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May 15, 2009

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, B.C. V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc. ("TGI", the "Company"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGW")
Collectively the "Terasen Utilities"
Return on Equity and Capital Structure

On behalf of the Terasen Utilities, we respectfully attach our application for Return on Equity and Capital Structure (the "Application").

We propose that a Procedural Conference be held, on Tuesday, June 9, 2009, to determine the most appropriate review process for the Application, subject to confirmation by the British Columbia Utilities Commission (the "Commission"). The Commission hearing room located at the 12th floor, 1125 Howe Street, Vancouver, BC was confirmed to be available and has been tentatively reserved.

Pursuant to Commission Order No. L-78-06, the Terasen Utilities have provided the Commission with a Draft forms of Procedural Order which includes a Draft Regulatory Timetable for the Commission's consideration.

Sincerely,

TERASEN GAS INC.
TERASEN GAS (VANCOUVER ISLAND) INC. and
TERASEN GAS (WHISTLER) INC.

Original signed by:

Scott A. Thomson
Vice President, Regulatory Affairs & CFO

Attachments

cc (email only): Parties to the TGI 2004-2009 Multi-Year PBR Settlement
Parties to the Terasen Gas (Vancouver Island) Inc. 2006-2009 Negotiated Settlement
Parties to the 2005 TGI-TGVI ROE Proceeding
PNG
FortisBC
BC Hydro
BCTC

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Return on Equity and Capital Structure

This Application is made pursuant to sections 59 and 60 of the *Utilities Commission Act* (the "Act") for an order or orders of the British Columbia Utilities Commission ("BCUC" or "Commission") to revise the rates of the Terasen Utilities to reflect the relief requested herein. The Terasen Utilities request that the Commission consider the relief requested and matters raised in the Application.

The Terasen Utilities request that the Commission determine an increased return on common equity ("ROE") for TGI for rate-setting purposes, and that the so determined ROE for TGI be used in establishing the ROE of TGVI and TGW used for rate-setting. The Terasen Utilities request that the revised ROE for TGI, TGVI and TGW be effective July 1, 2009.

The Terasen Utilities request that the Commission eliminate the use of an ROE automatic adjustment mechanism ("AAM") in the determination of the ROE to be used by the Terasen Utilities for rate-setting. While an AAM may be desirable for administrative efficiency, the AAM must produce an allowed ROE that is a fair return for the public utilities that are subject to the mechanism. The AAM used by the BCUC at the current time does not result in a fair return. For this reason, elimination of the current AAM is requested.

In replacement of the use of an AAM in the determination of their ROE, the Terasen Utilities request that the ROE determined in this proceeding to be appropriate for TGI be used as the benchmark or generic ROE ("Benchmark ROE") for the determination of the ROE of TGVI and TGW. TGVI and TGW request that the Commission continue to set their respective allowed returns on equity with reference to the Benchmark ROE established in this proceeding by adding a utility specific risk premium of 70 basis points in the case of TGVI and 50 basis points in the case of TGW to the Benchmark ROE.

TGI requests that the Commission alter and increase the common equity component of the capital structure of TGI for rate-setting purposes. TGI requests that the increased common equity component be included in the setting of TGI effective January 1, 2010.

The Company and TGW further request that the Commission set their current rates as interim, effective July 1, 2009, until such time as permanent rates are established which give effect to the relief requested in this Application.

TGVI is not requesting changes to its 2009 rates, but rather requests that, pursuant to the provisions of the Special Direction, the increase in its allowed ROE resulting from the Commission's determinations in this proceeding be treated as an increase to TGVI's cost of service, effective July 1, 2009, which will result in an adjustment to the 2009 Revenue Deficiency or Revenue Surplus and will be reflected in the Revenue Deficiency Deferral Account balance.

The Terasen Utilities recognize that other investor owned utilities regulated by the BCUC may wish to have their allowed returns established with reference to the Benchmark ROE and expect that they will indicate their positions on these matters through intervention in this proceeding.

Background to this Application

The Commission first introduced a generic ROE adjustment mechanism in 1994 to annually establish the allowed returns on equity for the utilities it regulates in the province. The 1994 Decision established a return on equity for the benchmark "low risk" utility in British Columbia and BC Gas Utility Ltd. (now Terasen Gas Inc.) was deemed the benchmark low risk utility. The 1994 Decision introduced an automatic adjustment mechanism to reset the annual generic allowed return on equity. The formula introduced at that time adjusted the allowed ROE on a one for one basis with movements in the forecast long-term Government of Canada Bond ("GCB") yield provided the yield had moved more than 50 basis points year over year.

Shortly thereafter, the National Energy Board ('NEB") established a generic allowed ROE for the pipelines it regulated in the 1995 Multi-Pipeline Cost of Capital Proceeding (Decision RH-2-94). In the RH-2-94 Decision, the NEB approved an ROE for a low risk, high-grade benchmark pipeline, based primarily on the equity risk premium test. The ROE was set at 12.25% for the 1995 test year and the Board also adopted a formula for adjusting the allowed ROE on an annual basis for 75% of the change in the forecast GCB yield from a base of 9.25%.

In 1997, the BCUC recalibrated the ROE adjustment mechanism by Order G-49-97 using a benchmark ROE of 12.25% at a long-term GCB yield of 9.25%. The Order introduced a sliding scale adjustment of 80% of the movement of the forecast yield of the 30 year GCB from a starting point of 9.25%. In that Order the Commission directed that the range of long-term GCB yields over which the adjustment formula will apply was 6% to 12%.

In 1999, the BCUC once again examined the generic ROE and automatic adjustment mechanism. In its Order G-80-99, the Commission set the low risk benchmark ROE at 9.50% when the long-term GCB yield was forecast to be 6.00% and fixed the equity risk premium at 350 basis points when the GCB yield was forecast to be below 6.00% and adjusted for 80% of the movement of the long-term GCB yield above 6.00%.

In the last hearing into Cost of Capital in 2005 (resulting in Order G-14-06), the Commission adjusted the starting point for the formula based ROE to 9.145% when the long-term GCB yield is forecast to be 5.25%, modified the sliding scale adjustment factor to 75% of the movement in the GCB forecast from 80% and eliminated the asymmetry in the sliding scale adjustment mechanism above and below 6%.

During this period, the Ontario Energy Board ("OEB") in 1997, the Régie de l'Energie de Québec ("Régie") in 1998 and the Alberta Energy and Utilities Board ("EUB") in 2004, adopted formulas substantially similar in design and resulting ROEs to the BCUC and NEB formulas.

While there has been some evolution in the parameters and the mechanics of the BCUC formula over the intervening decade and a half, it has converged with the design and ROE produced by the NEB formula. Today the BCUC formula continues to annually adjust allowed ROE by 75% of the movement in forecast 30 year GCB yields, a similar adjustment to the operation of the RH-2-94 formula.

In 2008 the NEB heard the application of Trans Quebec & Maritimes Pipeline ("TQM") to establish an allowed return on equity and capital structure for 2007 and 2008. The Decision in that proceeding was a major departure from the formulaic means by which the NEB had determined allowed ROE since 1995 for the major pipelines it regulated. In the RH-1-08 Reasons for Decision released in March 2009 (the "TQM Decision"), the NEB decided that the ROE for TQM should not be set by the RH-2-94 formula. Subsequent to this Decision the NEB communicated with the companies regulated by it, and regular Intervenors, advising that it had decided to consider whether it should initiate a review of the RH-2-94 Decision; and soliciting comments from interested parties. The Alberta Utilities Commission ("AUC") has a generic proceeding underway respecting cost of capital for the utilities it regulates and the OEB has sought submissions on the relationship between current economic and financial conditions and the returns produced by its ROE formula, and what adjustment should be made to cost of capital parameters.

This Commission must also review its formulaic approach to determining the ROE allowed in the rates of the utilities it regulates. Such a review is sought by this Application.

<u>Structure of the Application</u>

The evidence in this application is structured as follows:

- The Company's Application Letter
- Tab 1 – Business Risks
- Tab 2 – Testimony of Mr. Donald A. Carmichael, MBA
- Tab 3 – Opinion of Ms. Kathleen C. McShane, MBA, CFA
- Tab 4 - Evidence of Dr. James H. Vander Weide, PhD
- Appendices – Studies and expert commentary on Fair Returns and the shortcomings of the current formula ROE approach

<u>Reasons for a Review</u>

The Terasen Utilities believe there are four compelling reasons for the Commission to undertake this review and adjust both the Benchmark ROE and TGI's equity thickness.

The Commission's 2006 Decision Triggers Review

First, a review is required based on the Commission's March 2006 Decision respecting TGI's last application for a review of ROE and capital structure (the "2006 Decision").

The Commission's 2006 Decision[1] stated that:

> ***"In light of the AEUB finding in its 2004 Generic Cost of Capital Decision, the Commission Panel will adopt a review period of five years, while noting that any party continues to be free at any time to apply to the Commission to consider a review of the AAM. In addition, should the AAM result in a ROE for the benchmark low-risk utility of less than 8 percent or greater than 12 percent the Commission will canvass the views of the parties on whether the AAM should be reviewed."***

Under the current formula, when the forecast long-term GCB yields fall below 3.72% the formula produces an allowed ROE of less than 8%.

In December 2008, yields on 30 year GCBs hit 3.40%, a level not seen since the mid-1950s, and the January 2009 equivalent to the November Consensus forecast on which the annual benchmark ROE is set was 3.57%. The 3.57% forecast 30 year GCB yield falls below the level that would result in an ROE award of 8%, which the Commission recognized should trigger a review of the generic ROE adjustment mechanism.

Recent NEB Decision Suggests ROE and Cost of Capital Review Required

Second, the recent decision from the NEB respecting TQM suggests that it is imperative that the ROE formula be revisited.

On March 19, 2009 the NEB released its TQM Decision, on TQM's application relating to the cost of capital to be utilized by TQM in the calculation of its final tolls for the years 2007 and 2008. Effectively the TQM application was to allow for the determination of an overall fair return on capital for those two years. In its application TQM sought relief from the results of the NEB's formula for the setting of ROE, and in the TQM proceeding the formula and the appropriateness of its results were examined.

The results produced by the ROE formula that the NEB reviewed are very similar to those produced by the current BCUC formula under which the Terasen Utilities operate. For the period 1995 through 2006, TQM's returns had been set in accordance with the formula established in the 1994 Multi-Pipeline Cost of Capital Proceeding Decision RH-2-94. As noted above, while the NEB formula uses a different base GCB yield than the current BCUC formula (9.25% vs. 5.25%), the results are substantially the same; for 2009 the NEB formula produces an allowed ROE that is only 10 basis points different from the BCUC formula ROE for the benchmark low risk utility.

[1] Page 16, Section 3.2 Review Process, March 2, 2006 Decision

The TQM Decision is noteworthy in many respects, and supports the Company's conclusion that the BCUC should undertake a review of the benchmark ROE, the ROE adjustment formula, and TGI's capital structure.

In the RH-1-2008 Decision the NEB discarded the ROE determination from the RH-2-94 formula, and effectively increased the allowed ROE for TQM, at the previously approved capital structure, by almost 300 basis points over what the RH-2-94 formula produced for 2007 and 2008. The magnitude of the variance provides a strong indication that the formula had veered dramatically off course.

Although this recent Decision is only applicable to TQM, the NEB made a number of determinations that are applicable more generally. In the TQM Decision the NEB accepted a number of factors and arguments that TGI and other Canadian utilities have previously put forward in cost of capital proceedings but which had not previously been given weight by their respective regulators. These factors, which will be discussed further below, were instrumental in forming the TQM Decision and are widely applicable in informing a fair return for Canadian utilities generally and for TGI specifically.

It is also noteworthy that the significant increase in TQM's allowed return for 2007 and 2008 was based on an evidentiary record that preceded the deterioration in capital market conditions that occurred in the latter part of 2008 and early 2009. In other words, the NEB found that a significant increase in the allowed ROE was warranted even before the dramatic risk re-pricing evidenced in the run up in both corporate borrowing costs and equity costs. The risk re-pricing that occurred over the winter, and which was not considered by the NEB in its conclusion that the RH-2-94 formula produced results that were materially below a fair return, indicates that a similar review today would likely produce an even greater variance from the formula ROE.

Commission's Obligations Point to Need for Review

Third, the Terasen Utilities submit that the Commission is compelled to revisit the ROE formula based on its obligations under the *Utilities Commission Act*. In particular those parts of sections 59 and 60 which require that the Commission establish rates that are not unjust or unreasonable while providing investors in the public utilities regulated by the Commission an opportunity to earn a fair return on their capital. This is highlighted by the Commission's determinations at page 7 and 8 of the 2006 Decision as follows:

> *"The Commission's mandate is to ensure that ratepayers receive safe, reliable and non discriminatory energy services at fair rates from the public utilities it regulates, and that shareholders of those public utilities are afforded a reasonable opportunity to earn a fair return on their invested capital. The process to establish a fair return and just and reasonable rates is enshrined in the UCA where "the commission must consider all matters that it considers proper and relevant affecting the rate" and in doing so it must have due regard to the setting of a rate that "is not unjust or unreasonable" within the meaning of section 59 (of the Act) [UCA, s.60 (1)(a) and (b)(i)].*
>
> *The reasons of Locke J. and Martland J. in the B.C. Electric Railway case are ad idem on the matter of the need to consider both the costs of providing service and a fair return on invested capital used or prudently incurred to provide the service.*

[quotations from judgments of Locke J and Martland J omitted]

The submissions of the Applicants and the Intervenors in this proceeding are not ad idem regarding the appropriate consideration of the "balancing of interests". The Commission Panel finds the reasons of Locke J. and Martland J. instructive, and notes that they are accepted in the Bell Canada case. The Commission Panel does not accept that the reference by Martland J. to a "balancing of interests" to mean that the exercise of determining a fair return is an exercise of balancing the customers' interests in low rates, assuming no detrimental effects on the quality of service, with the shareholders' interest in a fair return. In coming to a conclusion of a fair return, the Commission does not consider the rate impacts of the revenue required to yield the fair return. Once the decision is made as to what is a fair return, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital."

The Commission must adhere to the Fair Return Standard which has been established by Canadian and US courts and was reaffirmed by the NEB in the recent TQM Decision at page 6:

"The Board has considered the arguments put forward by TQM and CAPP and continues to believe that the legal framework for determining a fair return is as set out in Chapter 2 of the RH-2-2004, Phase II Decision. The Board notes that these views were based on the Federal Court of Appeal Decision in TransCanada v. NEB.

When using the cost of service approach to determine tolls, the cost of capital is determined using the Board's sound judgment. Often the largest and therefore most important portion of cost of capital is the overall return on equity. While customers and consumers have an interest in ensuring that the cost of equity is not overstated, in the Board's view, this is factored in by having intervenors test and challenge the position the company has put forward. It does not mean that in determining the cost of capital that investor and consumer interests are balanced. In the Board's view, the Federal Court of Appeal was clear that the overall return on equity must be determined solely on the basis of a company's cost of equity capital, and that the impact of any resulting toll increase is an irrelevant consideration in that determination.

Therefore, the Board reaffirms the Fair Return Standard as articulated on page 17 of the RH-2-2004, Phase II Decision. The Fair Return Standard requires that a fair or reasonable overall return on capital should:

- *be comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement);*
- *enable the financial integrity of the regulated enterprise to be maintained (financial integrity requirement); and*
- *permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (capital attraction requirement)."*

The evidence presented in this Application demonstrates that this obligation is no longer being met by the current BCUC ROE formula. To properly serve the broad public interest, it is critical that British Columbia utilities are in a position to maintain their financial health. This is necessary to ensure that they can:

- meet their customers' service needs at a reasonable cost;
- attract investment capital at reasonable cost under all market conditions;
- earn a fair and reasonable return on previously invested capital;
- support the Energy and Environmental Policy objectives of the BC Government;
- pursue investments in efficiency; and
- be sustainable in the face of ongoing and changing business risks.

Worsening Market Conditions Shows Current Mechanism Is Flawed

Fourth, business conditions have changed dramatically since the 2005 BCUC cost of capital hearing, and the nature of those changes strongly suggests the Commission should reset the Benchmark ROE and increase the equity in TGI's capital structure.

Since 2006, the current mechanism has driven allowed ROE levels lower and lower even while utility debt costs have moved higher in absolute terms. Risk has been re-priced by the market and the costs of debt and equity capital have increased, as noted by the Company's witnesses in this proceeding and by market commentators, and as evidenced by the dramatic widening of corporate credit spreads in recent months. This has exacerbated the inadequate formula-driven ROE results that pre-date the recent market developments as the allowed ROEs in BC under the formula have continued to decline steadily:

- The gap between returns in BC (and other Canadian jurisdictions which employ a similar formulaic approach) has continued to increase relative to those in jurisdictions that have not relied on a formula tied to long bond rates (most notably jurisdictions in the US);
- No new pipelines are being built under formula based allowed returns in Canada. These have been constructed under negotiated capital structures and ROEs as the formula based ROEs are not adequate; and
- More recently, the formula is producing allowed returns that have narrowed in relation to investment grade utility corporate bond yields. In fact, in December 2008 indicative TGI 30 year new debt issue costs came within 18 basis points of the potential formula generated ROE based on that month's forecast of long-term GCB yields. This minimal spread between debt costs and formula based equity returns would not provide an adequate return for equity risk takers and underscores the fact that the formula isn't working.

There have been significant reductions in the yields on long-term GCBs used to determine the allowed return on equity since the automatic adjustment mechanism was first introduced, as well as material changes in both the general economic conditions and the risk profile of TGI over that period of time. These changes, and the allowed returns on equity calculated through the automatic adjustment mechanism, have resulted in inadequate returns for utility investments in British Columbia.

The evidence establishes that the current AAM has veered dangerously off course. With the benefit of hindsight, evidence is now available (see Section 3 B 4 of Dr. Vander Weide's testimony "Evidence on the Sensitivity of the Forward-looking Required Equity Risk Premium on Utility Stocks to Changes in Interest Rates") that indicates that the adjustment factor used in the current formula should have been less than 50% of the movement in long-term GCB rates. That information was not available to the Company or the Commission at the time of the 2005 hearing.

The Way Forward: Revisiting the ROE and Capital Structure

In light of these realities, it is appropriate at this time for the Commission to re-examine the cost of capital for TGI (and indirectly for the other Terasen Utilities) and increase the return on equity for TGI (which has been considered the benchmark utility). The Commission must also review and eliminate the use of the current ROE automatic adjustment mechanism, in order to provide the public utilities it regulates with the opportunity to earn a fair return on the capital they have invested.

In addition, the Commission should establish a capital structure for TGI that more appropriately reflects the business and financial risks of the company, and which is in line with its North American peers. Canadian utilities generally are thinly capitalized compared to the US utilities with whom they compete for capital. It is not sufficient to simply increase TGI's equity thickness to bring it in line with the increases in equity thickness granted to other Canadian utilities in recent years.

This Application presents the Company's case respecting the required change in ROE and also an increase to the deemed equity component of TGI's capital structure. The Application is structured around the following evidence and relief being sought:

Part 1: A Flawed Methodology. This Section presents evidence that the ROE resulting from the Commission's ROE formula is inadequate and must be increased in order for the Terasen Utilities to be allowed an opportunity earn a fair return This Section also provides evidence that the capital structure under which the Company operates should be changed if it is to compete for capital effectively.

