.

Consequently, OPG's need for financing flexibility is no less than that of an investor-owned utility. Thus, the financing allowance component of the fair return should be the same as for an investor-owned utility. Explicit inclusion of a financing flexibility allowance in the ROE for a government-owned utility has regulatory precedents. The government-owned utilities in both British Columbia and Alberta have been allowed returns that are equivalent to those of the

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$$\text{ROE} = \frac{1.075 \times 10\%}{1 + [.35\,(1.075 - 1.0)]}$$

$$\text{ROE} = 10.5\%$$

The difference between the ROE and the "bare-bones" cost of equity of 50 basis points is the financing flexibility allowance.

investor-owned utilities, which, in turn, include an allowance for financing flexibility. In Alberta, for example, in the recent Generic Cost of Capital decision (Decision 2004-052, July 2, 2004), the EUB allowed an adjustment of 50 basis points for flotation costs and financing flexibility to all of the utilities to which the decision applied, both investor- and government-owned.

The financing flexibility allowance for OPG should be, at a minimum, 50 basis points. As this financing flexibility adjustment is minimal, it does not fully address the comparable earnings standard.

APPENDIX H

DEBT RATING AGENCY FINANCIAL METRIC GUIDELINES

DBRS
GENERAL STANDARDS RATING BBB TO "A" (QUANTITATIVE FACTORS)

	Regulated	Mixed	Unregulated
Percent Debt	60%-70%	50%-60%	50%
Fixed-charge Coverage	1.5x	1.5 - 2.0 x	2.0 x +
Cash Flow / Debt	0.10	0.10 - 0.15	0.15 - 0.20

Source: DBRS, *DBRS Methodology in Rating Utilities*, June 2002

MOODY'S
PRIMARY FINANCIAL RATIOS

Business Risk	Aa Medium	Aa Low	A Medium	A Low	Baa Medium	Baa Low	Ba Medium	Ba Low
FFO Interest Coverage (X)	> 6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
FFO/Debt (%)	>30	>22	22-30	12-22	13-25	5-13	<13	<5
Retained Cash Flow/Debt (%)	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Debt/Capital (%)	<40	<50	40-60	50-75	50-70	60-75	>60	>70

Source: Moody's, *Rating Methodology: Global Regulated Electric Utilities*, March 2005

S&P INDUSTRY BENCHMARKS

Business Profile	AA		A		BBB		BB	
	Adjusted FFO interest coverage (x)							
1	3.0	2.5	2.5	1.5	1.5	1.0	< 1.0	< 1.0
2	4.0	3.0	3.0	2.0	2.0	1.0	< 1.0	< 1.0
3	4.5	3.5	3.5	2.5	2.5	1.5	1.5	1.0
4	5.0	4.2	4.2	3.5	3.5	2.5	2.5	1.5
5	5.5	4.5	4.5	3.8	3.8	2.8	2.8	1.8
6	6.0	5.2	5.2	4.2	4.2	3.0	3.0	2.0
7	8.0	6.5	6.5	4.5	4.5	3.2	3.2	2.2
8	10.0	7.5	7.5	5.5	5.5	3.5	3.5	2.5
9	N/A	N/A	10.0	7.0	7.0	4.0	4.0	2.8
10	N/A	N/A	11.0	8.0	8.0	5.0	5.0	3.0
	Adjusted FFO/average total debt (%)							
1	20	15	15	10	10	5	< 5.0	< 5.0
2	25	20	20	12	12	8	< 8.0	< 8.0
3	30	25	25	15	15	10	10	5
4	35	28	28	20	20	12	12	8
5	40	30	30	22	22	15	15	10
6	45	35	35	28	28	18	18	12
7	55	45	45	30	30	20	20	15
8	70	55	55	40	40	25	25	15
9	N/A	N/A	65	45	45	30	30	20
10	N/A	N/A	70	55	55	40	40	25
	Adjusted total debt/total capital (%)							
1	48	55	55	60	60	70	> 70.0	> 70.0
2	45	52	52	58	58	68	> 68.0	> 68.0
3	42	50	50	55	55	65	65	70
4	38	45	45	52	52	62	62	68
5	35	42	42	50	50	60	60	65
6	32	40	40	48	48	58	58	62
7	30	38	38	45	45	55	55	60
8	25	35	35	42	42	52	52	58
9	N/A	N/A	32	40	40	50	50	55
10	N/A	N/A	25	35	35	48	48	52

Note: Business profile scores are characterized from '1' (excellent) to '10' (weak).
FFO -- Funds from Operations. N/A--Not applicable.

Source: Standard & Poor's, *Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers*, September 2006

APPENDIX I

TRANSLATION OF RETURN REQUIREMENT TO COMMON EQUITY RATIO

BACKGROUND

The benchmark utility return was developed from market data for all publicly traded Canadian utilities and a sample of low risk U.S. utilities determined to be of equivalent risk to a benchmark Canadian utility. OPG faces higher business risk than the typical Canadian utility and the sample of low risk U.S. utilities used in the estimation of the benchmark return on equity. The objective of this appendix is to quantify the deemed common equity ratio for OPG's regulated operations that is required to equate OPG's total business and financial risk to that of a benchmark utility. At the identified common equity ratio, the benchmark utility return on equity will be applicable to OPG.

METHODOLOGY

To quantify the equity ratio required for the benchmark utility return on equity to be applicable to OPG, the following steps were taken:

Select a sample of vertically integrated U.S. utilities that have a significant proportion of their assets devoted to generation ("high Gx"), i.e., that are closer in business risk to OPG's regulated operations than the low risk U.S. utility sample. [163]

1. Estimate the betas and CAPM costs of equity for the "high Gx" utility sample.

2. Disaggregate the betas for the "high Gx" sample companies to derive an estimate of the betas for the generation-only portion of their businesses.
    a. Select a sample of "wires-only" utilities and use to estimate the "wires-only" beta.
    b. Determine the proportion of assets for each company in the "high Gx" sample devoted to generation, wires and "other operations".
    c. Using the estimated beta for wires and assuming a market average beta of 1.0 for "other operations", derive the generation-only betas.

3. Combine the generation-only betas with my estimates of the market risk premium and risk-free rate to arrive at an estimate of the generation-only CAPM cost of equity. Since the capital structures of both samples (wires, and high Gx) used to derive the generation-only betas each contain close to 45% equity, the generation-only return requirement would apply to OPG's regulated operations as estimated if OPG's deemed common equity ratio were set at 45%.

[163] The capital markets in the U.S. and Canada are significantly integrated; there are no publicly traded companies in Canada with nuclear assets. Based on Standard & Poor's comments that due to deregulation in European power markets (S&P, "Credit Aspects of North American and European Nuclear Power", January 2006), nuclear operators were offered no regulatory protection, we concluded that any investor-owned companies with nuclear facilities were not directly comparable to OPG.

4. Compare the capital structures for the benchmark low risk U.S. utility sample to the capital structures for the "wires" and "high Gx" samples to determine the extent to which differences in betas among samples are due to differences in financial risk versus business risk.[164]

5. Compare the betas for the benchmark low risk U.S. utility sample to those of the "high Gx" sample as well as to the generation-only betas and DCF costs derived from the "high Gx sample.

6. Use the difference between the benchmark low risk U.S. sample beta and the "high Gx" and generation-only betas in conjunction with the market risk premium to estimate the incremental (to the benchmark return) equity return requirement for a utility of similar business risk to OPG at a 45% common equity ratio.

7. Based on capital structure theory (discussed at page I-8 and I-9), translate the incremental required return at a 45% common equity ratio into the common equity ratio which would eliminate the need for an incremental return, i.e., would equate the equity return requirement of OPG's regulated operations to the benchmark return.

[164] The betas used to estimate the generation-only beta were investment risk betas, that is, they comprise both business and financial risk. To the extent that the samples have different capital structures (and thus different levels of financial risk), business risk betas rather than the traditional investment risk betas would need to be calculated and used. By isolating the financial risk from the business risk, the incremental cost of capital arising from exposure to the business risks of generation can then be estimated.

1. Selection of Vertically Integrated Utility Sample

A sample of U.S. vertically integrated utilities with a high proportion of their assets devoted to generation was selected, comprised of all utilities satisfying the following criteria:

a. Classified by *Value Line* as an electric utility;

b. Standard & Poor's debt rating of BBB- or higher;

c. I/B/E/S long-term earnings growth forecasts available;

d. Paid a dividend in 2006; and,

e. Generation assets comprising one-third or more of total assets.

The 21 utilities that met these criteria are listed on Schedule 28. The sample has a median S&P debt rating of BBB. The average proportion of generation assets to total assets for the sample is approximately 49%, with 16 of the sample companies having nuclear generation assets. Based on 2006 production in MWs, nuclear generation accounted for approximately 10%. The "wires" operations of the high generation sample comprised approximately 44% of total assets; "other operations" accounted for approximately 7% of the total assets.

2. Betas and CAPM Cost of Equity for the High Generation Sample

The beta for the "High Gx" utility sample was estimated to be approximately 0.84 based on both the *Value Line* and Standard & Poor's adjusted betas[165] for the firms in the sample.[166]

The *Value Line* and S&P betas are as follows:

Table I-1

	Value Line	**S&P Adjusted**
Mean	0.93	0.77
Median	0.95	0.81
Asset-Weighted Average	0.93	0.68

Source: Schedule 28.

The market risk premium and risk free rate used to deriving the CAPM costs of equity were the same 6.50% and 5.0% used in the development of the benchmark return on equity. At a 0.84 beta, the CAPM cost of equity for the high generation utility sample is approximately 10.5%, compared to approximately 9.5% for the low risk utility U.S. sample used to establish the benchmark return on equity (beta of 0.71).

[165] "Raw" betas were calculated using 60 monthly observations using the S&P 500 as the market index. The betas were adjusted using the following formula: ⅔ ("raw" beta) + ⅓ (market beta of 1.0). *Value Line*, Bloomberg and Merrill Lynch, major sources of financial information for investors, all publish adjusted betas. Their formulas for adjusting the calculated raw betas are slightly different, but all give approximately two-thirds weight to the "raw" beta of the specific stock and one-third weight to the market beta of 1.0.

[166] The 0.84 beta represents the average of the simple mean, median, and asset-weighted average betas of the sample.

3. Estimation of a Generation-Only Beta

Using the residual beta methodology, the generation-only beta was estimated from the beta of the high generation sample. The "residual beta" methodology is described in Roger Morin, *New Regulatory Finance*, Vienna, VA: Public Utilities Reports, Inc., 2006. It is based on the Capital Asset Pricing Model, which holds that the beta of a portfolio is the market value weighted average of the betas of the investments that make up the portfolio. The notion that the beta of a firm is equal to the weighted average of its divisional betas is a foundation for the "pure play" technique of estimating the betas for individual divisions of a multi-division firm. As stated in Russell J. Fuller and Halbert S. Kerr, "Estimating the Divisional Cost of Capital: An Analysis of the Pure-Play Technique," *Journal of Finance*, December 1981, "it can be shown that the beta for a multidivisional firm approximates the weighted average of its divisional betas". The pure play technique estimates the divisional betas using the betas of proxy firms. The proxy firms for each division operate in a single line of business (pure play), the same line of business as the individual divisions of the multi-division company.

The residual beta methodology is used to estimate the beta of a division for which there are no pure play proxies. The methodology entails disaggregating the beta of a multi-divisional firm into the betas of its divisions. Its application requires the beta of the firm as a whole and a "pure play" beta for each of the divisions other than the one for which there are no pure play proxies. In the disaggregation of the company beta into the divisional betas, the weights to be given to each division should be equal to their relative contribution to the operating income of the consolidated entity. For the purpose of this analysis, I have used assets as a proxy for the relative contribution of each division (or business segment) to the company as a whole. The disaggregation formula for estimating the generation-only beta is:

$$\beta_{HighGx} = \beta_{Gx} \text{ x } \%Assets_{Gx} + \beta_{Pure\ Wires} \text{ x } \%Assets_{Wires} + \beta_{Other} \text{ x } \%Assets_{Other}$$

The Wires beta was developed from a sample of Wires utilities. A Wires sample was selected, comprised of all U.S. utilities satisfying the following criteria:

a. classified by *Value Line* as an electric or gas distribution utility;
b. with at least 80% of total assets devoted to electricity and gas distribution operations;
c. has no more than 5% of its assets in generation;
d. whose Standard & Poor's debt rating is BBB- or higher; and,
e. has I/B/E/S forecasts.[167]

The 8 firms in the sample are found in Schedule 29. Wires assets account for 96% (average) of the total assets of the sample companies. The sample has a median S&P debt rating of A.

The beta for the "Wires" sample was estimated to be 0.72 based on both the *Value Line* and Standard & Poor's adjusted betas the firms in the sample.

[167] The existence of I/B/E/S forecasts ensures that the utilities have an analyst following, which in turn, ensures that the companies shares are traded frequently enough so that the betas are meaningful.

The *Value Line* and S&P betas are as follows:

Table I-2

	Value Line	**S&P Adjusted**
Mean	0.88	0.60
Median	0.83	0.57
Asset-Weighted Average	0.85	0.56

Source: Schedule 29.

From the "Wires" sample beta, a "pure wires" beta was estimated at 0.70, assuming a beta of 1.0 for "Other Operations" and using the following formula:

$$\beta_{Wires} = \beta_{Pure\ Wires} \text{ x } Assets_{Wires} + \beta_{Other} \text{ x } \%Assets_{Other}$$

Using a) the estimated beta for high generation of 0.84, b) the beta for pure wires of 0.70, c) an assumed market average beta of 1.0 for other operations and d) the proportion of assets for the "high Gx" sample devoted to generation, wires and other operations, the following equation was used to solved for the generation-only beta (β_{Gx}):

$$\beta_{HighGx} = \beta_{Gx} \text{ x } Assets_{Gx} + \beta_{Pure\ Wires} \text{ x } \%Assets_{Wires} + \beta_{Other} \text{ x } \%Assets_{Other}$$

The derived generation-only beta is 0.94.

4. Derivation of Generation-Only CAPM Cost of Equity

The generation-only beta of 0.94 was combined with the estimates of the market risk premium and risk-free rate to arrive at an estimate of the generation-only CAPM cost of equity of approximately 11.1%.

5. Comparison of Sample Capital Structures

The capital structures for the benchmark low risk U.S. utility sample, the "wires", and the "high Gx" samples were compared to determine the extent to which differences in betas among samples are due to differences in financial risk versus business risk. Since the common equity ratio of each of the three samples was approximately 45%, any difference in betas among the samples could be attributed to business risk. The table below compares the 2006 equity ratios of the benchmark low risk utility sample, the "wires" sample and the "high Gx" sample.

Table I-3

	Benchmark	**Wires**	**High Gx**
Mean	44.9%	44.9%	44.8%
Median	44.6%	47.0%	45.8%
Weighted Average	43.5%	44.2%	43.0%

Source: Schedules 13, 28 and 29

6. Comparison of Betas

The betas of the benchmark low risk utility U.S. utility sample, the "high Gx" sample and the derived generation-only beta are respectively 0.71, 0.84 and 0.94.

7. Calculation of the Incremental Cost of Equity at a 45% Common Equity Ratio

The differences between the beta for the benchmark low risk U.S. utility sample (0.71) and those of the "high Gx" sample (0.84) and the derived generation-only beta (0.94) were determined. These differences, in conjunction with estimated market risk premium, were used to estimate the incremental cost of equity for a utility of similar risk to OPG at a 45% common equity ratio. The incremental return requirement was calculated as follows:

Incremental Return Requirement at 45% Equity = Difference in Beta x Market Risk Premium

Based on the high generation sample, the incremental equity return requirement is equal to approximately 85 basis points; based on the derived generation-only betas, the incremental equity return requirement is approximately 150 basis points, estimated as follows:

$$\text{Incremental Equity Return} = (\beta_{\text{HighGx}} - \beta_{\text{Benchmark Sample}}) \times \text{MRP}$$
$$= (0.84\text{-}0.71) \text{ X } 6.5\%$$
$$= 0.85\%$$

$$\text{Incremental Equity Return} = (\beta_{\text{Gx}} - \beta_{\text{Benchmark Sample}}) \times \text{MRP}$$
$$= (0.94\text{-}0.71) \text{ X } 6.5\%$$
$$= 1.50\%$$

8. Application of Capital Structure Theory

Based on both the high generation sample beta and the derived generation-only betas compared to the benchmark low risk utility sample beta, the incremental required equity return for OPG's regulated operations at a 45% common equity ratio – equal to the common equity ratios of the samples – is in the range of 0.85% to 1.50%. Since OPG's regulated operations are 100% generation, the focus should be on the upper end of the range, i.e. in the range of approximately 1.25% to 1.50%. Thus, compared to the benchmark return on equity of 10.5%, which is based on the application of multiple tests, the return on equity for OPG at a 45% common equity ratio would be approximately 11.75% to 12.0%.

Using capital structure theory, the incremental required return at a 45% common equity ratio can be translated into the common equity ratio which would eliminate the need for an incremental return, i.e., would equate the return requirement of OPG's regulated operations to the benchmark return.

The estimation of the change in equity ratio for a given change in equity return is based on two different theories of the relationship between capital structure and return on equity. Theory 1 posits that income taxes and the deductibility of interest for corporate income tax purposes have no impact on the cost of capital. Under this theory, the overall cost of capital stays constant when the capital structure changes, although the costs of the debt and equity components change (i.e., the cost of equity rises when the equity ratio declines). Theory 2 posits that income taxes and the corporate deductibility of interest expense cause the overall cost of capital to continually decline as the equity ratio declines and the debt ratio increases. The underlying formulas for the two theories are contained in Schedule 31.[168]

The actual impact on the cost of capital most likely lies in between the results of the two theories; income taxes and the deductibility of interest do tend to decrease the cost of capital (as the income trust market has demonstrated), but as the debt ratio rises, there are increasing costs in terms of loss of financing flexibility and potential bankruptcy. Moreover, in the case of regulated companies, the benefit of the tax deductibility of interest is to the benefit of ratepayers, while in the unregulated sector, the benefit goes to the shareholder. Since both theories have merit, both were applied to estimate the impact of a change in return on equity on capital structure.

The table below indicates that, based on both theories, the range of common equity ratios required to equate an 11.75-12.0% return on equity for OPG's regulated operations at a 45%

[168] The inputs for the derivation of the common equity ratio required to equate the return requirement of OPG's regulated operations to the benchmark return include a cost of new long-term debt of 6.0% and a corporate income tax rate of 34%.

equity ratio to the benchmark return of 10.5% is in the range of 55-60% (mid-point of 57.5%).[169] Schedule 31 demonstrates the calculation at a 57.5% common equity ratio.

Table I-4

Return on Equity	**Common Equity Ratio**		
	55%	**57.5%**	**60%**
Theory 1	10.5%	10.2%	10.0%
Theory 2	11.0%	10.8%	10.6%
Average	10.75%	10.5%	10.3%

[169] At a 0% tax rate, Theories I and 2 are identical. At a 0% tax rate, the indicated common equity ratio for OPG's regulated operations required to equate OPG's return on equity to the benchmark ROE of 10.5% is 56%.

APPENDIX J

QUALIFICATIONS OF KATHLEEN C. McSHANE

Kathleen McShane is President and senior consultant with Foster Associates, Inc., where she has been employed since 1981. She holds an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. She has been a CFA charterholder since 1989.

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

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 150 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian telephone companies, gas pipelines and distributors, and electric utilities. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, stand-alone cost of debt, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

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

Publications, Papers and Presentations

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

Expert Testimony/Opinions

On

Rate of Return & Capital Structure

Alberta Natural Gas	1994
AltaGas Utilities	2000
Ameren (Central Illinois Public Service)	2000, 2002, 2005
Ameren (Central Illinois Light Company)	2005
Ameren (Illinois Power)	2004, 2005
Ameren (Union Electric)	2000 (2 cases), 2002 (2 cases), 2003, 2006 (2 cases)
ATCO Electric	1989, 1991, 1993, 1995, 1998, 1999, 2000, 2003
ATCO Gas	2000, 2003
ATCO Pipelines	2000, 2003
Bell Canada	1987, 1993
Benchmark Utility Cost of Equity (British Columbia)	1999
Canadian Western Natural Gas	1989, 1996, 1998, 1999
Centra Gas B.C.	1992, 1995, 1996, 2002
Centra Gas Ontario	1990, 1991, 1993, 1994, 1995
Direct Energy Regulated Services	2005
Dow Pool A Joint Venture	1992
Edmonton Water/EPCOR Water Services	1994, 2000, 2006
Enbridge Gas Distribution	1988, 1989, 1991-1997, 2001, 2002
Enbridge Gas New Brunswick	2000
Enbridge Pipelines (Line 9)	2007

Enbridge Pipelines (Southern Lights)	2007
FortisBC	1995, 1999, 2001, 2004
Gas Company of Hawaii	2000
Gaz Metropolitain	1988
Gazifère	1993, 1994, 1995, 1996, 1997, 1998
Generic Cost of Capital, Alberta (ATCO and AltaGas Utilities)	2003
Heritage Gas	2004
Hydro One	1999, 2001, 2006
Insurance Bureau of Canada (Newfoundland)	2004
Laclede Gas Company	1998, 1999, 2001, 2002, 2005
Mackenzie Valley Pipeline	2005
Maritimes NRG (Nova Scotia) and (New Brunswick)	1999
Multi-Pipeline Cost of Capital Hearing (National Energy Board)	1994
Natural Resource Gas	1994, 1997, 2006
New Brunswick Power Distribution	2005
Newfoundland & Labrador Hydro	2001, 2003
Newfoundland Power	1998, 2002, 2007
Newfoundland Telephone	1992
Northwestel, Inc.	2000, 2006
Northwestern Utilities	1987, 1990
Northwest Territories Power Corp.	1990, 1992, 1993, 1995, 2001, 2006
Nova Scotia Power Inc.	2001, 2002, 2005
Ozark Gas Transmission	2000
Pacific Northern Gas	1990, 1991, 1994, 1997, 1999, 2001, 2005
Platte Pipeline Co.	2002

St. Lawrence Gas	1997, 2002
Southern Union Gas	1990, 1991, 1993
Stentor	1997
Tecumseh Gas Storage	1989, 1990
Telus Québec	2001
Terasen Gas	1992, 1994, 2005
TransCanada PipeLines	1988, 1989, 1991 (2 cases), 1992, 1993
TransGas and SaskEnergy LDC	1995
Trans Québec & Maritimes Pipeline	1987
Union Gas	1988, 1989, 1990, 1992, 1994, 1996, 1998, 2001
Westcoast Energy	1989, 1990, 1992 (2 cases), 1993, 2005
Yukon Electric Co. Ltd./Yukon Energy	1991, 1993

**Expert Testimony/Opinions
On
Other Issues**

Client	Issue	Date
New Brunswick Power Distribution	Interest Coverage/Capital Structure	2007
Heritage Gas	Revenue Deficiency Account	2006
Hydro Québec	Cash Working Capital	2005
Nova Scotia Power	Cash Working Capital	2005
Ontario Electricity Distributors	Stand-Alone Income Taxes	2005
Caisse Centrale de Réassurance	Collateral Damages	2004
Hydro Québec	Cost of Debt	2004
Enbridge Gas New Brunswick	AFUDC	2004
Heritage Gas	Deferral Accounts	2004
ATCO Electric	Carrying Costs on Deferral Account	2001
Newfoundland & Labrador Hydro	Rate Base, Cash Working Capital	2001
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Rate Subsidies	2000
Enbridge Gas Distribution	Principles of Cost Allocation	1998
Enbridge Gas Distribution	Unbundling/Regulatory Compact	1998
Maritime Electric	Form of Regulation	1995
Northwest Territories Power	Rate Stabilization Fund	1995
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Gaz Metro/ Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984

STATISTICAL EXHIBIT
TO

Capital Structure and Fair Return on Equity

Prepared for

ONTARIO POWER GENERATION

Prepared by

KATHLEEN C. McSHANE

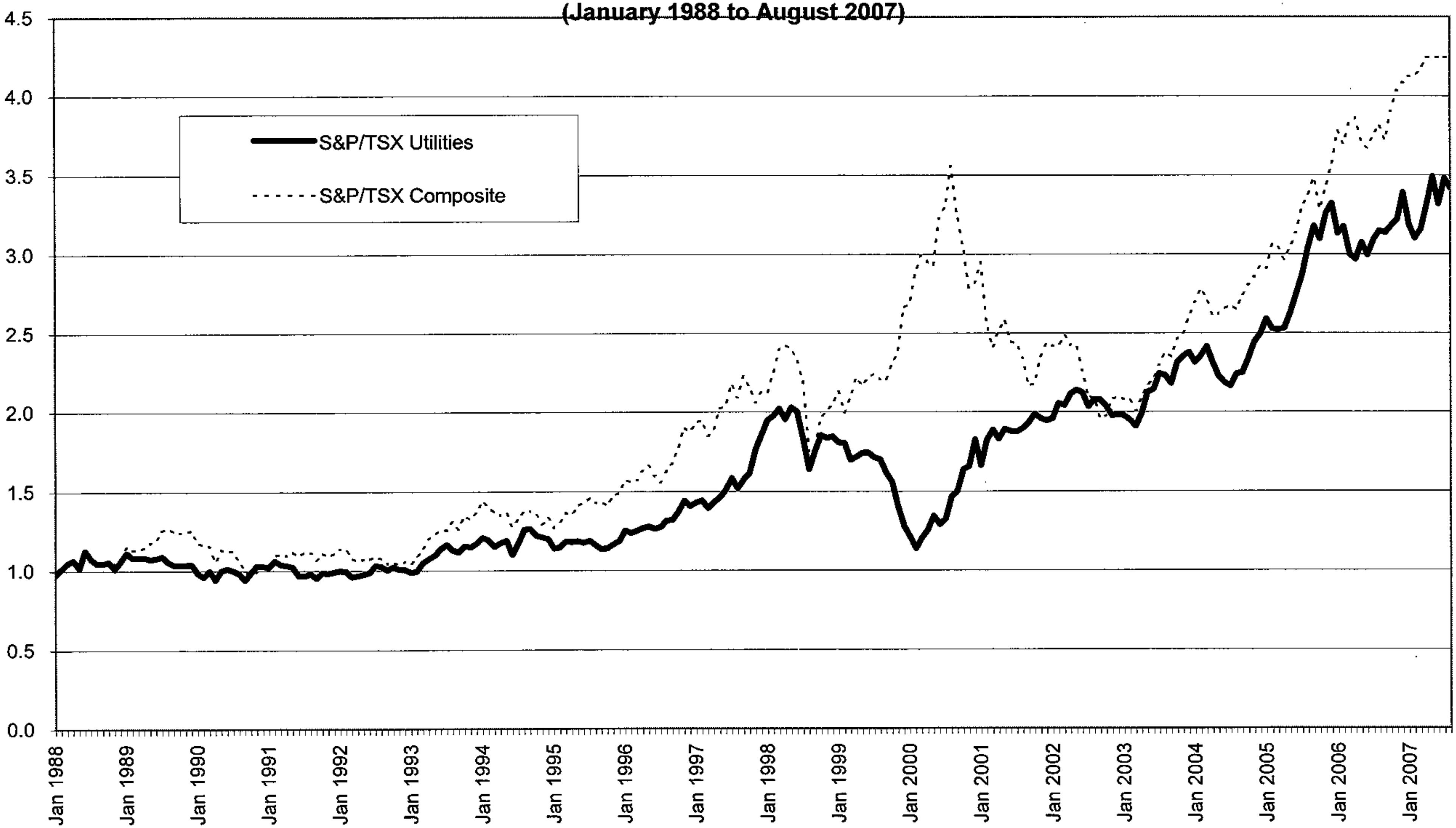
FOSTER ASSOCIATES, INC.

FOSTER ASSOCIATES INCORPORATED ECONOMIC CONSULTANTS

November 2007

STATISTICAL EXHIBIT

TREND IN S&P/TSX UTILITIES AND S&P/TSX PRICE INDICES
(January 1988 to August 2007)



TREND IN INTEREST RATES AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

Year		Government Securities: T-Bills Canadian	Government Securities: T-Bills U.S. [1]	Government Securities: 10 Year Canadian	Government Securities: 10 Year U.S.	Government Securities: Long-Term Canadian	Government Securities: Long-Term U.S. [2]	Canada Bonds Over 10 Years [3]	Canadian Inflation Indexed Bonds	Scotia Capital Long-Term Corporates	Canadian A-Rated Utility Bonds [4]	Moody's U.S. Utility Long-Term A-Rated Bonds	Exchange Rates (Canadian dollars in U.S. funds)
1993	q1	5.84	2.96	7.65	6.28	8.27	6.98	8.38	4.57	9.54	9.54	8.07	0.79
	q2	4.91	3.01	7.46	5.99	8.11	6.87	8.12	4.39	9.16	9.35	7.81	0.79
	q3	4.52	3.02	6.99	5.62	7.63	6.29	7.58	4.21	8.50	8.84	7.28	0.77
	q4	4.11	3.09	6.76	5.61	7.42	6.19	7.31	3.94	8.20	8.58	7.22	0.75
1994	q1	4.29	3.42	7.09	6.07	7.67	6.74	7.48	3.80	8.33	8.79	7.53	0.75
	q2	6.28	3.96	8.49	7.08	8.69	7.33	8.67	4.38	9.52	10.09	8.29	0.72
	q3	5.48	4.61	8.99	7.33	9.13	7.55	9.14	4.67	9.92	10.11	8.51	0.73
	q4	6.11	5.36	9.12	7.84	9.25	7.94	9.23	4.80	10.00	10.24	8.87	0.73
1995	q1	7.99	5.73	8.89	7.48	9.01	7.61	8.99	4.86	9.80	9.99	8.54	0.71
	q2	7.34	5.58	8.00	6.62	8.32	6.91	8.19	4.48	8.93	9.38	7.93	0.73
	q3	6.47	5.32	8.05	6.32	8.45	6.71	8.28	4.76	8.97	9.30	7.72	0.74
	q4	5.76	5.15	7.39	5.89	7.85	6.18	7.66	4.61	8.37	8.44	7.37	0.74
1996	q1	5.11	4.92	7.39	5.91	7.95	6.37	7.71	4.78	8.40	8.41	7.44	0.73
	q2	4.70	5.04	7.75	6.72	8.17	6.95	7.99	4.87	8.60	8.58	7.98	0.73
	q3	4.14	5.13	7.37	6.78	7.88	7.00	7.65	4.71	8.22	8.23	7.96	0.73
	q4	2.89	5.08	6.30	6.34	6.99	6.60	6.67	4.07	7.23	7.19	7.62	0.74
1997	q1	2.96	5.11	6.54	6.64	7.24	6.91	6.94	4.19	7.50	7.52	7.76	0.74
	q2	3.00	5.12	6.49	6.64	7.03	6.90	6.80	4.26	7.28	7.30	7.88	0.72
	q3	3.18	5.06	5.85	6.18	6.39	6.45	6.16	4.06	6.64	6.59	7.49	0.72
	q4	3.89	5.14	5.55	5.84	5.98	6.07	5.79	4.07	6.38	6.34	7.25	0.71
1998	q1	4.44	5.08	5.41	5.63	5.76	5.93	5.60	4.07	6.25	6.22	7.11	0.70
	q2	4.82	4.99	5.39	5.58	5.63	5.80	5.53	3.90	6.09	6.05	7.12	0.69
	q3	4.92	4.76	5.36	5.12	5.59	5.35	5.50	4.00	6.31	6.23	6.99	0.66
	q4	4.75	4.34	5.02	4.72	5.38	5.10	5.23	4.12	6.25	6.16	6.97	0.65
1999	q1	4.73	4.41	5.07	5.03	5.34	5.41	5.23	4.13	6.13	6.15	7.11	0.66
	q2	4.55	4.53	5.34	5.56	5.54	5.80	5.50	4.07	6.40	6.34	7.48	0.68
	q3	4.92	4.76	5.36	5.12	5.59	5.35	5.50	4.00	6.31	6.23	6.99	0.66
	q4	4.75	4.34	5.02	4.72	5.38	5.10	5.23	4.12	6.25	6.16	6.97	0.65
2000	q1	5.09	5.59	6.22	6.38	5.98	6.16	6.10	3.91	7.14	7.07	8.29	0.69
	q2	5.54	5.68	6.01	6.18	5.72	5.96	5.96	3.74	7.21	7.05	8.45	0.68
	q3	5.58	6.05	5.79	5.86	5.58	5.78	5.82	3.64	7.07	7.09	8.20	0.67
	q4	5.57	6.09	5.54	5.46	5.56	5.62	5.67	3.48	7.10	7.15	8.03	0.65
2001	q1	4.96	4.64	5.44	5.01	5.76	5.45	5.69	3.41	7.05	7.18	7.74	0.65
	q2	4.36	4.42	5.78	5.40	5.95	5.77	6.00	3.56	7.25	7.40	7.93	0.65
	q3	3.64	3.10	5.48	4.84	5.82	5.44	5.86	3.67	7.13	7.24	7.64	0.64
	q4	2.11	1.86	5.22	4.72	5.53	5.32	5.58	3.68	6.95	7.20	7.61	0.63
2002	q1	2.10	1.78	5.52	5.12	5.78	5.66	5.81	3.71	6.97	7.23	7.63	0.63
	q2	2.57	1.74	5.51	5.02	5.83	5.72	5.81	3.52	6.99	7.14	7.48	0.65
	q3	2.83	1.66	5.07	4.09	5.56	5.13	5.52	3.36	7.01	7.26	7.14	0.63
	q4	2.69	1.33	4.98	3.99	5.48	5.11	5.45	3.39	6.95	7.23	7.12	0.64
2003	q1	2.96	1.17	5.01	3.85	5.49	4.93	5.43	3.09	6.92	7.22	6.84	0.67
	q2	3.14	1.05	4.59	3.60	5.17	4.71	5.09	3.04	6.42	6.72	6.37	0.72
	q3	2.70	0.96	4.75	4.30	5.30	5.28	5.26	3.11	6.40	6.69	6.61	0.72
	q4	2.62	0.95	4.78	4.31	5.29	5.22	5.24	2.90	6.24	6.47	6.34	0.77
2004	q1	2.12	0.94	4.41	4.00	5.09	4.96	4.99	2.50	5.92	6.17	6.06	0.76
	q2	1.98	1.13	4.74	4.60	5.29	5.35	5.22	2.38	6.25	6.48	6.45	0.74
	q3	2.23	1.58	4.66	4.26	5.14	5.08	5.13	2.29	6.19	6.37	6.11	0.77
	q4	2.53	2.11	4.40	4.22	4.92	4.93	4.87	2.18	5.90	6.09	5.95	0.83
2005	q1	2.47	2.67	4.27	4.33	4.72	4.70	4.69	2.05	5.67	5.86	5.72	0.82
	q2	2.46	3.01	3.93	4.05	4.39	4.36	4.35	1.86	5.23	5.59	5.43	0.81
	q3	2.73	3.50	3.88	4.21	4.20	4.39	4.19	1.75	5.15	5.32	5.49	0.84
	q4	3.25	4.00	4.07	4.49	4.19	4.63	4.21	1.59	5.22	5.36	5.82	0.85
2006	q1	3.70	4.57	4.18	4.65	4.23	4.70	4.25	1.53	5.31	5.43	5.92	0.87
	q2	4.17	4.84	4.51	5.11	4.54	5.19	4.57	1.81	5.69	5.75	6.41	0.90
	q3	4.14	5.00	4.14	4.79	4.21	4.91	4.23	1.67	5.37	5.45	6.09	0.89
	q4	4.16	5.04	4.00	4.59	4.07	4.70	4.08	1.68	5.21	5.27	5.82	0.87
2007	q1	4.17	5.11	4.10	4.68	4.17	4.82	4.18	1.77	5.23	5.36	5.92	0.86
	q2	4.29	4.82	4.39	4.85	4.35	4.98	4.38	1.94	5.61	5.61	6.08	0.92
Annual													
	1990	12.81	7.49	10.76	8.55	10.69	8.61	10.85		11.91	12.13	9.86	0.86
	1991	8.73	5.38	9.42	7.86	9.72	8.14	9.76		10.80	11.00	9.36	0.84
	1992	6.59	3.43	8.05	7.01	8.68	7.67	8.77	4.62	9.90	10.01	8.64	0.82
	1993	4.84	3.02	7.22	5.87	7.86	6.59	7.85	4.28	8.85	9.08	7.59	0.77
	1994	5.54	4.34	8.43	7.08	8.69	7.39	8.63	4.41	9.44	9.81	8.30	0.73
	1995	6.89	5.44	8.08	6.58	8.41	6.85	8.28	4.68	9.02	9.29	7.89	0.73
	1996	4.21	5.04	7.20	6.44	7.75	6.73	7.50	4.61	8.11	8.38	7.75	0.73
	1997	3.26	5.11	6.11	6.32	6.66	6.58	6.42	4.14	6.95	7.19	7.60	0.72
	1998	4.73	4.79	5.30	5.26	5.59	5.54	5.47	4.02	6.22	6.38	7.04	0.68
	1999	4.69	4.71	5.55	5.68	5.72	5.91	5.69	4.07	6.64	6.92	7.62	0.67
	2000	5.45	5.85	5.89	5.98	5.71	5.88	5.89	3.69	7.13	7.02	8.24	0.67
	2001	3.78	3.34	5.49	4.99	5.77	5.50	5.76	3.59	7.09	7.25	7.73	0.65
	2002	2.55	1.63	5.27	4.56	5.67	5.41	5.65	3.49	6.98	7.22	7.35	0.64
	2003	2.86	1.03	4.78	4.02	5.31	5.03	5.26	3.04	6.50	6.78	6.54	0.72
	2004	2.21	1.44	4.55	4.27	5.11	5.08	5.05	2.34	6.06	6.28	6.14	0.77
	2005	2.73	3.29	4.04	4.27	4.38	4.52	4.36	1.81	5.32	5.53	5.62	0.83
	2006	4.05	4.86	4.21	4.79	4.26	4.87	4.28	1.67	5.40	5.47	6.06	0.89

[1] Rates on new Issues.
[2] 30-year maturities through January 2002. Theoretical 30-year yield, February 2002 to January 2006.
[3] Terms to maturity of l0 years or more.
[4] Series is comprised of the CBRS Utilities Index through 1995; CBRS 30-year Utilities Index from 1996- August 2000; a series of liquid long-term utility bonds maintained by Foster Associates from September 2000 forward.

Source: www.bankofcanada.ca; Globe and Mail; www.federalreserve.gov
www.ustreas.gov

TREND IN INTEREST RATES AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

		Government Securities												
		T-BILLS		10 Year		Long-Term		Canada Bonds Over 10 Years [3]	Canadian Inflation Indexed Bonds	Scotia Capital Long-Term Corporates [4]	Canadian A-Rated Utility Bonds [5]	Moody's U.S. Utility Long-Term A-Rated Bonds	Exchange Rates (Canadian dollars in U.S. funds)
Year		Canadian	U.S. [1]	Canadian	U.S.	Canadian	U.S. [2]						
2004	Jan	2.25	0.92	4.53	4.16	5.17	5.07	5.09	2.59	6.03	6.26	6.11	0.76
	Feb	2.12	0.96	4.36	3.99	5.05	4.95	4.94	2.52	5.87	6.13	6.08	0.75
	Mar	1.98	0.95	4.33	3.86	5.04	4.87	4.94	2.39	5.85	6.11	6.01	0.76
	Apr	1.92	0.98	4.62	4.53	5.24	5.36	5.15	2.46	6.15	6.41	6.46	0.73
	May	2.00	1.08	4.78	4.66	5.31	5.29	5.22	2.31	6.25	6.43	6.53	0.73
	June	2.01	1.33	4.83	4.62	5.33	5.41	5.30	2.37	6.36	6.60	6.36	0.75
	Jul	2.07	1.45	4.75	4.50	5.24	5.31	5.24	2.31	6.34	6.49	6.36	0.75
	Aug	2.17	1.59	4.60	4.13	5.09	4.97	5.08	2.24	6.17	6.33	6.02	0.76
	Sep	2.44	1.71	4.63	4.14	5.08	4.97	5.06	2.33	6.05	6.29	5.96	0.79
	Oct	2.57	1.91	4.47	4.05	4.94	4.87	4.91	2.26	5.99	6.17	5.89	0.82
	Nov	2.55	2.23	4.44	4.36	4.98	5.07	4.93	2.21	5.88	6.16	6.07	0.84
	Dec	2.48	2.22	4.30	4.24	4.83	4.86	4.77	2.07	5.82	5.94	5.99	0.83
2005	Jan	2.43	2.51	4.21	4.14	4.71	4.62	4.67	2.03	5.66	5.84	5.65	0.81
	Feb	2.46	2.76	4.28	4.36	4.75	4.71	4.71	2.09	5.62	5.86	5.76	0.81
	Mar	2.52	2.73	4.32	4.50	4.71	4.76	4.68	2.03	5.73	5.87	5.75	0.83
	Apr	2.45	2.90	4.14	4.21	4.58	4.53	4.54	1.90	5.04	5.79	5.54	0.80
	May	2.45	2.99	3.92	4.00	4.37	4.36	4.31	1.83	5.46	5.59	5.41	0.80
	Jun	2.48	3.13	3.74	3.94	4.21	4.19	4.20	1.85	5.20	5.40	5.35	0.82
	Jul	2.59	3.42	3.86	4.28	4.27	4.42	4.27	1.90	5.25	5.42	5.53	0.82
	Aug	2.72	3.52	3.81	4.02	4.12	4.23	4.09	1.74	5.04	5.23	5.30	0.84
	Sep	2.87	3.55	3.96	4.34	4.22	4.53	4.21	1.61	5.15	5.33	5.65	0.86
	Oct	3.06	3.98	4.17	4.57	4.35	4.73	4.36	1.66	5.34	5.49	5.91	0.85
	Nov	3.31	3.95	4.06	4.52	4.18	4.66	4.20	1.65	5.24	5.35	5.85	0.86
	Dec	3.39	4.08	3.98	4.39	4.05	4.51	4.06	1.45	5.09	5.23	5.69	0.86
2006	Jan	3.51	4.47	4.17	4.53	4.26	4.69	4.26	1.53	5.30	5.43	5.84	0.88
	Feb	3.74	4.62	4.12	4.55	4.17	4.51	4.17	1.47	5.27	5.37	5.77	0.88
	Mar	3.86	4.61	4.26	4.86	4.26	4.89	4.32	1.58	5.37	5.49	6.14	0.86
	Apr	4.04	4.65	4.51	5.07	4.52	5.17	4.57	1.72	5.67	5.70	6.37	0.89
	May	4.18	4.86	4.45	5.12	4.50	5.21	4.51	1.83	5.60	5.68	6.43	0.91
	Jun	4.30	5.01	4.58	5.15	4.61	5.19	4.63	1.88	5.81	5.86	6.43	0.90
	Jul	4.15	5.10	4.31	4.99	4.37	5.07	4.39	1.73	5.60	5.62	6.29	0.88
	Aug	4.12	5.02	4.11	4.74	4.19	4.88	4.20	1.62	5.33	5.42	6.07	0.90
	Sep	4.16	4.89	3.99	4.64	4.08	4.77	4.09	1.67	5.18	5.30	5.90	0.89
	Oct	4.17	5.08	4.02	4.61	4.08	4.72	4.10	1.69	5.33	5.28	5.84	0.89
	Nov	4.17	5.03	3.90	4.46	3.99	4.56	4.00	1.60	5.11	5.18	5.68	0.88
	Dec	4.15	5.02	4.08	4.71	4.14	4.81	4.15	1.75	5.18	5.34	5.95	0.86
2007	Jan	4.17	5.12	4.17	4.83	4.22	4.93	4.23	1.79	5.28	5.41	6.01	0.85
	Feb	4.19	5.16	4.03	4.56	4.09	4.68	4.10	1.75	5.15	5.28	5.78	0.85
	Mar	4.16	5.04	4.11	4.65	4.20	4.84	4.21	1.77	5.27	5.39	5.97	0.87
	Apr	4.16	4.91	4.14	4.63	4.19	4.81	4.20	1.76	5.38	5.45	5.90	0.90
	May	4.29	4.73	4.49	4.90	4.38	5.01	4.42	1.99	5.63	5.62	6.10	0.93
	Jun	4.43	4.82	4.55	5.03	4.49	5.12	4.51	2.08	5.82	5.75	6.24	0.94
	Jul	4.56	4.96	4.52	4.78	4.45	4.92	4.48	2.07		5.78	6.18	0.94
	Aug	3.99	4.01	4.42	4.54	4.46	4.83	4.47	2.14		5.76	6.17	0.95

[1] Rates on new issues.
[2] 20-year constant maturities for 1974-1978; 30-year maturities, 1978-January 2002. Theoretical 30-year yield, February 2002 to January 2006.
[3] Terms to maturity of I0 years or more.
[4] Series discontinued June 2007.
[5] Series is comprised of the CBRS Utilities Index through 1995; CBRS 30-year Utilities Index from 1996- August 2000; a series of liquid long-term utility bonds maintained by Foster Associates from September 2000 forward.

Note: Monthly data reflect rate in effect at end of month.

Source: www.bankofcanada.ca Globe and Mail; www.federalreserve.gov
RBC Capital Markets, www.ustreas.gov

SELECTED INDICATORS OF ECONOMIC ACTIVITY
(1989 = 100)

Year		Canada: Gross Domestic Product Constant Dollars (1)	Canada: Gross Domestic Product Current Dollars (2)	Canada: Industrial Production (3)	Canada: GDP Deflator Index (4)	Canada: Consumer Price Index (5)	United States: Gross Domestic Product Constant Dollars (6)	United States: Gross Domestic Product Current Dollars (7)	United States: Industrial Production (8)	United States: Implicit Price Index (9)	United States: Consumer Price Index (10)
1989		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1990		100.2	103.4	97.2	103.2	104.8	101.9	105.8	101.0	103.9	105.4
1991		98.1	104.2	93.5	106.2	110.7	101.7	109.3	99.5	107.5	109.8
1992		99.0	106.5	94.5	107.6	112.3	105.1	115.6	102.4	110.0	113.2
1993		101.3	110.6	98.8	109.2	114.4	107.9	121.4	105.8	112.5	116.5
1994		106.1	117.2	105.1	110.4	114.6	112.2	129.0	111.6	114.9	119.5
1995		109.1	122.7	109.9	112.9	117.1	115.0	134.9	117.2	117.2	122.9
1996		110.9	126.8	111.8	114.7	118.9	119.3	142.5	122.2	119.5	126.5
1997		115.6	133.5	118.0	116.1	120.8	124.7	151.4	131.1	121.5	129.5
1998		120.3	139.2	122.2	115.6	122.0	129.9	159.5	139.1	122.8	131.5
1999		127.0	149.4	129.8	117.6	124.2	135.7	169.0	145.6	124.6	134.4
2000		133.6	163.5	139.6	122.5	127.5	140.6	179.0	152.2	127.3	138.9
2001		136.0	168.5	134.6	123.9	130.8	141.7	184.7	146.9	130.4	142.8
2002		140.0	175.3	137.5	125.2	133.7	143.9	190.9	146.9	132.6	145.1
2003		142.6	184.4	137.8	129.4	137.4	147.6	199.9	148.5	135.4	148.4
2004		147.0	196.3	140.3	133.6	139.9	152.9	213.1	152.2	139.3	152.3
2005		151.5	209.1	141.6	138.1	143.0	157.6	226.7	157.1	143.8	157.5
2006		155.7	219.9	140.9	141.3	145.9	162.1	240.6	163.5	148.4	162.6
2002	1Q	138.5	170.2	135.5	122.9	131.4	142.9	188.4	144.9	131.8	143.5
	2Q	139.3	174.3	138.1	125.2	133.3	143.7	190.1	147.1	132.3	145.0
	3Q	140.5	176.7	138.5	125.7	134.7	144.5	192.0	148.0	132.8	145.6
	4Q	141.6	180.0	137.8	127.2	135.4	144.6	193.1	147.8	133.6	146.1
2003	1Q	142.2	183.8	137.4	129.3	137.2	145.0	195.2	148.7	134.6	147.6
	2Q	142.0	182.1	136.2	128.3	137.0	146.3	197.5	147.5	135.0	148.1
	3Q	142.5	185.1	137.8	129.9	137.6	148.9	202.1	148.4	135.7	148.8
	4Q	143.7	186.9	139.7	130.2	137.8	149.9	204.6	149.5	136.5	148.9
2004	1Q	144.7	190.5	139.7	131.7	138.5	151.0	208.0	150.7	137.7	150.2
	2Q	146.4	195.5	140.6	133.5	140.0	152.3	211.7	151.7	139.0	152.4
	3Q	148.0	198.4	140.9	134.2	140.3	153.7	214.8	152.4	139.8	152.9
	4Q	148.8	200.6	140.0	134.9	140.9	154.6	217.9	154.0	140.9	153.8
2005	1Q	149.4	202.9	140.0	135.8	141.4	155.8	221.6	155.7	142.2	154.8
	2Q	150.7	206.2	141.0	136.9	142.7	156.9	224.6	156.8	143.1	156.9
	3Q	152.2	211.5	142.3	138.9	144.0	158.6	229.0	157.1	144.4	158.8
	4Q	153.5	215.7	143.3	140.6	144.1	159.1	231.7	158.9	145.6	159.6
2006	1Q	154.8	217.6	142.6	140.6	144.8	161.0	236.4	160.9	146.9	160.4
	2Q	155.4	219.3	141.1	141.2	146.4	162.0	239.9	163.4	148.1	163.1
	3Q	155.9	220.8	140.7	141.7	146.5	162.4	241.9	165.1	149.0	164.1
	4Q	156.5	221.9	139.1	141.8	146.0	163.2	244.2	164.5	149.6	162.7
2007	1Q	158.0	227.5	140.2	144.1	147.4	163.5	247.1	164.9	151.2	164.3
	2Q	159.3	232.7	141.0	146.1	149.6	164.8	250.8	166.1	152.2	167.5

Note: Data are based on Chain Weighted Indexes.

Source: www.cansim2.statcan.ca , www.bea.gov , www.federalreserve.gov

HISTORIC EQUITY MARKET RISK PREMIUMS

Canada (1947-2006)

Average	Stock Return	Bond Return	Risk Premium
Arithmetic	12.4	7.0	5.5
Geometric	11.2	6.5	4.7

United States (1947-2006)

Average	Stock Return	Bond Return	Risk Premium
Arithmetic	13.2	6.2	6.9
Geometric	11.9	5.7	6.1

United Kingdom (1947-2006)

Average	Stock Return	Bond Return	Risk Premium
Arithmetic	15.0	8.7	6.3
Geometric	12.3	6.3	6.0

Source: Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2007 Yearbook Market Results for 1926-2006; Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006; www.statistics.gov.uk and Barclays Equity Gilt Study.

25-YEAR ROLLING AVERAGE MARKET RETURNS FOR CANADA AND THE U.S.