When the evidence is considered it will be clear that the allowed return on equity resulting from the current formula, as well as the common equity component in the capital structure of TGI deemed for rate making purposes, must be increased.

Part 2: The Proposed Solution. This Section will set forth a recalibrated ROE for TGI (and the Benchmark ROE) and a more appropriate capital structure for TGI. Specifically:

- The Terasen Utilities request that the return on equity allowed for TGI, which will be the Benchmark ROE, be set at 11% effective July 1, 2009;

- TGI requests that the deemed common equity component in its capital structure allowed for rate making purposes be increased to 40%, as compared to the current 35.01% with effect from January 1, 2010[2].

- TGW requests that the company specific risk premium of 50 basis points recently established by the Commission in the Commission's recent Decision in relation to TGW's 2009 Revenue Requirements continue, and be applied to the new Benchmark ROE that is to be made effective July 1, 2009; and

- TGVI requests that the company specific risk premium of 70 basis points that was established for TGVI in the 2006 Decision continue, and be applied to the new Benchmark ROE that is to be made effective July 1, 2009.

The Terasen Utilities are confident that the evidence presented in this Application demonstrates that these requests are reasonable and warranted.

Part 1: A Flawed Methodology

With the passage of time and the availability of empirical evidence, it has become clear that the Commission's AAM – even considering the revisions made to it – is flawed, and its results inadequate   The flaws are significant, with the consequence that the ROE determined by the AAM is not sufficient to produce fair returns on the equity invested in the utility assets of the Terasen Utilities. Moreover, the capital structure under which TGI operates is no longer appropriate if TGI is to ensure its cost-effective access to capital, and if it is to achieve comparability with its North American peers. Capital structure and ROE are inextricably linked and cannot be examined properly in isolation from one another. These two components, together with debt costs, must be considered so that they result in an overall return on rate base which is fair.

This Section of the Application presents the following evidence:

1.0 The Fair Return Standard is No Longer Being Met;

2.0 The Formula is Broken;

3.0 Unprecedented Turbulence In Credit Markets Further Reinforces The Need To Change The Formula; and

4.0 TGI's Business Risk is Changing

[2] TGI's deemed equity thickness was increased from 35% to 35.01% pursuant to a Special Direction related to the amalgamation of Terasen Gas (Squamish) Inc. and TGI to ensure the resultant capital structure reflected the weighted average capital structure of the two predecessor companies. TGI anticipates a final decision in this matter will not be rendered until late in 2009. TGI therefore proposes as a practical matter that that the increase in its common equity component be made effective January 1, 2010, and rates for 2010 be set on that basis, similar to the manner in which an increase in its equity component was dealt with in respect of the 2006 Decision.

Combined, these four realities mean that the results of the current formulaic approach to ROE are inadequate, and the current equity component in the capital structure of TGI should be increased. The Commission should update both the Benchmark ROE and TGI's capital structure. This will be an important and required determination to enable utilities in BC to operate from a healthy and sustainable foundation and continue to appropriately serve the public interest.

1.0 The Fair Return Standard Is No Longer Being Met

The evidence establishes that the current BCUC ROE formula and the results it is generating do not meet the Fair Return Standard for BC utilities.

The Fair Return Standard is an accepted and established standard. It has been derived from accepted legal precedents and has been referred to in numerous regulatory decisions in Canada and the US. It was also re-affirmed by the NEB in its TQM Decision earlier this year. Section III of the evidence of Ms. Kathleen McShane discusses the derivation of the Fair Return Standard. According to the standard a fair return must give 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.**

Ms. McShane states that:

> "*The legal precedents make it clear that the three requirements are separate and distinct. None of the three requirements is given priority over the others. The fair return standard is met only if all three requirements are satisfied. In other words, the fair return standard is only satisfied if the utility can attract capital on reasonable terms and conditions, its financial integrity can be maintained and the return allowed is comparable to the returns of enterprises of similar risk."*

In March 2008 the Honourable John C. Major, former Justice, Supreme Court of Canada, and Roland Priddle, former Chair of the National Energy Board, published "The Fair Return Standard for Return on Investment by Canadian Gas Utilities"[3]. This paper discusses the legal foundations of the Fair Return Standard ("FRS') and the obligations it places on regulators to set a fair and reasonable return. It also discusses the convergence of Canadian regulators on the adoption of formula based Automatic Adjustment Mechanisms very similar to the current AAM used by the BCUC. Significantly Major/Priddle state that:

> *"The now-universal generic ROE approach by Canadian regulators of major gas utilities has created some regulatory economies. But unfortunately its mechanistic character suspends for lengthy periods the previously-valued application of informed*

[3] The Fair Return Standard for Return on Investment by Canadian Gas Utilities: Meaning, Application, Results, Implications; by the Honourable John C. Major and Roland Priddle - March 2008, see Appendix 1

> *judgment to the results of alternative methods of achieving the FRS required by Canadian jurisprudence in ROE awards.*
>
> *A wide and unprecedented gap has developed between Canadian gas utility ROEs and those of USA utilities and of North American low risk industrials.* ***This is factual ground for concluding that the FRS, essentially the opportunity cost of capital needed to ensure financial integrity and capital attraction, is no longer being achieved by the generic ROE approach.***" [emphasis added]

The paper concludes by saying:

> *"Finally, in an era of North American economic and business integration, the question must be asked "Can Canadian gas utilities successfully compete for capital if their regulators continue to award lower returns on generally thinner equity shares than those enjoyed by the American industry?"*
>
> *"Absent such a reconsideration and consequent adjustment, in an environment of continuing very low interest rates and bond yields, the present generic ROE formula alone may not be protecting the public interest in the provision by incumbent utilities of a robust, flexible natural gas delivery structure financially strong to support future sustainability of our energy economy."*

Many industry observers erroneously attribute the introduction of an AAM to the NEB. The NEB adopted its formula to adjust the return on equity of the major pipelines it regulates shortly after the BCUC introduced an AAM in 1994. Nonetheless, there is a widely held belief that provincial regulators take notice of and are mindful of the findings of the NEB, and that the NEB's adoption of a formula based approach influenced the adoption of similar approaches in Alberta, Manitoba, Ontario, Quebec and Newfoundland.

It is significant that former NEB Chair Priddle (who was the Presiding Member of the NEB panel in the RH-2-94 proceeding that adopted a formulaic approach to ROE determination), now no longer has confidence that the current AAM provides Canadian utilities with an opportunity to earn a fair return, or attract capital when in competition with American utilities of similar risk profile.

The events that have occurred in financial markets since the Major/Priddle paper was published create a heightened sense of urgency as well as need for action by regulators.

1.1 Despite Adjustments, Fair Return Still Not Being Achieved

The Terasen Utilities do not believe they are earning a fair return and share Justice Major's and former Chair Priddle's lack of confidence in the formula's ability to allow Canadian utilities an opportunity to earn a fair rate of return relative to their peers. Improvements have been made to the sliding scale mechanism in the BCUC ROE formula, but these have been insufficient to allow the formula to meet the Fair Return Standard for investors in BC utilities.

With its 2006 Decision, by eliminating the asymmetry of the risk adjustment where long GCB yields were above and below 6%, the Commission addressed a flaw in the sliding scale mechanism that had been introduced in 1999. Nonetheless, the point of departure for the re-calibration of the current adjustment mechanism, which now adjusts for 75% of the change in forecast long-term GCB yields, was set based on an equity risk premium of 390 basis points over the forecast yield. This, when combined with the deemed capital structure of TGI, produces an allowed ROE that results in investors in TGI earning the lowest effective return in Canada.

The evidence demonstrates that, despite some recalibration by the Commission, the current ROE formula under which BC utilities operate, combined with the current capital structure, does not allow equity invested in TGI's utility assets to obtain a fair return.

1.2 BC Policy: A Commitment to Attracting Capital (at Odds with Allowed ROE)

The disadvantaged position of utilities in BC is even less favourable when considered in light of the Provincial Government commitment to capital attraction. The 2002 Policy document *"Energy for our Future: A Plan for BC"*, the Minister for Energy and Mines stated:

> *"Rising energy demands and aging facilities call for major financial investment in plant upgrades and new energy production and delivery facilities. This, in turn, requires better access to energy resources and the timely, cost-effective development of new supplies. Unless domestic energy sources are developed, British Columbians could find themselves increasingly dependent on imports and vulnerable to price swings. The government, faced with competing fiscal priorities, is looking to the private sector for much-needed energy development."*

These capital attraction objectives are even more relevant in 2009 when the Provincial Government is incurring deficits to stimulate the economy in the face of the current economic crisis. The Government is looking to the private sector to provide much needed investment in the provincial economy both directly, and through public private partnerships.

The February 2009 budget discusses the government's focus on the private sector in driving the economy and providing the source of capital investment in the province for infrastructure:

> *"In 2002, government committed to increase the role of the private sector in the delivery of public infrastructure with the intention of minimizing costs and risks to taxpayers. By 2007, public-private partnerships (P3) became the base case for capital investment decisions over $20 million.*
>
> *The government places a high priority on encouraging a thriving private sector economy that creates high-paying jobs while maintaining high environmental standards. A focus on results based regulation has created an environment that supports sustainable resource management."*

The message is clear – the Government is increasingly looking to the private sector to drive the economy through capital investment. Inadequate returns for investor-owned utilities are contrary to the Government's objectives.

1.3 Lack of Fair Return Hinders Competition for Capital in Canada

Such investment is increasingly unlikely to take place if the current allowed rates of return on equity are not changed. Under the Commission's current AAM, TGI has amongst the lowest allowed returns on equity of any regulated gas or electric utility in Canada at 8.47% (which was set based on a forecast long-term GCB yield of 4.35%) and the lowest effective total return on equity. At 35.01% TGI also has the lowest level of common equity in its capital structure of the major Canadian investor-owned gas and electric distribution utilities.

This higher leverage (more debt, less equity) makes TGI even less attractive to equity investors. Because higher leverage increases financial risk, it can impact the company's credit ratings, degrade financial ratios and debt covenant tests and impact its ability to attract capital on reasonable terms and in sufficient quantities under all market conditions.

Sub-standard utility investment returns do not create the investment climate the Provincial Government wants to foster given the infrastructure challenges we are facing in BC.

TGI's disadvantage can perhaps best be illustrated by the following table. The table reflects the effective returns on equity of the utilities listed for 2008/09. TGI's allowed return was set using a forecast long GCB yield of 4.35%. The first two columns show the disadvantage that TGI suffers against comparable Canadian utilities in allowed equity thickness and in allowed returns on equity. The third column shows how these two disadvantages compound to create an approximate fifty basis point disadvantage on average for return on investment in TGI rate base compared to other major gas and electric utilities in Canada.

	Current Allowed ROE	Equity Component	Effective Return	Advantage to Terasen (bps)	Year Set
Newfoundland Power	8.95%	44.55%	3.99%	102.2	2009
Maritime Electric	9.75%	40.00%	3.90%	93.5	2009
TGVI	9.17%	40.00%	3.67%	70.3	2009
FortisBC	8.87%	40.00%	3.55%	58.3	2009
Gaz Metro	8.94%	38.50%	3.44%	47.7	2009
TCPL	8.57%	40.00%	3.43%	46.3	2009
Atco Gas *	8.75%	38.00%	3.33%	36.0	2008*
FortisAlberta*	8.75%	37.00%	3.24%	27.2	2008*
Westcoast Energy Inc (Spectra)	8.57%	36.00%	3.09%	12.0	2009
Union Gas **	8.54%	36.00%	3.07%	10.9	2007
Enbridge Gas **	8.39%	36.00%	3.02%	5.5	2007
TGI	8.47%	35.01%	2.97%	N/A	2009

* The current ROE for the Alberta utilities is based on the 2008 formula setting pending a determination in the generic AUC cost of capital proceeding now underway.
** The Enbridge and Union rates are set for five years based on the formula reset for 2007

While TGI has the lowest effective return of all the major gas utilities, it must be noted that **all** of the major utilities, Gaz Metro, Atco Gas[4], Union Gas, Enbridge Gas, TCPL and Spectra (Westcoast Energy Inc.) have their allowed ROEs set by an automatic adjustment mechanism

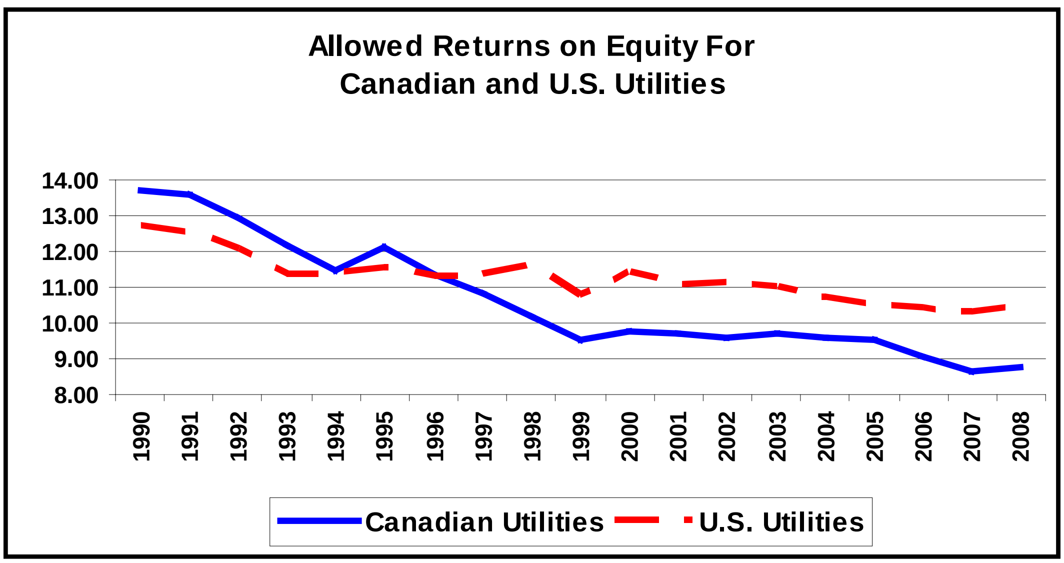
[4] Alberta utilities whose ROE and capital structure are set by the AUC pursuant to its generic formula are continuing to use the 2008 cost of capital on an interim basis while the AUC conducts its current review of the generic formula.

substantially similar to the BCUC formula. The Terasen Utilities understand that ***all of the gas distribution utilities are seeking to change the formula allowed returns in their respective jurisdictions to the extent permissible*** (Union and Enbridge are currently under PBR arrangements which may restrict them from pursuing changes to the formula but the OEB is currently considering whether its formula should be adjusted in light of current market conditions).

In addition, as discussed in the Background Section above, the AUC, the NEB and the OEB are all in the process of considering cost of capital issues.

1.4 Lack of Fair Return Hinders Competition for Capital Globally

The Commission should further consider that TGI competes for capital not just with utilities and other companies in Canada, but also with participants in capital markets outside of Canada. While TGI has the lowest effective return on equity in Canada, the returns on equity in Canada for the last 10 years have been substantially lower on average than they have been in the U.S (see figure below).



This is of significant concern as U.S. investments are more accessible to Canadian individuals and institutions as a result of changes in foreign content investment rules, and as utility investment analysts provide more coverage of U.S. utility investment opportunities. Circumstances have changed since the ROE automatic adjustment mechanism was first introduced, and since the Commission held its last hearing on cost of capital in 2005 the returns on equity produced by the AAM have tracked abnormally low GCB yields. The changed circumstances require a different response if British Columbia wishes to be seen as an attractive place in which to invest capital.

The NEB holds a view consistent with the position TGI is taking. At page 66 and 67 of the TQM Decision, the NEB found that:

> *"In the Board's view, global financial markets have evolved significantly since 1994. Canada has witnessed increased flows of capital and implemented tax policy changes that facilitate these flows. As a result, the Board is of the view that Canadian firms are increasingly competing for capital on a global basis. The Board notes that Canada has been diversifying its business partners such that there is currently proportionally less Canadian foreign direct investment in the United States than there was in the 1990's. Nonetheless, the evidence is also clear that the United States is the single most important recipient of Canadian investments.*
>
> *A fair return on capital should, among other things, be comparable to the return available from the application of the invested capital to other enterprises of like risk and permit incremental capital to be attracted to the regulated company on reasonable terms and conditions. TQM needs to compete for capital in the global market place. The Board has to ensure that TQM is allowed a return that enables TQM to do so. Comparisons to returns in other countries would be useful, but challenging, in terms of differences in business risks and business environment. As a result, the Board is of the view that pipeline companies operating in the U.S. have the potential to act as a useful proxy for the investment opportunities available in the global market place."*

The NEB also found that the regulatory environment in the US and Canada was similar and was not persuaded that US utilities were exposed to greater risk of cost disallowance and where that has happened in the past it related to unique events, and *"are not likely to weigh significantly in investors' perceptions today, and would thus have little or no impact on cost of capital."*

The NEB summarized its findings on the comparability and relevance of US utility return data when considering allowed returns in Canada vs. the US as follows:

> *"In light of the Board's views expressed above on the integration of U.S. and Canadian financial markets, the problems with comparisons to either Canadian negotiated or litigated returns, and the Board's view that risk differences between Canada and the U.S. can be understood and accounted for, the Board is of the view that U.S. comparisons are very informative for determining a fair return for TQM for 2007 and 2008."*

These findings are no less applicable to TGI and the other investor-owned BC Utilities. The above considerations, which are not reflected in the current levels of allowed returns in British Columbia, highlight why the Fair Return Standard is no longer being met in BC. Without a fair return, BC utilities are at a disadvantage when competing for capital.

2.0 The Formula is Broken

A growing body of evidence makes it clear that the formulaic approach to ROE used by regulatory commissions across Canada is broken and the allowed ROEs in Canada governed by a formula are too low. Numerous studies and articles have been published which point to the problems with the construction of, and the returns produced by, the automatic adjustment mechanisms.

Since the introduction of the automatic adjustment mechanism in BC in 1994, the NEB and most provincial utility regulators have adopted similar mechanisms, which primarily rely on an adjustment factor by which 75% of the movement in forecast long GCB yields is used to annually adjust allowed returns on equity.

The shortcomings of the currently employed formulae include the facts that:

- They rely on a single variable, and adjust for 75% of the year over year change of the forecast 30 year GCB yield, which the evidence indicates materially overstates the relationship between the cost of equity and the long-term GCB yield;
- They ignore factors directly relevant to equity return requirements in the markets, such as returns available to comparable risk companies, changes in dividend yields, and changes in corporate bond yields;
- They do not consider changes in equity markets which have occurred over time; and
- By focusing solely on the change in long-term GCB yields, they are incapable of expressly taking into account returns available to enterprises or investments of comparable risk.

2.1 Recent NEB Decision Reinforces that the Formula Approach is Flawed

In its TQM Decision, the NEB in effect acknowledged that the generic ROE formula it has applied since 1995 no longer produces fair returns for TQM. It can be inferred from the NEB's subsequent actions to canvas its regulated entities and interested parties regarding the need to review the RH-2-94 Formula that the Board has concerns that the formula does not produce reasonable results for any of the pipelines it regulates.

The NEB formula works in essentially the same way as the BCUC formula and effectively produces a similar level of generic ROE awards. If the major federal regulator, which was one of the original adopters of the formula, has concerns its formula is no longer working, then it is time that the BCUC revisit and change its approach to the determination of ROEs for utilities in British Columbia.