	Canada		U.S.	
	Stock Returns	Long Government Bond Returns	Stock Returns	Long Government Bond Returns
1947-1971	12.7%	2.9%	13.7%	2.0%
1948-1972	13.8%	2.8%	14.3%	2.3%
1949-1973	13.3%	3.0%	13.5%	2.1%
1950-1974	11.3%	2.7%	11.7%	2.0%
1951-1975	10.1%	2.8%	11.9%	2.4%
1952-1976	9.6%	3.7%	11.9%	3.2%
1953-1977	10.1%	3.9%	10.8%	3.2%
1954-1978	11.2%	3.8%	11.1%	3.0%
1955-1979	11.4%	3.3%	9.8%	2.6%
1956-1980	11.5%	3.4%	9.8%	2.5%
1957-1981	10.6%	3.4%	9.4%	2.8%
1958-1982	11.6%	4.9%	10.6%	4.1%
1959-1983	11.8%	5.5%	9.8%	4.4%
1960-1984	11.5%	6.3%	9.6%	5.1%
1961-1985	12.4%	7.0%	10.8%	5.8%
1962-1986	11.5%	7.3%	10.5%	6.7%
1963-1987	12.0%	7.2%	11.1%	6.4%
1964-1988	11.8%	7.4%	10.8%	6.7%
1965-1989	11.6%	7.8%	11.4%	7.3%
1966-1990	10.8%	7.9%	10.8%	7.5%
1967-1991	11.5%	8.8%	12.4%	8.1%
1968-1992	10.8%	9.4%	11.8%	8.8%
1969-1993	11.2%	10.4%	11.7%	9.6%
1970-1994	11.2%	10.0%	12.1%	9.4%
1971-1995	11.9%	10.2%	13.5%	10.2%
1972-1996	12.7%	10.3%	13.8%	9.7%
1973-1997	12.2%	11.0%	14.4%	10.1%
1974-1998	12.2%	11.5%	16.1%	10.6%
1975-1999	14.5%	11.3%	18.0%	10.1%
1976-2000	14.0%	11.7%	16.2%	10.6%
1977-2001	13.1%	11.1%	14.7%	10.1%
1978-2002	12.2%	11.3%	14.1%	10.8%
1979-2003	12.0%	11.5%	15.0%	10.9%
1980-2004	10.8%	12.0%	14.7%	11.3%
1981-2005	10.6%	12.5%	13.6%	11.8%
1982-2006	11.7%	12.7%	14.5%	11.7%
Min	**9.6%**	**2.7%**	**9.4%**	**2.0%**
Max	**14.5%**	**12.7%**	**18.0%**	**11.8%**
Mean	**11.8%**	**7.6%**	**12.5%**	**6.8%**
Stdev.	**1.1%**	**3.5%**	**2.1%**	**3.5%**
+1 Std	**12.8%**	**11.1%**	**14.6%**	**10.3%**
-1 Std dev.	**10.7%**	**4.1%**	**10.4%**	**3.4%**

Source: Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2007 Yearbook Market Results for 1926-2006; Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006

CUMULATIVE AVERAGE MARKET RETURNS FOR CANADA AND THE U.S.
(1947 Forward)

	Canada		U.S.	
	Stock Returns	Long Government Bond Returns	Stock Returns	Long Government Bond Returns
1947-1971	12.7%	2.9%	13.7%	2.0%
1947-1972	13.2%	2.8%	13.9%	2.1%
1947-1973	12.8%	2.8%	12.9%	2.0%
1947-1974	11.4%	2.6%	11.5%	2.1%
1947-1975	11.6%	2.6%	12.4%	2.3%
1947-1976	11.6%	3.2%	12.7%	2.8%
1947-1977	11.6%	3.3%	12.1%	2.7%
1947-1978	12.1%	3.2%	11.9%	2.6%
1947-1979	13.1%	3.0%	12.1%	2.5%
1947-1980	13.6%	3.0%	12.7%	2.3%
1947-1981	12.9%	2.8%	12.2%	2.3%
1947-1982	12.7%	3.9%	12.5%	3.3%
1947-1983	13.4%	4.1%	12.7%	3.2%
1947-1984	12.9%	4.4%	12.6%	3.6%
1947-1985	13.3%	4.9%	13.1%	4.3%
1947-1986	13.1%	5.2%	13.2%	4.8%
1947-1987	13.0%	5.1%	13.0%	4.6%
1947-1988	12.9%	5.2%	13.1%	4.7%
1947-1989	13.1%	5.5%	13.5%	5.0%
1947-1990	12.5%	5.4%	13.2%	5.0%
1947-1991	12.5%	5.9%	13.5%	5.4%
1947-1992	12.2%	6.0%	13.4%	5.4%
1947-1993	12.6%	6.4%	13.3%	5.7%
1947-1994	12.3%	6.0%	13.1%	5.4%
1947-1995	12.4%	6.4%	13.6%	6.0%
1947-1996	12.7%	6.6%	13.8%	5.8%
1947-1997	12.7%	6.8%	14.2%	6.0%
1947-1998	12.5%	7.0%	14.4%	6.1%
1947-1999	12.8%	6.7%	14.6%	5.9%
1947-2000	12.7%	6.8%	14.1%	6.1%
1947-2001	12.3%	6.8%	13.7%	6.1%
1947-2002	11.8%	6.8%	13.0%	6.3%
1947-2003	12.1%	6.8%	13.3%	6.2%
1947-2004	12.1%	6.9%	13.2%	6.3%
1947-2005	12.3%	7.0%	13.1%	6.3%
1947-2006	12.4%	7.0%	13.2%	6.2%
Min	**11.4%**	**2.6%**	**11.5%**	**2.0%**
Max	**13.6%**	**7.0%**	**14.6%**	**6.3%**
Mean	**12.6%**	**5.1%**	**13.1%**	**4.4%**
Stdev.	**0.5%**	**1.6%**	**0.7%**	**1.6%**
+1 Std	**13.1%**	**6.7%**	**13.8%**	**6.1%**
-1 Std dev.	**12.0%**	**3.4%**	**12.4%**	**2.8%**

Source: Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2007 Yearbook Market Results for 1926-2006; Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006

CUMULATIVE AVERAGE MARKET RETURNS FOR CANADA AND THE U.S.
(2006 Backward)

	Canada		U.S.	
	Stock Returns	Long Government Bond Returns	Stock Returns	Long Government Bond Returns
1947-2006	12.4%	7.0%	13.2%	6.2%
1948-2006	12.6%	7.0%	13.3%	6.4%
1949-2006	12.6%	7.2%	13.4%	6.4%
1950-2006	12.5%	7.2%	13.3%	6.4%
1951-2006	11.8%	7.3%	13.0%	6.5%
1952-2006	11.6%	7.5%	12.8%	6.7%
1953-2006	11.8%	7.6%	12.7%	6.8%
1954-2006	12.0%	7.7%	12.9%	6.9%
1955-2006	11.5%	7.7%	12.2%	6.9%
1956-2006	11.2%	7.8%	11.8%	7.0%
1957-2006	11.1%	8.1%	11.9%	7.3%
1958-2006	11.8%	8.1%	12.4%	7.3%
1959-2006	11.4%	8.4%	11.7%	7.6%
1960-2006	11.5%	8.7%	11.7%	7.8%
1961-2006	11.7%	8.7%	12.0%	7.6%
1962-2006	11.2%	8.7%	11.6%	7.8%
1963-2006	11.7%	8.8%	12.1%	7.8%
1964-2006	11.6%	8.9%	11.8%	8.0%
1965-2006	11.2%	9.0%	11.7%	8.1%
1966-2006	11.4%	9.1%	11.7%	8.2%
1967-2006	11.8%	9.3%	12.3%	8.4%
1968-2006	11.7%	9.6%	12.0%	8.8%
1969-2006	11.4%	9.9%	12.0%	9.0%
1970-2006	11.7%	10.2%	12.5%	9.4%
1971-2006	12.1%	9.9%	12.8%	9.4%
1972-2006	12.2%	9.9%	12.7%	9.2%
1973-2006	11.8%	10.1%	12.5%	9.3%
1974-2006	12.1%	10.4%	13.4%	9.7%
1975-2006	13.3%	10.7%	14.6%	9.8%
1976-2006	13.2%	11.0%	13.9%	9.8%
1977-2006	13.2%	10.7%	13.6%	9.6%
1978-2006	13.3%	10.9%	14.3%	10.0%
1979-2006	12.7%	11.2%	14.5%	10.4%
1980-2006	11.6%	11.8%	14.4%	10.8%
1981-2006	10.8%	12.1%	13.7%	11.4%
1982-2006	11.7%	12.7%	14.5%	11.7%
Min	**10.8%**	**7.0%**	**11.6%**	**6.2%**
Max	**13.3%**	**12.7%**	**14.6%**	**11.7%**
Mean	**11.9%**	**9.2%**	**12.8%**	**8.3%**
Stdev.	**0.7%**	**1.6%**	**0.9%**	**1.5%**
+1 Std	**12.6%**	**10.8%**	**13.7%**	**9.9%**
-1 Std dev.	**11.3%**	**7.6%**	**11.9%**	**6.8%**

Source: Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2007 Yearbook Market Results for 1926-2006; Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006

**FIVE-YEAR STANDARD DEVIATIONS OF MARKET RETURNS
FOR 10 SECTOR INDICES OF S&P/TSX COMPOSITE
FOR FIVE YEAR PERIODS ENDING:**

	1997 (%)	1998 (%)	1999 (%)	2000 (%)	2001 (%)	2002 (%)	2003 (%)	2004 (%)	2005 (%)	2006 (%)	Average
S&P / TSX Composite	**3.57**	**4.68**	**4.84**	**5.40**	**5.87**	**5.83**	**4.97**	**4.59**	**4.04**	**3.24**	**4.70**
10 Sector Indices											
Consumer Discretionary	3.69	4.36	4.62	4.99	5.38	5.73	5.35	5.00	4.35	3.69	4.72
Consumer Staples	3.57	4.01	3.70	4.04	4.17	4.76	4.45	4.37	4.05	3.88	4.10
Energy	5.60	6.16	7.31	7.97	8.30	8.10	6.98	5.72	5.56	5.46	6.72
Financials	4.27	5.89	5.92	6.22	6.17	6.06	4.58	4.23	3.77	3.36	5.05
Health Care	6.62	7.73	8.19	9.38	9.00	9.39	8.93	8.68	6.98	6.57	8.15
Industrials	4.13	4.93	4.69	5.12	6.50	7.18	6.92	6.87	6.48	5.16	5.80
Information Technology	7.99	9.17	10.35	12.27	15.16	17.12	16.64	17.09	15.81	13.36	13.50
Materials	5.87	6.98	7.22	7.29	7.40	7.25	5.89	5.65	5.67	5.88	6.51
Telecommunication Services	3.66	5.82	7.37	7.87	8.46	8.71	7.54	5.74	4.97	4.64	6.48
Utilities	3.12	3.80	4.00	4.80	5.06	4.88	4.49	4.09	3.36	3.13	4.07
Mean	**4.85**	**5.89**	**6.34**	**7.00**	**7.56**	**7.92**	**7.18**	**6.75**	**6.10**	**5.51**	**6.51**
Median	**4.20**	**5.85**	**6.57**	**6.76**	**6.95**	**7.21**	**6.41**	**5.68**	**5.27**	**4.90**	**5.98**

Ratios of Standard Deviations

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	Average
S&P/TSX Utilities Index as a Percent of:											
10 Sector Indices (Mean)	**0.64**	**0.65**	**0.63**	**0.69**	**0.67**	**0.62**	**0.63**	**0.61**	**0.55**	**0.57**	**0.62**
10 Sector Indices (Median)	**0.74**	**0.65**	**0.61**	**0.71**	**0.73**	**0.68**	**0.70**	**0.72**	**0.64**	**0.64**	**0.68**

Source: TSX Review

TSE 300 SUB-INDEX COMPOUND RETURNS AND BETAS

	Compound Returns						Betas					
	56-03	56-97	64-73	74-83	84-93	94-03	56-03	56-97	64-73	74-83	84-93	94-03
Metals/Minerals	0.08	0.08	0.07	0.11	0.07	0.07	1.15	1.23	1.14	1.22	1.37	0.87
Gold/Precious Metals	0.10	0.10	0.16	0.16	0.11	-0.03	0.85	0.96	0.36	1.31	1.24	0.64
Oil and Gas	0.10	0.08	0.15	0.12	0.05	0.15	1.06	1.20	1.25	1.40	0.98	0.52
Paper/Forest Products	0.07	0.07	0.05	0.12	0.10	0.03	1.02	1.07	1.15	1.00	1.27	0.85
Consumer Products	0.11	0.12	0.10	0.14	0.11	0.10	0.83	0.86	0.84	0.90	0.89	0.73
Industrial Products	0.07	0.10	0.08	0.11	0.06	0.01	1.17	1.02	1.11	0.87	1.08	1.69
Real Estate [1/]	0.05	0.05	0.01	0.17	-0.02	0.01	1.00	1.18	1.21	1.28	1.06	0.46
Transportation/Environmental	0.10	0.11	0.13	0.18	0.03	0.09	0.94	1.04	0.94	1.08	1.22	0.62
Pipelines	0.12	0.12	0.05	0.14	0.14	0.13	0.68	0.85	0.80	0.92	0.76	0.02
Utilities	0.11	0.11	0.03	0.18	0.11	0.16	0.54	0.48	0.50	0.47	0.40	0.79
Communications/Media	0.13	0.15	0.19	0.15	0.13	0.07	0.77	0.77	0.96	0.69	0.95	0.80
Merchandising	0.10	0.11	0.11	0.12	0.09	0.07	0.78	0.86	0.93	0.84	0.83	0.46
Finance	0.12	0.13	0.12	0.12	0.12	0.18	0.83	0.85	0.95	0.71	0.93	0.77
Conglomerates	0.11	0.11	0.13	0.15	0.09	0.14	0.94	1.03	1.26	0.97	1.20	0.68
Intercept							**0.18**	**0.18**	**0.12**	**0.15**	**0.14**	**0.12**
Adjusted R Square							**47%**	**44%**	**1%**	**1%**	**11%**	**9%**
Beta							**-0.088**	**-0.082**	**-0.020**	**-0.008**	**-0.056**	**-0.053**

[1/] Data only available starting July 1961

Source: TSX Review

S&P/TSX COMPOSITE SECTOR COMPOUND RETURNS AND BETAS

	Compound Returns [1/]			Betas		
	88-06	88-97	97-06	88-06	88-97	97-06
Consumer Discretionary	0.086	0.102	0.078	0.787	0.904	0.731
Consumer Staples	0.135	0.127	0.178	0.348	0.727	0.165
Energy	0.129	0.084	0.167	0.656	0.765	0.580
Financials	0.160	0.183	0.170	0.784	1.039	0.677
Health Care	0.053	0.155	-0.056	0.871	0.807	0.955
Industrials	0.066	0.083	0.061	0.969	1.131	0.864
Information Technology	0.077	0.218	-0.021	1.799	1.213	2.167
Materials	0.066	0.034	0.057	0.919	1.257	0.722
Telecommunication Services	0.144	0.154	0.160	0.738	0.578	0.866
Utilities	0.116	0.115	0.140	0.232	0.624	0.052
Intercept				**0.14**	**0.14**	**0.17**
Adjusted R Square				**23%**	**1%**	**45%**
Beta				**-0.043**	**-0.017**	**-0.098**

[1/] Data only available starting December 1987

Source: TSX Review

5-YEAR PRICE BETAS FOR S&P/TSX SECTOR INDICES

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Consumer Discretionary	0.91	0.81	0.82	0.82	0.80	0.73	0.69	0.68	0.73	0.74	0.80	0.83	0.86
Consumer Staples	0.75	0.68	0.65	0.62	0.60	0.44	0.23	0.10	0.08	-0.08	-0.07	0.07	0.37
Energy	0.68	0.93	0.92	0.97	0.85	0.90	0.66	0.49	0.43	0.26	0.17	0.48	1.03
Financials	1.14	0.93	1.02	0.94	1.12	1.00	0.78	0.66	0.66	0.38	0.39	0.56	0.68
Health Care	0.84	0.35	0.39	0.60	1.01	1.00	1.09	0.98	0.99	0.85	0.82	0.72	0.85
Industrials	1.15	1.20	1.10	0.97	0.93	0.78	0.72	0.82	0.86	0.91	1.05	1.13	1.06
Information Technology	1.12	1.26	1.36	1.57	1.41	1.55	1.78	2.13	2.28	2.74	2.87	2.68	2.07
Materials	1.26	1.39	1.27	1.32	1.12	1.04	0.74	0.60	0.57	0.43	0.41	0.77	1.32
Telecommunication Services	0.61	0.56	0.64	0.64	0.92	1.11	0.92	0.94	0.93	0.83	0.58	0.74	0.52
Utilities	0.63	0.67	0.65	0.53	0.55	0.30	0.14	-0.03	-0.06	-0.25	-0.13	0.00	0.25

Source: TSX Review

BETAS FOR REGULATED CANADIAN UTILITIES

"Raw" Betas
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Canadian Utilities	0.46	0.54	0.48	0.55	0.63	0.62	0.54	0.38	0.27	0.19	0.05	0.03	0.20	0.32
Emera	na	na	na	0.52	0.40	0.55	0.41	0.27	0.20	0.15	-0.05	0.01	0.07	0.12
Enbridge	0.35	0.53	0.46	0.44	0.43	0.48	0.26	0.07	-0.10	-0.18	-0.37	-0.32	-0.19	0.22
Fortis	0.35	0.44	0.51	0.37	0.30	0.49	0.33	0.23	0.14	0.13	-0.06	0.01	0.21	0.48
PNG	0.51	0.56	0.42	0.30	0.39	0.55	0.47	0.44	0.42	0.44	0.37	0.49	0.54	0.54
Terasen Inc [1/]	0.40	0.53	0.59	0.53	0.46	0.48	0.36	0.25	0.18	0.12	0.02	-0.02	0.06	na
TransCanada Pipelines	0.40	0.57	0.56	0.52	0.36	0.55	0.21	0.15	-0.08	-0.09	-0.38	-0.16	-0.15	0.34
Mean	**0.41**	**0.53**	**0.50**	**0.46**	**0.42**	**0.53**	**0.37**	**0.26**	**0.14**	**0.11**	**-0.06**	**0.01**	**0.11**	**0.34**
Median	**0.40**	**0.54**	**0.50**	**0.52**	**0.40**	**0.55**	**0.36**	**0.25**	**0.18**	**0.13**	**-0.05**	**0.01**	**0.07**	**0.33**
TSE Gas/Electric Index	0.42	0.48	0.52	0.52	0.46	0.55	0.38	0.21	0.17	0.14	NA	NA	NA	NA
S&P/TSX Utilities	0.55	0.63	0.67	0.65	0.53	0.55	0.30	0.14	-0.03	-0.06	-0.25	-0.13	0.00	0.25

Adjusted Betas [2/]
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Canadian Utilities	0.64	0.69	0.65	0.70	0.75	0.75	0.69	0.58	0.51	0.46	0.37	0.35	0.47	0.54
Emera	NA	NA	NA	0.68	0.60	0.70	0.60	0.51	0.46	0.43	0.29	0.33	0.38	0.41
Enbridge	0.56	0.69	0.64	0.62	0.62	0.65	0.50	0.38	0.26	0.21	0.08	0.12	0.21	0.48
Fortis	0.57	0.62	0.67	0.58	0.53	0.66	0.55	0.48	0.42	0.41	0.29	0.34	0.47	0.65
PNG	0.67	0.71	0.61	0.53	0.59	0.70	0.65	0.63	0.61	0.63	0.58	0.66	0.69	0.69
Terasen Inc	0.60	0.69	0.72	0.69	0.64	0.65	0.57	0.50	0.45	0.41	0.35	0.32	0.37	na
TransCanada Pipelines	0.60	0.71	0.71	0.68	0.57	0.70	0.47	0.43	0.28	0.27	0.08	0.22	0.23	0.56
Mean	**0.61**	**0.68**	**0.67**	**0.64**	**0.61**	**0.69**	**0.58**	**0.50**	**0.43**	**0.40**	**0.29**	**0.33**	**0.40**	**0.56**
Median	**0.60**	**0.69**	**0.66**	**0.68**	**0.60**	**0.70**	**0.57**	**0.50**	**0.45**	**0.41**	**0.29**	**0.33**	**0.38**	**0.55**
TSE Gas/Electric Index	0.61	0.65	0.68	0.68	0.64	0.70	0.59	0.47	0.44	0.42	NA	NA	NA	NA
S&P/TSX Utilities	0.70	0.76	0.78	0.77	0.69	0.70	0.53	0.42	0.31	0.29	0.16	0.24	0.33	0.50

[1/] Due to its purchase by Kinder Morgan, Terasen betas are calculated through November 2005.
[2/] Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.

Source: Standard and Poor's Research Insight and TSX Review.

RECENT SUB-PERIOD BETAS FOR REGULATED CANADIAN UTILITIES

Including Nortel in the Market Index

"Raw" Betas

	Jan 00 to June 02	July 00 to Dec 02	Jan 01 to June 03	July 01 to Dec 03	Jan 02 to June 04	July 02 to Dec 04	Jan 03 to June 05	July 03 to Dec 05	July 02 to Dec 05	July 02 to Dec 06	July 02 to Jun 07
Canadian Utilities	-0.09	-0.07	0.08	0.33	0.42	0.52	0.72	0.46	0.55	0.36	0.45
Emera	-0.04	-0.01	0.00	0.06	0.13	0.16	0.48	0.20	0.20	0.14	0.19
Enbridge	-0.52	-0.42	-0.46	0.13	0.28	0.35	0.33	0.38	0.30	0.25	0.29
Fortis	-0.12	-0.06	0.06	0.17	0.33	0.44	0.46	0.70	0.64	0.53	0.55
PNG	0.32	0.57	0.71	0.95	0.99	0.96	0.84	0.60	0.74	0.57	0.55
Terasen Inc [1]	-0.07	-0.11	-0.06	-0.02	0.17	0.18	0.41	0.30	0.25	0.25	0.25
TransCanada Pipelines	-0.34	-0.08	-0.39	0.12	0.35	0.47	0.59	0.43	0.47	0.43	0.45
Mean	**-0.12**	**-0.03**	**-0.01**	**0.25**	**0.38**	**0.44**	**0.55**	**0.44**	**0.45**	**0.36**	**0.39**
Median	**-0.09**	**-0.07**	**0.00**	**0.13**	**0.33**	**0.44**	**0.48**	**0.43**	**0.47**	**0.36**	**0.45**
S&P/TSX Utilities	-0.30	-0.16	-0.22	0.18	0.33	0.44	0.50	0.48	0.47	0.29	0.35

Adjusted Betas

	Jan 00 to June 02	July 00 to Dec 02	Jan 01 to June 03	July 01 to Dec 03	Jan 02 to June 04	July 02 to Dec 04	Jan 03 to June 05	July 03 to Dec 05	July 02 to Dec 05	July 02 to Dec 06	July 02 to Jun 07
Canadian Utilities	0.27	0.28	0.38	0.55	0.61	0.68	0.81	0.64	0.70	0.57	0.63
Emera	0.31	0.32	0.33	0.37	0.42	0.43	0.65	0.47	0.46	0.42	0.46
Enbridge	-0.02	0.05	0.02	0.41	0.52	0.56	0.55	0.59	0.53	0.50	0.52
Fortis	0.25	0.29	0.37	0.44	0.55	0.62	0.64	0.80	0.76	0.69	0.70
PNG	0.55	0.72	0.80	0.96	0.99	0.98	0.89	0.73	0.82	0.71	0.70
Terasen Inc [1]	0.28	0.26	0.29	0.32	0.44	0.45	0.61	0.53	0.50	0.50	0.50
TransCanada Pipelines	0.10	0.28	0.07	0.41	0.56	0.65	0.72	0.61	0.65	0.62	0.63
Mean	**0.25**	**0.31**	**0.32**	**0.50**	**0.58**	**0.62**	**0.70**	**0.62**	**0.63**	**0.57**	**0.59**
Median	**0.27**	**0.28**	**0.33**	**0.41**	**0.55**	**0.62**	**0.65**	**0.61**	**0.65**	**0.57**	**0.63**
S&P/TSX Utilities	0.13	0.22	0.18	0.45	0.55	0.62	0.67	0.65	0.64	0.52	0.56

Excluding Nortel from the Market Index

"Raw" Betas

	Jan 00 to June 02	July 00 to Dec 02	Jan 01 to June 03	July 01 to Dec 03	Jan 02 to June 04	July 02 to Dec 04	Jan 03 to June 05	July 03 to Dec 05	July 02 to Dec 05	July 02 to Dec 06	July 02 to Jun 07
Canadian Utilities	0.06	0.14	0.18	0.37	0.41	0.46	0.57	0.39	0.52	0.31	0.40
Emera	0.00	0.03	0.02	0.09	0.15	0.19	0.40	0.18	0.21	0.15	0.19
Enbridge	-0.33	-0.16	-0.31	0.19	0.50	0.58	0.58	0.57	0.45	0.37	0.39
Fortis	-0.11	0.04	0.16	0.25	0.26	0.37	0.31	0.54	0.58	0.48	0.49
PNG	0.96	1.21	1.21	1.03	1.12	0.97	0.77	0.49	0.70	0.54	0.52
Terasen Inc [1]	0.13	0.06	0.04	0.04	0.37	0.37	0.55	0.47	0.39	0.38	0.38
TransCanada Pipelines	-0.29	0.10	-0.28	0.16	0.48	0.57	0.66	0.52	0.54	0.47	0.49
Mean	**0.06**	**0.21**	**0.14**	**0.31**	**0.47**	**0.50**	**0.55**	**0.45**	**0.48**	**0.39**	**0.41**
Median	**0.00**	**0.06**	**0.04**	**0.19**	**0.41**	**0.46**	**0.57**	**0.49**	**0.52**	**0.38**	**0.40**
S&P/TSX Utilities	-0.14	0.06	-0.09	0.23	0.47	0.55	0.59	0.57	0.54	0.34	0.39

Adjusted Betas

	Jan 00 to June 02	July 00 to Dec 02	Jan 01 to June 03	July 01 to Dec 03	Jan 02 to June 04	July 02 to Dec 04	Jan 03 to June 05	July 03 to Dec 05	July 02 to Dec 05	July 02 to Dec 06	July 02 to Jun 07
Canadian Utilities	0.37	0.43	0.45	0.58	0.61	0.64	0.71	0.59	0.68	0.54	0.60
Emera	0.33	0.35	0.34	0.39	0.43	0.46	0.60	0.45	0.47	0.43	0.46
Enbridge	0.11	0.22	0.12	0.46	0.66	0.72	0.72	0.71	0.63	0.58	0.59
Fortis	0.26	0.36	0.44	0.50	0.51	0.58	0.53	0.69	0.72	0.65	0.66
PNG	0.97	1.14	1.14	1.02	1.08	0.98	0.84	0.66	0.80	0.69	0.68
Terasen Inc [1]	0.42	0.37	0.35	0.36	0.58	0.58	0.70	0.65	0.59	0.58	0.59
TransCanada Pipelines	0.14	0.40	0.14	0.44	0.65	0.71	0.77	0.68	0.69	0.64	0.66
Mean	**0.37**	**0.47**	**0.43**	**0.53**	**0.65**	**0.67**	**0.70**	**0.63**	**0.65**	**0.59**	**0.60**
Median	**0.33**	**0.37**	**0.35**	**0.46**	**0.61**	**0.64**	**0.71**	**0.66**	**0.68**	**0.58**	**0.60**
S&P/TSX Utilities	0.23	0.37	0.27	0.49	0.64	0.70	0.73	0.71	0.69	0.56	0.59

[1] Due to its purchase by Kinder Morgan, Terasen betas are calculated through November 2005.

Source: Standard and Poor's Research Insight and <u>TSX Review</u>

HISTORIC UTILITY EQUITY RISK PREMIUMS

Canada (1956-2006)

Average	Utilities Index Return	Bond Return	Risk Premium
Arithmetic	12.6	7.8	4.8
Geometric	11.5	7.4	4.1

United States (1947-2006)

Average	S&P/Moody's Electric Index Return	Bond Return	Risk Premium
Arithmetic	11.4	6.2	5.2
Geometric	10.2	5.7	4.5

Average	S&P / Moody's Gas Distribution Index Return	Bond Return	Risk Premium
Arithmetic	12.4	6.2	6.2
Geometric	11.2	5.7	5.5

Note: The Canadian Utilities Index is based on the Gas/Electric Index of the TSE 300 (from 1956 to 1987) and on the S&P/TSX Utilities Index from 1988-2006.

The S&P/Moody's Electric Index reflects S&P's Electric Index from 1947 to 1998 and Moody's Electric Index from 1999 to 2001. The 2002 to 2006 data were estimated using simple average of the prices and dividends for the utilities included in Moody's Electric Index as of the end of 2001. These utilities include American Electric Power, Centerpoint Energy, CH Energy, Cinergy, Consolidated Edison, Constellation, Dominion Resources, DPL, DTE Energy, Duke Energy, Energy East, Exelon, FirstEnergy, IDACORP, Nisource, OGE Energy, Pepco Holdings, PPL, Progress Energy, Public Service Enterprise Grp., Southern Co., Teco and Xcel Energy.

The S&P/Moody's Gas Distribution Index reflects S&P's Natural Gas Distributors Index from 1947 to 1984, when S&P eliminated its gas distribution index. The 1985-2001 data are for Moody's Gas index. The index was terminated in July 2002. The 2002-2006 returns were estimated using simple averages of the prices and dividends for the utilities that were included in Moody's Gas Index as of the end of 2001. These LDCs include AGL Resources, Keyspan Corp., Laclede Group, Northwest Natural, Peoples Energy and WGL Holdings.

Sources: TSX Review, Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006, Standard & Poor's Analysts' Handbook, Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2007 Yearbook, Mergent Corporate News Reports, and www.federalreserve.gov

25-YEAR ROLLING AVERAGE RETURNS FOR CANADIAN & U.S. UTILITIES AND GOVERNMENT BONDS

	Canada		U.S.		
	S&P/TSX Utilities Returns	Long Government Bond Returns	S&P/Moody's Electric Returns	S&P/Moody's Gas Distributors Returns	Long Government Bond Returns
1947-1971			9.7%	10.7%	2.0%
1948-1972			10.3%	11.3%	2.3%
1949-1973			9.5%	10.2%	2.1%
1950-1974			7.5%	9.0%	2.0%
1951-1975			9.3%	9.9%	2.4%
1952-1976			9.6%	11.1%	3.2%
1953-1977			9.1%	11.0%	3.2%
1954-1978			8.6%	10.8%	3.0%
1955-1979			7.7%	11.1%	2.6%
1956-1980	12.3%	3.4%	7.5%	12.0%	2.5%
1957-1981	10.9%	3.4%	8.2%	11.1%	2.8%
1958-1982	12.3%	4.9%	9.2%	11.0%	4.1%
1959-1983	11.5%	5.5%	8.2%	10.8%	4.4%
1960-1984	11.7%	6.3%	9.0%	11.4%	5.1%
1961-1985	11.6%	7.0%	9.1%	11.4%	5.8%
1962-1986	11.4%	7.3%	9.1%	11.1%	6.7%
1963-1987	12.3%	7.2%	8.8%	10.9%	6.4%
1964-1988	12.3%	7.4%	9.0%	11.3%	6.7%
1965-1989	12.2%	7.8%	9.7%	12.6%	7.3%
1966-1990	11.0%	7.9%	9.7%	12.6%	7.5%
1967-1991	11.7%	8.8%	11.1%	13.9%	8.1%
1968-1992	11.3%	9.4%	11.4%	14.3%	8.8%
1969-1993	11.4%	10.4%	11.6%	14.2%	9.6%
1970-1994	12.2%	10.0%	11.6%	14.4%	9.4%
1971-1995	11.6%	10.2%	12.4%	14.3%	10.2%
1972-1996	12.2%	10.3%	12.3%	14.7%	9.7%
1973-1997	13.4%	11.0%	13.2%	15.0%	10.1%
1974-1998	14.1%	11.5%	14.8%	15.6%	10.6%
1975-1999	13.1%	11.3%	15.2%	15.5%	10.1%
1976-2000	14.3%	11.7%	15.5%	15.6%	10.6%
1977-2001	13.4%	11.1%	14.4%	13.8%	10.1%
1978-2002	12.9%	11.3%	13.6%	13.7%	10.8%
1979-2003	13.3%	11.5%	14.5%	14.5%	10.9%
1980-2004	12.5%	12.0%	15.1%	13.6%	11.3%
1981-2005	13.1%	12.5%	15.1%	12.3%	11.8%
1982-2006	13.7%	12.7%	15.1%	13.6%	11.7%
Min	**10.9%**	**3.4%**	**7.5%**	**9.0%**	**2.0%**
Max	**14.3%**	**12.7%**	**15.5%**	**15.6%**	**11.8%**
Mean	**12.4%**	**9.0%**	**11.0%**	**12.5%**	**6.8%**
Stdev.	**0.9%**	**2.7%**	**2.6%**	**1.8%**	**3.5%**
+1 Std	**13.3%**	**11.8%**	**13.6%**	**14.3%**	**10.3%**
-1 Std dev.	**11.4%**	**6.3%**	**8.4%**	**10.7%**	**3.4%**

Sources: TSX Review, Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006, Standard & Poor's Analysts' Handbook, Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2007 Yearbook, Mergent Corporate News Reports and Standard and Poor's Research Insight

CUMULATIVE AVERAGE RETURNS FOR
CANADIAN & U.S. UTILITIES AND GOVERNMENT BONDS
(Forward)

Canada			U.S.			
	S&P/TSX Utilities Returns	Long Government Bond Returns		S&P/Moody's Electric Returns	S&P/Moody's Gas Distributors Returns	Long Government Bond Returns
			1947-1971	9.7%	10.7%	2.0%
			1947-1972	9.4%	10.8%	2.1%
			1947-1973	8.4%	9.7%	2.0%
			1947-1974	7.2%	9.4%	2.1%
			1947-1975	8.7%	9.9%	2.3%
			1947-1976	9.2%	11.2%	2.8%
			1947-1977	9.2%	11.2%	2.7%
			1947-1978	8.8%	10.7%	2.6%
			1947-1979	8.5%	11.5%	2.5%
1956-1980	12.3%	3.4%	1947-1980	8.5%	12.1%	2.3%
1956-1981	10.9%	3.1%	1947-1981	8.8%	11.5%	2.3%
1956-1982	12.3%	4.6%	1947-1982	9.6%	11.1%	3.3%
1956-1983	11.5%	4.8%	1947-1983	9.7%	11.7%	3.2%
1956-1984	11.7%	5.1%	1947-1984	10.1%	11.9%	3.6%
1956-1985	11.6%	5.8%	1947-1985	10.5%	12.0%	4.3%
1956-1986	11.4%	6.2%	1947-1986	10.9%	12.4%	4.8%
1956-1987	12.3%	6.0%	1947-1987	10.4%	11.9%	4.6%
1956-1988	12.3%	6.1%	1947-1988	10.6%	12.1%	4.7%
1956-1989	12.2%	6.4%	1947-1989	11.1%	12.8%	5.0%
1956-1990	11.0%	6.3%	1947-1990	10.9%	12.5%	5.0%
1956-1991	11.7%	6.8%	1947-1991	11.4%	12.7%	5.4%
1956-1992	11.3%	7.0%	1947-1992	11.3%	12.8%	5.4%
1956-1993	11.4%	7.4%	1947-1993	11.3%	12.9%	5.7%
1956-1994	12.2%	7.0%	1947-1994	10.8%	12.4%	5.4%
1956-1995	11.6%	7.5%	1947-1995	11.2%	12.7%	6.0%
1956-1996	12.2%	7.6%	1947-1996	11.0%	12.7%	5.8%
1956-1997	13.4%	7.9%	1947-1997	11.3%	12.8%	6.0%
1956-1998	14.1%	8.0%	1947-1998	11.5%	12.5%	6.1%
1956-1999	13.1%	7.7%	1947-1999	11.0%	12.3%	5.9%
1956-2000	14.3%	7.8%	1947-2000	11.8%	12.5%	6.1%
1956-2001	13.4%	7.7%	1947-2001	11.5%	12.4%	6.1%
1956-2002	12.9%	7.8%	1947-2002	11.1%	12.3%	6.3%
1956-2003	13.3%	7.8%	1947-2003	11.3%	12.4%	6.2%
1956-2004	12.5%	7.8%	1947-2004	11.3%	12.4%	6.3%
1956-2005	13.1%	7.9%	1947-2005	11.3%	12.2%	6.3%
1956-2006	13.7%	7.8%	1947-2006	11.4%	12.4%	6.2%
Min	**10.9%**	**3.1%**	**Min**	**7.2%**	**9.4%**	**2.0%**
Max	**14.3%**	**8.0%**	**Max**	**11.8%**	**12.9%**	**6.3%**
Mean	**12.4%**	**6.6%**	**Mean**	**10.3%**	**11.9%**	**4.4%**
Stdev.	**0.9%**	**1.4%**	**Stdev.**	**1.2%**	**0.9%**	**1.6%**
+1 Std	**13.3%**	**8.0%**	**+1 Std**	**11.5%**	**12.8%**	**6.0%**
-1 Std dev.	**11.4%**	**5.2%**	**-1 Std dev.**	**9.1%**	**10.9%**	**2.8%**

Sources: TSX Review, Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006, Standard & Poor's Analysts' Handbook, Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2007 Yearbook, Mergent Corporate News Reports and Standard and Poor's Research Insight

CUMULATIVE AVERAGE RETURNS FOR CANADIAN & U.S. UTILITIES AND GOVERNMENT BONDS

(2006 Backward)

	Canada		U.S.		
	S&P/TSX Utilities Returns	Long Government Bond Returns	S&P/Moody's Electric Returns	S&P/Moody's Gas Distributors Returns	Long Government Bond Returns
1947-2006			11.4%	12.4%	6.2%
1948-2006			11.8%	12.6%	6.4%
1949-2006			12.0%	12.7%	6.4%
1950-2006			11.8%	12.3%	6.4%
1951-2006			11.9%	12.5%	6.5%
1952-2006			11.8%	12.4%	6.7%
1953-2006			11.7%	12.4%	6.8%
1954-2006			11.7%	12.6%	6.9%
1955-2006			11.5%	12.3%	6.9%
1956-2006	12.6%	7.8%	11.5%	12.4%	7.0%
1957-2006	12.3%	8.1%	11.6%	12.4%	7.3%
1958-2006	12.5%	8.1%	11.7%	12.6%	7.3%
1959-2006	12.2%	8.4%	11.1%	12.0%	7.6%
1960-2006	12.2%	8.7%	11.2%	12.3%	7.8%
1961-2006	11.9%	8.7%	11.0%	12.1%	7.6%
1962-2006	11.9%	8.7%	10.6%	11.6%	7.8%
1963-2006	12.5%	8.8%	10.8%	12.0%	7.8%
1964-2006	12.6%	8.9%	10.8%	12.0%	8.0%
1965-2006	12.7%	9.0%	10.7%	12.0%	8.1%
1966-2006	12.2%	9.1%	10.9%	12.3%	8.2%
1967-2006	12.9%	9.3%	11.3%	13.0%	8.4%
1968-2006	12.8%	9.6%	11.6%	13.1%	8.8%
1969-2006	12.6%	9.9%	11.7%	12.9%	9.0%
1970-2006	13.3%	10.2%	12.4%	13.7%	9.4%
1971-2006	13.2%	9.9%	12.4%	13.2%	9.4%
1972-2006	13.3%	9.9%	12.7%	13.6%	9.2%
1973-2006	13.5%	10.1%	12.9%	13.6%	9.3%
1974-2006	14.3%	10.4%	13.9%	14.5%	9.7%
1975-2006	14.8%	10.7%	15.1%	14.9%	9.8%
1976-2006	14.6%	11.0%	14.0%	14.7%	9.8%
1977-2006	14.1%	10.7%	13.7%	13.5%	9.6%
1978-2006	13.9%	10.9%	13.8%	13.6%	10.0%
1979-2006	13.8%	11.2%	14.4%	14.2%	10.4%
1980-2006	13.2%	11.8%	15.0%	13.4%	10.8%
1981-2006	12.9%	12.1%	15.3%	12.7%	11.4%
1982-2006	13.7%	12.7%	15.1%	13.6%	11.7%
Min	**11.9%**	**7.8%**	**10.6%**	**11.6%**	**6.2%**
Max	**14.8%**	**12.7%**	**15.3%**	**14.9%**	**11.7%**
Mean	**13.1%**	**9.8%**	**12.3%**	**12.9%**	**8.3%**
Stdev.	**0.8%**	**1.3%**	**1.4%**	**0.8%**	**1.5%**
+1 Std	**13.9%**	**11.1%**	**13.7%**	**13.7%**	**9.9%**
-1 Std dev.	**12.2%**	**8.5%**	**10.9%**	**12.1%**	**6.8%**

Sources:

TSX Review, Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006, Standard & Poor's Analysts' Handbook, Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2007 Yearbook, Mergent Corporate News Reports, Standard and Poor's Research Insight

DCF-BASED EQUITY RISK PREMIUM STUDY FOR BENCHMARK US ELECTRIC AND GAS UTILITIES
(Quarterly Averages of Monthly Data)

		Expected Dividend Yield [1/]	I/B/E/S EPS Growth Forecast	DCF Cost	Long Treasury Yield	Risk Premium
1993	q1	5.6	4.7	10.3	7.0	3.3
	q2	5.6	4.7	10.3	6.9	3.4
	q3	5.3	4.8	10.1	6.3	3.8
	q4	5.5	4.5	10.0	6.2	3.8
1994	q1	5.9	4.2	10.2	6.7	3.4
	q2	6.2	4.3	10.5	7.3	3.2
	q3	6.3	4.3	10.6	7.6	3.0
	q4	6.5	4.0	10.6	7.9	2.6
1995	q1	6.3	3.9	10.3	7.6	2.7
	q2	6.2	4.0	10.1	6.9	3.2
	q3	6.0	3.9	10.0	6.7	3.3
	q4	5.6	4.0	9.6	6.2	3.4
1996	q1	5.5	4.0	9.5	6.4	3.1
	q2	5.8	4.0	9.8	7.0	2.9
	q3	5.8	4.1	9.9	7.0	2.9
	q4	5.6	4.1	9.7	6.6	3.1
1997	q1	5.7	4.2	9.9	6.9	3.0
	q2	5.8	4.3	10.1	6.9	3.2
	q3	5.5	4.3	9.8	6.5	3.4
	q4	4.9	4.3	9.2	6.1	3.2
1998	q1	4.7	4.4	9.1	5.9	3.2
	q2	4.7	4.6	9.3	5.8	3.5
	q3	4.8	4.6	9.5	5.4	4.1
	q4	4.5	4.5	9.1	5.1	4.0
1999	q1	5.2	4.6	9.9	5.4	4.5
	q2	5.1	4.7	9.8	5.8	4.0
	q3	5.1	4.8	9.9	6.1	3.9
	q4	5.4	4.9	10.3	6.4	3.9
2000	q1	5.9	4.9	10.8	6.2	4.6
	q2	5.9	5.1	11.0	6.0	5.0
	q3	5.8	5.4	11.2	5.8	5.4
	q4	5.0	5.4	10.4	5.6	4.8
2001	q1	5.0	5.4	10.4	5.4	5.0
	q2	5.1	5.9	10.9	5.8	5.2
	q3	5.2	5.5	10.7	5.4	5.3
	q4	5.1	5.7	10.8	5.3	5.4
2002	q1	4.9	5.8	10.7	5.7	5.0
	q2	4.7	5.8	10.5	5.7	4.8
	q3	5.2	5.7	10.9	5.1	5.8
	q4	5.1	5.6	10.7	5.1	5.6
2003	q1	5.2	5.5	10.8	4.9	5.8
	q2	4.8	5.2	10.0	4.7	5.3
	q3	4.8	4.9	9.7	5.3	4.5
	q4	4.6	4.7	9.4	5.2	4.1
2004	q1	4.5	4.5	9.0	5.0	4.1
	q2	4.7	4.5	9.2	5.4	3.9
	q3	4.6	4.5	9.1	5.1	4.0
	q4	4.3	4.4	8.8	4.9	3.8
2005	q1	4.3	4.5	8.8	4.7	4.1
	q2	4.2	4.4	8.5	4.4	4.2
	q3	4.0	4.2	8.2	4.4	3.8
	q4	4.3	4.6	8.9	4.6	4.3
2006	q1	4.3	4.9	9.3	4.7	4.6
	q2	4.5	5.0	9.5	5.2	4.3
	q3	4.2	5.0	9.2	4.9	4.3
	q4	4.0	4.6	8.7	4.7	4.0
2007	q1	4.0	4.7	8.7	4.8	3.9
	q2	4.1	4.9	9.0	5.0	4.0
Means for Long Treasury Yields:						
Under 5.0		4.4	4.8	9.2	4.7	4.4
5.0-5.99		4.9	5.1	10.0	5.5	4.5
6.0-6.99		5.6	4.4	10.0	6.5	3.5
7.0 and above		6.2	4.2	10.4	7.5	2.9
Means:						
1993 - 2007Q2		5.1	4.7	9.8	5.8	4.0
1998 - 2007Q2		4.8	5.0	9.8	5.3	4.5

[1/] Dividend Yield is adjusted for I/B/E/S/ growth
Source: Standard & Poor's Research Insight, I/B/E/S andwww.federalreserve.gov

INDIVIDUAL COMPANY RISK DATA FOR BENCHMARK SAMPLE OF
US ELECTRIC AND GAS UTILITIES

	Value Line									S & P		Moody's	Average
	Safety	Earnings Predictability	Financial Strength	Forecast Common Equity Ratio 2010-2012	Forecast Return On Average Common Equity 2010-2012	Dividend Payout Forecast 2010-2012	Beta	Research Insight Beta 1/	Common Equity Ratio 2006	Business Profile	Debt Rating	Debt Rating 2/	Market/ Book Ratio 1994-2006
AGL Resources	2	75	B++	50.8%	14.2%	58.1%	0.95	0.58	42.7%	4	A-	A3	1.76
Consol. Edison	1	85	A++	50.5%	9.1%	70.6%	0.75	0.43	47.0%	2	A	A2	1.49
FPL Group	1	80	A+	51.0%	12.4%	51.8%	0.85	0.69	44.6%	5	A	A2	1.89
Integrys Energy	2	70	B++	49.5%	11.1%	65.7%	0.85	0.66	42.4%	5	A-	A3	1.62
New Jersey Resources	1	95	A	69.3%	10.7%	54.6%	0.80	0.39	50.2%	2	A+	na	2.19
NICOR Inc.	3	75	A	69.0%	13.2%	63.5%	1.30	0.99	50.7%	3	AA	A3	2.28
Northwest Nat. Gas	1	80	A	52.0%	11.6%	60.0%	0.75	0.44	48.1%	1	AA-	A3	1.56
NSTAR	1	95	A	55.5%	15.7%	58.3%	0.80	0.64	34.4%	1	A+	A2	1.74
Piedmont Natural Gas	2	80	B++	52.8%	11.2%	71.9%	0.80	0.60	47.0%	2	A	A3	2.00
SCANA Corp.	2	95	A	49.0%	11.1%	61.5%	0.85	0.70	43.4%	4	A-	A3	1.64
Southern Co.	1	95	A	44.0%	13.0%	74.0%	0.70	0.33	40.6%	4	A	A3	2.08
Vectren Corp.	2	70	A	51.0%	10.5%	71.5%	0.95	0.71	40.6%	4	A-	Baa1	1.91
WGL Holdings Inc.	1	65	A	64.5%	11.1%	63.3%	0.85	0.54	52.2%	3	AA-	A2	1.71
Mean	**2**	**82**	**A**	**54.5%**	**11.9%**	**63.4%**	**0.86**	**0.59**	**44.9%**	**3**	**A**	**A2**	**1.84**
Median	**1**	**80**	**A**	**51.0%**	**11.2%**	**63.3%**	**0.85**	**0.60**	**44.6%**	**3**	**A**	**A3**	**1.76**
Weighted Average	**1**	**86**	**A**	**50.0%**	**12.0%**	**64.6%**	**0.80**	**0.53**	**43.5%**	**4**	**A**	**A2**	**1.84**

1/ Calculated using monthly data against the S&P 500 (60 months ending June 2007); adjusted towards the market mean of 1.0.

2/ Rating for WGL Holdings is Washington Gas Light.

Source: Standard and Poor's Research Insight, Value Line (June 2007), www.Moodys.com,
Standard and Poor's, *Issuer Ranking: U.S. Integrated Utility And Merchant Power Companies, Strongest To Weakest* (July 24, 2007) and

DCF COST OF EQUITY FOR BENCHMARK SAMPLE OF US ELECTRIC AND GAS UTILITIES (BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)

Company	Annualized Last Paid Dividend (1)	Average Daily Closing Prices 7/15-8/15/2007 (2)	Expected Dividend Yield [1/] (3)	I/B/E/S Long-Term EPS Forecasts (4)	DCF Cost of Equity [2/] (5)
AGL Resources	1.64	38.77	4.4	4.5	8.9
Consolidated Edison	2.32	45.41	5.3	3.5	8.7
FPL	1.64	59.01	3.0	9.1	12.2
Integrys Energy	2.64	50.78	5.5	5.3	10.8
New Jersey Resources	1.52	48.91	3.2	4.5	7.7
Nicor Inc.	1.86	41.20	4.7	4.6	9.3
Northwest Nat. Gas	1.42	44.12	3.4	4.8	8.2
NSTAR	1.30	32.21	4.3	6.3	10.5
Piedmont Natural Gas	1.00	24.64	4.2	4.5	8.7
Scana	1.76	38.11	4.8	4.5	9.3
Southern Co.	1.61	34.87	4.8	4.6	9.4
Vectren	1.26	26.45	5.0	4.3	9.3
WGL Holdings Inc.	1.37	31.65	4.5	3.3	7.8
Mean	**1.64**	**39.70**	**4.4**	**4.9**	**9.3**
Median	**1.61**	**38.77**	**4.5**	**4.5**	**9.3**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (4))
[2/] Expected Dividend Yield (Col (3)) + I/B/E/S Growth Forecast (Col (4))

Source: Standard and Poor's Research Insight, Yahoo.com and I/B/E/S (July 2007)

DCF COST OF EQUITY FOR BENCHMARK SAMPLE OF US ELECTRIC AND GAS UTILITIES (TWO STAGE MODEL)

Company	Annualized Last Paid Dividend (1)	Average Daily Closing Prices 7/15-8/15/2007 (2)	I/B/E/S Long-Term EPS Forecasts (3)	Stage 2 GDP Growth [1/] (4)	DCF Cost of Equity [2/] (5)
AGL Resources	1.64	38.77	4.5	5.1	9.3
Consolidated Edison	2.32	45.41	3.5	5.1	10.0
FPL	1.64	59.01	9.1	5.1	8.4
Integrys Energy	2.64	50.78	5.3	5.1	10.6
New Jersey Resources	1.52	48.91	4.5	5.1	8.1
Nicor Inc.	1.86	41.20	4.6	5.1	9.7
Northwest Nat. Gas	1.42	44.12	4.8	5.1	8.3
NSTAR	1.30	32.21	6.3	5.1	9.5
Piedmont Natural Gas	1.00	24.64	4.5	5.1	9.2
Scana	1.76	38.11	4.5	5.1	9.8
Southern Co.	1.61	34.87	4.6	5.1	9.8
Vectren	1.26	26.45	4.3	5.1	9.9
WGL Holdings Inc.	1.37	31.65	3.3	5.1	9.2
Mean	**1.64**	**39.70**	**4.9**	**5.1**	**9.4**
Median	**1.61**	**38.77**	**4.5**	**5.1**	**9.5**

[1/] Consensus forecast nominal rate of GDP growth, 2009-18
[2/] Internal Rate of Return: I/B/E/S EPS forecast growth rate applies for first 5 years; GDP growth thereafter.