2.2 Numerous External Experts Have Identified ROE Formula's Shortcomings

In December 2006, then BMO Capital Markets Equity Analyst Karen Taylor and Michael McGowan identified that there were significant shortcomings in the formula. In their research article entitled "2007 ROEs Decline to Unprecedented Levels", they pointed out that there were problems with the level of returns being generated by the automatic adjustment mechanisms.[5]

They concluded:

[5] BMO Capital Markets - 2007 ROEs Decline to Unprecedented Levels; by Karen Taylor and Michael McGowan - December 7, 2006, see Appendix 2

> *"We believe on a collective basis, that the allowed returns as established by the formulas highlighted above [referring to the NEB, EUB, BCUC and OEB formulas] are confiscatory and likely violate the Fair Return Standard."*

In 2007, Concentric Energy Advisors ("Concentric") was commissioned by the Ontario Energy Board to compare the returns allowed Ontario utilities to those allowed by American regulators.[6] The Concentric paper noted that the average allowed ROEs awarded to comparable risk US gas utilities is 160 to 200 basis points higher than those awarded by the formula to Union Gas and Enbridge. Concentric went on to conclude that ***"on the whole, there are no evident fundamental differences in the business and operating risks facing Ontario utilities as compared to those facing U.S. companies or other provinces' utilities that would explain the difference in ROEs."*** [emphasis added]

In February 2008, National Energy Research Associates, Inc. (NERA) of Boston published "Allowed Return on Equity in Canada and the United States"[7], a study commissioned by the Canadian Gas Association. The purpose of the paper was to examine the root causes of the disparity between Canadian and US ROEs (which was identified in the Concentric study) and assess whether Canadian utilities face sufficiently less risk than their US counterparts. The NERA study also examined whether the difference in allowed returns for ratemaking is merely a symptom of a structurally inflexible formula rather than an indicator of underlying risk differences.

The study's conclusions were unequivocal and damning with respect to formula allowed ROEs:

> *"The Canadian ROEs produced by the generic Canadian ROE formula are biased downward. The formula has, since its inception, ridden on autopilot the declining Canadian long-bond interest rates (the cost of a kind of debt) with no independent check on the cost of equity. The generic Canadian formula might not always be biased, and indeed in an era of stable interest rates and equity markets it may have held a true course for many years. But it has been overtaxed by the relatively unprecedented decline in interest rates since the late 1990s. The uncorrected, un-calibrated formula—not risk differences or inherent Canadian regulatory differences—has driven the divergence between observed Canadian and US ROEs."*

In April of 2008, the Canadian Gas Association published "Natural Gas Utility Return Determination in Canada: Time For a New approach".[8] This paper drew from the research of the prior studies and reached a number of important conclusions:

- The systemic bias evident in Canadian formula-based utility return determination and the significant gap that has emerged between Canadian ROE and US ROE levels warrants a Canadian proceeding to redetermine the cost of equity to gas utilities and to establish an improved approach in the future. The following processes and principles would help

[6] A Comparative Analysis of Return on Equity of Natural Gas Utilities, Prepared for: The Ontario Energy Board; by Concentric Energy Advisors - June 14, 2007, see Appendix 3

[7] Return on Equity in Canada and the United States – An Economic, Financial and Institutional Analysis; by National Economic Research Associates Inc. ("NERA") - February 2008, see Appendix 4

[8] Natural Gas Utility Return Determination in Canada: Time for a New Approach; by the Canadian Gas Association ("CGA") – April 2008, see Appendix 5

ensure a sound and enduring approach. There is a need to rebase Canadian ROEs based on a comprehensive review of the cost of capital using all accepted approaches including comparison with a broad comparator group extending across all reasonably comparable industrial groups and jurisdictions including the US.

- There is a need to refresh the formula. In order to meet the requirements of transparency and stability the formula would need to be established on a reasonably stable and readily observable base with an adjustment factor that accounts as fully as possible for the changing relationship between the cost of equity and the cost of debt.
- The formula should be allowed to stand for no more than five years (and probably not less) after which there would need to be another comprehensive cost of capital review which brings in other methodologies and comparators.

Most recently in January 2009, Equity Analyst Robert Kwan for RBC Capital Markets published his article entitled, "The Formula is Broken but will Regulators Fix It?"[9] Mr. Kwan commented:

> *"With higher equity risk premiums and higher long bond yields for Energy Infrastructure companies that are trading at levels close to the allowed ROEs, it appears that the formula is broken. Forgetting the magnitude of change, it appears that the formula is producing a result that is directionally incorrect (i.e., ROEs declining yet corporate bond yields and equity risk premiums are rising)."*

Mr. Kwan recommended from a risk/reward perspective *"We would focus on companies with the least exposure to the formula."*

2.3 BC Government's Actions Indicate it Recognizes the Current ROE is Inadequate

The actions of the Provincial Government only further reinforce the conclusion that the current ROE does not meet the Fair Return Standard.

In February 2009, the Province amended Heritage Special Direction No. HC2 by Order in Council No. 074, which directed the Commission to increase, effective April 1, 2009, the allowed return for BC Hydro by 163 basis points over the return it would otherwise receive pursuant to the formula benchmark return (previously BC Hydro had received the same return as the most comparable investor-owned public utility in BC). By virtue of Special Direction No. 9, BCTC, another crown corporation owned by the Province, also has the 163 basis point increase in ROE extended to it. It is evident that the shareholder of BC Hydro and BCTC is not satisfied with the returns allowed by the formula.

Unlike the shareholder of BC Hydro and BCTC, the Terasen Utilities have no power to issue a special direction to the Commission to provide the Company with fair returns, but the legislative framework of the Utilities Commission Act requires that the Commission must do so.

[9] RBC Capital Markets – Allowed ROEs: The Formula is Broken, but will Regulators Fix It? – January 2009, see Appendix 6

3.0 Unprecedented Turbulence in Capital Markets Further Reinforces the Need to Change the Formula

The evidence presented above strongly suggests that the formula is broken, and in and of itself constitutes a reason for the Commission to act. Recent turbulence in the capital markets has further reinforced the concern that utilities operating under the BCUC ROE formula are receiving inadequate returns and, absent a change, will be hampered in their efforts to compete for capital.

3.1 Capital Markets Push Yields on 30 Year GCBs to Abnormally Low Levels

The events taking place in the capital markets since 2005 have had the effect of driving down the yield on the long-term GCB yield that is the foundation of the current BCUC adopted AAM. This has significantly reduced the allowed ROE, even as the cost of debt and equity has increased.

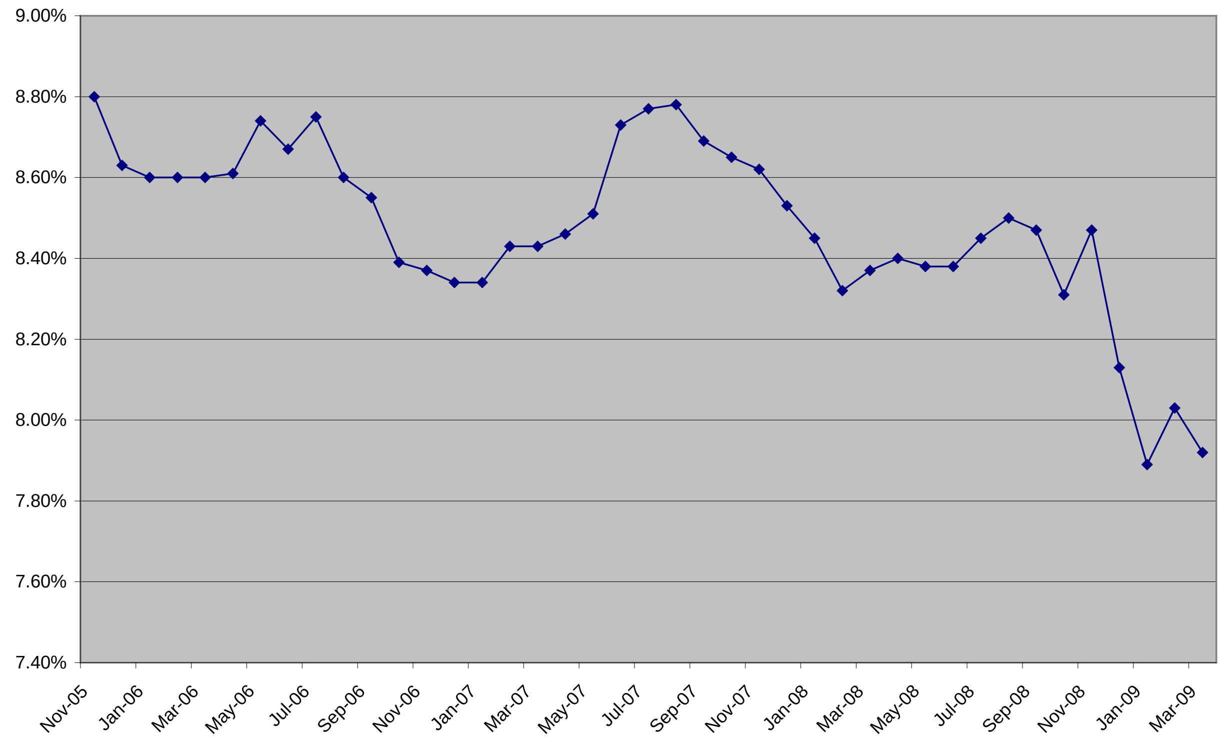
In his evidence filed under Tab 2, Mr Donald Carmichael discusses developments in the capital markets since 2005, and the impacts of those developments on the cost of debt and equity capital. His conclusion is that the costs of debt and equity have increased – in stark contrast to the decline in allowed ROEs under the automatic adjustment mechanisms.

This decline in GCB yields, and consequent decline in allowed ROE, has been driven in part by a "flight to safety", or "flight to quality", in capital markets, which has pushed down yields on government securities, including yields on long-term GCBs.

Lenders liquidated portfolios of corporate bonds and improved the credit quality of their portfolios by adding to their existing federal government bond portfolios. Investors abandoned, or reduced exposure to, the equity market in favour of risk-free securities. This flight to quality, was characterized by an increasing demand for relatively scarce medium and longer term government bonds, including GCBs, which drove the price of such securities continually higher and the yields progressively lower.

As a consequence, the current ROE formula, which is tied to long-term GCB yields, produces inappropriately low ROE for utilities, due to the impact of the flight to quality on GCB yields. The chart below shows how the benchmark ROE allowed by the BCUC formula has declined in response to declining yields on GCBs. The chart below also shows that the ROE allowed by the formula is to some extent "luck of the draw", being highly dependent on the month used for the forecast of the GCB yield.

BCUC Formula ROE Based on Monthly GCB Forecasts



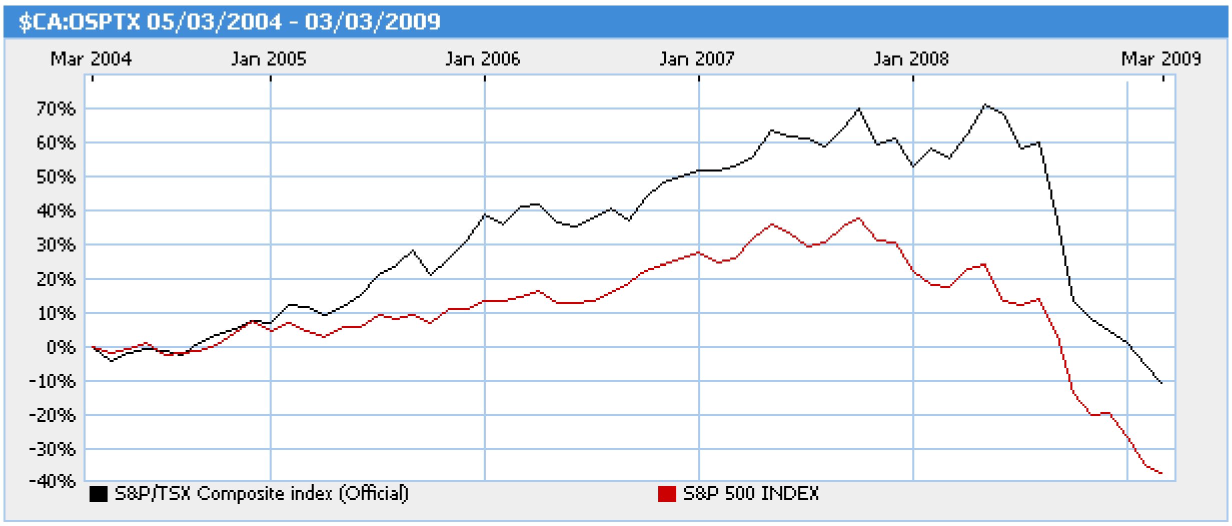
3.2 Even as ROE Falls, Cost of Debt and Equity Rises

Mr. Carmichael's evidence shows that even as the allowed ROE has declined during the past two years, the cost of debt and equity capital has increased for corporations.

The markets have rapidly re-priced risk and are demanding substantially higher returns for debt and equity investments compared to those required earlier in the last economic cycle. Lenders were the first to react to deteriorating conditions caused by the increased levels of consumer and corporate debt, the decline of housing values across the United States, the slowing of growth in the global economy and the collapse of many commodity prices.

A severe liquidity crisis and credit crunch developed in North American corporate debt and credit markets as lenders demanded higher risk premiums from corporate issuers of reasonable credit quality, such as utilities, reflecting the re-pricing of business and financial risks and have cut off the funding of lower quality credits. Additionally the collapse of the proposed takeover of Bell Canada Enterprises by the Ontario Teachers Pension Fund and private equity investors highlighted the issues of much more limited liquidity in the financial system and higher cost of capital for investors.

On the common equity side, North American and international stock markets sold off dramatically as investors began discounting the economic outlook and demanding higher rates of return for the risks associated with the lack of liquidity in the financial system and more uncertain economic times. The chart below illustrates the relative value of the S&P/TSX Composite Index and the S&P 500 Index for the five years commencing March 2004. Price/earnings multiples declined and dividend yields increased signalling a relatively significant increase in the cost of common equity. In Canada, exacerbated by the rapid collapse in commodity prices, the S&P/TSX Composite Index declined from a high of 15,073 in June 2008 to a low of 7,566 in March 2009, a reduction of 50%. Ms. McShane discusses the widening equity risk premium in Canada in Section II of her testimony.



Although the costs of common equity and debt capital have increased for utilities operating in Canada; the ROE formulas used in virtually all regulatory jurisdictions in Canada are producing lower ROEs. The impacts of the economic forces leading to higher costs of capital are simply not captured in the automatic adjustment mechanisms. ***Capital market analysts, including Robert Kwan of RBC Capital Markets in his January 2009 report[10], have become more and more aware of the deficiencies of the automatic ROE adjustment mechanisms and are currently advising investors to avoid utility companies exposed to this form of regulation*** unless the potential for much lower ROEs is addressed by regulators.

3.3 Recent Widening of Credit Spreads Exacerbates Formula's Flaws

Because the regulatory models used to determine the allowed equity returns for utilities have not been updated to reflect changes in the capital markets, the result is that the inadequacy of the returns for utilities in BC and elsewhere in Canada has been further exacerbated.

As previously shown, the decline in long-term GCB yields has driven down the ROE for utilities that operate under the BCUC formula. Yet there is no evidence that required equity returns in

[10] RBC Capital Markets – Allowed ROEs: The Formula is Broken, but will Regulators Fix It? – January 2009, see Appendix 6

Canada or equity returns available on similar risk investments have been decreasing at the same time. The divergence between equity returns generally and the ROE formula results further highlights the flawed nature of the current formula. ***The returns allowed on investments in the equity of Canadian utilities should relate to the returns that investors can earn or expect on other equity investments of similar risk. The operation of the automatic adjustment mechanism, which is producing lower than adequate ROEs, fails to meet that requirement.***.

Although the inadequacy of the formula generated ROE pre-dates the current financial crisis, recent developments in the capital markets further reinforce the fact that formula-based allowed ROEs are too low. In latter part of 2008 and early 2009, spreads over long-term GCB yields more than doubled across the utility industry even as long-term GCB yields declined. From January 2000 to June 2008, the indicative monthly new issue spread[11] for Terasen Gas 30 year bonds averaged 141 basis points (bps) with a standard deviation of +/- 20 bps. Between June 2008 and March 2009, the average indicative spread was approximately 290 bps, peaking in December at 410. The increase in both volatility and quantum of credit spreads is evidence that risk premiums required by investors have been increasing. Yet the formula produces an ROE that erroneously suggests that the premium required by equity investors over corporate bonds has shrunk to a minimal level. While corporate credit spreads have come off their peak values, they continue to be volatile and no one can predict with confidence whether they will continue to narrow, or how long the turmoil in the markets will continue.

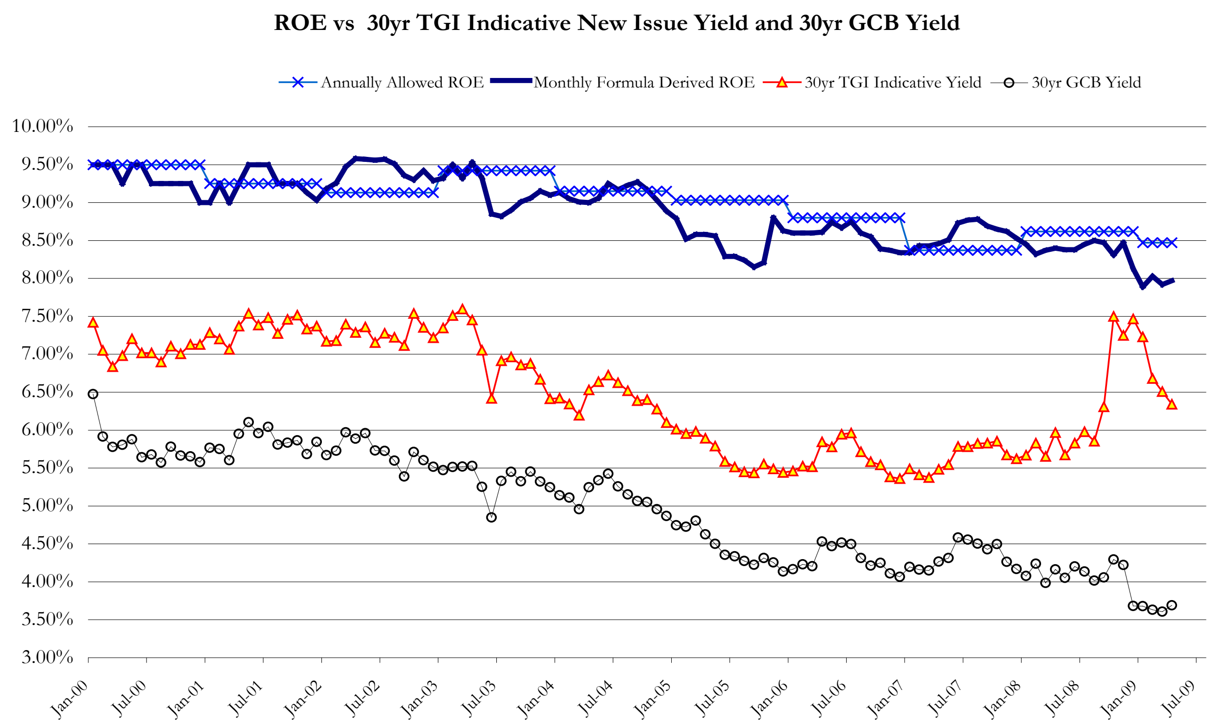
The current ROE formula leaves the Terasen Utilities unable to satisfy equity investors' requirement for increased risk premiums. The 2009 BCUC formula allowed ROE of 8.47% was set in November of 2008. By January 2009, TGI's indicative new issue spread was approximately 385 basis points over 30 year GCB yields, indicating that a new TGI bond issue would be priced to yield 7.57%. At the same time, if the annual allowed ROE were set in January 2009 based on the underlying Consensus Forecast of benchmark 30 year GCB yields, it would have resulted in an allowed ROE of 7.89%. This would have resulted in an equity risk premium of only 32 bps over the corporate debt rate.