Source: Standard and Poor's Research Insight, Yahoo.com, Blue Chip *Economic Indicators* (March 2007) and I/B/E/S (July 2007)

RISK MEASURES FOR 20 LOW RISK CANADIAN INDUSTRIALS

Company Name	Debt Ratings S&P	Debt Ratings DBRS	CBS Stock Rating	Beta 2002-2006 Raw	Beta 2002-2006 Adjusted	2006 Equity Ratio Based On Total Capital
ANDREW PELLER LTD			Average	0.43	0.62	48.4%
ARBOR MEMORIAL SERVICES-CL B			Conservative	0.26	0.50	67.4%
ASTRAL MEDIA INC -CL A			Conservative	0.88	0.92	100.0%
CANADA BREAD CO LTD			Conservative	0.44	0.63	85.8%
CANADIAN TIRE CORP -CL A	BBB+	A(low)	Very Conservative	0.69	0.79	70.4%
FINNING INTERNATIONAL INC	BBB+	BBB(high)	Conservative	0.65	0.76	57.7%
JEAN COUTU GROUP			Very Conservative	0.30	0.53	99.6%
LEON'S FURNITURE LTD			Average	0.29	0.53	99.8%
LINAMAR CORP			Average	0.88	0.92	72.9%
LOBLAW COMPANIES LTD	BBB+	A(low)	Very Conservative	0.35	0.57	52.7%
MAGNA INTERNATIONAL -CL A	A	A	Conservative	0.93	0.95	90.3%
MAPLE LEAF FOODS INC			Very Conservative	0.31	0.54	43.8%
METRO INC -CL A	BBB	BBB	Very Conservative	0.82	0.88	60.5%
REITMANS (CANADA) -CL A			Average	0.31	0.54	96.4%
THOMSON CORP	A-	A(low)	Very Conservative	0.50	0.66	70.3%
TORSTAR CORP -CL B		BBB	Very Conservative	0.26	0.50	54.6%
TRANSCONTINENTAL INC -CL A	BBB	BBB(high)	Very Conservative	0.51	0.67	70.6%
TVA GROUP INC -CL B			Average	0.72	0.82	65.3%
UNI-SELECT INC			Average	0.33	0.55	76.2%
WESTON (GEORGE) LTD	BBB	BBB(high)	Very Conservative	0.35	0.57	33.7%
Mean	**BBB+**	**BBB(high)**	**Conservative**	**0.51**	**0.67**	**70.8%**
Median	**BBB+**	**BBB(high)**	**Conservative**	**0.44**	**0.62**	**70.3%**

Source: Standard and Poor's Research Insight, DBRS and The Blue Book of CBS Stock Reports.

**RETURNS ON AVERAGE COMMON STOCK EQUITY FOR
20 LOW RISK CANADIAN INDUSTRIALS**

Company Name	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	Average 1994-2006
ANDREW PELLER LTD	10.0	12.3	13.8	13.1	10.3	18.7	6.2	7.9	9.8	12.4	10.1	6.9	10.2	11.0
ARBOR MEMORIAL SERVICES-CL B	8.1	7.1	7.3	7.5	7.6	2.2	7.5	5.1	14.5	19.7	13.0	10.6	10.5	9.2
ASTRAL MEDIA INC -CL A	7.0	1.3	-9.5	7.1	7.8	6.4	4.4	8.2	10.0	10.0	10.9	12.1	13.1	6.3
CANADA BREAD CO LTD	14.5	12.6	12.8	14.2	1.3	2.7	7.4	8.6	13.9	9.6	14.3	14.5	9.5	10.5
CANADIAN TIRE CORP -CL A	0.5	10.2	10.4	11.4	13.0	11.2	10.6	11.5	11.9	12.8	13.6	13.9	13.4	10.9
FINNING INTERNATIONAL INC	14.9	16.3	16.0	16.2	0.5	8.7	10.5	14.1	15.5	14.0	10.1	12.0	13.4	12.4
JEAN COUTU GROUP	17.0	15.2	16.2	15.3	15.5	15.7	14.9	15.7	16.6	16.2	8.9	6.6	8.1	14.5
LEON'S FURNITURE LTD	15.3	14.0	13.4	15.1	16.7	21.1	19.3	17.3	17.1	16.5	18.9	19.2	19.6	17.0
LINAMAR CORP	27.7	22.3	29.0	36.9	21.9	14.7	15.7	7.8	9.7	6.5	14.0	13.6	12.3	18.3
LOBLAW COMPANIES LTD	12.4	13.3	14.2	15.3	12.8	13.7	15.7	16.8	18.9	19.1	19.1	13.2	-3.9	15.4
MAGNA INTERNATIONAL -CL A	21.7	21.8	15.8	21.6	12.3	12.0	15.9	14.7	11.8	9.5	13.3	10.5	7.7	15.1
MAPLE LEAF FOODS INC	7.5	-6.7	14.8	14.7	-6.3	17.9	8.0	10.3	12.2	4.8	13.0	9.9	0.5	8.3
METRO INC -CL A	16.2	22.6	22.8	24.7	20.5	20.8	22.8	24.1	23.9	23.8	21.0	16.1	15.6	21.6
REITMANS (CANADA) -CL A	9.0	6.2	0.8	8.9	9.4	30.1	10.2	12.6	10.5	15.4	22.0	23.5	20.0	13.2
THOMSON CORP	14.6	22.4	14.2	12.9	34.7	8.0	17.9	10.2	7.3	8.8	10.3	9.3	11.0	14.2
TORSTAR CORP -CL B	7.9	6.7	11.3	38.4	-0.7	12.8	5.4	-14.6	21.3	17.8	14.6	14.5	9.2	11.3
TRANSCONTINENTAL INC -CL A	8.1	9.3	0.8	10.6	11.2	11.4	13.7	4.0	18.9	17.5	13.9	13.3	12.2	11.1
TVA GROUP INC -CL B	0.3	9.2	10.4	15.0	20.5	19.8	16.4	-49.5	27.0	23.7	20.9	12.9	-1.7	10.6
UNI-SELECT INC	24.7	21.4	19.9	20.7	20.6	18.7	15.2	16.1	16.7	19.2	15.5	16.3	15.4	18.8
WESTON (GEORGE) LTD	8.7	12.9	15.1	14.5	37.3	14.0	17.4	18.5	18.3	19.4	10.2	16.2	1.6	16.9
Mean	**12.3**	**12.5**	**12.5**	**16.7**	**13.3**	**14.0**	**12.8**	**8.0**	**15.3**	**14.8**	**14.4**	**13.3**	**9.9**	**13.3**
Median	**11.2**	**12.7**	**14.0**	**14.9**	**12.6**	**13.8**	**14.3**	**10.9**	**15.0**	**15.8**	**13.8**	**13.3**	**10.8**	**12.8**
Average of Annual Medians														**13.3**

Source: Standard and Poor's Research Insight.

RISK MEASURES FOR 157 LOW RISK US INDUSTRIALS

Company Name	S&P Debt Rating	Value Line Safety	Value Line Beta	Research Insight "Raw" Beta	Research Insight Adjusted Beta	2006 Equity Ratio Based on Total Capital
AARON RENTS INC		3	0.75	0.30	0.53	82.4%
ABM INDUSTRIES INC		3	0.85	0.81	0.87	100.0%
ALAMO GROUP INC		3	0.60	0.72	0.81	68.9%
ALBANY INTL CORP -CL A		3	1.10	0.87	0.91	56.9%
ALBERTO-CULVER CO	BBB-	1	nmf	0.16	0.43	91.9%
ALEXANDER & BALDWIN INC	A-	3	1.00	0.84	0.89	69.9%
ALICO INC		3	0.75	0.35	0.57	68.8%
ANDERSONS INC		3	0.65	0.31	0.54	51.3%
APOGEE ENTERPRISES INC		3	1.30	0.88	0.92	86.9%
APPLEBEES INTL INC		3	0.80	0.67	0.78	73.5%
APPLIED INDUSTRIAL TECH INC		3	1.20	0.64	0.76	84.5%
ARCHER-DANIELS-MIDLAND CO	A	3	0.90	0.81	0.87	67.7%
AVERY DENNISON CORP	BBB+	2	0.95	0.48	0.65	63.5%
BADGER METER INC		3	0.85	0.56	0.71	75.8%
BARNES GROUP INC		3	0.95	0.64	0.76	54.9%
BELO CORP -SER A COM	BBB-	3	0.95	0.73	0.82	54.3%
BLACK & DECKER CORP	BBB	3	1.05	0.67	0.78	42.4%
BLOCK H & R INC	BBB+	3	1.20	0.15	0.43	39.2%
BOB EVANS FARMS		3	0.90	0.68	0.79	77.4%
BOEING CO	A+	2	1.00	0.73	0.82	33.2%
BRINKS CO	BBB+	3	1.10	0.67	0.78	81.6%
BROWN-FORMAN -CL B	A	1	0.75	0.33	0.55	57.2%
BRUNSWICK CORP	BBB+	3	1.10	0.90	0.94	72.0%
BURLINGTON NORTHERN SANTA FE	BBB	2	1.00	0.83	0.89	58.5%
CARLISLE COS INC	BBB	2	1.05	0.75	0.83	68.8%
CASEYS GENERAL STORES INC		3	1.10	0.85	0.90	69.8%
CATO CORP -CL A		3	1.20	0.59	0.73	100.0%
CHURCHILL DOWNS INC		3	0.80	0.52	0.68	96.3%
CIRCUIT CITY STORES INC		3	1.30	0.43	0.62	96.9%
CLARCOR INC		2	1.05	0.64	0.76	97.1%
COACHMEN INDUSTRIES INC		3	1.35	0.79	0.86	89.7%
CONAGRA FOODS INC	BBB+	2	0.75	0.41	0.60	57.0%
CON-WAY INC	BBB	3	1.00	0.34	0.56	51.7%
COURIER CORP		3	0.90	0.88	0.92	91.3%
CSX CORP	BBB-	3	1.05	0.98	0.98	60.0%
CUBIC CORP		3	1.30	0.96	0.98	85.6%
CURTISS-WRIGHT CORP		3	0.95	0.22	0.48	67.6%
DANAHER CORP	A+	2	0.95	0.68	0.78	73.2%
DARDEN RESTAURANTS INC	BBB+	3	0.85	0.42	0.61	60.9%
DEB SHOPS INC		3	0.80	0.36	0.57	100.0%
DONALDSON CO INC		2	0.90	0.94	0.96	75.2%
DONNELLEY (R R) & SONS CO	BBB+	2	0.95	0.70	0.80	63.4%
ENNIS INC		3	0.85	0.51	0.67	77.9%
ETHAN ALLEN INTERIORS INC	BBB+	3	1.05	0.94	0.96	67.3%
EW SCRIPPS -CL A	A	2	0.85	0.48	0.65	77.1%
EXPEDITORS INTL WASH INC		3	0.80	0.44	0.62	100.0%
FAMILY DOLLAR STORES		3	1.00	0.71	0.80	82.9%
FARMER BROS CO		3	0.60	0.10	0.40	100.0%
FASTENAL CO		3	1.25	0.70	0.80	100.0%
FLEXSTEEL INDUSTRIES INC		3	0.40	0.61	0.74	77.4%

RISK MEASURES FOR 157 LOW RISK US INDUSTRIALS

Company Name	S&P Debt Rating	Value Line Safety	Value Line Beta	Research Insight "Raw" Beta	Research Insight Adjusted Beta	2006 Equity Ratio Based on Total Capital
FLUOR CORP	A-	3	1.20	0.98	0.99	75.6%
FORTUNE BRANDS INC	BBB	1	0.80	0.66	0.77	44.7%
FRANKLIN ELECTRIC CO INC		3	1.00	0.70	0.80	84.7%
FREDS INC		3	1.20	0.91	0.94	99.2%
FRISCH'S RESTAURANTS INC		3	0.60	0.42	0.61	81.2%
G&K SERVICES INC -CL A		3	1.10	0.48	0.65	71.9%
GANNETT CO	A-	1	0.80	0.36	0.57	61.7%
GENERAL DYNAMICS CORP	A	1	1.00	0.68	0.78	77.9%
GENERAL ELECTRIC CO	AAA	1	1.10	0.82	0.88	20.6%
GENUINE PARTS CO		1	0.80	0.69	0.79	83.6%
GORMAN-RUPP CO		3	1.05	0.81	0.87	100.0%
GRAINGER (W W) INC	AA+	2	1.10	0.76	0.84	99.6%
HARTE HANKS INC		1	0.85	0.35	0.57	70.7%
HAVERTY FURNITURE		3	1.20	0.80	0.87	85.3%
HEICO CORP		3	0.85	0.58	0.72	85.2%
HNI CORP		2	0.90	0.64	0.76	61.4%
HORMEL FOODS CORP	A	1	0.75	0.37	0.57	83.7%
HUBBELL INC -CL B	A+	2	1.10	0.99	0.99	82.2%
ILLINOIS TOOL WORKS	AA	1	1.00	0.88	0.92	86.4%
INTERPOOL INC		3	0.80	1.00	1.00	28.0%
INTL SPEEDWAY CORP -CL A	BBB	3	0.65	0.14	0.43	75.8%
JOHNSON CONTROLS INC	A-	2	1.05	0.73	0.82	60.8%
KAMAN CORP	BBB-	3	1.25	0.31	0.54	79.9%
KELLY SERVICES INC -CL A		3	1.20	0.81	0.87	91.7%
KENNAMETAL INC	BBB	3	1.20	0.96	0.97	75.9%
KIMBERLY-CLARK CORP	A+	1	0.70	0.40	0.60	62.9%
LANCASTER COLONY CORP		1	0.80	0.16	0.44	97.9%
LANCE INC		3	0.85	0.60	0.73	81.6%
LAWSON PRODUCTS		3	1.05	0.65	0.76	99.7%
LA-Z-BOY INC		3	1.20	0.90	0.93	76.5%
LEE ENTERPRISES INC		2	0.80	0.61	0.74	39.1%
LEGGETT & PLATT INC	A	2	1.00	0.95	0.97	66.9%
LENNAR CORP	BBB	3	1.30	0.47	0.65	60.2%
LIMITED BRANDS INC	BBB-	3	1.15	0.93	0.95	63.9%
LINCOLN ELECTRIC HLDGS INC		2	1.10	0.98	0.99	84.1%
LINDSAY CORP		3	1.05	0.67	0.78	80.1%
LIZ CLAIBORNE INC	BBB	1	0.95	0.79	0.86	78.2%
LOCKHEED MARTIN CORP	A-	1	0.85	-0.21	0.19	60.8%
LONGS DRUG STORES CORP		3	0.80	0.60	0.73	85.8%
LOWE'S COMPANIES INC	A+	2	1.00	0.77	0.84	78.0%
LSI INDUSTRIES INC		3	1.25	0.71	0.80	90.9%
MARCUS CORP		3	1.05	0.54	0.69	55.5%
MASCO CORP	BBB+	2	1.10	0.91	0.94	47.3%
MATTEL INC	BBB-	3	0.75	0.68	0.78	77.7%
MATTHEWS INTL CORP -CL A		3	0.95	0.32	0.54	72.5%
MCCORMICK & COMPANY INC	A	2	0.55	0.46	0.64	58.9%
MDC HOLDINGS INC	BBB-	3	1.40	0.77	0.84	65.7%
MEDIA GENERAL -CL A		3	0.90	0.74	0.83	50.6%
MEREDITH CORP		1	0.75	0.46	0.64	55.3%
MET-PRO CORP		2	0.65	0.51	0.67	90.8%
MINE SAFETY APPLIANCES CO		3	1.00	0.44	0.63	78.6%
MOLSON COORS BREWING CO	BBB	3	nmf	0.94	0.96	73.2%
MOVADO GROUP INC		3	0.95	0.92	0.95	82.5%
NATIONAL PRESTO INDS INC		3	0.85	0.72	0.81	100.0%
NEW YORK TIMES CO -CL A	BBB	2	0.85	0.61	0.74	36.2%
NEWELL RUBBERMAID INC	BBB+	3	1.00	0.72	0.81	45.7%

RISK MEASURES FOR 157 LOW RISK US INDUSTRIALS

Company Name	S&P Debt Rating	Value Line Safety	Value Line Beta	Research Insight "Raw" Beta	Research Insight Adjusted Beta	2006 Equity Ratio Based on Total Capital
NIKE INC -CL B	A+	1	0.90	0.57	0.71	92.8%
NORDSON CORP		3	1.15	0.85	0.90	77.2%
NORFOLK SOUTHERN CORP	BBB+	3	1.05	0.74	0.82	58.8%
NORTHROP GRUMMAN CORP	BBB+	2	0.80	0.08	0.38	78.6%
OIL DRI CORP AMERICA		3	0.55	0.74	0.83	67.5%
PENTAIR INC	BBB	3	1.10	0.84	0.89	69.2%
PEPSIAMERICAS INC	A	3	0.70	0.53	0.68	48.5%
PULTE HOMES INC	BBB	3	1.50	0.95	0.97	60.0%
RAVEN INDUSTRIES INC		3	1.00	0.80	0.86	100.0%
RAYTHEON CO	BBB+	2	0.95	0.79	0.86	73.7%
ROBBINS & MYERS INC		3	1.10	0.72	0.81	76.2%
ROLLINS INC		3	0.90	0.36	0.57	99.7%
RUBY TUESDAY INC		3	0.95	0.61	0.74	46.1%
RUDDICK CORP		3	1.00	0.80	0.87	73.0%
RYDER SYSTEM INC	BBB+	3	1.05	0.57	0.71	37.9%
SCHAWK INC -CL A		3	0.60	0.33	0.55	65.3%
SHERWIN-WILLIAMS CO	A-	2	1.05	0.92	0.95	69.5%
SKYLINE CORP		3	0.95	0.68	0.78	100.0%
SMITH (A O) CORP		3	0.85	0.42	0.61	60.9%
SMUCKER (JM) CO		2	0.75	0.24	0.49	80.8%
SOUTHWEST AIRLINES	A	3	1.05	0.93	0.95	79.2%
SPARTAN MOTORS INC		3	0.80	-0.39	0.07	80.0%
STANDEX INTERNATIONAL CORP		3	1.10	0.84	0.89	63.0%
STANLEY WORKS	A	3	1.00	0.93	0.95	60.8%
SUPERIOR INDUSTRIES INTL		3	1.05	0.35	0.57	100.0%
SUPERIOR UNIFORM GROUP INC		3	0.65	0.25	0.50	94.8%
TELEFLEX INC		2	1.00	0.84	0.89	69.6%
TENNANT CO		3	1.00	0.88	0.92	98.4%
TOOTSIE ROLL INDUSTRIES INC		1	0.80	0.73	0.82	98.8%
TORO CO	BBB-	3	1.00	0.70	0.80	69.1%
TREDEGAR CORP		3	1.00	0.62	0.74	89.2%
TWIN DISC INC		3	0.75	0.63	0.75	67.9%
TYSON FOODS INC -CL A	BBB-	3	0.80	0.51	0.67	52.7%
UNIFIRST CORP		3	0.90	0.01	0.34	68.2%
UNION PACIFIC CORP	BBB	1	0.95	0.69	0.79	69.3%
UNITED INDUSTRIAL CORP		3	0.75	0.84	0.90	34.0%
UNITED PARCEL SERVICE INC	AAA	1	0.75	0.42	0.61	79.0%
UNITED TECHNOLOGIES CORP	A	1	1.10	0.65	0.76	68.6%
UNIVERSAL CORP/VA	BBB-	2	0.80	0.65	0.77	47.4%
VF CORP	A-	2	1.00	0.70	0.80	80.5%
WALGREEN CO	A+	1	0.75	0.39	0.59	94.3%
WAL-MART STORES INC	AA	1	0.80	0.57	0.71	61.2%
WASHINGTON POST -CL B	A+	1	0.75	0.31	0.54	88.3%
WASTE MANAGEMENT INC	BBB	2	0.90	0.85	0.90	42.8%
WATTS WATER TECHNOLOGIES INC	BBB	3	1.15	0.67	0.78	64.0%
WEIS MARKETS INC		1	0.85	0.37	0.58	100.0%
WERNER ENTERPRISES INC		3	1.05	0.85	0.90	89.7%
WEYCO GROUP INC		3	0.80	-0.17	0.21	93.1%
WILEY (JOHN) & SONS -CL A		3	0.70	0.37	0.58	34.6%
WOLVERINE WORLD WIDE		3	0.95	0.90	0.93	95.9%
WOODWARD GOVERNOR CO		3	0.80	0.93	0.96	86.7%
Mean	**A-**	**3**	**0.95**	**0.62**	**0.75**	**73.4%**
Median	**BBB+**	**3**	**0.95**	**0.67**	**0.78**	**75.6%**

Source: Standard & Poor's Research Insight and Value Line

RETURNS ON AVERAGE COMMON STOCK EQUITY FOR 157 LOW RISK US INDUSTRIALS

Company Name	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	Average 1994-2005
AARON RENTS INC	15.6	11.2	15.5	16.4	15.1	14.5	13.9	5.8	11.0	12.1	15.1	14.3	15.1	13.5
ABM INDUSTRIES INC	12.5	13.3	13.9	14.8	15.4	15.2	14.8	9.6	12.5	21.8	6.9	12.6	18.3	14.0
ALAMO GROUP INC	20.0	16.5	9.3	13.4	3.9	5.7	9.7	9.1	5.1	5.9	8.8	7.0	6.7	9.3
ALBANY INTL CORP -CL A	9.3	15.0	15.4	14.6	9.7	9.4	11.7	10.4	15.3	11.3	1.9	12.8	10.8	11.4
ALBERTO-CULVER CO	14.1	15.1	15.8	18.5	16.1	15.6	17.1	16.1	17.2	16.9	11.9	14.8	12.6	15.5
ALEXANDER & BALDWIN INC	12.2	8.7	9.8	11.6	4.4	9.2	11.5	15.8	8.1	10.6	11.8	13.1	12.0	10.7
ALICO INC	12.0	12.5	5.8	13.5	7.6	4.5	14.5	14.9	6.7	10.6	13.1	4.2	4.5	9.6
ANDERSONS INC	25.4	15.5	9.2	5.6	12.6	10.0	11.5	9.8	10.7	10.6	15.3	17.8	16.9	13.2
APOGEE ENTERPRISES INC	10.9	13.5	16.9	-36.2	21.0	9.1	10.5	16.4	17.1	-3.2	9.6	12.6	14.6	8.7
APPLEBEES INTL INC	19.2	18.3	16.9	16.9	17.3	19.7	23.6	21.6	23.1	22.0	23.2	22.4	18.0	20.2
APPLIED INDUSTRIAL TECH INC	8.9	10.7	13.2	13.7	12.0	6.8	10.5	9.2	4.8	6.5	9.7	15.1	17.9	10.7
ARCHER-DANIELS-MIDLAND CO	9.8	14.6	11.6	6.2	6.4	4.4	4.9	6.2	7.8	6.5	6.7	12.9	14.4	8.6
AVERY DENNISON CORP	15.1	18.6	21.4	24.5	26.7	26.2	34.6	27.7	25.9	22.6	19.5	14.8	23.0	23.1
BADGER METER INC	11.6	12.1	14.9	16.7	18.5	21.4	16.1	7.8	16.0	14.7	16.2	19.3	10.4	15.0
BARNES GROUP INC	20.4	23.3	22.8	23.9	18.7	15.5	18.7	9.6	13.3	12.5	10.1	16.5	16.1	17.0
BELO CORP -SER A COM	18.9	17.3	23.1	9.8	5.0	13.5	11.0	-0.2	9.6	8.6	8.3	8.1	8.5	10.9
BLACK & DECKER CORP	12.1	21.2	15.2	13.3	-63.8	43.7	37.8	15.0	34.0	40.5	37.9	35.3	36.2	21.4
BLOCK H & R INC	15.4	20.5	4.7	33.5	17.9	22.1	23.1	34.2	38.2	39.6	32.4	23.9	-24.3	21.6
BOB EVANS FARMS	14.4	7.3	8.7	10.4	12.4	11.8	11.5	13.8	13.9	12.1	5.8	8.1	8.6	10.7
BOEING CO	9.2	4.0	10.5	-1.5	8.9	19.4	18.9	25.9	25.0	9.1	19.3	22.9	28.0	15.4
BRINKS CO	14.0	21.5	20.9	21.2	18.8	8.6	-33.3	3.3	5.8	6.7	20.8	19.6	73.8	15.5
BROWN-FORMAN -CL B	30.1	27.5	25.1	24.2	23.5	22.2	20.9	18.3	22.8	26.8	25.7	22.3	24.8	24.1
BRUNSWICK CORP	15.0	13.0	16.6	12.0	14.2	2.9	-8.1	7.8	9.4	11.2	17.8	20.9	7.0	10.7
BURLINGTON NORTHERN SANTA FE	23.2	5.1	16.1	13.8	15.8	14.3	12.5	9.6	9.6	9.5	8.9	16.3	19.0	13.4
CARLISLE COS INC	15.2	16.9	19.2	21.5	22.5	21.6	18.7	4.6	13.2	15.0	12.0	14.9	25.8	17.0
CASEYS GENERAL STORES INC	13.5	13.9	12.3	13.5	14.2	12.9	10.8	8.9	10.2	8.6	8.1	12.4	11.3	11.6
CATO CORP -CL A	13.5	8.3	4.7	11.2	14.5	18.7	19.7	19.5	18.2	13.5	17.2	19.9	19.9	15.3
CHURCHILL DOWNS INC	15.6	14.0	17.1	18.1	17.7	14.7	11.3	10.5	9.3	9.6	3.6	28.5	8.9	13.8
CIRCUIT CITY STORES INC	21.1	18.5	10.6	7.1	8.5	10.2	6.9	7.9	4.3	-3.9	2.9	7.0	-0.5	7.7
CLARCOR INC	18.6	17.7	18.0	17.0	17.9	17.8	17.8	16.2	15.8	15.9	16.0	16.8	16.2	17.1
COACHMEN INDUSTRIES INC	21.8	21.2	21.1	13.8	16.7	14.1	1.0	-1.9	4.8	3.5	7.0	-12.6	-18.0	7.1
CONAGRA FOODS INC	20.0	7.6	26.0	23.9	12.6	13.2	19.9	18.9	17.3	17.5	13.3	11.2	16.6	16.8
CON-WAY INC	6.4	6.7	3.1	19.4	18.2	20.9	12.8	-48.8	14.9	11.8	-16.8	27.5	33.8	8.4
COURIER CORP	13.0	15.3	6.7	10.7	16.9	15.6	17.0	17.8	18.4	19.0	16.4	15.2	16.8	15.3
CSX CORP	18.9	15.5	18.5	14.9	9.2	0.9	9.6	4.8	7.6	3.0	5.1	15.5	15.5	10.7
CUBIC CORP	1.5	3.4	6.8	7.1	0.5	7.9	0.4	11.4	14.6	15.6	13.3	3.9	7.8	7.2
CURTISS-WRIGHT CORP	12.9	11.0	9.1	14.4	13.4	16.0	15.0	19.6	11.9	11.7	12.3	12.4	11.5	13.2
DANAHER CORP	19.4	20.4	30.0	18.0	16.1	17.1	17.8	14.3	17.7	16.1	18.0	18.5	19.1	18.7
DARDEN RESTAURANTS INC	4.1	6.2	-7.9	9.7	14.2	18.4	19.7	22.0	20.0	19.2	23.7	27.0	17.3	14.9
DEB SHOPS INC	-2.8	-5.1	-5.1	8.7	18.1	23.6	19.6	15.9	15.1	7.0	9.6	15.7	15.4	10.5
DONALDSON CO INC	17.6	18.8	19.3	21.4	22.8	24.1	25.9	25.2	24.8	23.0	21.3	20.6	24.7	22.3

**RETURNS ON AVERAGE COMMON STOCK EQUITY FOR
157 LOW RISK US INDUSTRIALS**

Company Name	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	Average 1994-2006
DONNELLEY (R R) & SONS CO	14.1	14.4	-8.3	8.1	20.4	25.3	22.5	2.4	15.8	18.6	7.4	3.6	10.2	11.9
ENNIS INC	31.2	25.2	16.9	12.5	17.1	17.6	14.7	16.0	15.8	17.3	12.0	14.2	13.6	17.2
ETHAN ALLEN INTERIORS INC	15.2	12.5	13.6	20.1	24.8	24.5	24.4	18.6	16.9	14.4	16.0	17.8	20.1	18.4
EW SCRIPPS -CL A	12.6	11.7	14.7	15.8	12.4	13.2	13.4	10.5	13.1	16.2	15.5	11.4	14.5	13.5
EXPEDITORS INTL WASH INC	14.0	15.9	18.9	24.8	24.4	23.7	25.8	25.0	24.0	20.9	21.5	25.4	23.7	22.2
FAMILY DOLLAR STORES	17.9	14.9	14.2	15.8	19.2	22.1	23.1	21.6	20.5	20.1	19.5	15.7	14.8	18.4
FARMER BROS CO	5.3	9.5	10.4	7.0	12.8	10.3	12.5	11.1	8.5	6.4	4.0	-2.0	1.8	7.5
FASTENAL CO	31.8	33.8	29.5	28.0	27.6	26.2	25.2	17.9	16.2	15.6	20.8	22.7	23.3	24.5
FLEXSTEEL INDUSTRIES INC	9.3	7.2	6.1	8.1	9.9	13.0	14.3	5.4	6.6	9.1	10.4	5.9	4.4	8.4
FLUOR CORP	17.0	17.5	17.3	8.6	14.4	6.7	7.8	1.6	19.6	17.1	15.4	15.3	15.7	13.4
FORTUNE BRANDS INC	16.5	12.8	13.2	2.7	7.2	-26.2	-5.7	18.3	23.9	23.1	26.8	18.4	19.8	11.6
FRANKLIN ELECTRIC CO INC	32.3	21.3	23.9	26.5	26.9	28.5	20.9	22.7	23.3	19.9	17.8	18.3	18.6	23.1
FREDS INC	7.5	2.4	4.9	7.9	6.6	7.6	9.7	10.4	12.0	12.5	9.2	8.0	7.5	8.2
FRISCH'S RESTAURANTS INC	3.7	3.6	1.8	7.9	8.4	11.2	13.9	13.5	14.9	14.1	17.1	9.4	8.9	9.9
G&K SERVICES INC -CL A	15.5	16.7	17.5	18.7	17.5	17.1	14.9	11.8	11.9	9.4	8.8	8.9	8.2	13.6
GANNETT CO	25.0	24.1	37.2	22.2	26.8	22.3	35.3	15.3	18.3	15.8	15.9	15.8	14.6	22.2
GENERAL DYNAMICS CORP	19.1	22.3	16.5	17.4	17.6	32.7	25.8	22.6	18.9	18.1	18.7	19.1	20.7	20.7
GENERAL ELECTRIC CO	18.1	23.5	24.0	25.0	25.4	26.3	27.4	26.8	25.5	21.8	17.7	15.2	18.8	22.7
GENUINE PARTS CO	19.4	19.5	19.5	19.1	18.2	17.9	17.4	12.9	16.4	15.9	16.3	16.7	18.1	17.5
GORMAN-RUPP CO	15.7	14.7	14.2	14.1	14.5	14.9	14.3	14.0	8.1	8.6	7.8	8.8	14.9	12.7
GRAINGER (W W) INC	13.0	16.9	15.8	16.8	18.5	13.1	12.8	11.1	14.4	12.9	14.7	15.9	17.2	14.8
HARTE HANKS INC	24.9	24.9	19.4	82.2	12.0	12.6	14.5	14.4	16.7	16.1	17.3	20.2	21.2	22.8
HAVERTY FURNITURE	10.0	9.0	8.4	8.6	10.6	16.8	16.0	11.9	11.4	10.2	8.6	5.5	5.6	10.2
HEICO CORP	5.6	9.4	27.6	13.9	16.5	15.8	17.0	8.8	7.7	5.7	8.8	8.8	10.8	12.0
HNI CORP	29.1	20.0	29.1	27.4	25.2	18.1	19.8	12.8	14.7	14.5	16.5	21.8	22.6	20.9
HORMEL FOODS CORP	19.2	17.3	10.5	13.8	17.2	19.8	19.9	19.5	17.9	15.7	17.5	17.0	16.9	17.1
HUBBELL INC -CL B	18.3	19.1	20.1	16.6	20.3	17.2	17.0	6.4	14.7	14.6	17.4	17.0	15.7	16.5
ILLINOIS TOOL WORKS	19.8	22.4	22.5	22.6	21.9	20.6	18.8	14.1	14.7	14.1	17.3	19.7	20.7	19.2
INTERPOOL INC	16.6	14.3	11.4	12.1	14.1	7.5	13.3	11.7	1.3	11.4	2.0	14.6	21.2	11.7
INTL SPEEDWAY CORP -CL A	23.6	23.9	20.5	18.8	13.9	8.9	5.4	8.8	12.8	15.6	19.4	16.6	10.6	15.3
JOHNSON CONTROLS INC	13.9	14.9	16.1	17.7	18.4	19.6	19.4	17.2	18.6	17.7	17.4	16.1	15.4	17.1
KAMAN CORP	-10.6	10.5	12.1	31.6	10.7	8.0	11.4	3.5	-10.7	6.5	-4.0	4.7	11.2	6.5
KELLY SERVICES INC -CL A	14.9	15.3	14.7	15.0	15.4	15.2	14.5	2.7	3.0	0.8	3.4	5.9	8.9	10.0
KENNAMETAL INC	3.8	19.1	16.8	16.0	11.9	5.3	6.8	6.8	5.1	2.5	9.1	12.8	22.6	10.7
KIMBERLY-CLARK CORP	21.2	1.1	34.5	20.5	27.3	36.6	33.2	28.2	29.8	27.3	26.9	25.9	25.7	26.0
LANCASTER COLONY CORP	27.9	27.4	25.3	25.7	24.7	23.1	23.9	20.6	19.1	21.5	14.1	15.9	15.3	21.9
LANCE INC	11.2	-3.2	12.9	16.2	14.8	13.5	12.4	13.5	11.1	10.1	13.0	9.2	8.7	11.0
LAWSON PRODUCTS	15.1	16.6	15.9	15.9	13.8	16.3	18.2	5.5	7.7	9.6	12.1	14.6	7.3	13.0
LA-Z-BOY INC	11.8	11.8	12.9	13.4	16.5	16.3	10.1	8.8	14.5	0.4	6.7	-0.6	0.8	9.5
LEE ENTERPRISES INC	21.9	21.1	14.3	19.9	19.5	20.2	22.3	58.3	11.5	10.1	10.3	8.5	7.4	18.9
LEGGETT & PLATT INC	20.2	19.8	18.3	19.7	19.0	18.8	15.4	10.3	12.1	10.1	12.9	11.0	13.1	15.4

**RETURNS ON AVERAGE COMMON STOCK EQUITY FOR
157 LOW RISK US INDUSTRIALS**

Company Name	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	Average 1994-2006
LENNAR CORP	13.6	12.3	13.5	14.9	25.0	21.6	21.7	28.9	28.0	27.4	25.8	29.1	10.8	21.0
LIMITED BRANDS INC	17.2	32.3	16.9	11.0	96.0	21.0	19.2	20.5	13.2	14.2	18.6	27.7	24.9	25.6
LINCOLN ELECTRIC HLDGS INC	28.4	23.5	20.6	20.6	20.2	15.7	17.4	17.7	14.4	12.0	15.3	19.9	23.3	19.1
LINDSAY CORP	18.2	17.1	22.7	24.5	26.4	14.7	16.5	10.0	12.4	13.2	8.6	4.4	10.2	15.3
LIZ CLAIBORNE INC	8.4	12.9	15.5	19.0	17.8	20.4	21.3	20.3	19.7	19.5	18.5	16.6	12.3	17.1
LOCKHEED MARTIN CORP	26.4	11.8	22.8	-10.5	17.7	11.8	-6.3	-14.9	8.1	16.7	18.4	24.5	34.3	12.4
LONGS DRUG STORES CORP	9.5	8.8	10.9	10.1	10.4	10.3	6.5	6.7	4.4	4.2	5.1	9.9	9.4	8.2
LOWE'S COMPANIES INC	19.5	14.7	15.1	14.8	16.8	17.2	15.9	16.8	19.6	20.2	19.9	21.4	20.7	17.9
LSI INDUSTRIES INC	19.2	23.1	16.1	14.5	17.2	18.9	15.6	8.1	10.6	5.9	6.8	11.0	9.5	13.6
MARCUS CORP	11.8	18.2	11.7	9.8	7.5	7.1	6.6	6.5	5.7	6.4	22.4	7.1	10.7	10.1
MASCO CORP	9.4	-23.4	16.9	18.8	19.2	19.4	18.0	5.3	14.5	15.0	16.4	18.3	10.5	12.2
MATTEL INC	26.4	30.0	27.7	17.1	17.8	-4.6	-25.6	19.8	26.0	25.6	24.9	18.6	26.2	17.7
MATTHEWS INTL CORP -CL A	21.2	19.5	21.4	19.0	21.6	22.9	23.1	23.4	23.5	20.5	19.8	18.5	18.3	21.0
MCCORMICK & COMPANY INC	12.8	19.3	10.3	23.3	26.6	26.8	37.1	35.7	34.1	31.6	26.1	25.4	23.3	25.6
MDC HOLDINGS INC	10.5	8.7	9.9	10.9	19.5	26.0	28.3	27.4	23.0	23.4	32.1	30.0	10.4	20.0
MEDIA GENERAL -CL A	41.9	15.0	17.3	12.3	15.8	97.6	4.3	1.6	4.8	6.2	7.0	7.9	8.5	18.5
MEREDITH CORP	10.0	16.0	21.5	32.4	23.6	25.3	19.2	17.2	19.1	18.1	20.3	20.7	21.5	20.4
MET-PRO CORP	12.5	14.6	16.2	16.9	15.9	15.7	17.0	12.7	11.1	10.9	7.8	11.2	10.3	13.3
MINE SAFETY APPLIANCES CO	5.9	7.4	9.4	9.2	7.6	6.8	10.0	13.4	13.1	22.1	20.9	21.7	15.7	12.6
MOLSON COORS BREWING CO	8.9	6.3	6.2	11.3	9.0	11.4	12.4	13.1	16.7	15.5	13.7	4.0	6.5	10.4
MOVADO GROUP INC	16.9	9.8	11.2	12.7	13.4	8.7	13.5	10.3	9.8	8.9	8.9	8.3	14.3	11.3
NATIONAL PRESTO INDS INC	9.0	7.7	6.0	6.8	7.8	8.2	6.1	2.6	3.7	6.4	6.2	7.3	10.2	6.8
NEW YORK TIMES CO -CL A	13.6	8.6	5.2	15.6	17.6	20.8	29.1	36.6	24.8	22.7	21.0	18.2	-46.5	14.4
NEWELL RUBBERMAID INC	18.6	18.3	18.4	18.1	21.8	4.1	16.4	10.8	13.9	-2.3	-6.1	14.8	21.8	13.0
NIKE INC -CL B	21.6	25.2	28.5	12.5	13.7	17.9	17.8	18.2	18.9	21.6	23.2	23.3	22.4	20.4
NORDSON CORP	22.8	23.7	22.3	21.5	9.6	21.8	23.3	9.6	8.3	12.4	18.0	21.3	23.8	18.3
NORFOLK SOUTHERN CORP	14.4	15.0	15.7	13.8	12.9	4.0	2.9	6.3	7.3	6.2	12.3	14.8	15.7	10.9
NORTHROP GRUMMAN CORP	2.7	18.3	13.0	17.1	7.1	15.8	16.9	7.2	4.3	5.7	6.7	8.4	9.2	10.2
OIL DRI CORP AMERICA	14.1	10.6	4.3	8.8	6.3	9.8	3.0	1.3	-1.6	4.5	7.1	9.0	7.2	6.5
PENTAIR INC	13.2	17.0	14.3	15.9	16.6	12.5	5.7	3.2	12.3	11.9	12.6	12.3	11.4	12.2
PEPSIAMERICAS INC	19.3	22.6	22.0	0.7	14.3	-1.2	6.2	1.3	9.0	10.5	11.4	12.2	10.0	10.6
PULTE HOMES INC	26.1	7.9	22.6	6.4	11.8	17.7	16.1	17.1	18.0	20.1	24.8	28.5	11.0	17.5
RAVEN INDUSTRIES INC	14.1	13.1	14.5	13.6	10.0	11.6	12.5	17.7	20.3	22.2	27.0	32.2	27.9	18.2
RAYTHEON CO	14.5	19.3	17.1	7.0	8.1	4.2	1.3	-6.8	-1.3	4.0	3.8	8.2	11.8	7.0
ROBBINS & MYERS INC	11.6	18.6	25.2	26.7	22.7	7.8	11.2	10.8	6.3	5.2	3.3	-0.1	-6.1	11.0
ROLLINS INC	28.0	19.3	11.3	0.9	5.8	9.4	12.7	20.6	30.8	31.2	38.0	30.6	29.8	20.6
RUBY TUESDAY INC	26.6	-1.3	11.9	13.3	16.8	16.2	23.0	18.8	23.6	23.6	18.9	18.5	19.0	17.6
RUDDICK CORP	11.2	12.9	12.9	13.1	11.8	11.9	11.1	-0.2	11.5	12.6	12.4	11.8	11.3	11.1
RYDER SYSTEM INC	14.5	13.1	-2.7	16.2	14.8	36.9	7.2	1.5	9.6	11.1	15.1	15.1	15.3	12.9
SCHAWK INC -CL A	23.6	7.3	-41.9	21.0	38.7	17.9	15.1	10.4	16.0	17.3	19.1	16.8	11.3	13.3
SHERWIN-WILLIAMS CO	17.9	17.7	17.5	17.4	16.5	17.8	1.0	17.8	22.0	23.7	25.3	27.4	30.9	19.5

**RETURNS ON AVERAGE COMMON STOCK EQUITY FOR
157 LOW RISK US INDUSTRIALS**

Company Name	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	Average 1994-2006
SKYLINE CORP	8.8	10.8	11.6	11.1	13.6	7.8	5.8	6.3	3.1	3.1	2.8	7.4	1.4	7.2
SMITH (A O) CORP	19.7	17.9	16.4	37.3	11.1	10.2	6.8	3.2	10.7	9.6	6.1	7.7	11.8	13.0
SMUCKER (JM) CO	14.7	11.0	10.9	12.2	12.1	8.3	11.3	11.7	13.7	9.5	8.9	8.4	8.9	10.9
SOUTHWEST AIRLINES	15.6	13.7	13.5	17.4	19.7	18.1	19.9	13.7	5.7	9.3	5.9	9.0	7.6	13.0
SPARTAN MOTORS INC	18.4	5.6	3.8	-24.1	7.5	-3.2	-15.2	18.1	25.1	10.3	9.1	11.8	19.1	6.7
STANDEX INTERNATIONAL CORP	22.6	30.5	23.0	19.5	14.0	20.3	16.9	14.8	11.6	8.3	6.5	13.9	12.3	16.5
STANLEY WORKS	17.6	8.0	12.8	-6.0	21.6	21.4	26.4	20.2	20.4	11.7	35.3	20.2	19.3	17.6
SUPERIOR INDUSTRIES INTL	29.9	24.7	19.5	20.6	17.5	21.3	21.2	13.1	16.0	13.1	7.5	-1.2	-1.6	15.5
SUPERIOR UNIFORM GROUP INC	14.5	5.4	12.1	12.0	10.0	11.2	9.0	7.9	6.5	6.9	6.3	1.5	2.9	8.2
TELEFLEX INC	14.2	14.7	15.0	16.1	16.5	16.7	16.9	15.3	14.8	11.1	0.9	12.3	12.0	13.6
TENNANT CO	17.5	18.7	17.3	18.4	19.1	14.9	19.3	3.0	5.4	8.9	7.9	12.5	14.1	13.6
TOOTSIE ROLL INDUSTRIES INC	16.8	15.7	16.1	18.3	18.1	17.2	17.0	13.6	12.8	12.2	11.6	13.0	10.6	14.9
TORO CO	14.2	20.7	18.2	16.1	1.6	12.9	15.2	15.3	17.0	20.3	24.7	29.0	33.0	18.3
TREDEGAR CORP	22.7	14.1	23.5	24.1	23.6	15.4	25.6	2.0	-0.5	-5.8	6.3	3.4	7.6	12.5
TWIN DISC INC	6.9	8.1	8.8	10.4	12.0	-1.4	5.2	9.0	3.5	-4.4	10.4	11.0	18.5	7.5
TYSON FOODS INC -CL A	-0.2	15.9	5.8	11.7	1.4	11.2	7.0	3.2	10.9	8.9	9.8	8.3	-4.2	6.9
UNIFIRST CORP	13.4	13.0	13.7	14.1	14.3	9.6	7.5	8.3	9.0	9.1	9.6	11.1	9.1	10.9
UNION PACIFIC CORP	10.9	16.5	12.4	5.3	-8.1	10.5	10.1	10.6	13.3	11.4	4.8	7.8	11.1	9.0
UNITED INDUSTRIAL CORP	6.0	1.0	7.3	15.4	12.3	5.7	6.9	4.6	-46.5	-13.2	73.9	143.5	106.2	24.9
UNITED PARCEL SERVICE INC	22.0	21.3	20.7	15.2	26.3	9.0	26.4	24.3	28.7	21.2	21.3	23.3	26.0	22.0
UNITED TECHNOLOGIES CORP	15.3	18.6	21.0	24.8	28.9	26.1	24.0	23.8	26.4	23.3	21.7	20.4	21.8	22.8
UNIVERSAL CORP/VA	9.7	6.7	17.7	22.7	27.8	23.4	22.0	21.5	18.7	14.8	12.1	1.0	3.7	15.5
VF CORP	16.5	8.8	15.8	18.0	19.4	17.0	12.1	6.1	19.3	21.9	21.2	19.4	17.5	16.4
WALGREEN CO	19.1	19.1	19.4	19.7	20.6	19.7	20.1	18.8	17.8	17.5	17.6	18.3	18.4	18.9
WAL-MART STORES INC	22.8	19.9	19.2	19.8	22.4	23.8	22.0	20.1	21.6	21.8	22.1	21.9	19.7	21.3
WASHINGTON POST -CL B	15.3	16.5	17.6	22.4	30.0	15.2	9.5	14.4	12.2	12.3	14.8	12.4	11.3	15.7
WASTE MANAGEMENT INC	17.2	11.8	4.2	14.4	-21.9	-9.0	-2.1	9.9	15.4	13.2	16.1	19.6	18.6	8.3
WATTS WATER TECHNOLOGIES INC	11.8	11.9	-13.9	15.8	15.1	9.4	7.7	11.0	12.0	9.1	10.1	10.8	11.0	9.4
WEIS MARKETS INC	10.2	10.2	9.8	9.4	9.6	8.8	7.9	6.8	11.0	9.7	10.0	10.8	9.1	9.5
WERNER ENTERPRISES INC	13.9	12.4	12.3	13.0	13.7	12.8	9.3	8.5	10.0	10.9	11.8	12.0	11.4	11.7
WEYCO GROUP INC	10.1	11.0	13.1	14.4	14.9	16.6	15.3	13.1	16.7	18.7	18.6	15.1	15.4	14.8
WILEY (JOHN) & SONS -CL A	20.2	22.8	16.5	25.3	24.6	31.3	30.0	23.1	28.1	23.4	20.7	27.6	21.4	24.2
WOLVERINE WORLD WIDE	13.5	14.3	14.8	15.9	14.3	10.2	3.2	12.7	12.9	12.9	14.8	16.2	17.3	13.3
WOODWARD GOVERNOR CO	-1.6	6.1	10.9	8.7	10.0	13.3	18.2	17.9	13.4	3.5	8.4	13.7	15.3	10.6
Mean	**15.7**	**14.6**	**14.5**	**15.3**	**15.6**	**15.5**	**14.3**	**12.8**	**13.9**	**13.4**	**14.3**	**15.6**	**14.9**	**14.6**
Median	**15.1**	**14.9**	**15.4**	**15.4**	**15.9**	**15.5**	**15.0**	**12.7**	**13.9**	**12.5**	**13.3**	**14.9**	**14.6**	**13.6**
Average of Annual Medians														**14.5**

Source: Standard & Poor's Research Insight

ESTIMATE OF MARKET VALUE CAPITAL STRUCTURES FOR CANADIAN UTILITIES

Company	Stock Price (Average Monthly High/Low 7/2002-6/2007) (1)	Book Value Per Share Average 2002-2006 (2)	Market/Book Ratio (3) = (1)/(2)	Book Value Permanent Capital Common Equity Ratio 2002-2006 (4)	Market Value Common Equity Ratio (Debt at Par) (5)=[(4)*(3)]/[(4)*(3)+(1-(4))]	Market Value Debt Ratio 1.0-Col.(7)
CANADIAN UTILITIES -CL A	33.57	16.52	2.03	37.7%	55.1%	44.9%
EMERA INC	18.53	12.37	1.50	46.1%	56.1%	43.9%
ENBRIDGE INC	29.94	11.04	2.71	34.1%	58.3%	41.7%
FORTIS INC	18.77	10.34	1.82	33.5%	47.7%	52.3%
PNG	18.08	20.62	0.88	46.4%	43.1%	56.9%
TERASEN INC 1/	24.47	13.62	1.80	39.9%	54.4%	45.6%
TRANSCANADA CORP	30.10	14.01	2.15	38.1%	57.0%	43.0%
Mean				**39.4%**	**53.1%**	**46.9%**

1/ Terasen price is through November 2005 due to Kinder Morgan acquisition; book value per share is through 2005.

Sources: Standard & Poor's Research Insight

ESTIMATE OF MARKET VALUE CAPITAL STRUCTURES FOR BENCHMARK SAMPLE OF US ELECTRIC AND GAS UTILITIES

Company	Stock Price (Average Daily Closing 7/16-8/15/2007) (1)	Book Value Per Share (Avg. 2005 and 2006) (2)	Market/Book Ratio (3) = (1)/(2)	Book Value Permanent Capital Common Equity Ratio 2006 (4)	Market Value Common Equity Ratio (Debt at Par) (5)=[(4)*(3)]/[(4)*(3)+(1-(4))]	Market Value Debt Ratio 1.0-Col.(7)
AGL Resources	38.77	19.99	1.94	49.8%	65.8%	34.2%
Consolidated Edison	45.41	30.38	1.49	48.4%	58.4%	41.6%
FPL	59.01	23.01	2.56	50.9%	72.6%	27.4%
Integrys Energy	50.78	33.95	1.50	53.4%	63.2%	36.8%
New Jersey Resources	48.91	19.20	2.55	65.2%	82.7%	17.3%
Nicor Inc.	41.20	18.90	2.18	63.7%	79.2%	20.8%
Northwest Nat. Gas	44.12	21.63	2.04	53.7%	70.3%	29.7%
NSTAR	32.21	14.59	2.21	39.7%	59.2%	40.8%
Piedmont Natural Gas	24.64	11.61	2.12	51.7%	69.4%	30.6%
Scana	38.11	23.80	1.60	47.2%	58.9%	41.1%
Southern Co.	34.87	14.82	2.35	46.2%	66.9%	33.1%
Vectren	26.45	15.24	1.74	49.3%	62.8%	37.2%
WGL Holdings Inc.	31.65	18.61	1.70	60.4%	72.2%	27.8%
Mean				**52.3%**	**67.8%**	**32.2%**

Sources: Schedule 14 for stock prices and Standard & Poor's Research Insight

QUANTIFICATION OF IMPACT ON EQUITY RETURN REQUIREMENT FOR DIFFERENCE BETWEEN MARKET VALUE AND BOOK VALUE CAPITAL STRUCTURES: CANADIAN UTILITIES

Formula for After-Tax Weighted Average Cost of Capital:

$WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

THEORY 1:
The after-tax weighted average cost of capital ($WACC_{AT}$) is invariant to changes in the capital structure. The cost of equity rises as leverage (debt ratio) rises, but the $WACC_{AT}$ stays the same.