In December 2008, the notional equity risk premium over indicative corporate new issue yield was only 18 bps. Historically, spreads between corporate bond yields and the GCB yield have been approximately 130-140 bps. The dramatic widening of the spread between the yield on GCBs and investment grade corporate bonds, as illustrated in the chart below, is a function of several factors, including a flight to quality and the relative scarcity of long-term GCBs as noted above, as well as a broader re-pricing of risk by investors in corporate securities.

While the reduction in long-term GCB yields to abnormally low levels may well reverse over time, the reality is still that corporate bond issues are more costly – and this is relevant to the determination of cost of equity. Because equity investors require a premium over corporate

[11] Each week, Terasen obtains estimates of the prospective new issue spreads for Terasen bonds from four of the primary investment dealers Terasen utilizes for debt issuance, i.e. CIBC, RBC, Scotia and TD. The banks provide estimates of the new issue credit spreads based on their analysis of the secondary trading spreads for existing issues and discussions with institutional investors who buy such debt to estimate the current credit spreads on new debt issuance by the major utilities including Terasen. Terasen relies on this information to time the launch of its credit issuance in the market as well as to set the offered yield.

debt investors, it would be reasonable to expect that the cost of equity will be positively correlated with the cost of corporate debt.



Given widening spreads, equity investors will be less likely to invest capital in utilities whose ROEs are tied to the current formula driven by the 30 year GCB yield as a benchmark. Since the summer of 2007, spreads between corporate and GCB yields have widened dramatically. That investors require greater absolute returns on corporate bonds underscores the fact that equity return expectations would be higher still; investors in the equity of utilities will require an appropriate "equity risk premium" over the return required by investors in the debt of those utilities; but ROEs formulaically tied to GCB yields fail to account for this fact, and instead the formula produces lower ROE results at the same time as required return on utility debt is increasing.

In summary, the last three years have seen extraordinary turbulence in the capital markets. This turbulence has led to a flight to quality which has created an abnormal demand for long-term GCBs that were already in short supply. This flight to safety or flight to quality has driven down the yield on the GCBs, and consequently driven down the formulaic ROE that uses the long-term GCB as a benchmark. Yet even as the allowed ROE has declined, the cost of capital for utilities has risen dramatically, as investors have demanded higher premiums for risk. Unless TGI can offer a return to equity to investors similar to returns available to comparable risk investments, it will be disadvantaged in competing for capital in the future, even if the capital markets return to historical norms.

4.0 TGI's Business Risk is Changing

Business risk is comprised of many elements. For a gas distribution utility, significant components of business risk are the competitiveness of the natural gas commodity as compared to alternate energy forms and the utility's related ability to attract customers and retain its customer base, which affect throughput levels and system load factors. Consumer sentiment, environmental considerations and government policy also play important roles in the determination of the gas distribution utility's risk profile and competitive position. These risk factors determine whether the utility will be able to recover its investments in rate base over time and affect its ability to achieve its allowed return.

When the automatic adjustment mechanism for ROE was introduced, the competitive environment in which TGI operated was very different than it is today. Changes in government policy and public perception of the desirability of natural gas (given it is a fossil fuel) have changed TGI's business landscape since 1994 when the Commission first adopted an AAM, and since 2005 when the Commission last examined the ROE adjustment mechanism. A detailed discussion of TGI's changing business risks is included with this Application in Tab 1.

The evidence establishes that TGI's business risks have increased, but the current formulaic approach to setting the allowed ROE incorrectly suggests that business risk is decreasing. Contrary to the results of the formulaic approach, both a higher ROE and a capital structure containing more common equity is appropriate for TGI rate making purposes.

The following key drivers of competitiveness and business risk have changed for TGI in recent years:

- Provincial climate change and energy policies has increased the risk inherent to TGI's core natural gas business;
- Natural gas' competitive position relative to electricity has been weakened;
- TGI is capturing a smaller percentage of new construction;
- Electricity is increasingly the choice of high-density housing;
- Alternative energy sources further weaken TGI's competitive position; and
- Fuel switching has also diminished demand for natural gas.

Under the current ROE formula mechanism, ***TGI is discouraged from investing capital in the utility facilities beyond that which is required to meet the Company's basic obligation to serve existing customers in its service areas,*** much less to respond to the changing consumer demands and government policy directives. However, unless TGI participates in meeting business and government policy challenges it will see its traditional business and share of the energy delivery market erode and with it, its ability to recover its existing investments over time.

If TGI is to be part of the solution, as it proposes to be, to the government's climate change challenge, then it requires higher returns to deal with the increased business risks related to introducing new technologies and service offerings. As it stands today, the government's introduction of carbon taxes, escalating to $30/tonne (approximately $1.50/GJ) by 2012 (with no certainty the tax will not increase beforehand or thereafter) threatens the immediate and longer term competitiveness of TGI's base business and its ability to recover its capital investments over the longer term. It is unclear just how significant that threat may prove to be in the future should the "price of carbon" escalate further over time but the current challenges demand a higher allowed return on equity than that being produced by the formula today.

Notwithstanding the fact that the ROE formula is broken and demands a response from the Commission to establish a more appropriate, higher level of ROE for TGI, TGI's increased business risk warrants (i) a higher return than it did in 2006 when the Commission last considered the benchmark ROE and (ii) the equity component of TGI's capital structure be increased.

Summary

In summary, the evidence establishes that:

- The Fair Return Standard is not being met;
- The ROE formula that produces that return is broken;
- The recent turbulence in credit markets have further highlighted the formula's flaws; and
- TGI's business risks are increasing.

Because of these realities, the BCUC must update both the TGI ROE (that is the Benchmark ROE) and TGI's capital structure.

Part 2: Proposed Solution

The Terasen Utilities request that the Commission takes steps to award a return on equity for TGI that provides a fair return on TGI's investment in its utility assets and serves as a Benchmark ROE to be used in establishing the allowed return of TGVI and TGW. TGI also requests that the Commission establish a capital structure for TGI that enables the Company to compete effectively for capital with other Canadian utilities and with utilities in the United States.

Specifically, TGI requests that the Commission allow the Company a common equity component of 40% in its capital structure, and the Terasen Utilities request that the Commission set a return on equity of 11% for TGI, which 11% return will also be the Benchmark ROE to be used in establishing the allowed return on equity of TGVI and TGW.

It is requested that the 11% allowed return on equity for TGI and as the Benchmark ROE take effect as of July 1, 2009. It is requested that the common equity component of 40% in the capital structure of TGI take effect as of January 1, 2010.

This section of the Application outlines how these requests were arrived at. Specifically, it is respectfully submitted that:

5.0 An Appropriate Benchmark ROE Is One Based On A Number of Relevant Tests (Rather Than A Single One);

6.0 The Current Adjustment Mechanism Should Be Abandoned; and,

7.0 TGI's Capital Structure Should Be Changed To Allow For A Higher Equity Component.

By taking these actions the Commission will allow TGI and the other Terasen Utilities to compete for capital for the foreseeable future.

5.0 An Appropriate Benchmark ROE Is One Based On A Number Of Relevant Tests (Rather Than A Single One)

Prior to the 1994 introduction of the generic ROE adjustment mechanism for setting allowed returns to equity investors, the Commission and other regulatory tribunals used a number of tests to determine the appropriate return on equity for an investor in a utility. The *discounted cash flow* test, the *comparable earnings* test and the *equity risk premium* test were all used, but in its 1994, 1999 and 2006 Decisions the Commission adopted, for all intents and purposes, the *equity risk premium* test as the only test used. Moreover, the Commission implicitly concluded that the return required by investors in the equity of utilities always moves in the same direction as changes in the forecast yields on GCBs. The Company believes reliance on a single approach is inadequate, and has resulted in unfair low returns on equity for the investors in TGI and other investor owned utilities whose ROE is set pursuant to the BCUC adopted formula.

In its 2006 Decision, the BCUC stated that these other tests, in particular the comparable earnings test, had merit but that inadequate data was available to give it any weight. The Commission stated at page 56 of the Decision:

> *"the Commission Panel is not convinced that the CE methodology has outlived its usefulness, and believes that it may yet play a role in future ROE hearings."*

Notwithstanding the view expressed in that quotation, in past proceedings the Commission has given no weight to the evidence presented on Comparable Earnings, in part because of concerns regarding the limited number of companies in the sample data. In this proceeding Ms. McShane has identified a larger number of Canadian proxy companies to address this issue, and has also examined US non-regulated companies of similar risk. In addition, Dr. Vander Weide provides evidence of the allowed returns of a large sample of comparable US utilities as one of a number of additional tests he applies in determining the appropriate level of return for TGI.

5.1 Independent Experts Agree on A Fair Return for TGI

In her testimony at Tab 3, Section I, Ms. McShane reaches the following conclusions:

1. The automatic adjustment formula is clearly not producing returns that meet the fair return standard. The fair return and automatic adjustment mechanism for setting the allowed return on equity both need to be recalibrated.
2. The sensitivity of the cost of equity to government bond yields is materially lower than the existing automatic adjustment mechanism implies. In addition, the cost of equity moves in the same direction as the utility cost of debt; this relationship has not been reflected in the automatic adjustment mechanism. As a result, the allowed ROEs have decreased over time to a much greater extent than is justified and recently have moved in the wrong direction.
3. The allowed return for TGI must meet all three criteria of the Fair Return Standard, including the comparable return requirement. The fair return extends to both the capital structure and return on equity, that is, the overall return allowed must satisfy the fair return standard.
4. The capital structure and the return on equity are inextricably linked; the fair return on equity cannot be established without reference to the level of financial risk inherent in the capital structure adopted for regulatory purposes.
5. The TGI proposed capital structure in the application is reasonable in light of the increase in the Company's business risks, the importance of maintaining the existing credit ratings, the trend toward stronger capital structures among other Canadian utilities, and the stronger capital structures and credit metrics of TGI's U.S. peers, with whom TGI competes for capital and whose total returns form a basis for satisfying the comparable returns standard.
6. The fair return on equity for TGI is estimated at 11.0%. The fair return for TGI reflects the following:

- The return on equity is based on the results of three tests: equity risk premium, discounted cash flow and comparable earnings;
- The equity risk premium test results are based on three separate approaches. The equity risk premium tests indicate the following costs of equity before adjustment for financing flexibility:

Risk Premium Test	Cost of Equity
Risk-Adjusted Equity Market	8.75%-9.0%
DCF-Based	10.0%
Historic Utility	10.75%

- The discounted cash flow test, applied to a sample of benchmark low risk U.S. utilities, supports a cost of equity of 10.5-11.0%;
- The allowance for financing flexibility should be, at a minimum, 0.5%. The addition of a 0.5% financing flexibility adjustment results in a cost of equity based on the market-based risk premium and DCF tests of approximately 10.25-11.25%;
- The comparable earnings test shows that, based on the achievable earnings returns of low risk competitive unregulated Canadian firms, a fair return applicable to a benchmark utility would be approximately 11.5-11.75%. and the test also shows that, based on U.S. companies the return would be approximately 14% (underscoring the reasonableness of the comparable earnings result based on Canadian unregulated companies); and
- With primary weight given to the capital market-based tests, equity risk premium and discounted cash flow, the fair return on equity for TGI is 11.0%.

Dr. Vander Weide's evidence at Tab 4 considers the Fair Return Standard, assesses the validity of the current automatic adjustment mechanism for setting ROEs in BC using six separate tests, and estimates the cost of equity for companies whose risk is similar to TGI using equity risk premium tests and discounted cash flow approaches. Dr. Vander Weide also examines the capital structures of utilities with comparable risks to those of TGI.

The key findings in Dr. Vander Weide's testimony are that:

1. Experienced equity risk premiums on investments in Canadian utilities stocks provide evidence that investors require an equity return that is at least 5.5 percent above the yield on GCBs, whereas the AAM ROE Formula implies an equity premium of only 4.3 percent.
2. Recent average allowed returns for U.S. utilities are in the range of 10.3% to 10.4%, whereas the AAM ROE Formula implies an ROE equal to 7.9 percent (based on capital market data at March 2009).

3. The forward-looking required equity risk premium on utility stocks is less sensitive to changes in government bond yields than is implied by the AAM ROE Formula.
4. The allowed equity risk premium for U.S. utilities is less sensitive to changes in government bond yields than is implied by the AAM ROE Formula.
5. The risk of investing in Canadian utilities stocks is higher relative to the Canadian market as a whole than is implied by the AAM ROE Formula.
6. The cost of equity for investments in comparable risk utilities is 11.0 percent based on ex post risk premium, ex ante risk premium, and discounted cash flow studies.
7. Allowed equity ratios for U.S. utilities are in the range 48 percent to 49 percent, whereas the allowed equity ratio for TGI is 35.01 percent.
8. The business risk of TGI is somewhat less than the average business risk of U.S. utilities, whereas the average financial risk of TGI is significantly greater than the average financial risk of U.S. utilities.

Dr. Vander Weide concludes that the allowed return on rate base, or overall rate of return, for TGI is significantly less than the overall return that investors can earn on other investments of similar risk. He has determined that the overall allowed return (return on rate base) of comparable US utilities is approximately 8.0%. In his opinion, an allowed ROE of 11.0% on 40% equity would produce an overall return on capital (return on rate base) of approximating 8.0% and that would be reasonable.

Based on the evidence presented by Ms. McShane and Dr. Vander Weide, a fair ROE for TGI, which will establish the Benchmark ROE, is 11%, with a deemed equity thickness of 40%.

5.2 The Company Specific Risk Premia for Remaining Terasen Utilities Should Continue to be Applied to the new Benchmark ROE

At present, the allowed ROE of TGVI and TGW are set with reference to the annual determination for the benchmark utility, which has been TGI. The allowed ROEs for TGVI and TGW, and the other investor-owned utilities regulated by the BCUC, have been determined by adding to the benchmark ROE a company specific risk premium. With the establishment of a new Benchmark ROE pursuant to this application, the company specific premia for TGVI and TGW, as previously determined by the Commission, should continue to be used in the determination of their allowed ROEs.

Section 4 and Tab 1 of this Application present evidence respecting the increase in TGI's business risks over time and how new risk factors have manifested themselves since 2006. These new business risk factors also apply to TGVI and TGW, and accordingly continuation of the use of a Benchmark ROE that is used in establishing the allowed ROEs for all the Terasen Utilities is appropriate.

5.2.1 Continuation of the TGW Company Specific Risk Premium - 50 Basis Points

In its October 2008 Revenue Requirements application, TGW applied to have its company specific risk premium increased from 60 basis points to 75 basis points. In the proceeding relating to that application the Commission considered the business risks of TGW and evidence relating to the appropriate TGW risk premium over the benchmark ROE. The Commission's Decision of April 7, 2009 on that application, at page 57, said:

> *"Accordingly, the Commission Panel orders that the ROE for TGW be established at 50 bps over the benchmark low risk utility."*

TGW is not seeking reconsideration of that Decision. The relative risk of TGW as compared to the benchmark utility (TGI) since the proceeding that led to the April 2009 Decision has not changed. TGW requests simply that the new Benchmark ROE, which will replace, at least for the Terasen Utilities, the generic benchmark ROE determined under the BCUC's AAM, be substituted in the establishment of TGW's allowed ROE.

5.2.2 Continuation of the TGVI Company Specific Risk Premium – 70 Basis Points

Similar to TGW, no request is being made in this Application to adjust the company specific premium for TGVI. Evidence was presented in the 2005 TGI and TGVI cost of capital proceeding that demonstrated that TGVI's business risks were greater than TGI, the benchmark utility. Those risk differentiators continue to exist today. At page 57 of the 2006 Decision the Commission said:

> *"The Commission Panel determines that a suitable premium to TGVI over the benchmark low-risk utility ROE is 70 basis points."*

TGVI is not seeking any change from the Commission's determination of 70 basis points as the appropriate company specific risk premium for TGVI. The relative risk of TGVI as compared to the benchmark utility (TGI) since the proceeding that led to the 2006 Decision has not changed. TGVI requests simply that the new Benchmark ROE, which will replace, at least for the Terasen Utilities, the generic benchmark ROE determined under the BCUC's AAM, be substituted in the establishment of TGVI's allowed ROE.

5.3 Changes to the Benchmark ROE Should Be Effective July 1, 2009, and Interim Rates for TGI and TGW Should be Established as of that Date

The evidence in this Application demonstrates that the return on equity currently allowed for the Terasen Utilities is inadequate and less than a fair return. The current benchmark ROE of 8.47%, which is used in establishing the allowed ROEs of the three Terasen Utilities, does not allow them an opportunity to earn a fair return as required under the Act, and as a result the current rates which reflect the inadequate allowed ROEs are not fair, just or reasonable.

A hearing to consider the matters addressed in this Application will not be completed at an early date, and the Commission decision on this Application will follow later. The Terasen Utilities request interim relief effective July 1, 2009. If interim relief is not granted, and if the relief requested in this Application is not effective until after the Commission decision on this

Application, the Terasen Utilities would be denied the opportunity to earn a fair return on their investment in utility assets until subsequent to the date of that decision. Such a result would be unfair and unreasonable.

TGI and TGW request, pursuant to section 89 of the Act, that their existing rates be made interim effective July 1, 2009 and be adjusted when permanent rates can be established incorporating the Commission' decision on this Application.

TGVI requests, pursuant to section 89 of the Act, that effective July 1, 2009 its cost of service under the Special Direction be made interim, and subsequently be adjusted to reflect the increase in its allowed ROE resulting from the Commission's determinations in this proceeding. Granting the interim relief requested will preserve the ability of intervenors to take issue with the evidence presented in this Application while providing the Terasen Utilities with the opportunity to earn a fair return. The Terasen Utilities respectfully submit that the requested interim relief should be granted.

6.0 The Adjustment Mechanism Cannot Survive In Its Present Form

In the past, TGI has supported the use of an automatic adjustment mechanism to adjust annual allowed ROEs between cost of capital reviews. TGI recognizes that cost of capital reviews entail considerable time, effort and money for testimony preparation, information requests, a hearing and submissions. An automatic adjustment mechanism can be an administratively efficient means of avoiding annual ROE reviews for utilities under the jurisdiction of the BCUC, while providing regular changes in the allowed return on equity. In addition to the reduction in regulatory burden, automatic adjustment mechanisms result in increased predictability of the allowed returns and limit the potential arbitrariness of the outcome.