$WACC_{AT(LL)}$ = $WACC_{AT(ML)}$

Wherevered (lower debt ratio)

ML = more levered (higher debt ratio)

ASSUMPTIONS:

Debt Cost	=	Current Cost of Long Term Debt for A rated utility
	=	6.0%[1]
Equity Cost	=	Cost of Equity[2]
	=	9.75%
Tax Rate	=	34.0%[3]

STEPS:

1. Estimate $WACC_{AT}$ for the less levered sample (average market value common equity ratio of 53%)

   $WACC_{AT}$ = (6.0%)(1-.34)(47%) + (9.75%)(53%)
   = 7.03%

2. Estimate Cost of Equity for sample at 39% book value common equity ratio with $WACC_{AT}$ unchanged at 7.03%

   $WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)
   7.03% = (6.0%)(1-.34)(61%)+(X)(39%)
   Cost of Equity at 39% Equity Ratio = 11.80%

3. Difference between Equity Return at 39% and 53% common equity ratios:

   11.8% - 9.75% = 2.05% (205 basis points)

[1] Forecast Long Canada plus spread on A-rated utility debt.
[2] Based on the mid-point of Equity Risk Premium and DCF tests.
[3] Combined Federal/Ontario tax rate.

THEORY 2:

After-Tax Cost of Capital Declines as Debt Ratio Rises; Cost of Equity Rises

$$WACC_{AT(ML)} = WACC_{AT(LL)} \times \frac{(1-tD_{ML})}{(1-tD_{LL})}$$

Where LL,ML as before
t = tax rate
D = debt ratio

ASSUMPTIONS:

Debt Cost	=	Current Cost of Long Term Debt for A rated utility
	=	6.00%
Equity Cost	=	Cost of Equity
	=	9.75%
Tax Rate	=	34.0%

STEPS:

1. Estimate $WACC_{AT}$ for less levered sample (average market value common equity ratio of 53%)

$$WACC_{AT} = (6.0\%)(1-.34)(47\%) + (9.75\%)(53\%)$$
$$= 7.03\%$$

2. Estimate $WACC_{AT}$ for more levered firm (book value common equity ratio of 39%)

$$WACC_{AT(ML)} = WACC_{AT(LL)} \times (1\text{-t x Debt Ratio}_{ML})/(1\text{-t x Debt Ratio}_{LL})$$

$$WACC_{AT(ML)} = 7.03\% \times \frac{(1-.34 \times 61\%)}{(1-.34 \times 47\%)}$$

$$WACC_{AT(ML)} = 6.63\%$$

3. Estimate Cost of Equity at new $WACC_{AT}$ for more levered firm:

$$WACC_{AT(ML)} = (\text{Debt Cost})(1\text{-tax rate})(\text{Debt Ratio}_{ML}) + (\text{Equity Cost})(\text{Equity Ratio}_{ML})$$
$$6.63\% = (6.0\%)(1-.34)(61\%) + (X)(39\%)$$

Cost of Equity at 39% equity ratio = 10.80%

4. Difference between Equity Return at 39% and 53% common equity ratios:

10.8% - 9.75% = 1.05% (105 basis points)

ESTIMATE OF IMPACT OF CHANGE IN CAPITAL STRUCTURE ON COST OF EQUITY
105 - 205 BASIS POINTS

QUANTIFICATION OF IMPACT ON EQUITY RETURN REQUIREMENT FOR DIFFERENCE BETWEEN MARKET VALUE AND BOOK VALUE CAPITAL STRUCTURES: BENCHMARK LOW RISK U.S. GAS & ELECTRIC UTILITIES

Formula for After-Tax Weighted Average Cost of Capital:

$WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

THEORY 1:
The after-tax weighted average cost of capital ($WACC_{AT}$) is invariant to changes in the capital structure. The cost of equity rises as leverage (debt ratio) rises, but the $WACC_{AT}$ stays the same.

$WACC_{AT(LL)}$ = $WACC_{AT(ML)}$

Where LL = less levered (lower debt ratio)
ML = more levered (higher debt ratio)

9.5

ASSUMPTIONS:

Debt Cost	=	Current Cost of Long Term Debt for A rated utility
	=	6.0%[1]
Equity Cost	=	Cost of Equity[2]
	=	9.75%
Tax Rate	=	34.0%[3]

STEPS:

1. Estimate $WACC_{AT}$ for the less levered sample (average market value common equity ratio of 68%)

   $WACC_{AT}$ = (6.0%)(1-.34)(32%) + (9.75%)(68%)
   = 7.90%

2. Estimate Cost of Equity for sample at 52% book value common equity ratio with $WACC_{AT}$ unchanged at 7.90%

   $WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)
   7.90% = (6.0%)(1-.34)(48%)+(X)(52%)
   Cost of Equity at 52% Equity Ratio = 11.50%

3. Difference between Equity Return at 52% and 68% common equity ratios:

   11.5% - 9.75% = 1.75% (175 basis points)

[1] Forecast Long Canada plus spread on A-rated utility debt.
[2] Based on the mid-point of Equity Risk Premium and DCF tests.
[3] Combined Federal/Ontario tax rate.

THEORY 2:

After-Tax Cost of Capital Declines as Debt Ratio Rises; Cost of Equity Rises

$$WACC_{AT(ML)} = WACC_{AT(LL)} \times \frac{(1\text{-}tD_{ML})}{(1\text{-}tD_{LL})}$$

Where LL,ML as before
t = tax rate
D = debt ratio

ASSUMPTIONS:

Debt Cost	=	Current Cost of Long Term Debt for A rated utility
	=	6.00%
Equity Cost	=	Cost of Equity
	=	9.75%
Tax Rate	=	34.0%

STEPS:

1. Estimate $WACC_{AT}$ for less levered sample (average market value common equity ratio of 68%)

   $WACC_{AT}$ = (6.0%)(1-.34)(32%) + (9.75%)(68%)
   = 7.90%

2. Estimate $WACC_{AT}$ for more levered firm (book value common equity ratio of 52%)

   $WACC_{AT(ML)} = WACC_{AT(LL)}$ x (1-t x Debt $Ratio_{ML}$)/(1-t x Debt $Ratio_{LL}$)

   $$WACC_{AT(ML)} = 7.90\% \quad x \quad \frac{(1\text{-}.34 \times 48\%)}{(1\text{-}.34 \times 32\%)}$$

   $WACC_{AT(ML)}$ = 7.42%

3. Estimate Cost of Equity at new $WACC_{AT}$ for more levered firm:

   $WACC_{AT(ML)}$ = (Debt Cost)(1-tax rate)(Debt $Ratio_{ML}$) + (Equity Cost)(Equity $Ratio_{ML}$)
   7.42% = (6.0%)(1-.34)(48%) + (X)(52%)

   Cost of Equity at 52% equity ratio = 10.6%

4. Difference between Equity Return at 52% and 68% common equity ratios:

   10.6% - 9.75% = .85% (85 basis points)

ESTIMATE OF IMPACT OF CHANGE IN CAPITAL STRUCTURE ON COST OF EQUITY
85 -175 BASIS POINTS

CAPITAL STRUCTURE RATIOS OF CANADIAN UTILITIES (2006)

Company	Long-term Debt [1/]	Short-Term Debt	Preferred Stock [2/]	Common Stock Equity [3/]
Electric Utilities				
AltaLink L.P.	62.2	0.0	0.0	37.8
CU Inc.	55.2	2.3	6.2	36.3
Enersource	58.1	0.0	0.0	48.9
ENMAX Corp.	20.1	2.8	0.0	77.1
EPCOR Utilities Inc.	43.7	4.3	6.9	45.0
FortisAlberta Inc.	60.6	0.7	0.0	38.7
FortisBC Inc.	59.5	0.0	0.0	40.5
Hamilton Utilities	36.7	0.0	0.0	63.3
Hydro One Inc.	52.1	0.3	3.2	44.5
Hydro Ottawa Holding Inc.	47.2	0.0	0.0	52.8
Maritime Electric	38.0	21.2	0.0	40.8
Newfoundland Power	54.5	0.1	1.2	44.2
Nova Scotia Power	50.6	0.1	9.4	39.9
Toronto Hydro	57.5	0.0	0.0	42.5
Gas Distributors				
Enbridge Gas Distribution	47.1	17.3	2.1	33.5
Gaz Metropolitain	59.2	1.6	0.0	39.2
Pacific Northern Gas	46.0	3.0	3.0	47.9
Terasen Gas	54.7	8.8	0.0	36.5
Union Gas	63.8	0.0	2.9	33.3
Pipelines				
Enbridge Pipelines	39.3	13.9	0.0	46.7
Nova Gas Transmission Ltd.	57.5	2.5	0.0	39.9
TransCanada PipeLines Ltd. [4/]	58.7	2.3	1.9	37.1
Westcoast Energy Inc.	54.5	0.0	5.0	40.5
Medians				
Electric T&D	**54.5**	**0.0**	**0.0**	**44.5**
Electric Integrated	**50.6**	**2.3**	**6.2**	**40.5**
All Electric	**53.3**	**0.1**	**0.0**	**43.4**
Gas Distributors	**54.7**	**3.0**	**2.1**	**36.5**
All Companies	**54.5**	**0.7**	**0.0**	**40.5**

1/ Includes current portion of long-term debt and preferred securities classified as debt.

2/ Includes minority interest in preferred shares of subsidiary companies and preferred securities.

3/ Includes minority interest in common shares of subsidiary companies.

4/ Excludes non-recourse debt

Source: Reports to Shareholders

FINANCIAL METRICS
FOR CANADIAN UTILITIES
2004-2006

Company	EBIT Coverage	EBITDA Coverage	FFO/ Total Debt	FFO Coverage [1]
Electric Utilities				
AltaLink L.P.	1.8	3.4	11.4	3.1
CU Inc.	2.7	4.1	18.7	3.6
Enersource	2.1	na	16.7	3.8
ENMAX Corp.	6.4	8.5	46.3	8.1
EPCOR Utilities Inc.	3.0	4.2	23.4	4.2
FortisAlberta Inc.[2]	2.3	4.5	17.5	3.0
FortisBC Inc.[2]	2.2	3.1	10.9	2.8
Hamilton Utilities	3.4	5.6	32.0	4.7
Hydro One Inc.	3.2	4.6	20.0	4.4
Hydro Ottawa Holding Inc.	2.8	5.0	26.1	5.7
Maritime Electric	2.5	3.3	12.9	2.6
Newfoundland Power [2]	2.4	3.3	14.0	2.9
Nova Scotia Power	2.4	3.5	14.2	3.3
Toronto Hydro	2.7	4.0	17.5	3.4
Gas Distributors				
Enbridge Gas Distribution	2.1	2.8	12.5	3.0
Gaz Metropolitain	2.5	3.9	24.0	4.6
Pacific Northern Gas [4]	2.5	3.7	26.4	3.2
Terasen Gas	2.0	2.7	9.7	2.4
Union Gas [3]	2.1	3.1	12.8	2.8
Pipelines				
Enbridge Pipelines [3]	3.3	2.8	17.2	3.1
Nova Gas Transmission Ltd.[3]	2.4	3.7	18.5	2.8
TransCanada PipeLines Ltd.[3]	2.6	3.4	15.7	2.8
Westcoast Energy Inc.	2.1	3.1	16.4	3.1
Medians				
Electric T&D	**2.7**	**4.5**	**17.5**	**3.8**
Electric Integrated	**2.5**	**3.5**	**14.2**	**3.3**
All Electric	**2.6**	**4.1**	**17.5**	**3.5**
Gas Distributors	**2.1**	**3.1**	**12.8**	**3.0**
All Companies	**2.5**	**3.6**	**17.2**	**3.1**

[1] S&P defines Funds from Operations as follows:
FFO = (income from continuing operations + depreciation & amortization + deferred income taxes – AFUDC).

[2] EBIT, EBITDA and Cashflow to total debt for 2004-2006 from DBRS, FFO data for 2003-2005

[3] FFO Coverage for 2003-2005

[4] EBIT and EBITDA from DBRS, FFO data from annual report

Source: Annual Reports to Shareholders, DBRS and Standard and Poor's

DEBT AND COMMON STOCK QUALITY RATINGS
OF CANADIAN UTILITIES

Company	Debt Rated	DBRS Bond Rating	Moody's Bond Rating	S&P Bond Rating	CBS Stock Ranking
AltaLink L.P.	Senior Secured	A		A-	
CU Inc.	Senior Unsecured	A(high)		A	Very conservative
Enbridge Gas Distribution	Senior Unsecured	A		A-	Very conservative
Enbridge Pipelines	Senior Unsecured	A(high)		A-	Very conservative
ENMAX	Unsecured Debentures (DBRS) Issuer (S&P)	A		A-	
Enersource	Issuer	A			
EPCOR Utilities Inc	Senior Unsecured	A(low)	Baa2	BBB+	
FortisAlberta Inc.	Senior Unsecured	A(low)	Baa1		Very conservative
FortisBC Inc	Secured Debentures	BBB(high)	Baa2		Very conservative
Gaz Metropolitain	Senior Secured	A		A	
Hamilton Utilities	Senior Unsecured			A	
Hydro One	Senior Unsecured	A(high)	Aa3	A	
Hydro Ottawa Holding Inc.	Senior Unsecured	A (low)		A-	
Maritime Electric	Senior Secured			A-	Very conservative
Newfoundland Power	Senior Secured	A	Baa1	NR [2/]	Very conservative
NOVA Gas Transmission	Senior Unsecured	A	A2	A-	Very conservative
Nova Scotia Power	Senior Unsecured	A(low)	Baa1	BBB	Very conservative
Pacific Northern Gas	Senior Secured	BBB(low)		NR [2/]	Average
Terasen Gas	Senior Secured Senior Unsecured	A A	A2 A3	AA- A	Very conservative
Toronto Hydro	Senior Unsecured	A		A-	
TransCanada PipeLines	Senior Secured Senior Unsecured	A A	 A2	A A-	Very conservative
Union Gas Limited	Senior Unsecured	A		BBB+	Very conservative
Veridian Corp.	Issuer	A			
Westcoast Energy	Senior Unsecured	A(low)		BBB+	Very conservative
Mean		**A**	**A3**	**A-**	**Very conservative**
Median		**A**	**Baa1**	**A-**	**Very conservative**

[1/] Withdrawn by company; BBB+ prior to withdrawal.
[2/] Withdrawn by company; BBB- prior to withdrawal.

Note: Debt ratings are for utility; Stock rankings are for parent.

Source: DBRS Bond Ratings, Moodys.com, Standard & Poor's, The Blue Book of CBS Stock Reports.

DEBT RATINGS AND FINANCIAL METRICS FOR U.S. ELECTRIC UTILITIES

	S&P			S&P Credit Stats					
					Average 2003-2005				
Name	Debt Rating	Business Profile	2005 Debt Ratio 1/	2005 Debt Ratio	Debt Ratio	EBIT Coverage	FFO/Debt	FFO coverage	Average ROE 2003-2005
Madison Gas & Electric Co.	AA-	4	50.0	55.5	54.9	4.5	20.7	5.3	11.1
Alabama Power Co.	A	4	52.6	56.8	56.6	3.6	23.4	5.1	13.7
Boston Edison Co.	A+	1	55.7	56.8	64.7	4.2	22.7	4.9	15.2
Central Hudson Gas & Electric Corp.	A	3	54.0	68.0	70.1	4.4	15.9	3.6	13.3
Consolidated Edison Co. of New York Inc.	A	2	49.8	59.6	57.2	2.8	19.2	4.0	10.5
Consolidated Edison Inc.	A	2	52.2	62.1	59.2	2.5	17.2	3.8	8.8
Florida Power & Light Co.	A	4	40.4	40.4	39.0	6.7	32.3	7.6	12.3
FPL Group Inc.	A	5	55.5	51.7	51.9	2.7	19.4	4.4	12.2
Georgia Power Co.	A	4	51.6	53.5	54.2	4.8	25.5	6.1	14.1
Gulf Power Co.	A	4	53.1	52.5	54.1	3.8	21.6	4.9	12.3
KeySpan Corp.	A	4	50.7	61.0	64.1	3.2	16.0	3.8	11.4
MidAmerican Energy Co.	A-	5	47.9	49.1	49.9	4.8	31.7	6.5	14.1
MidAmerican Energy Holdings Co.	A-	4	77.4	77.8	80.0	2.4	10.6	3.2	13.3
Mississippi Power Co.	A	4	44.7	50.6	50.3	5.7	35.4	9.2	13.9
Orange and Rockland Utilities Inc.	A	2	56.9	77.8	71.7	3.7	17.5	4.1	12.6
PacifiCorp	A-	5	50.7	59.0	61.9	2.5	15.9	3.6	8.3
PPL Electric Utilities Corp.	A-	3	64.1	53.9	53.8	1.8	33.8	5.1	4.0
Public Service Co. of North Carolina Inc.	A-	2	41.3	41.4	40.5	3.0	18.0	3.7	5.3
San Diego Gas & Electric Co.	A	5	55.9	61.5	57.3	5.0	30.7	6.5	20.9
Savannah Electric & Power Co.	A	4	51.3	54.9	56.7	3.7	21.8	4.8	na
SCANA Corp.	A-	4	56.1	57.9	59.7	2.5	21.4	4.6	12.0
South Carolina Electric & Gas Co.	A-	4	48.6	48.4	49.9	2.8	24.6	4.8	10.8
Southern Co.	A	4	57.1	56.7	56.6	4.3	23.5	5.5	15.5
Vectren Corp.	A-	4	57.6	59.7	59.7	2.9	16.7	4.0	11.2
Wisconsin Electric Power Co.	A-	4	50.7	48.8	48.0	5.2	31.2	7.6	12.1
Wisconsin Power & Light Co.	A-	4	35.5	49.8	42.6	4.3	36.8	6.4	11.0
Wisconsin Public Service Corp.	A+	4	36.1	36.1	40.6	4.7	28.4	4.9	10.4
WPS Resources Corp.	A	5	45.6	55.9	56.8	3.6	16.6	4.4	12.3
Mean	**A**	**4**	**51.6**	**55.6**	**55.8**	**3.8**	**23.3**	**5.1**	**12.0**
Median	**A**	**4**	**51.6**	**55.9**	**56.6**	**3.7**	**21.8**	**4.8**	**12.2**

DEBT RATINGS AND FINANCIAL METRICS FOR U.S. ELECTRIC UTILITIES

	S&P			S&P Credit Stats					
					Average 2003-2005				Average ROE
Name	Debt Rating	Business Profile	2005 Debt Ratio 1/	2005 Debt Ratio	Debt Ratio	EBIT Coverage	FFO/Debt	FFO coverage	2003-2005
AEP Texas Central Co.	BBB	3	67.0	57.8	54.5	2.4	12.5	2.2	15.7
AEP Texas North Co.	BBB	3	46.7	47.6	53.0	4.1	28.6	4.9	19.0
ALLETE Inc.	BBB+	6	39.3	55.4	48.9	1.9	21.0	4.7	10.1
Alliant Energy Corp.	BBB+	5	46.9	55.2	54.8	2.3	21.5	3.9	4.9
Ameren Corp.	BBB	7	46.3	52.1	54.3	3.8	19.5	4.8	11.0
AmerenEnergy Generating Co.	BBB	9	66.3	67.4	73.2	2.7	20.2	3.4	24.3
American Electric Power Co. Inc.	BBB	5	57.7	66.4	68.5	2.4	15.7	3.3	8.6
Appalachian Power Co.	BBB	5	56.4	57.5	58.9	2.8	15.2	3.6	11.7
Arizona Public Service Co.	BBB-	6	46.2	52.4	59.6	2.8	17.2	4.4	7.9
Atlantic City Electric Co.	BBB	3	66.2	51.5	52.7	2.3	19.2	2.6	9.9
Baltimore Gas & Electric Co.	BBB+	5	45.1	46.6	52.2	3.2	22.8	4.2	10.4
CenterPoint Energy Houston Electric LLC	BBB	2	71.1	70.9	54.4	2.5	33.0	3.5	13.6
CenterPoint Energy Inc.	BBB	3	87.3	89.7	90.7	1.5	16.7	2.7	16.3
CenterPoint Energy Resources Corp.	BBB	4	41.5	59.5	63.2	1.5	11.4	2.6	6.5
Central Illinois Light Co.	BBB-	8	35.0	36.0	44.2	3.8	28.6	7.5	6.5
Central Illinois Public Service Co.	BBB-	8	43.5	43.6	49.6	2.6	16.8	3.8	na
CILCORP Inc.	BBB-	8	56.7	57.0	61.6	1.2	10.1	2.6	2.2
Cincinnati Gas & Electric Co.	BBB	6	47.7	67.3	64.4	3.0	15.6	4.1	15.0
Cinergy Corp.	BBB	6	55.2	61.7	63.0	2.6	14.5	3.6	na
Cleco Corp.	BBB	6	47.9	52.0	61.0	3.9	27.3	5.3	11.3
Cleco Power LLC	BBB	6	50.7	52.6	51.1	3.6	31.4	6.1	12.2
Cleveland Electric Illuminating Co.	BBB	6	54.9	56.3	57.3	3.1	13.4	3.3	12.5
Columbus Southern Power Co.	BBB	4	55.5	58.2	55.9	4.3	25.0	5.3	16.5
Commonwealth Edison Co.	BBB-	8	42.7	37.9	38.9	4.4	24.5	4.1	3.9
Connecticut Light & Power Co.	BBB	3	64.6	60.4	61.4	2.4	21.8	5.6	9.8
Constellation Energy Group Inc.	BBB+	7	48.8	56.6	57.8	3.2	21.6	4.0	12.4
Delmarva Power & Light Co.	BBB	3	51.9	62.1	68.2	2.8	13.2	2.8	10.7
Detroit Edison Co.	BBB	6	62.3	67.2	68.4	2.4	14.9	3.6	8.1
Dominion Resources Inc.	BBB	7	63.6	61.6	61.0	2.5	17.0	3.6	8.0
DTE Energy Co.	BBB	6	60.2	64.4	64.3	1.6	11.8	3.2	9.5
Duke Energy Corp.	BBB	6	49.4	50.6	54.3	2.5	19.4	3.9	4.2
Duquesne Light Co.	BBB	4	45.0	51.6	59.1	3.2	16.2	3.7	11.8
Edison International	BBB-	6	57.3	60.5	63.2	3.1	21.2	4.3	17.0
El Paso Electric Co.	BBB	6	53.2	57.7	57.2	1.9	23.1	4.1	5.8
Empire District Electric Co.	BBB-	6	52.9	57.1	57.9	2.3	16.8	3.6	6.7
Energy East Corp.	BBB+	3	58.7	63.0	64.7	2.2	14.4	3.1	8.8
Entergy Arkansas Inc.	BBB	5	47.5	54.6	56.1	3.7	29.5	6.2	10.6
Entergy Corp.	BBB	6	53.1	59.3	55.6	3.4	21.0	4.5	10.5
Entergy Gulf States Inc.	BBB	6	51.7	51.8	55.0	2.6	15.4	3.4	8.1
Entergy Louisiana LLC	BBB	5	50.6	54.7	52.8	4.1	31.1	6.1	13.0
Entergy Mississippi Inc.	BBB	6	52.7	56.8	58.0	3.1	29.7	6.0	12.2
Exelon Corp.	BBB+	7	60.3	66.8	64.3	3.5	30.4	3.8	13.6
FirstEnergy Corp.	BBB	6	53.8	61.4	63.8	2.6	17.3	3.9	8.2
Great Plains Energy Inc.	BBB	7	48.3	56.9	61.9	3.4	24.1	4.9	15.3
Green Mountain Power Corp.	BBB	5	45.2	74.1	76.4	1.8	7.9	2.2	10.6
Hawaiian Electric Co. Inc.	BBB+	5	45.7	54.1	52.9	3.2	25.4	5.8	10.2
IDACORP Inc.	BBB+	5	51.8	58.2	57.0	1.8	14.5	3.7	6.5
Idaho Power Co.	BBB+	5	51.2	51.8	51.7	2.4	16.7	3.8	7.4
Illinois Power Co.	BBB-	8	44.6	43.1	51.4	2.6	15.9	3.1	8.7
Indiana Michigan Power Co.	BBB	6	56.3	68.4	69.7	2.3	15.7	3.7	11.1
Interstate Power & Light Co.	BBB+	5	46.5	51.3	50.3	3.6	24.7	5.1	10.8
Jersey Central Power & Light Co.	BBB	4	29.7	26.5	30.6	3.3	24.0	4.8	3.8
Kansas City Power & Light Co.	BBB	6	46.9	49.4	56.2	3.5	25.8	5.0	14.0
Kentucky Power Co.	BBB	5	58.8	60.9	62.8	2.1	14.9	3.5	8.4
Kentucky Utilities Co.	BBB+	5	44.4	51.7	51.1	6.2	23.4	7.5	11.8
Louisville Gas & Electric Co.	BBB+	5	46.7	52.5	53.1	5.3	21.5	6.8	10.9
Metropolitan Edison Co.	BBB	4	38.7	39.8	38.8	2.7	13.0	3.5	4.5
NiSource Inc.	BBB	4	56.9	62.0	62.9	2.4	13.2	3.1	6.0
Northeast Utilities	BBB	5	63.5	61.8	61.3	0.9	19.4	4.3	-0.1
Northern Indiana Public Service Co.	BBB	5	41.1	47.6	52.5	6.0	32.4	8.7	16.0
Northern States Power Co.	BBB	5	51.2	55.6	55.5	2.7	22.2	4.1	11.3
Northern States Power Wisconsin	BBB+	4	46.5	46.9	45.9	4.0	24.9	4.7	10.8
OGE Energy Corp.	BBB+	6	50.1	58.4	62.2	3.4	22.5	4.7	13.5
Ohio Edison Co.	BBB	6	36.8	47.5	49.1	5.5	23.1	5.2	12.4
Ohio Power Co.	BBB	4	56.5	58.3	59.5	3.4	22.1	4.7	16.1

DEBT RATINGS AND FINANCIAL METRICS FOR U.S. ELECTRIC UTILITIES

	S&P			S&P Credit Stats					
					Average 2003-2005				
Name	Debt Rating	Business Profile	2005 Debt Ratio [1]	2005 Debt Ratio	Debt Ratio	EBIT Coverage	FFO/Debt	FFO coverage	Average ROE 2003-2005
Otter Tail Corp.	BBB+	8	36.6	50.5	53.2	3.7	24.3	4.4	12.2
Pacific Gas & Electric Co.	BBB	5	57.0	60.4	59.0	2.6	26.4	3.2	30.1
PECO Energy Co.	BBB+	4	73.6	48.3	52.7	5.7	65.0	11.5	45.3
Pennsylvania Electric Co.	BBB	4	35.6	36.1	35.1	2.2	11.4	3.0	2.1
Pennsylvania Power Co.	BBB	6	40.6	41.3	39.8	9.1	53.4	10.9	18.6
PEPCO Holdings Inc.	BBB	5	60.1	64.0	65.1	2.1	12.1	3.0	7.4
Pinnacle West Capital Corp.	BBB-	6	46.8	57.5	60.3	2.5	16.5	3.6	7.6
PNM Resources Inc.	BBB	6	61.6	65.9	60.7	2.2	18.0	4.5	6.5
Portland General Electric Co.	BBB+	5	42.6	52.8	51.3	2.2	24.0	4.1	5.8
Potomac Electric Power Co.	BBB	3	55.5	52.2	54.7	2.8	21.8	4.2	11.8
PPL Corp.	BBB	7	62.3	66.8	69.3	2.7	18.2	4.0	20.0
Progress Energy Inc.	BBB	5	57.8	62.3	61.6	2.0	12.7	3.1	10.1
PSEG Power LLC	BBB	8	55.4	55.4	55.3	6.9	22.3	8.4	13.8
PSI Energy Inc.	BBB	4	57.1	57.6	56.2	3.7	15.4	4.5	9.7
Public Service Co. of Colorado	BBB	4	47.3	54.7	57.5	2.4	16.2	3.5	9.8
Public Service Co. of New Hampshire	BBB	5	66.7	64.7	65.9	3.9	23.0	6.4	11.6
Public Service Co. of Oklahoma	BBB	5	54.0	57.2	57.1	2.5	19.1	3.7	10.1
Public Service Electric & Gas Co.	BBB	3	62.6	52.5	55.4	3.3	20.9	4.2	12.0
Public Service Enterprise Group Inc.	BBB	7	67.9	69.8	65.6	3.7	16.6	4.6	13.8
Puget Energy Inc.	BBB-	4	55.6	60.5	64.3	1.7	14.1	3.3	6.4
Puget Sound Energy Inc.	BBB-	4	56.1	60.5	62.8	2.0	15.2	3.1	8.0
Rochester Gas & Electric Corp.	BBB+	3	54.5	53.6	52.1	2.3	31.9	4.4	9.1
Sempra Energy	BBB+	7	49.2	53.5	53.3	3.7	27.9	5.0	19.3
Southern California Edison Co.	BBB+	6	48.2	58.4	58.3	3.9	37.8	5.8	19.0
Southwestern Electric Power Co.	BBB	5	50.9	54.4	56.1	2.9	24.1	4.5	11.7
Southwestern Public Service Co.	BBB	5	52.8	54.6	53.5	2.8	19.2	3.9	8.2
Tampa Electric Co.	BBB-	4	50.9	51.3	50.1	3.3	21.7	3.9	9.4
Toledo Edison Co.	BBB	6	27.1	52.6	60.9	2.3	12.6	3.5	6.5
Union Electric Co.	BBB	5	48.0	48.8	46.4	6.4	30.5	7.9	13.8
Union Light Heat & Power Co.	BBB	5	38.7	73.0	71.5	1.3	8.5	2.7	9.2
Virginia Electric & Power Co.	BBB	5	49.7	52.2	54.5	3.5	20.3	4.6	7.3
Western Massachusetts Electric Co.	BBB	1	68.3	64.5	60.7	3.1	18.7	7.4	9.0
Wisconsin Energy Corp.	BBB+	5	59.5	63.2	65.6	2.7	15.2	4.0	11.8
Xcel Energy Inc.	BBB	5	57.6	64.3	63.2	2.2	16.8	3.5	9.7
All BBB Rated Companies									
Mean	**BBB**	**5**	**52.3**	**56.4**	**57.5**	**3.1**	**20.9**	**4.5**	**11.1**
Median	**BBB**	**5**	**51.8**	**56.8**	**57.2**	**2.8**	**19.5**	**4.1**	**10.5**
BBB Subgroup Business Profile 1-4									
Mean	**BBB**	**3**	**55.6**	**55.5**	**56.2**	**2.9**	**20.8**	**4.2**	**11.6**
Median	**BBB**	**4**	**55.6**	**57.6**	**55.9**	**2.7**	**18.7**	**3.7**	**11.1**
BBB Subgroup Business Profile 1-5									
Mean	**BBB**	**3**	**52.8**	**56.3**	**56.7**	**3.2**	**21.4**	**4.6**	**11.2**
Median	**BBB**	**3**	**51.9**	**55.6**	**56.1**	**2.9**	**20.9**	**4.2**	**10.8**
BBB Subgroup Business Profile 5									
Mean	**BBB**	**5**	**51.5**	**57.6**	**58.0**	**3.1**	**20.4**	**4.6**	**10.8**
Median	**BBB**	**5**	**51.0**	**55.4**	**56.1**	**2.7**	**20.9**	**4.0**	**10.6**
BBB Subgroup Business Profile 6									
Mean	**BBB**	**6**	**50.1**	**57.1**	**58.5**	**3.1**	**21.4**	**4.6**	**10.7**
Median	**BBB**	**6**	**51.2**	**57.3**	**59.0**	**2.7**	**18.7**	**4.2**	**10.5**
BBB Subgroup Business Profile 7									
Mean	**BBB**	**7**	**55.8**	**60.5**	**60.9**	**3.3**	**21.9**	**4.3**	**14.2**
Median	**BBB**	**7**	**54.7**	**59.3**	**61.5**	**3.5**	**20.6**	**4.3**	**13.7**
BBB Subgroup Business Profile 7-10									
Mean	**BBB**	**8**	**51.7**	**54.7**	**57.2**	**3.4**	**21.1**	**4.5**	**12.3**
Median	**BBB**	**8**	**49.0**	**56.0**	**56.6**	**3.5**	**20.9**	**4.1**	**12.4**
Entire Sample									
Mean	**BBB**	**5**	**52.1**	**56.2**	**57.1**	**3.2**	**21.4**	**4.6**	**11.3**
Median	**BBB**	**5**	**51.7**	**56.6**	**56.8**	**2.9**	**20.7**	**4.2**	**10.9**

1/ Sum of long- and short-term debt divided by the sum of long-term debt, short-term debt, common equity and preferred stock.

Source: Standard and Poor's Research Insight and Credit Stats.

INDIVIDUAL COMPANY RISK DATA FOR SAMPLE OF HIGH GENERATION US ELECTRIC UTILITIES

		Percent of Total Assets										
	Total Assets ($millions)	Generation	Wires (2006)	Other	Nuclear Supply %	Nuclear Assets as % of Total Assets 1/	Value Line Beta	Research Insight Beta 2/	Common Equity Ratio 2006	S&P Debt Rating	S&P Business Profile	Moody's Debt Rating
Allete	1368	45.9%	41.6%	12.5%	0.0%	0.0%	0.90	1.02	63%	BBB+	6	Baa2
Ameren	21250	54.1%	40.5%	5.5%	13.0%	7.0%	0.75	0.60	50%	BBB-	7	Baa2
American Electric Power	37289	39.3%	59.9%	0.8%	9.0%	3.5%	1.35	1.00	40%	BBB	5	Baa2
Black Hills	1498	51.4%	21.8%	26.9%	0.0%	0.0%	1.10	0.85	50%	BBB-	8	Baa3
Constellation	20084	80.3%	19.7%	0.0%	52.0%	41.8%	0.95	0.72	47%	BBB+	7	Baa1
Dominion	45800	35.3%	28.5%	36.3%	20.5%	7.2%	1.05	0.69	39%	BBB	7	Baa2
DPL	4553	88.4%	10.6%	1.0%	0.0%	0.0%	0.95	0.98	28%	BBB	6	Baa3
DTE Energy	23762	34.9%	43.1%	22.0%	15.9%	5.5%	0.75	0.72	39%	BBB	6	Baa2
Empire District	1397	33.4%	65.0%	1.6%	0.0%	0.0%	0.85	0.81	46%	BBB-	6	Baa2
Entergy	30608	55.0%	45.0%	0.0%	55.9%	30.8%	0.90	0.52	46%	BBB	6	Baa3
FPL	34444	56.2%	43.8%	0.0%	24.1%	13.5%	0.85	0.69	45%	A	5	A2
Great Plains Energy	4318	51.8%	37.6%	10.6%	22.0%	11.4%	0.95	0.83	50%	BBB	7	Baa2
IDACORP	3310	44.8%	51.2%	4.0%	0.0%	0.0%	1.05	0.81	49%	BBB+	5	Baa2
Pinnacle	11456	40.9%	51.3%	7.8%	25.4%	10.4%	1.00	0.94	51%	BBB-	6	Baa3
PNM	5400	44.3%	55.7%	0.0%	23.7%	10.5%	0.95	0.96	40%	BBB	6	Baa3
PPL	19747	40.7%	59.3%	0.0%	30.0%	12.2%	0.95	0.57	39%	BBB	7	Baa2
Progress Energy	20881	46.1%	52.6%	1.3%	45.7%	21.1%	0.95	0.81	47%	BBB+	5	Baa2
Scana	8032	42.1%	49.6%	8.3%	19.0%	8.0%	0.85	0.70	43%	A-	4	A3
Southern Co.	43449	47.6%	47.9%	4.4%	15.0%	7.1%	0.70	0.33	41%	A	4	A3
Westar	5455	58.6%	41.4%	0.0%	16.0%	9.4%	0.95	1.12	47%	BBB-	5	Baa3
Wisconsin Energy	11399	48.9%	51.1%	0.0%	25.3%	12.4%	0.80	0.47	40%	BBB+	4	A3
Mean	**16928**	**49.5%**	**43.7%**	**6.8%**	**19.6%**	**10.1%**	**0.93**	**0.77**	**44.8%**	**BBB**	**6**	**Baa2**
Median	**11456**	**46.1%**	**45.0%**	**1.6%**	**19.0%**	**8.0%**	**0.95**	**0.81**	**45.8%**	**BBB**	**6**	**Baa2**
Weighted Average		**47.8%**	**44.2%**	**8.0%**	**24.6%**	**12.6%**	**0.93**	**0.68**	**43.0%**	**BBB+**	**6**	**Baa1**

1/ Nuclear Assets % of Total Assets = Total Generation % * Nuclear Supply % (excluding purchased power)

2/ Calculated using monthly data against the S&P 500 (60 months ending June 2007); adjusted towards the market mean of 1.0.

Source: Standard and Poor's Research Insight, Value Line (data downloaded July 13, 2007), www.Moodys.com and
Standard and Poor's, *Issuer Ranking: U.S. Integrated Utility And Merchant Power Companies, Strongest to Weakest* (July 24, 2007).

INDIVIDUAL COMPANY RISK DATA FOR SAMPLE OF US WIRES UTILITIES

	Total Assets ($millions) (2006)	Total Gx % (2006)	Total Wires % (2006)	Other % (2006)	Value Line Beta	Research Insight Beta 1/	Common Equity Ratio 2006	S&P Business Profile	S&P Debt Rating	Moody's Debt Rating
Consolidated Edison	24584	2.9%	97.1%	0.0%	0.75	0.43	47.0%	2	A	A2
Energy East	11562	3.0%	94.3%	2.6%	0.95	0.69	41.0%	3	BBB+	Baa2
Nicor Inc.	4090	0.0%	92.8%	7.2%	1.30	0.99	50.7%	3	AA	Baa2
Northwest Nat. Gas	1957	0.0%	98.0%	2.0%	0.75	0.44	48.1%	1	AA-	A3
NSTAR	7769	2.6%	97.4%	0.0%	0.80	0.64	34.4%	1	A+	A2
Piedmont Natural Gas	2734	0.0%	97.2%	2.8%	0.80	0.60	47.0%	2	A	A3
Southwest Gas	3485	0.0%	96.1%	3.9%	0.85	0.51	38.9%	4	BBB-	Baa3
WGL Holdings Inc.	2791	0.0%	92.0%	8.0%	0.85	0.54	52.2%	3	AA-	A2
Mean	**7372**	**1.1%**	**95.6%**	**3.3%**	**0.88**	**0.60**	**44.9%**	**2**	**A**	**A1**
Median	**3788**	**0.0%**	**96.6%**	**2.7%**	**0.83**	**0.57**	**47.0%**	**3**	**A**	**A2**
Weighted Average		**2.2%**	**96.0%**	**1.8%**	**0.85**	**0.56**	**44.2%**	**2**	**A**	**A1**

1/ Calculated using monthly data against the S&P 500 (60 months ending June 2007); adjusted towards the market mean of 1.0.

2/ WGL Holdings is Washington Gas Light

Source: Standard and Poor's Research Insight, Value Line (Data pulled July 13, 2007), www.Moodys.com and
Standard and Poor's, *Issuer Ranking: U.S. Integrated Utility And Merchant Power Companies, Strongest to Weakest* (July 24, 2007).

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES
(Percentages)

	Decision Date	Regulator	Order/ File Number	Debt	Preferred Stock	Common Stock Equity	Equity Return	Forecast 30-Year Bond Yield
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Electric Utilities								
AltaLink	7/04; 11/06	EUB	2004-052; U2006-292	67.00	0.00	33.00	8.51	4.22
ATCO Electric		EUB						
Transmission	7/04; 11/06		2004-052; U2006-292	61.00	6.00	33.00	8.51	4.22
Distribution	7/04; 11/06		2004-052; U2006-292	56.10	6.90	37.00	8.51	4.22
EPCOR		EUB						
Transmission	7/04; 11/06		2004-052; U2006-292	65.00	0.00	35.00	8.51	4.22
Distribution	7/04; 11/06		2004-052; U2006-292	61.00	0.00	39.00	8.51	4.22
FortisAlberta Inc.	7/04; 11/06	EUB	2004-052; U2006-292	63.00	0.00	37.00	8.51	4.22
FortisBC Inc.	3/06; 12/06	BCUC	G-14-06; L-75-06	60.00	0.00	40.00	8.77	4.22
Hydro One Transmission	8/07	OEB	EB-2006-0501	60.00	0.00	40.00	8.35	4.16
Maritime Electric	6/06	IRAC	UE20934	57.31	0.00	42.69	10.25	na
Newfoundland Power	6/03;12/06	NLPub	PU 19(2003); PU 40(2006)	54.06	1.39	44.55	8.60	4.16
Nova Scotia Power	1/05;2/07	UARB	2005 NSUARB 27; 2007 NSUARB 8	53.30	9.20	37.50	9.55	na
Gas Distributors								
ATCO Gas	7/04; 11/06	EUB	2004-052; U2006-292	55.10	6.90	38.00	8.51	4.22
Enbridge Gas Distribution Inc	1/04; 7/07	OEB	RP-2002-0158; EB-2006-0034	61.33	2.67	36.00	8.39	4.23
Gaz Metropolitain	9/06	Régie	D-2006-140	54.00	7.50	38.50	8.73	4.55
Pacific Northern Gas	11/06; 5/07	BCUC	L-75-06; G-55-07	56.20	3.80	40.00	9.02	4.22
Terasen Gas	3/06; 12/06	BCUC	G-14-06; L-75-06	65.00	0.00	35.00	8.37	4.22
Union Gas	1/04; 3/04; 5/06	OEB	RP-2002-0158; RP-2003-0063; EB-2005-0520	60.60	3.40	36.00	8.54	4.23
Gas Pipelines								
Alberta Natural Gas	11/06; 2/06	NEB	RH-2-94;TG-02-2006	64.00	0.00	36.00	8.46	4.22
Foothills Pipe Lines (Yukon) Ltd.	11/06; 12/05	NEB	RH-2-94;TG-08-2005	64.00	0.00	36.00	8.46	4.22
TransCanada PipeLines	11/06; 5/07	NEB	RH-2-94/RH-2-2004/TG-06-2007	60.00	0.00	40.00	8.46	4.22
Trans Quebec & Maritimes Pipeline	11/06	NEB	RH-2-94	70.00	0.00	30.00	8.46	4.22
Westcoast Energy	11/06; 12/06	NEB	RH-2-94;TG-05-2006	64.00	0.00	36.00	8.46	4.22

Source: Board Decisions.

RATES OF RETURN ON COMMON EQUITY ADOPTED BY REGULATORY BOARDS FOR INVESTOR-OWNED CANADIAN UTILITIES

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Electric Utilities																		
AltaLink	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.40	9.60	9.50	8.93	8.51
ATCO Electric	13.50	13.50	13.25	11.88	NA	NA	11.25	1/	1/	1/	1/	1/	1/	9.40	9.60	9.50	8.93	8.51
FortisAlberta Inc.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.50	9.50	9.60	9.50	8.93	8.51
FortisBC Inc.	13.50	NA	11.75	11.50	11.00	12.25	11.25	10.50	10.25	9.50	10.00	9.75	9.53	9.82	9.55	9.43	9.20	8.77
Newfoundland Power	13.95	13.25	NA	NA	NA	NA	11.00	NA	9.25	9.25	9.59	9.59	9.05	9.75	9.75	9.24	9.24	8.60
Nova Scotia Power	NA	NA	NA	11.75	NA	NA	10.75	NA	NA	NA	NA	NA	10.15	NA	NA	9.55	9.55	9.55
TransAlta Utilities	13.50	13.50	13.25	11.88	NA	12.25	11.25	1/	2/	9.25	9.25	NA	9.40	NA	NA	NA	NA	NA
Mean of Electric Utilities	**13.61**	**13.42**	**12.75**	**11.75**	**11.00**	**12.25**	**11.10**	**10.50**	**9.75**	**9.33**	**9.61**	**9.67**	**9.53**	**9.57**	**9.62**	**9.45**	**9.13**	**8.74**
Gas Distributors																		
ATCO Gas	13.25	13.25	12.25	12.25	NA	NA	NA	10.50	9.38	NA	NA	9.75	9.75	9.50	9.50	9.50	8.93	8.51
Enbridge Gas Distribution	13.25	13.13	13.13	12.30	11.60	11.65	11.88	11.50	10.30	9.51	9.73	9.54	9.66	9.69	NA	9.57	8.74	8.39
Gaz Metro	14.25	14.25	14.00	12.50	12.00	12.00	12.00	11.50	10.75	9.64	9.72	9.60	9.67	9.89	9.45	9.69	8.95	8.73
Pacific Northern Gas	15.00	14.00	13.25	NA	11.50	12.75	11.75	11.00	10.75	10.00	10.25	10.00	9.88	10.17	9.80	9.68	9.45	9.02
Terasen Gas	NA	NA	12.25	NA	10.65	12.00	11.00	10.25	10.00	9.25	9.50	9.25	9.13	9.42	9.15	9.03	8.80	8.37
Union Gas	13.75	13.50	13.50	13.00	12.50	11.75	11.75	11.00	10.44	9.61	9.95	9.95	9.95	9.95	9.62	9.62	9.62	8.54
Mean of Gas Distributors	**13.90**	**13.63**	**13.06**	**12.51**	**11.65**	**12.03**	**11.68**	**10.96**	**10.27**	**9.60**	**9.83**	**9.68**	**9.67**	**9.77**	**9.50**	**9.52**	**9.08**	**8.59**
Gas Pipelines (NEB)																		
TransCanada PipeLines	13.25	13.50	13.25	12.25	11.25	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46
Westcoast Energy	13.25	13.75	12.50	12.25	11.50	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46
Mean of Gas Pipelines	**13.25**	**13.63**	**12.88**	**12.25**	**11.38**	**12.25**	**11.25**	**10.67**	**10.21**	**9.58**	**9.90**	**9.61**	**9.53**	**9.79**	**9.56**	**9.46**	**8.88**	**8.46**
Mean of All Companies	**13.68**	**13.56**	**12.94**	**12.16**	**11.50**	**12.13**	**11.36**	**10.84**	**10.15**	**9.52**	**9.78**	**9.67**	**9.59**	**9.70**	**9.56**	**9.48**	**9.07**	**8.64**

Note: A rate freeze was in effect for BC Gas (now Terasen Gas) in 1990 and 1991, BCUC regulation resumed in late 1991.
Nova Scotia Power was privatized in 1992.

1/ Negotiated settlement, details not available.
2/ Negotiated settlement, implicit ROE made public is 10.5%.

Source: Regulatory Decisions

COMPARISON BETWEEN ALLOWED EQUITY RISK PREMIUMS FOR CANADIAN AND U.S. UTILITIES

	Canadian Utilities			U.S. Utilities		
Year	Allowed ROE 1/	Average Long Canada Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium
1990	13.66	10.69	2.97	12.69	8.61	4.08
1991	13.58	9.72	3.86	12.51	8.14	4.37
1992	12.99	8.68	4.31	12.06	7.67	4.39
1993	12.19	7.86	4.33	11.37	6.59	4.78
1994	11.54	8.69	2.85	11.34	7.39	3.95
1995	12.13	8.41	3.72	11.51	6.85	4.66
1996	11.36	7.75	3.61	11.29	6.73	4.56
1997	10.88	6.66	4.22	11.34	6.58	4.76
1998	10.20	5.59	4.61	11.59	5.54	6.05
1999	9.52	5.72	3.80	10.74	5.91	4.83
2000	9.78	5.71	4.07	11.41	5.88	5.53
2001	9.67	5.77	3.90	11.04	5.50	5.54
2002	9.59	5.67	3.92	11.10	5.41	5.69
2003	9.70	5.31	4.39	10.98	5.03	5.95
2004	9.56	5.11	4.45	10.73	5.08	5.65
2005	9.48	4.38	5.10	10.50	4.52	5.98
2006	9.07	4.33	4.74	10.39	4.93	5.46
2007q2	8.57	4.26	4.31	10.30	4.90	5.40
Means:						
1990-1993	**13.10**	**9.24**	**3.87**	**12.16**	**7.75**	**4.41**
1994-1998	**11.22**	**7.42**	**3.80**	**11.41**	**6.62**	**4.80**
1999-2007q2	**9.44**	**5.14**	**4.30**	**10.80**	**5.24**	**5.56**

1/ 2007 ROE represents results for the entire year.

Note: For U.S. Treasury yields, 30-year maturities used through January 2002; theoretical 30-year yield from February 2002 to January 2005; 30-year maturities February 2002 forward.

Sources: Regulatory Research Associates; www.snl.com; Various Canadian Regulatory Decisions; Bank of Canada; Federal Reserve; U.S. Treasury.

QUANTIFICATION OF IMPACT ON EQUITY RATIO REQUIREMENT TO EQUATE EQUITY RETURN FOR OPG'S REGULATED OPERATIONS TO THE ROE REQUIRED FOR BENCHMARK LOW RISK U.S. GAS & ELECTRIC UTILITIES
(Example at Mid-Point of Recommended Range)

Formula for After-Tax Weighted Average Cost of Capital:

$WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

ASSUMPTIONS:

	Debt Cost	=	Current Cost of Long Term Debt for A rated utility
		=	6.0%[1]
	Equity Cost	=	Cost of Equity [2]
		=	11.88%
	Tax Rate	=	34.0%[3]
Average of Results Under the Two Approaches		=	10.50%

THEORY 1:
The after-tax weighted average cost of capital ($WACC_{AT}$) is invariant to changes in the capital structure. The cost of equity falls as leverage (debt ratio) decreases, but the $WACC_{AT}$ stays the same.
STEPS:

1. Estimate $WACC_{AT}$ at the benchmark common equity ratio of 45%
   $WACC_{AT}$ = (6.0%)(1-.34)(55%) + (11.875%)(45%)
   = 7.52%
2. Estimate Cost of Equity for sample at 55.0% common equity ratio with $WACC_{AT}$ unchanged at 7.35%
   $WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)
   7.52% = (6.0%)(1-.34)(42.5%)+(X)(57.5%)
   Cost of Equity at 55% Equity Ratio = 10.20%

THEORY 2:

After-Tax Cost of Capital Increases as Debt Ratio Decreases; Cost of Equity Declines
STEPS:

1. Estimate $WACC_{AT}$ at the benchmark common equity ratio of 45%
   $WACC_{AT}$ = (6.0%)(1-.34)(55%) + (11.875%)(45%)
   = 7.52%
2. Estimate $WACC_{AT}$ for 57.5% common equity ratio (LL - less levered)
   $WACC_{AT(LL)} = WACC_{AT(Benchmark)}$ x (1-t x Debt $Ratio_{LL}$)/(1-t x Debt $Ratio_{Benchmark}$)
   $WACC_{AT(LL)}$ = 7.52% x $\frac{(1-.34 \times 42.5\%)}{(1-.34 \times 55.0\%)}$
   $WACC_{AT(LL)}$ = 7.91%
3. Estimate Cost of Equity at new $WACC_{AT}$ for less levered firm:
   $WACC_{AT(LL)}$ = (Debt Cost)(1-tax rate)(Debt $Ratio_{LL}$) + (Equity Cost)(Equity $Ratio_{LL}$)
   7.91% = (6.0%)(1-.34)(42.5%) + (X)(57.5%)
   Cost of Equity at 57.5% equity ratio = 10.80%

[1] Forecast Long Canada plus spread on A-rated utility debt.
[2] Based on Incremental Return Analysis, Appendix I
[3] Combined Federal/Ontario tax rate.