There are disadvantages to automatic adjustment mechanisms, however. Formulaic ROEs limit the regulator's flexibility to address issues such as financing flexibility requirements. If the initial ROE is set either too high or too low, the operation of an automatic adjustment formula could simply compound the problem instigated by the initial ROE. Further, even if the initial ROE is set appropriately, if the formula does not track changes in the cost of equity (which the current BCUC formula does not), the AAM will not produce allowed ROEs that meet the Fair Return Standard. Finally, the formula may produce significant changes in the ROE from year to year, which in turn may result in unduly volatile customer rates. These disadvantages should be taken into account in determining if an AAM can continue to be used, and if an AAM is used, the design of the AAM and its ROE formula.

In designing an automatic adjustment formula, there should be a balance among the following criteria. An automatic adjustment formula should:

1. be relatively simple to understand and apply;
2. be based on changes in one or more reasonably available and verifiable variables;
3. exclude changes in variables due to abnormal market events;
4. incorporate variables which vary in a quantifiable way with the utility cost of equity; and

5. incorporate variables which are not vulnerable to changes caused by company-specific circumstances which may not impact on the cost of equity for the utilities to which the formula applies.

The current BCUC AAM does not meet all these criteria, and does not result in a fair return for the utilities subject to it. The Terasen Utilities request that use of the current BCUC AAM be eliminated.

6.1 Expert Testimony Suggests That 75% Elasticity Is Too High

The evidence of Ms. McShane, Dr. Vander Weide and Mr. Carmichael all underscore the problems resulting from the current formula's reliance on 75% of the movement in long-term GCB yields as the indicator of the appropriate return on equity. With the benefit of hindsight, including fifteen years of observations, it appears that the relationship is approximately 50% of the movement of long-term bond yields over a "normal" range. Recent experience shows that long-term GCB yields are driven by many factors including scarcity of supply, government fiscal and monetary policy, sovereign debt reduction and market turmoil such that GCB yields can move in a direction opposite of that of the cost of corporate debt and equity. In principle, an automatic adjustment formula should incorporate one or more variables that either track the utility cost of equity directly, or track it more directly than the yield on long-term GCBs. For example, the yields on an index of Canadian long-term public utility bonds would likely provide additional valuable information as an indicator of the trend in the utility cost of equity. Unfortunately no such publicly available index exists.

6.2 Alternative Approaches

As noted above, the NEB, AUC and OEB are currently undertaking or considering generic reviews of their ROE formula mechanisms. These proceedings are likely to attract considerably wider input than that of this proceeding before the BCUC and an acceptable alternative to the traditional ROE formulas may emerge from those proceedings.

In the absence of an objective, independently created alternative index or variable, a pragmatic solution is to abandon the automatic adjustment mechanism and establish a return on equity as the allowed ROE for TGI and as the Benchmark ROE. The ROE so established would continue until one or more parties conclude it is no longer meeting the Fair Return Standard and seek to have the Commission review the Benchmark ROE. This approach has merit given that the cost of equity does not appear to swing dramatically from year to year in any event, and certainly does not change with the same degree of volatility as the "so-called" risk free GCB yield, from month to month let alone on an inter-year basis.

Another alternative is to continue to rely on a formula based on the Consensus Forecast of GCB yields, as such a formula is simple to administer and is based on objective, easily accessible data. It also reflects at least a portion of the current financial market conditions at the time of annual reset. However, as discussed elsewhere in this Application, the GCB is influenced by factors (such as government policy) that do not directly relate to requirements of equity investors, and the GCB does not appropriately reflect all the factors that impact the business and financial circumstances of utilities. Furthermore, any continued reliance on a GCB-based formula would require explicit recognition of the shortcomings of the current formula and explicit recognition of the inadequate ROEs that have resulted from the formula; a major re-calibration would be required. Moreover, it would be difficult to address abnormal market conditions that affect long-term government bond yields with this approach.

As noted in 6.1 above, the sensitivity of the utility cost of equity to long-term Canada bond yields is materially less than the 75% elasticity factor that currently underpins the formula; in fact it appears to be less than 50%. It is critical to recognize that it would not be reasonable to change the elasticity factor in the current formula to 50% and not simultaneously reset the allowed ROE at a level which recognizes that the allowed ROEs that have been established in the past have reflected the presumed 75% relationship. Since long-term GCB yields have been on a fairly consistent downward trend since the time the formula was introduced in British Columbia in 1994, the application of the formula over time has overstated the corresponding decline in the utility cost of equity. Implementation of a 50% elasticity factor would only be appropriate if it were applied to a starting allowed ROE which is fair, including the recognition that the operation of the existing formula has resulted in ROEs which are too low.

For the reasons discussed in this Section, ***TGI is not prepared to propose or commit to an automatic adjustment mechanism at this time.*** The Company will continue to work towards developing a proposal for an adjustment mechanism in the future, ideally in time to establish rates for 2011. By that time the volatility in the capital markets may have eased and additional information may be available which would assist in developing a workable proposal. Moreover, the Company is not in a position to commit to a formula until it understands the base ROE that the formula would start from.

Absent a material re-calibration of the starting point to establish a fair return for a revised formula, even a perfect adjustment mechanism will fail to produce fair returns.

7.0 The Capital Structure Should Be Changed To Allow For A Higher Equity Component.

A public utility must always have sufficient financial flexibility to meet the capital requirements imposed by customer growth, technological change or emergent situations. Utilities are large consumers of both equity and debt capital. Their fundamentals are watched carefully and scrutinized thoroughly by the financial analyst community for equity investors and by the debt rating agencies. The latter are very sensitive to the proportion of common equity in a utility's capital structure as it provides security for investors lending money to a utility, and to the cash generated by the allowed returns to ensure that the interest on the debt of the utility can be serviced.

With the downward trend in allowed ROEs, and as utility allowed returns and utility bond yields have converged recently (as described in Section 3), the financial flexibility for Canadian utilities in general and BC and the Terasen Utilities in particular, has been reduced. In addition, the capital structure under which TGI currently operates (35.01% equity component) makes it less attractive to investors of both equity and debt capital.

This is why TGI submits that the equity component of TGI's capital structure should be increased from the current 35.01% to 40%.[12]

A capital structure with 40% common equity ratio in addition to an ROE of 11%, will adequately reflect the increasing business risks facing TGI, and appropriately address the requirements that meet the Fair Return Standard from a capital structure perspective, ensuring that financial integrity and flexibility is maintained, as well as allow TGI to attract capital on a comparable basis with its Canadian and US peers.

Ms. McShane, Dr. Vander Weide and Mr. Carmichael have put forth evidence that supports TGI's belief that the current common equity ratio is too low and a 40% equity component is reasonable and justified**.**

Ms. McShane has addressed the appropriateness of the requested equity ratio with respect to its role in meeting the Fair Return Standard, the trend in TGI's business risk, the need to maintain existing credit ratings, and the stronger capital structures and credit metrics for TGI's Canadian and US utility peers, with whom TGI needs to achieve comparability in competing for capital.

Dr. Vander Weide provides an analysis of US electric and gas utilities' equity ratios and states that TGI carries significantly higher financial risk than its US peers, who have an average equity ratio of approximately 49%, well above what is being sought by TGI.

Mr. Carmichael addresses the weak financial metrics of TGI compared to its peers, its dependence on other factors to achieve it's A category credit rating and the risk of loss of that credit rating, the increasing competition for capital facing TGI, the need to maintain an A category credit rating, and the need for comparability to its utility peer group.

7.1 Increase in Equity Component Critical to Preserving Financial Flexibility

TGI interprets the financial integrity standard to mean a capital structure and return on equity that in tandem will allow the utility to maintain a minimum credit rating in the A category, which will allow TGI access to the capital markets on reasonable terms and pricing in all economic conditions. This credit rating is critical if the utility is to maintain financial flexibility.

TGI has a significant requirement for capital, stemming from its obligation to ensure system deliverability, reliability and safety, support customer growth, and meet both the challenges and opportunities from emerging situations. TGI does not have the ability to defer financing its existing or new assets, therefore, its need to access capital occurs during both strong and weak economic conditions and when financial markets are robust and when they are challenging.

[12] The current deemed capital structure of TGI reflects the effect of amalgamation of Terasen Gas (Squamish) Inc. increasing it from 35% to 35.01%. The capital structure proposed by TGI reflects and increase of 3% equity preserving the effect of the weighting of the two predecessor company capital structures pursuant to the Special Direction

7.2 Decrease in Credit Worthiness would have Significant Repercussions

One of the key elements to maintaining this financial flexibility is for TGI to carry a minimum credit rating of A from its rating agencies. A ratings downgrade to BBB would have adverse consequences on TGI with respect to its cost of debt (both short-term and long-term debt), potentially to its access to long-term debt, and to its gas supply procurement and hedging activities.

Moody's in its May 2008 rating report on TGI, notes that its rating methodology model for North American LDC's would indicate a Baa1 credit rating for TGI, however, the A3 rating, which is one rating notch above Baa1, is achieved when qualitative factors such as supportive business and regulatory environment are considered.

> *"TGI's financial metrics are generally weaker than those of its A3 rated global LDC peers such as Piedmont Natural Gas Company, Inc., Northwest Natural Gas Company, Connecticut Natural Gas Corporation, Public Service Co. of North Carolina, UGI Utilities and sister company, TGVI. Moody's recognizes that TGI's relatively weaker financial metrics are largely a function of the relatively low deemed equity and allowed ROE permitted by the BCUC. In general, Canadian deemed equity ratios and allowed ROEs are low relative to those of other jurisdictions and TGI's are among the lowest in Canada. However, TGI's A3 senior unsecured rating reflect Moody's view that TGI's relatively weaker financial metrics are offset to a significant degree by the supportiveness of the business and regulatory environments in which TGI. Moody's rating methodology model for North American LDCs indicates a Baa1 rating for TGI which is one notch below the company's A3, senior unsecured published rating assigned by Moody's rating committee. TGI's published rating exceeds the methodology-implied rating because Moody's rating committee places greater emphasis on the supportiveness of TGI's regulatory and business environments than the rating methodology model does. The methodology-implied rating falls within the one to two notch band that Moody's rating methodologies aim to achieve."* [13]

In addition, Moody's has signified that a further weakening of its financial ratios, arising from among other causes an ROE below 8%, would likely lead to a ratings downgrade.

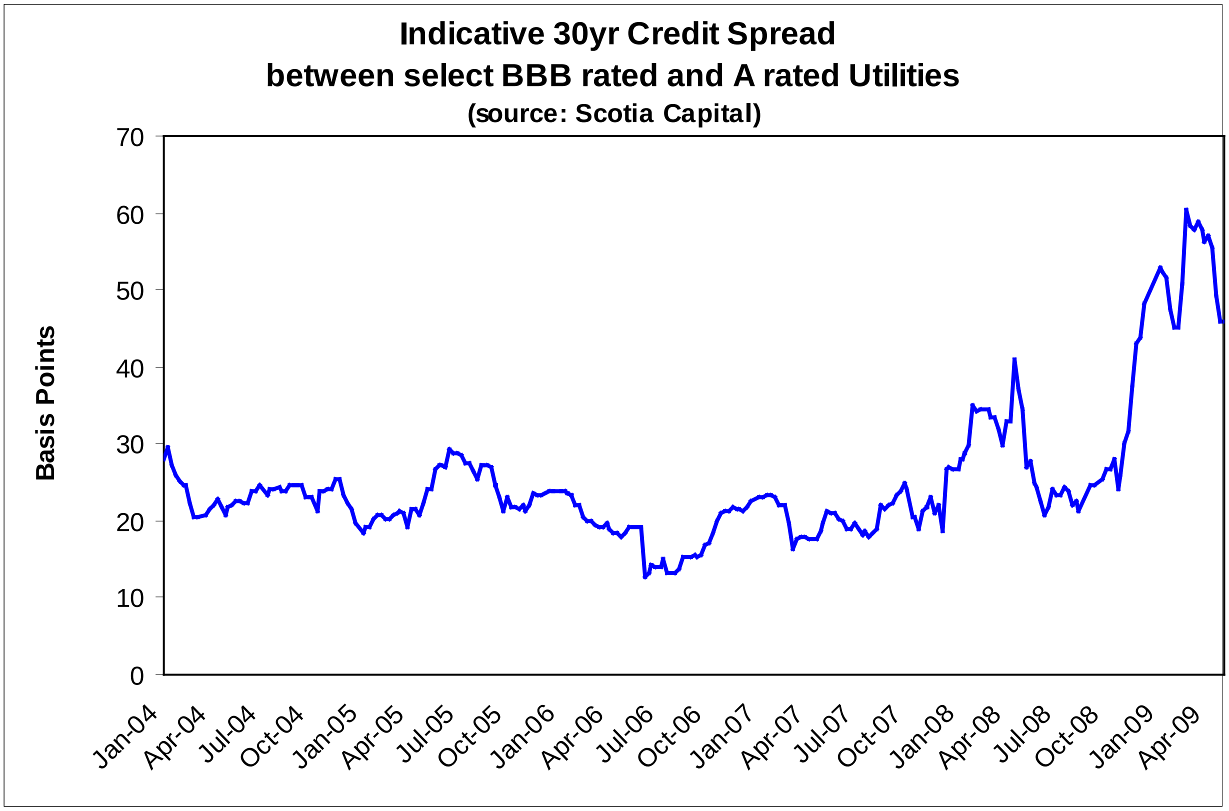
> *"Notwithstanding TGI's relatively low risk business profile, its financial profile is considered weak at the A3, senior unsecured rating level. Accordingly, further sustained weakening of TGI's financial metrics, for instance ROE below 8%, EBIT to Interest below 2x, RCF to Debt below 5% and/or Debt to Book Capitalization (Excluding Goodwill) above 65%, would likely lead to a downgrade of TGI's rating."* ibid

Therefore, further weakening of the financial metrics of TGI, or a determination of Moody's that the regulatory or business environment is no longer as supportive, could result in a credit rating that is below the A category. As noted by Mr. Carmichael, with the TQM Decision and the expectations that it creates more broadly for improvements to allowed returns and capital

[13] Excerpt from Moody's Investor Services Global Credit Research Credit Opinion for Terasen Gas Inc., dated May 27, 2008.

structures for Canadian utilities, should TGI be left behind it is difficult to see how the credit rating agencies could continue to view the regulatory environment in BC as being supportive.

In the context of cost of debt, the credit spread associated with a BBB credit rating is significantly higher than that associated with an A credit rating. The chart below shows the incremental credit spread, expressed in basis points, between the average indicative new issue spreads, on a weekly basis, of six Canadian utilities (Fortis BC, Union Gas, Westcoast Energy, Newfoundland Power, Nova Scotia Power and Epcor) with, at a minimum a split rating, or a majority of their ratings in the BBB category and four Canadian utilities (Enbridge Gas, Fortis Alberta, Gaz Metro, TGI) with all or a majority of its ratings in the A category.



When accessing debt markets, firms that are BBB rated are more constrained in issuing for terms in excess of 10 years, and in certain situations could be shut out of the debt markets for a period of time. As noted in Ms. McShane's evidence, in the Canadian debt capital markets, the issuance by BBB rated parties between January 2006 and March 2009 has accounted for approximately 6% of the dollar value of corporate debt issuance, and since mid-2007 to March 2009, of the 189 reported issues, less than 10 were of BBB rated entities, none of which exceeded 10 years in term. This demonstrates that while there is a market for BBB rated issuers in Canada, the demand is more robust in strong capital markets, but in more difficult times, as seen commencing in 2007, a BBB rated issuer will face market constraints, underlying the need for a frequent issuer, such as TGI, to maintain its A rating.

From an operational perspective, an A rating plays a key role in TGI's gas supply and hedging strategies. In a typical year, TGI will purchase in excess of $1 billion of natural gas depending on market prices. In addition, TGI utilizes commodity derivatives to hedge the price volatility of natural gas faced by consumers. Derivatives are placed on underlying gas supply for amounts in excess of $300 million in a typical year. Currently, counterparties to TGI do not require collateral in the form of letters of credit, nor has TGI experienced any restrictions on the amount of unsecured credit counterparties have extended to TGI. Such restrictions would limit TGI's ability to pursue its gas supply and hedging strategies. This lack of restrictions to date is due in part to the counterparties' view of TGI as a strong investment grade entity, based on the minimum A credit rating.

A credit rating downgrade below the A rating category could lead to TGI being required to post letters of credit with its counterparties, which would incur a direct cost in the form of letter of credit fees. In addition, and of more concern, would be the potential restriction this could place on TGI's hedging activities. The commodity hedges can extend out three years, and given the volatility in gas prices, the mark to market exposure on a derivative can vary significantly. TGI, when it enters into financial hedges, restricts its activities to A rated or higher counterparties. As a BBB rated entity, TGI could face similar restrictions and be constrained in pursuing its hedging activity, to the potential detriment of its customers.

The need for an A rating is even more important when considering the increasing competition for capital. TGI, from an asset perspective, builds energy infrastructure and it competes for capital with other infrastructure to which investors can direct their investment funds. The American Society of Civil Engineers, in their 2009 Infrastructure Scorecard[14] has estimated that over a five year period, the United States will require approximately $2.2 trillion dollars for infrastructure. In Canada, market commentators have estimated that $120 billion will be spent on public infrastructure (excluding privately owned infrastructure, such as energy) in the next 10 years. The sheer magnitude of potential spending will give investors, from a global and North American perspective, significant options to invest in, and will increase the competition for debt and equity capital for TGI.

7.3 Increase in Common Equity Ratio Improves Credit Metrics

The primary determinant to TGI's credit rating is its credit metrics, which are currently viewed by the rating agencies to be at the bottom end or below the range acceptable for an A rating. This is driven by a common equity ratio and allowed ROE, both of which are at the lower end of the range of comparable utilities. By increasing TGI's common equity ratio the Commission will improve TGI's credit metrics and increase the likelihood that it will maintain its A level rating.

If no action is taken it is quite possible that TGI's credit metrics will weaken further and jeopardize its credit rating. The interest coverage ratio is the ratio of earnings before interest and taxes (EBIT) to interest expense. TGI will face pressure on its interest coverage ratio if EBIT were to be reduced over time due to lower allowed ROE, as would result from the current ROE formula (the allowed ROE, if set in April would result in a sub 8% return), given the loss of incentive earnings from the cessation of performance based regulation and decreasing tax rates. As well, the denominator, interest expense, may increase over time due to higher debt

[14] Taken from the 2009 Report Card for America's Infrastructure from www.asce.org

costs as investors have repriced corporate and utility risk. TGI's debt to capital ratio, with a 35% equity ratio, is also at the bottom end of the range acceptable for A rated utilities

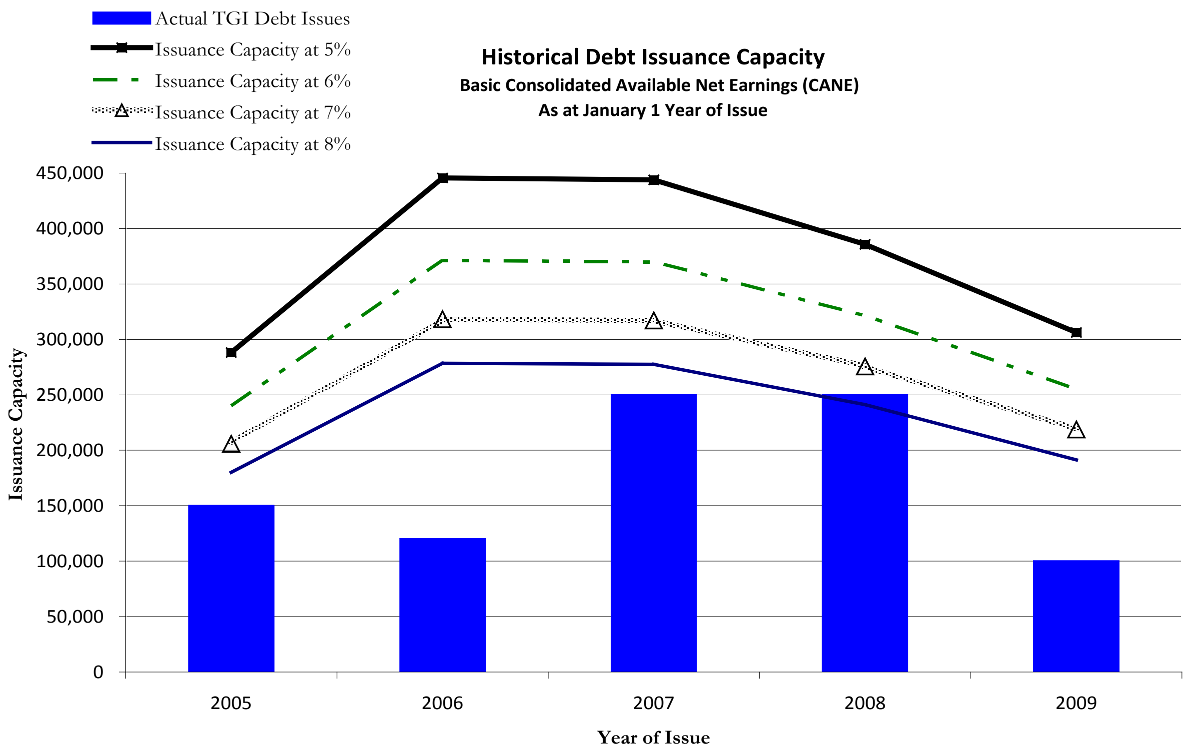
By increasing the common equity ratio to 40%, in tandem with an increase of the ROE to 11%, the pressure on credit metrics will be materially lessened and will positively contribute to TGI maintaining its A rating. An A rating will be a key factor in ensuring continued access to the debt capital markets through all economic cycles, will allow access to longer terms to maturity, and will ensure the credit spreads on debt will be reasonable. TGI does not believe it appropriate to continue a capital structure and ROE at levels that may result in TGI experiencing a downgrade in its rating to a level below that acceptable and required to address the financial integrity standard.

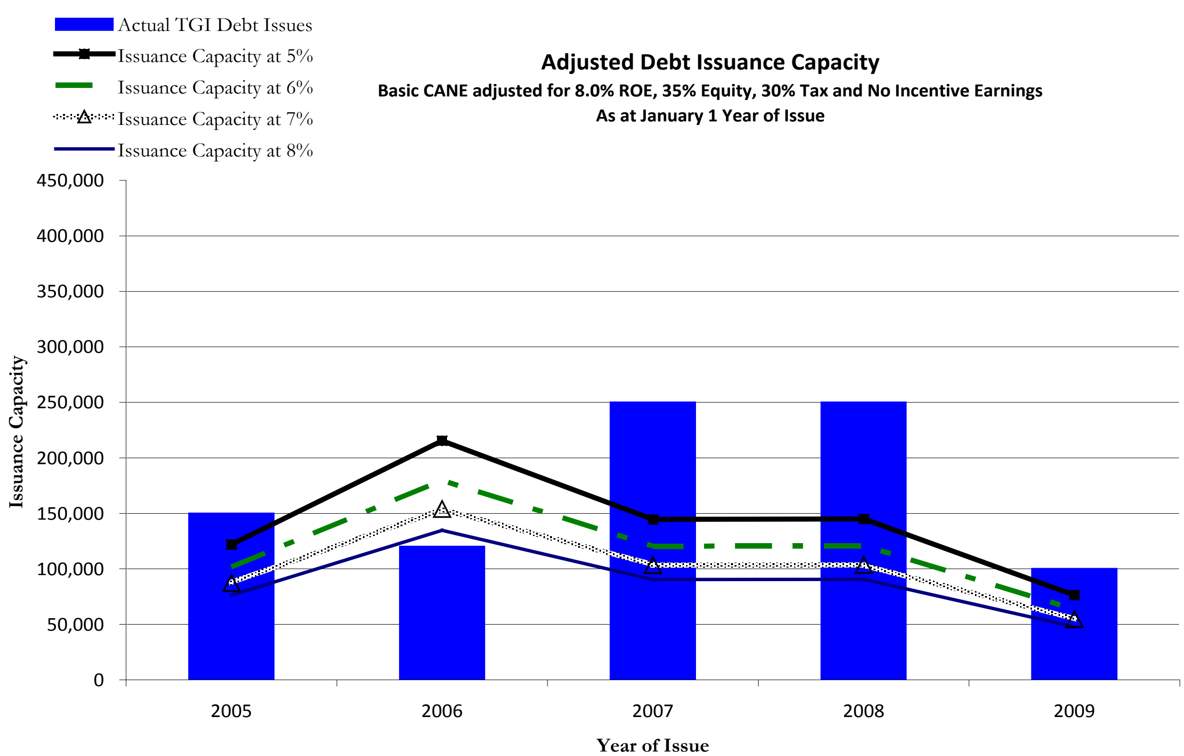
An additional implication of weakening financial ratios is that TGI could be constrained at a future point, absent an increase in ROE and equity ratio, in issuing long-term debt under its Trust Indenture. In order to issue new long-term debt, TGI is required to meet a debt incurrence interest coverage test. The test requires that consolidated available net earnings (CANE) must be at least two times interest on funded obligations (interest on debentures). Failure to meet this test would restrict the ability to issue long-term debt.

Historically, TGI has not been constrained by the new issue test. CANE is arrived at by starting with net income, and adding back income taxes, as well as interest on debentures. Historically, the achieved level of ROE, tax rates and the existence of incentive earnings combined to result in a level of CANE sufficient to allow TGI to issue long-term debt as required.

However, in the face of continuing low equity thickness, declining allowed ROEs, decreasing tax rates, and the loss of incentive earnings, TGI may be constrained in its future ability to issue debt. To demonstrate this potential constraint, TGI back-cast its debt issue capacity under its Trust Indenture on each January 1 between 2005 and 2009, using preceding year audited financial results and then adjusting CANE for each period by removing incentive earnings, lowering the tax rate to the current 30%, and reducing net income to reflect the impact of an 8% allowed ROE for each year.

The first of the following two graphs below shows the approximate debt issuance capacity (the horizontal lines) at a range of interest rates (that is, the amount of debt at each interest rate that could have been issued as at January 1 each year) under the actual CANE. The graph also shows what TGI actually issued for long-term debt each year (the shaded bars). The second graph demonstrates debt issuance capacity, under the scenario where CANE has been adjusted to remove incentive earnings, lower the tax rate, and to reflect an 8% allowed ROE consistent with that indicated by today's forecast Long GCB yields. Under the conditions as illustrated, TGI would have had a material reduction in its debt issuance capacity and would have been unable to issue the debt that it did in all years covered except 2006.


Actual TGI Debt Issues
Issuance Capacity at 5%
Issuance Capacity at 6%
Issuance Capacity at 7%
Issuance Capacity at 8%
Historical Debt Issuance Capacity
Basic Consolidated Available Net Earnings (CANE)
As at January 1 Year of Issue
Issuance Capacity
450,000
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
2005
2006
2007
2008
2009
Year of Issue


Actual TGI Debt Issues
Issuance Capacity at 5%
Issuance Capacity at 6%
Issuance Capacity at 7%
Issuance Capacity at 8%
Adjusted Debt Issuance Capacity
Basic CANE adjusted for 8.0% ROE, 35% Equity, 30% Tax and No Incentive Earnings
As at January 1 Year of Issue
Issuance Capacity
450,000
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
2005
2006
2007
2008
2009
Year of Issue

An increase in the common equity ratio to 40%, in conjunction with an increase in the allowed ROE, would alleviate the potential constraints on debt issuance capacity TGI may face in the future.

7.4 Current ROE and Capital Structure Mean TGI does not Compare Well to Industry Peers as an Investment Opportunity

In a financial market that is becoming more integrated on a North American basis, and facing significantly more competition for capital from both energy utilities and infrastructure entities, a lack of direct comparability on allowed ROE and capital structure will negatively impact TGI's ability to attract capital on reasonable terms. TGI should have an allowed ROE and capital structure comparable to its peers of comparable risk to allow it to compete effectively for capital in all market conditions – yet it does not presently have either.

Investors will examine the relative business and financial risks of comparable investment opportunities in making investment choices. TGI has business risks which are at least comparable to, if not greater than, its major Canadian and US gas distribution peers given its challenging competitive position with low cost hydroelectric generation and negative government policy implications; and TGI has higher financial leverage in its capital structure. The Commission, in its 2006 Decision, accepted that an increase to TGI's equity ratio at that time was supported by comparisons to the approved capital structures of comparable risk utilities. Accepting that TGI's business risk is comparable to, or in some cases higher than that of the major Canadian energy utilities, and similar to that of US gas and electric distribution utilities, the financial risk, as measured by its approved capital structure, should also be comparable. The analysis in Table 7.4, compares the approved equity ratios and other credit metrics of a sample of Canadian utilities with those of TGI.

Table 7.4

Comparison of Industry Metrics

	EBIT Interest Coverage				Debt to Total Capital				Allowed ROE				Equity Thickness			
Fiscal Year	05 x	06 x	07 x	08 x	05 %	06 %	07 %	08 %	05 %	06 %	07 %	08 %	05 %	06 %	07 %	08 %
Enbridge Gas Distribution Inc.[1]	2.29	1.80	2.24	2.27	62.0	63.3	59.6	55.0	9.57	8.74	8.39	8.39	35.0	35.0	36.0	36.0
FortisAlberta Inc.[2]	2.55	2.15	1.98	2.03	60.1	62.5	59.4	61.5	9.50	8.93	8.51	8.75	40.0	37.0	37.0	37.0
FortisBC Inc.	2.20	2.11	2.04	n/a	62.5	61.6	61.7	n/a	9.43	9.20	8.77	9.02	40.0	40.0	40.0	40.0
Gaz Metro inc.	2.65	2.45	2.30	2.21	60.1	60.8	64.8	66.1	11.64	9.33	9.57	9.52	38.5	38.5	38.5	38.5
Hydro One Inc. [3]	2.78	2.77	2.83	2.68	52.6	53.3	54.2	55.2	9.88	9.50	8.63	8.44	36.0	36.0	40.0	40.0
Newfoundland Power[2]	2.33	2.26	2.16	2.00	54.7	55.0	55.1	56.1	9.24	9.24	8.60	8.95	45.0	45.0	45.0	45.0
TransCanada Pipelines Limited[4]	2.32	2.60	2.75	3.31	61.9	62.7	59.6	58.8	9.46	8.88	8.46	8.75	36.0	36.0	40.0	40.0
Union Gas Limited[2]	2.09	1.91	2.24	2.28	64.9	64.5	62.4	58.3	9.62	9.63	8.54	8.54	35.0	35.0	36.0	36.0
Composite Avg	**2.40**	**2.26**	**2.32**	**2.40**	**59.9**	**60.5**	**59.6**	**58.7**	**9.79**	**9.18**	**8.68**	**8.80**	**38.2**	**37.8**	**39.1**	**39.1**
Terasen Gas Inc.[2]	**1.94**	**2.00**	**1.95**	**1.96**	**67.6**	**64.7**	**66.5**	**65.8**	**9.03**	**8.80**	**8.37**	**8.62**	**33.0**	**35.0**	**35.0**	**35.0**
Difference to Industry Avg	**(0.46)**	**(0.26)**	**(0.37)**	**(0.44)**	**7.8**	**4.2**	**6.9**	**7.1**	**(0.76)**	**(0.38)**	**(0.31)**	**(0.18)**	**(5.2)**	**(2.8)**	**(4.1)**	**(4.1)**

[1] *'08 data is for the 12 mos. ended June 2008*

[2] *'08 data is for the 12 mos. ended March 31, 2008*

[3] *Allowed ROE data is split between Distribution and Transmission 43/57*

[4] *'08 data is for the 12 mos. ended September 2008; Equity Thickness and Allowed ROE relate to Canadian Mainline*

Source: DBRS Reports

As can be seen, TGI currently has amongst the lowest common equity ratio and weaker credit metrics than the sample Canadian utilities, and is lower than the group average. The contrast is even more glaring when comparing TGI to US gas and electric distributors. In Exhibit 3 of his Evidence, Dr. Vander Weide lists the allowed returns granted to 101 US electric utilities between 2006 and 2008, which averaged 10.4% over the entire period and 10.5% for 2008. Over the same period the awards for 84 natural gas utilities averaged 10.3% and 10.4% respectively. Exhibit 4 of Dr. Vander Weide's testimony lists the deemed equity in the related utilities capital structures over the period which averaged 48.35% for the electric utilities and 49.07% for natural gas utilities. This imbalance in the capital structure and credit metrics, over time, will adversely affect TGI in comparisons with other utilities with which TGI competes for capital.

7.5 Increasing Common Equity Ratio is Essential to Put TGI on Even Footing with North American Utilities

An increase in the TGI equity ratio to 40%, along with an increase to 11% in the ROE allowed for TGI (and as the Benchmark ROE), is a required response to address this imbalance.

TGI is not unique in seeking such changes – and many precedents have been set that suggest these requests are warranted. In many regulatory jurisdictions in Canada, utilities have been or are anticipated to be involved in proceedings dealing with allowed ROE and capital structure matters. In the TQM Decision, the NEB granted TQM an after tax weighted average cost of capital and the freedom to set the capital structure that it deemed appropriate and move away from the 30% deemed equity component previously approved. TQM had applied for 11% ROE on 40% equity which was a significant increase from the previously deemed common equity component of TQM of 30%. The net effect of the TQM Decision was to materially increase the overall allowed return on capital from what had been allowed by the ROE formula and deemed equity level under the formula. In addition, Union Gas, Enbridge Gas Distribution, Hydro One and TransCanada have all had their deemed equity thickness increased since 2006.

The TQM Decision, together with widespread commentary by analysts that the ROE formula is broken, has led to the anticipation that other decisions will follow, resulting in substantive changes to allowed ROEs in the rest of Canada. If the BCUC and other regulatory bodies do not adequately address the low returns for utilities in Canada, and the disparity between the capital structure and returns in Canadian jurisdictions as compared to the U.S., it is quite possible that there will be negative credit rating implications for TGI and other Canadian utilities.

Summary of Part 2: Proposed Solution

The Terasen Utilities respectfully submit that the Commission must modify the ROE allowed for TGI, which will also serve as the Benchmark ROE for the other Terasen Utilities. It is also respectfully submitted that the equity component in the capital structure of TGI should be increased to 40%. These changes are critical if TGI and the other Terasen Utilities are to successfully compete for capital with other Canadian utilities, with utilities in the U.S., and with other participants in the capital markets.

It is requested that:

- The return on equity for TGI be set at 11.0% with effect from July 1, 2009 and that this rate be used effective July 1, 2009 as the Benchmark ROE for the other Terasen Utilities, with the company specific ROE for TGVI continuing to be set at a 70 basis point premium over the Benchmark ROE and the company specific ROE for TGW continuing to be set at a 50 basis point premium over the Benchmark ROE;

- The deemed common equity component in its capital structure of Terasen Gas Inc. for rate-setting purposes be 40%, with effect from January 1, 2010;

- The current rates of TGI and TGW be made interim effective July 1, 2009 until a final determination in this proceeding is rendered by the Commission and permanent rates can be set that incorporate the Commission's determinations; and

- The increase in the ROE determined for TGVI, be treated as an increase in TGVI's cost of service effective July 1, 2009 which will, pursuant to the Special Direction for TGVI, be an adjustment to the 2009 Deficiency or Surplus and will be reflected in the Revenue Deficiency Deferral Account balance.

By taking these actions the Commission will provide TGI and the other Terasen Utilities with the opportunity to earn a fair return on the investment in their utility assets which meets the Fair Return Standard and will also ensure that the Commission satisfies its obligations under the *Utilities Commission Act*.

Conclusion

In 1994, when the Commission introduced its ground-breaking ROE adjustment mechanism for setting rates of returns, the starting allowed ROE reflected the economic climate and circumstances of the day, but the adjustment mechanism was really an experiment with little evidence to support the adjustment factor. The adjustment factor is entirely based on an equity risk premium approach to determining the appropriate return on equity. While the adjustment formula has been modified over the years its fundamental parameters have not changed; it continues to rely on the implicit conclusion that there is a year to year relationship between forecast GCB yields and the required return on equity investments in utility assets. The evidence now available throws into question any year to year relationship between bond yields and equity returns, particularly in times of market turbulence when utility required equity and debt costs are increasing but the formula is produced a decreased ROE. The evidence now available demonstrates that over time the relationship between GCB yields and the required utility equity returns is not 75% (as in the current BCUC formula) but rather has been approximately 50%. The formulaic approach that has been based on one test for determining equity returns, and which has made use of an approximate 75% relationship to the movements in the long GCB yields, has resulted in the mechanism veering off course, with the formula not producing appropriate, adequate or fair returns on utility investments.

In British Columbia, in Canada and in North America, there is and will continue to be intense competition for capital in the future. Recent capital market conditions have led central governments and central banks around the world to take unprecedented steps to stabilize the financial markets, ease investor concerns and boost confidence. Market turbulence has led a flight to quality, with resultant abnormally low long-term government bond yields. Notwithstanding recent market conditions, the returns utility investors expect haven't changed dramatically over time, although recent market conditions indicate a re-pricing of all corporate risk. The returns available on comparable investments have been and are expected to continue to be materially higher than those produced by the current ROE adjustment formula. The Commission should adopt a more balanced approach to establishing a fair return for utility equity investors in British Columbia.

The Commission must recognize that a strong financial foundation is necessary to support healthy public utilities in the province. Debt investors require and demand adequate equity support in the capital structure of utilities to which they provide financing. It is not appropriate to subject investors in TGI to essentially the lowest allowed returns on equity in North America while at the same time failing to provide debt investors with adequate equity underpinning in the capital structure. The result is the lowest overall return from equity of the major gas/electric utilities in Canada.

The Commission must recognize that British Columbia utilities compete for capital with other Canadian utilities and with utilities in the U.S. The Commission should recognize that the results of the current ROE formula are inappropriate. The Commission must award returns on equity, and establish capital structures, that are appropriate in today's financial markets and reflect the business and financial risks of the utilities in British Columbia.

Terasen requests that the Commission acknowledge changed circumstances by allowing TGI a common equity component of 40% in its capital structure effective January 1, 2010, and the Terasen Utilities request that a return on equity of 11% be established effective July 1, 2009 for TGI, and as the Benchmark ROE for the other Terasen Utilities. This level of return as the ROE for TGI and as the Benchmark ROE will apply until an application to the Commission at a future date for a change. The Terasen Utilities will pursue development of an appropriate ROE adjustment mechanism with the goal of presenting a proposal to the Commission in time to be considered in setting final rates for 2011, if possible.

Questions concerning this application may be directed to Scott Thomson (604) 443-6565 or Tom Loski (604) 592-7464.

All of which is respectfully submitted,

TERASEN GAS INC.
TERASEN GAS (VANCOUVER ISLAND) INC. and
TERASEN GAS (WHISTLER) INC.

Original signed by:

Scott A. Thomson
Vice President, Regulatory Affairs & CFO

Terasen Gas Business Risks

Introduction

Business risk for TGI is the Company's ability to recover (i) the capital investments it has made to serve customers over the long term and (ii) an appropriate return on those investments. The Company's business risk continues to increase since the ROE decision made by the Commission in 2006.

By their very nature, a gas utility's primary investments have a useful life that extends over a long period of time. Therefore, when evaluating the business risk of a gas distribution utility, it is the longer-term fundamental business risks that must be given primary consideration.

Historically, the elements that made up TGI business risk were: the competitiveness of natural gas to alternative energy sources, namely electricity; the ability to attract customers and retain its customer base. These two elements influence the volume of natural gas (throughput) flowing through the TGI system. Ultimately throughput is the vehicle, from variable rates charged to customers, by which almost all of TGI's investments are recovered. All else equal, if throughput levels decline for whatever reason, TGI business risk increases.

The business risks and related trends that TGI identified in the 2005 ROE proceeding have continued to materialize. As an example, TGI normalized use rate for Rate Schedule 1 customers has declined.[1] This decline in use rate can be attributed to such factors as the price of natural gas compared to other energy prices and changes in housing mix within the residential sector. It is expected that these factors will continue to pose challenges to TGI into the future.

In addition to historical business risk factors discussed in the 2005 ROE proceeding (which continue), TGI faces new business risks that were not foreseen at that time. These factors include government efforts and mandates to reduce energy consumption to mitigate the impacts of climate change and aboriginal rights. It is reasonable to conclude that these new risk factors have increased the Company's business risk, and will increase TGI's business risk into the future. TGI investments relate to transporting a fossil fuel to customers. Investments in assets to enable the use of a fossil fuel are perceived by some elements of society to be at odds with the expectations of governments and customers regarding climate change.

Significant factors that have emerged since 2005 which increase the longer-term business risks of TGI are:

1) BC Government Policies:

    1.1 BC Energy Plan 2007 – energy conservation and efficiency policies
    1.2 BC GHG reduction targets
    1.3 BC Carbon Tax

[1] TGI normalized annual usage rate for Rate Schedule 1 customers (residential customers) has declined from 103.1 GJ's in 2003 to 92.5 GJ's in 2008. Projected annual use rate for Rate Schedule 1 for 2010 is 89.7 GJ's.

1.4 Climate Action Plan
1.5 Climate Action Team Recommendations
1.6 Province of British Columbia Strategic Plan 2009/10 - 2011/12

2) Aboriginal Rights Effects on BC Utilities

As discussed in Section 2.0 below, uncertainty of the nature and extent of aboriginal rights and title in B.C. and the lack of treaties, create operational and regulatory complexity, and a risk of litigation, that is greater than that faced by businesses in other jurisdictions. The Court of Appeal now requires that the Commission examine and determine the adequacy of aboriginal consultation, and possible accommodation. These factors contribute to TGI facing a higher degree of risk than utility operations in other provinces.

These new business risks are layered over the risks identified in the 2005 ROE application. These risks are:

1) The Competitiveness of Natural Gas Is Declining.

Natural gas no longer enjoys a substantial operating cost advantage over electricity. Electricity is a requirement for every home and business; adding a furnace and ducting for gas heating adds to the front end cost of building a home. As gas prices have risen over the past decade and electricity prices remained relatively flat (decreasing in real terms) natural gas has lost much of its competitive price advantage.

2) TGI's Ability to Attract and Retain Its Customer Base Is At Risk.

TGI is being negatively affected by two trends: TGI's declining rate of capture of the new construction market and the continued decline in annual use rates from existing customers.

With housing affordability challenged in the Lower Mainland, a greater proportion of new housing in recent years has been, and into the future will be, multi-family dwellings for which electricity achieves the overwhelming heating market share. This is resulting in substantially lower customer additions at similar housing start levels. The impact is significant, particularly when new customer additions are required to assist in offsetting the declining use per account of TGI existing customer's base due to energy conservation and efficiency efforts.

At the same time TGI is seeing a shift (decline) in annual demand. A greater number of competitive alternative energy sources are available now to prospective customers (i.e. heat pumps). This is evident by incentives being offered to customers through such programs as LiveSmart BC.

Collectively these fundamental business risk factors determine whether a utility will be able to recover its investments in rate base over time and an appropriate return on those investments. In addition these business risks contribute to shorter term risk associated with earnings volatility. These factors are discussed in detail below.

1.0 BC Government Policies Negatively Impact Terasen's Competitiveness

The British Columbia Throne Speech delivered on February 13, 2007 outlined the province's Greenhouse Gas ("GHG") reduction target, coupled with a second announcement on February 19, 2008 that introduced the BC Carbon Tax. Together these two policies and subsequent implementation into law have increased TGI's business risk since the last ROE application that was before the BCUC in 2005.

The aggressive GHG reduction targets send a strong message to consumers and businesses in BC that over the long term they must do things differently than in the past to reduce GHG emissions. This is evident from the Carbon Tax, which directly taxes the consumption of carbon based fuels within British Colombia. With natural gas providing over 20% of the energy consumed in the province, the new legislation and government policy create challenges to the longer term recovery of investment in gas delivery infrastructure in the province, and therefore to the level of business risk faced by TGI since the Commission last examined ROE and capital structure for the benchmark utility.[2]

Since 2007, with the announcement of "The BC Energy Plan: A Vision for Clean Energy Leadership" ("Energy Plan"), the BC Provincial Government has taken a leadership role in the fight against climate change/global warming. Page 1 of the Energy Plan states:

> *"This plan outlines the steps that all of us – including industry, environmental agencies, communities, and citizens – must take to reach these goals for conservation, energy efficiency and clean energy so we can arrest the growth of greenhouse gases and reduce human impacts on the climate."*

By taking this leadership role, many policy initiatives introduced by the BC provincial government on behalf of residents of BC have increased TGI business risk over the long term. These policies relate to the need for more energy conservation, the legislating of aggressive GHG emission reduction targets, and the introduction of the BC Carbon Tax. These policy items have the potential to reduce natural gas throughput levels or use per account, which in turn negatively impacts TGI's competiveness and its ability to recover its investment over the long term.

In moving the policy items outlined in the 2007 Energy Plan forward, the BC Provincial Government in the Spring 2008 Legislative Session introduced the following bills:

1. Bill 15 – Utilities Commission Amendment Act
2. Bill 16 – Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act
3. Bill 18 – Greenhouse Gas Reduction (Cap and Trade) Act
4. Bill 31 – Greenhouse Gas Reduction (Emission Standards) Statutes Amendment Act
5. Bill 27 – Local Government (Green Communities) Statutes Amendment Act, 2008
6. Bill 37 – Carbon Tax Act

[2] http://www.oee.nrcan.gc.ca/corporate/statistics/neud/dpa/tabletrends2/res

These Bills enact policy items from the Energy Plan. Each of these bills was enacted by the end of the Spring 2008 Legislative Session and has received Royal Assent.

As an example, the Local Government Act was amended by Bill 27 (Local Government Statues Amendment Act, 2008) to help ensure the 2020 GHG reduction target are met by amending Section 877 of the Act to state:

> *"An official community plan must include targets for the reduction of greenhouse gas emissions in the area covered by the plan, and policies and actions of the local government proposed with respect to achieving those targets*."[3]

1.1 Energy Conservation and Efficiency Policies

The Energy Plan was released on February 27, 2007 with many of the policies outlined in the Plan focused on the need for reduced energy use or energy conservation.

Many of these policies will have the ultimate effect of reducing throughput on the TGI system.

The relevant policies outlined in the Energy Plan:

- Encourage utilities to pursue cost effective and competitive demand side management opportunities.
- Explore with BC utilities new rate structures that encourage energy efficiency and conservation.[4]
- Implement Energy Efficiency Standards for Buildings by 2010.
- Undertake a pilot project for energy performance labeling of homes and buildings in coordination with local and federal governments.
- Require new provincial public sector buildings to integrate environmental design to achieve the highest standard for greenhouse gas emissions reductions, water conservations and other building performance results such as a certified standard. Supporting the goal of the government of BC being carbon neutral by 2010.
- Develop an Industrial Energy Efficiency Program for British Columbia to address specific challenges faced by the British Columbia industrial sector.

These policies are commendable, as they emphasize energy efficiency and conservation, objectives which TGI supports from a societal perspective. However, the overall result of these policies will be a reduction in natural gas average use per account which translates into less total throughput across the TGI distribution system. Over the long term, a decrease in throughput volume leads to high unit delivery costs for customers, which

[3] Bill 27 -2008 Local Government (Green Communities) Statutes Amendment Act, 2008 Legislative Session
[4] Notwithstanding the stated policy objective is sound, its application has been inconsistent. The 2008 BCUC decision on BC Hydro rate design relating to moving revenue to cost ratios toward parity was rolled back by the Provincial Government over concerns of customer rate impacts

makes natural gas less competitive, which in turn hinders TGI's ability to recover its investments.

Energy conservation and efficiency policies also fit well with helping to reach the primary goal of reduction GHGs. By using less energy derived from fossil fuels, less GHGs are produced.

1.2 BC GHG Reduction Targets Will Hurt the Competitiveness of Natural Gas

Of the policy items introduced by the Provincial government the one that presents the most significant business risk to TGI's traditional business and rate base investment is the policy relating to the reduction of GHG emissions in the Province.

For the year 2006, 12 per cent of BC's total emissions came from the consumption of natural gas in the residential and commercial sectors[5] (see Figure 1.2 below). Additionally, 14 per cent of BC's total emissions came from the "Other Industry" sector. Consumption of natural gas in the industrial sector is one of the sources of emissions embedded in the total emission from this sector. The final area of BC's emission that comes from natural gas consumption is in the electricity sector at 2 per cent. It is estimated that the operating emissions of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. and the emissions of their customers from natural gas consumption make up approximately 17 per cent of BC total emissions for 2006.

The Province passed Bill 44 (2007 Greenhouse Gas Reduction Target Act) in the 3rd Session of the 2007 Legislative Session. Part 1 of Bill 44 outlines BC GHG emission targets levels as being:

> *"By 2020 and for each subsequent calendar year, BC greenhouse gas emissions will be at least 33% less than the level of those emissions in 2007; and by 2050 and for each subsequent year, BC greenhouse gas emissions will be at least 80% less than the level of those emissions in 2007*."[6]

On November 25, 2008 GHG interim targets were set by Ministerial Order as follows:

- 2012 – six per cent below 2007; and
- 2016 – eighteen per cent below 2007 levels.

As a further commitment to provincial GHG reduction targets, the Province and the Union of BC Municipalities on September 26, 2007 committed to a goal of becoming carbon neutral by 2012.[7] As of March 31, 2009, 174 local governments have signed on to this agreement.

These reduction targets ignore regional emissions impacts and focus on reducing consumption of carbon based fuels including natural gas in British Columbia even though

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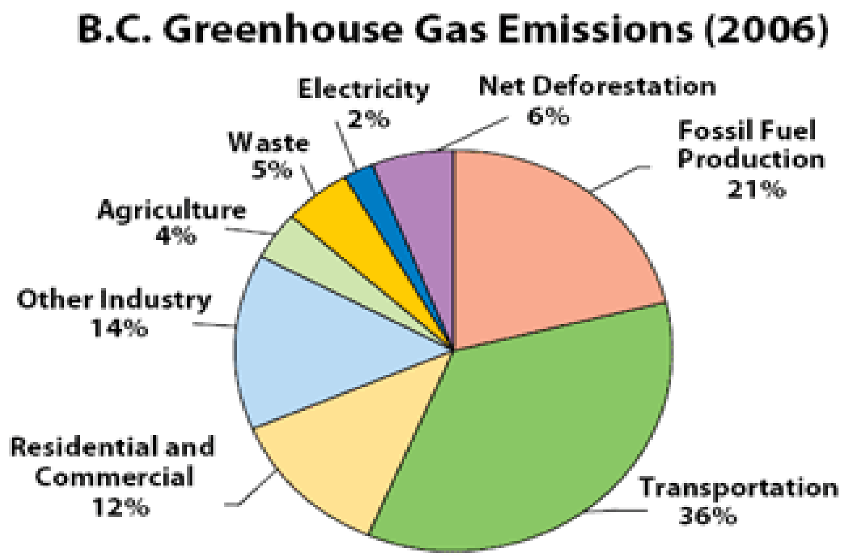
5 http://www.livesmartbc.ca/learn/emissions.html#Total

6 This means that GHG's emissions within BC must be reduced by 33% from 2007 levels by 2020. This may come in the form of a physical reduction or purchasing an offset that qualifies under the regulations.

7 New Release, Government of BC, B.C. Communities Commit to Carbon Neutrality By 2012, September 26, 2007

this can lead to a net increase in climate change impacts in the region through importation of electricity generated by fossil fuel combustion. The targets, which are enacted into law, have increased TGI business risk over the long term given that about 17% of BC GHG emissions come from the direct consumption of natural gas.

Figure 1.2: Electricity Generates Few GHG Emissions in BC



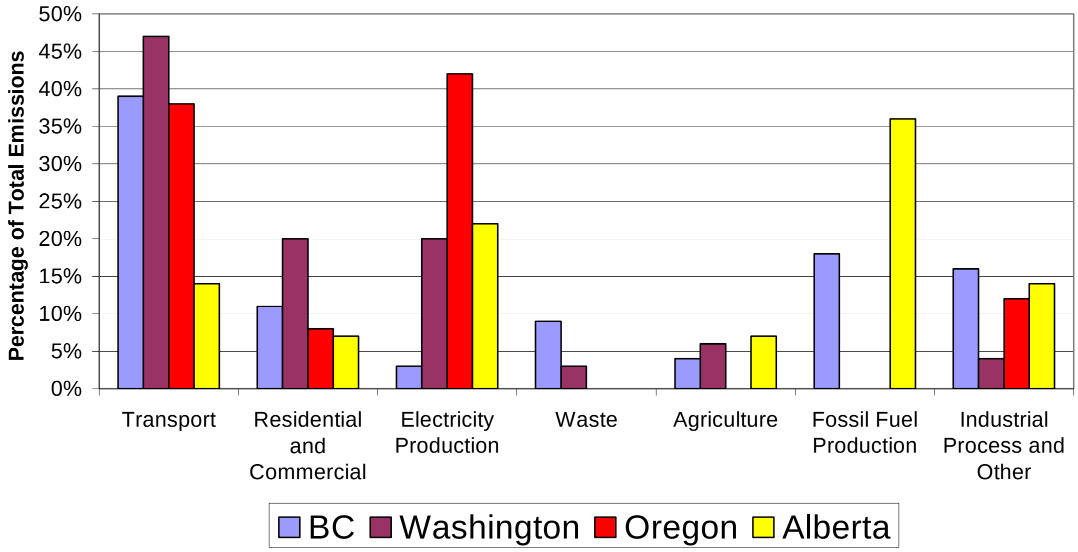
Source: British Columbia, Climate Action Plan, page 25

What makes BC unique relative to other jurisdictions regarding the output of GHG is the sources of these emissions. As Figure 1.2 shows, BC has only 2 per cent of its GHG emissions coming from the electricity sector. This is a much lower proportion compared to many other jurisdictions where a much higher proportion of the provincial or state emissions come from the electricity sector. For example, Alberta produces over 20 per cent of its emissions from producing electricity (see Figure 1.2.1). The difference between the two provinces arises from the difference in the types of electricity production: most of BC electricity is produced from hydro sources while Alberta produces most of its electricity from a combination of coal and natural gas. This is recognized by TGI customers as recently indicated by the British Columbia Public Interest Advocacy Centre on behalf of the British Columbia Old Age Pensioners Organization *et al* ("BCOAPO"),

> *"As a natural gas utility, they are in an admittedly more difficult position here in British Columbia than they would in many other jurisdictions, both in North America and internationally, because they are fighting to survive in a jurisdiction where they aren't the clean generation option. That does not, however, justify overlooking the simple truth: we have cleaner options more in line with planetary imperatives and the public's desire to take positive action to reduce their carbon footprint*."[8]

8 BCOAPO, Final Argument in BC Hydro 2008 LTAP, dated April 27, 2009, page 8

Figure 1.2.1: GHG Emissions by Sector (BC, Washington State, Oregon, Alberta)



Source: Data is available to the public from various provincial and state government web sites and documents. The data presented is for different years based on what was publicly available.

Note: If a column is missing for a particular state/province it means the number is zero for the category for that state/province. In some cases the number being zero may have to do with how that state or province classifies and reports the GHG output.

How GHG emissions are generated in each jurisdiction is important because it gives an indication of potential areas where emissions reductions will be targeted over time. In 2006, BC produced 69 million tonnes of GHG emissions.[9] This relatively small total emissions output as compared to other jurisdictions makes BC's aggressive reduction target of 33 per cent by 2020 a challenge. As a point of comparison, in 2005 Washington State produced an estimate of 88 million tonnes of GHG emission and its stated reduction target is by 2020 to reduce GHG emission to 1990 levels. This would be about an 11% reduction or 10 million tonnes in reduction based on 2005 output levels.[10]

With many policy items in the BC Energy Plan targeted at stimulating growth in the BC oil and gas sector, it will be a significant challenge for BC to reduce GHG emission from the fossil fuel production sector (21 per cent in Figure 1.2). This leaves the transportation sector at 36 per cent, other industry at 14 per cent, the residential and commercial sector at 12 per cent as the biggest areas for potential GHG reductions. By default this puts TGI's natural gas business at risk from the Province's GHG reduction targets policy.

Given this backdrop, some customers groups and competitors, believe that BC-produced clean electricity should be used at a greater rate in applications that historically have been filled by natural gas, namely in such applications as space and water heating.

9 British Columbia, Climate Action Plan, page 57
10 Washington Climate Change Challenge, Executive Order 07-02, Office of the Governor, February 7, 2007

As an example, before the release of the Energy Plan, BC Hydro, one of TGI's competitors for space and water heating, believed that natural gas was the best choice for space and water heating, as evidenced by the following public statement in 2006:

> *"It is important to match your energy source to its best use. Electricity is best suited for lighting, and powering appliances and televisions, whereas natural gas is ideal for space and water heating*."[11] says Steve Hobson, Manager of Power Smart at BC Hydro.

Also, in the past, BC Hydro had information on its company website that encouraged customers to use natural gas instead of electricity for space heating based on economic and environmental considerations. In the 2007 BC Hydro Rate Design Application proceedings, BC Hydro commented on this website posting, stating: BC Hydro from time to time since the 1980's, has encouraged natural gas for space heating, and that the referenced statement was first placed on its website in 2005.[12]

The provincial GHG reduction targets have the potential to adversely change people's perception of natural gas over the long term. The targets will likely shift investment and consumption decisions of the consumer away from natural gas towards the consumption of electricity or other renewable energy alternatives (such as solar or geothermal). This focus on renewable energy may supersede historical decision criteria such as cost of product, ease of use, and reliability.

Some customer groups and competitors have placed the need to reduce GHGs in the British Columbia above other decision criteria such as cost. This is demonstrated by BCOAPO's recent statement in its final argument in the BC Hydro 2008 LTAP proceeding, which states:

> *"As a result the world is a very different place than in the 1970's when global warming was fodder for science fiction and fossil fuels were commonly thought to be our civilization's salvation. How then, BCOAPO asks, are we to reconcile Terasen's desire to increase natural gas use with the facts: we have very little time to effect large changes to cut GHG emission levels in order to make any sort of impact?*
>
> *British Columbia is blessed with a rich hydrology that lends itself well to hydroelectric generation projects, both large and small and as a result, we do not as a province rely on dirty coal or natural gas generation for our power as do most jurisdictions in the world. Why then, when governments across the continent and around the world are adopting strong messages to avoid a climate catastrophe, and our provincial government has set its own aggressive GHG emission reduction goals, and our population is concerned about air quality, pollution, and climate change, would we support our relatively clean hydroelectric utility embarking upon a program that would encourage their current and future customers to switch to natural gas? In short: we shouldn't, we wouldn't, and we don't*."[13]

[11] Terasen Gas, Service Line publication, Spring 2006
[12] BC Hydro Rate Design, Exhibit B-31, BC Hydro undertaking, July 12, 2007
[13] BCOAPO, Final Argument in BC Hydro 2008 LTAP, dated April 27, 2009, page 7-8

Based on these statements it is clear that BCOAPO has placed a priority on climate change policy, erroneously considering only emissions in BC rather than net emissions affecting climate concerns, over historic considerations such as cost of product and ease of use. This is against a backdrop of a downturn in the economy and from an organization that represents low income groups. It is a strong example of how the provincial GHG targets, along with a lack of policy clarity respecting net emissions and general environmental concerns, can influence and shape customers perception against natural gas despite the direct economic benefits. Clearly, provincial GHG targets have changed customer's views and are likely to contribute to the reduction of TGI throughput volumes over time.

These statements made by BCOAPO in the BC Hydro 2008 LTAP proceeding are consistent with other opinions expressed by BCOAPO on the change in customer views towards natural gas.

For example, in the November 28, 2008 final argument related to TGI Resource Plan 2008 Application, BCOAPO stated:

> *"It seems inevitable that climate change policies, carbon pricing, and the public drive for clean renewable energy will have some impact on Terasen's future operations…."*[14]

Further, in response to the arguments of the Terasen Utilities in the TGI and TGVI 2008 Energy Efficiency and Conservation Application, BCOAPO submitted that,

> *"the Commission may take notice of the general message of the provincial energy and GHG reduction policies as clear indication that a move from electricity generated in a province so rich in clean, renewable resources to any fossil fuel, including natural gas, is contrary to what is currently perceived as that optimal balance*."[15]

A final example of shift in perception comes in the form of BC Hydro changing its policy regarding supporting natural gas for space heating. During the 2007 Rate Design Application proceedings it stated that,

> *"BC Hydro is reviewing this practice in light of the 2007 Energy Plan"*[16].

BC Hydro has since removed its website messaging to customers, which had encouraged natural gas for space and water heating. A demonstration of how the GHG policies in BC have shaped BC Hydro actions and therefore messaging to customers in BC, was the position that BC Hydro took in the Terasen Utilities 2008 Energy Efficiency and Conservation Programs Application that was submitted to the BCUC on May 28, 2008. In its final argument dated November 28, 2008, BC Hydro stated:

[14] Terasen Gas Inc., Resource Plan 2008, BCOAPO final argument dated October 16, 2008
[15] Terasen Gas Inc., and Terasen Gas (Vancouver Island) Inc., Energy Efficiency and Conservation Program Application, BCOAPO final argument dated November 28, 2008
[16] BC Hydro Rate Design, Exhibit B-3, Terasen Gas Inc. IR #1.3.1

> *"…that part of the EEC Application expenditures targeting fuel switching from electricity to natural gas is not in the public interest at this time*..."[17]

It is clear from the discussion above that the risk profile of TGI has increase substantially due to the climate change challenge, the provincial GHG reduction targets and how these targets have shaped customers view towards natural gas. There can be no doubt that this will have an impact on the use of natural gas, TGI's opportunities, and TGI's ability to recover its investment over the long term.

1.3 BC Carbon Tax Will Make Natural Gas Even More Costly

To help reach its GHG reduction targets, BC implemented the BC Carbon Tax, which came into effect in July 1, 2008. This tax reduces the competiveness of natural gas relative to alternative energy sources that are not subject to the carbon tax, and provides a direct pricing signal to customers in relation to GHG emissions.

As the Province Strategic Plan 2009/10 - 2011/12 emphasizes, the role of the carbon tax is to send appropriate price signals to enable customers to make choices with respect to energy consumption:

> *"It gives British Columbia's a choice on how they wish to adapt their behavior to reduce their consumption of fossil fuel."*[18]

As natural gas is a fossil fuel, and given the aggressive provincial GHG reductions targets, the BC Carbon Tax translates into an increase in the business risk profile for TGI.

According to the British Columbia Climate Action Plan (page 14):

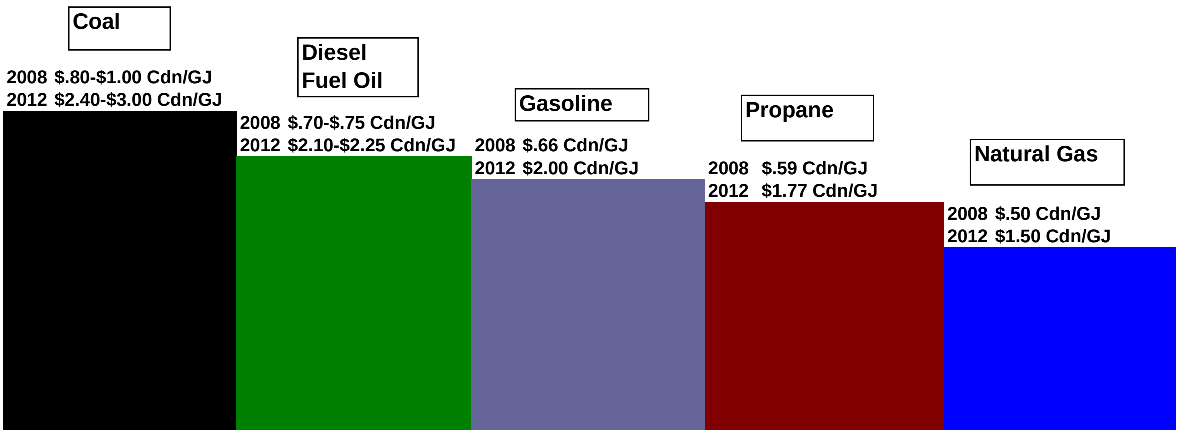
> *"A carbon tax is usually defined as a tax based on GHG emissions generated from burning fossil fuels. It puts a price on each tonne of GHG emitted, sending a price signal that will, over time, elicit a powerful market response across the entire economy, resulting in reduced emissions. It has the advantage of providing an incentive without favoring any one way of reducing emissions over another. By reducing fuel consumption, increasing fuel efficiency, using cleaner fuels, and adopting new technology, business and individuals can reduce the amount they pay in carbon tax, or even offset it altogether."*

The BC Carbon Tax started at $10/tonne of GHG and will increase by $5/tonne each year to $30/tonne by 2012. Figure 1.3 illustrates the cost per GJ on each fossil fuel based on their different GHG emissions profile at $10/tonne and $30/tonne. By 2012, natural gas consumers in BC will be paying $1.50/GJ in carbon tax. The carbon tax beyond 2012 is unknown at the present time. However, in its report entitled "Meeting British Columbia's Targets: A report from the BC Climate Action Team", the Climate Action Team recommends the following:

[17] Terasen Gas Inc., and Terasen Gas (Vancouver Island) Inc., Energy Efficiency and Conservation Program Application, BC Hydro, final submissions dated November 28, 2008, page 7
[18] The BC Strategic Plan 2009/10-2011/12

> *"After 2012, if required to achieve the emissions targets, increase the British Columbia carbon tax in a manner that aligns with the policies of other jurisdictions and key economic facts*."[19]

Figure 1.3: GHG Emission Cost Profile



Cost of $10/tonne for GHG Emsssions for 2008
Cost of $30/tonne for GHG Emsssions for 2012

The main energy source absent from the emission cost profile in Figure 1.3 is electricity. That is because the carbon tax imposed on electricity depends on the electricity's production mix. In most jurisdictions electricity is produced from a variety of sources. Thus the unit cost associated with carbon tax would vary according to the production supply mix. In BC, most electricity production is from hydro sources, with up to 15% of the electricity consumed being imported electricity produced in other jurisdictions, which likely is produced from a fossil fuel.[20] At present, this imported electricity is not subject to the carbon tax and the rules of carbon tax are not consistent across all energy forms in BC.[21] Therefore natural gas and other fossil fuel consumption in BC is disadvantaged from a price point of view as compared to electricity.

The carbon tax reduces natural gas' competiveness relative to alternative energy sources that are not subject to the carbon tax, and the carbon tax will help to sensitize customers to the level of GHG emissions they generate by sending them price signals. The provincial carbon tax increases the business risks of TGI.

[19] Meeting British Columbia's Targets, A Report from the B.C. climate Action Team, July 28, 2008, page 3
[20] BC Hydro 2006 Integrated Electricity Plan, Section 3, Figure 3-3 BC Hydro's Net Imports and Exports of Electricity
[21] BC Hydro has implicitly acknowledged that offsets and the carbon tax provide alternative price signals for GHG emissions by requesting confirmation from the Province that it will not be necessary for BC Hydro to purchase offsets and pay the carbon tax after 2016. This statement is from the BC Hydro LTAP 2008, Transcript, Vol. 6, at 824; Transcript, Vol. 6, at 870 (confirming Ms. Van Ruyven's statement).

1.4 Climate Action Plan Continues the Provincial Government Message on Climate Change

Both the 2007 Energy Plan and the more recent released Climate Action Plan[22] present the vision of the provincial Government and its resolve for BC to tackle climate change, and in doing so to change the way British Columbians think and act with respect to energy usage. As an example, the message from the government in the Climate Action Plan states:

> *"Global warming is the challenge of our generation. How we respond will shape the future of not just our environment, but also our economy, our society, our communities, and our way of life. British Columbia is taking decisive action to ensure these changes are positive. Since 2007 we have built a solid framework that addresses climate action in four key ways:*
>
> - *We have entrenched greenhouse gas reduction in law, including a commitment to reduce B.C. emissions by one-third by 2020.*
> - *We are taking targeted action in all sectors of the B.C. economy to help reduce emissions and set the course for the new low-carbon economy of the future.*
> - *We are taking steps to help British Columbians adapt to the realities of climate change and its impact on the province.*
> - *We are beginning a process to educate and engage British Columbians. This includes holding public forums and developing our LiveSmart BC initiative to support individuals, families, communities, business and industry to make cleaner choices and help."*

The Climate Action Plan maintains a consistent message from the provincial government about the commitment it has to reduction of GHGs and mitigation of climate change. As the summary of the Climate Action Plan suggests, *"we are taking action in all sectors of the BC economy to help reduce emission"*. Given that about 17% of BC GHG emissions come from the direct consumption of natural gas this will no doubt increase business risk for TGI.

1.5 Climate Action Team Recommendations Likely To Increase TGI Risk

To help the Province reach its goals relating to GHG, the British Columbia's Climate Action Team ("CAT") was established in November 2007.[23] On July 28, 2008, a report entitled: "Meeting British Columbia's Targets, was released by the CAT. In this report the CAT outline 31 recommendations that may help the Province reach is GHG reduction targets. The specific policy recommendations that could have a direct impact to Terasen Gas business risk are:

- Increase the British Columbia carbon tax after 2012 (if required to achieve the emission targets) in a manner that aligns with the policies of other jurisdictions and key economic factors.

[22] Climate Action Plan was released June 26, 2008
[23] Meeting British Columbia's Targets, A Report from the B.C. Climate Action Team, July 28, 2008, page 2

- Develop a comprehensive, multidimensional public engagement and outreach campaign in collaboration with public and private partners. This campaign will: 1) educate British Columbians about the importance of climate change and the policies that are necessary to address this issue and 2) help British Columbians reduce their own greenhouse gas emissions in the most efficient way possible, and 3) make British Columbia's aware of the incentives and savings available by taking action on climate change.
- Update B.C.'s Green Building Code at least every three years to ensure B.C.'s code is a leader among North American energy codes.
- Require that, by 2016, all new publicly-funded buildings in the province have net-zero GHG emissions and that by 2020 all new houses and building have net-zero GHG emission.
- Introduce an aggressive energy efficiency and renewable energy program for houses and buildings, combining incentives and regulatory approaches and coordinated across governments and utilities.

An example of how these recommendations and other provincial policy objectives can influence customers choices around energy consumption comes in the form of the University of British Columbia (UBC) issuing a request for a proposal to explore alternative energies at UBC. According to the UBC web site, UBC Utilities currently produces steam on campus with four natural gas fed steam boilers. Two of the four steam boilers are scheduled to be replaced in the next seven years. That is why UBC Utilities is aggressively looking to alternative non-polluting technologies to heat campus and ancillary tenant buildings.[24] One of the reasons why UBC is exploring this avenue is, as stated on its web site, is to ensure carbon neutrality in all provincial public sector operations. Thus, the CAT recommendations appear to be influencing and shaping purchasing decisions of customers that were historically natural gas customers.

All of the above recommendations have the intent of reducing fossil fuel use within homes and business, which by their nature threaten the Terasen franchise and increase business risk for TGI.

1.6 Province of British Columbia Strategic Plan: Discourages Use of Natural Gas

In February, 2009 the Province of BC released its "Strategic Plan 2009/10 – 2011/12." This plan continues BC's strong commitment to be a "*champion for climate change*"[25]. This commitment, while laudable, also challenges natural gas as a fuel source choice through government policy and by influencing public perception towards natural gas by lumping it in with all other fossil fuels.

For example, the Plan says that,

> *"B.C. has charted its course on climate change, with the establishment of its legislated goals for carbon emissions and greenhouse gas emissions. Our strategies developed over the last few years outline our plans and targets on everything from energy, bio-energy, agriculture, mountain pine*

[24] http://climateaction.ubc.ca/2009/02/26/ubc-utilities-leads-alternative-energy-project-to-reduce-greenhouse-gas-emissions, dated Feb. 26, 2009
[25] Province of British Columbia, Strategic Plan 2009/10 – 2011/12, February, 2009, page 1

> *beetle, to water, air, transit, and construction. Over the coming years, we will be focusing our efforts on implementing these strategies in order to achieve our objectives*.[26]"

Government policy that discourages consumers from using natural gas will have the effect of reducing throughput volumes on the TGI system and reducing the attachment of new customers. The recovery of fixed costs from a smaller customer base, and on lower throughput, leads to rate pressure for the remaining customers. Left unmitigated and unchecked, these effects can lead to loss of existing natural gas customers and a potential "downward spiral" in which the risk of non-recovery of invested capital increases and asset potentially become stranded.

Policy changes and objectives, and changes in customers' perception arising from those policies and objectives, and from general concerns respecting GHGs, climate change and fossil fuel consumption are new factors that have increased TGI's business risks since the last ROE proceeding in 2005.

2.0 Aboriginal Rights Effects on BC Utilities

With respect to aboriginal issues, there is a greater risk for utilities in BC as compared to other parts of Canada.

BC has a disproportionately higher number of First Nations in British Columbia than in other provinces, with the Province recognizing approximately 285 different First Nations, Bands and Tribal Councils. The need to recognize and deal with Tribal Councils flows from the lack of treaties, as it is more difficult to identify the appropriate aboriginal representative. Ontario has approximately 150 aboriginal groups, Québec approximately 68 and Alberta approximately 65, many of which are signatories to the treaties. The high number of aboriginal groups in British Columbia leads to overlapping territories and competing claims for aboriginal title, as well as strong differences in opinion as to the appropriate forum for reconciling aboriginal rights and title; there is a division amongst First Nations as to whether to enter the current treaty negotiation process. Since TGI's activities span large parts of British Columbia, the large number of different aboriginal groups whose interests may overlap increases business risk.

There are very few treaties in British Columbia. Historical treaties only cover a relatively small part of B.C. (portions of Vancouver Island and the northeast corner of the Province). There have been treaty negotiations in recent years but only three treaties have been completed. Due to the small number of treaties in B.C., there are many unestablished claims for aboriginal rights or title. This leads to uncertainty both as to the scope of the right, and the area in which it is exercised. The lack of treaties has also fostered a more litigious atmosphere than appears in other Provinces as First Nations in B.C. have sought to establish the existence of their rights through the courts. Further, there is the practical reality that the duty to consult with respect to aboriginal rights arises most clearly on Crown, as opposed to private, lands. In B.C. approximately 95 percent of the land is Crown land. In other provinces the proportion of crown land is generally less. Many of TGI's facilities are located on land owned by the Crown. Recently the Court of Appeal has ruled that BCUC decisions could affect aboriginal rights, and that the BCUC must

[26] Province of British Columbia, Strategic Plan 2009/10 – 2011/12, February, 2009, page 38

determine the adequacy of aboriginal consultation and accommodation before making such decisions.

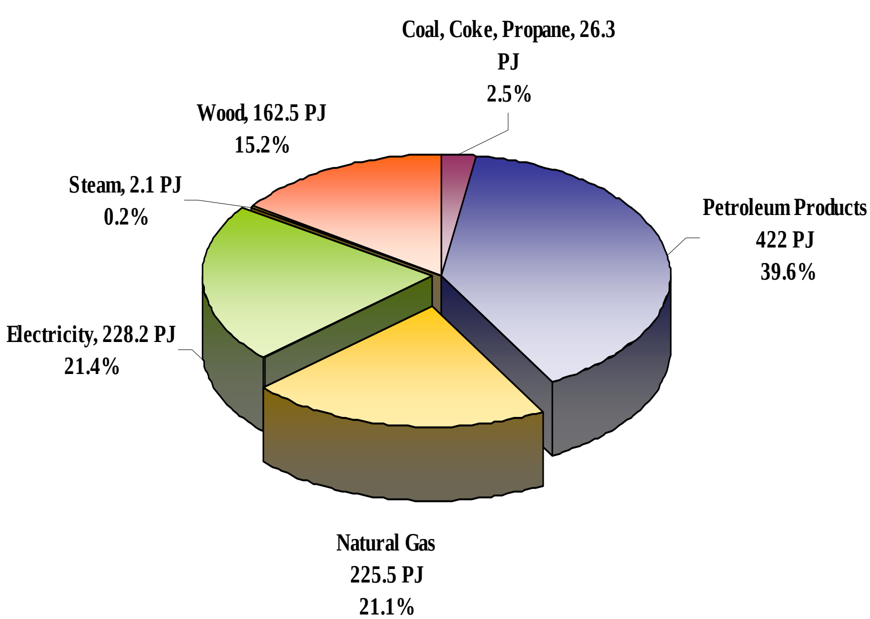
Uncertainty of the nature and extent of aboriginal rights and title in B.C. and the lack of treaties, create operational and regulatory complexity, and a risk of litigation, that is greater than that faced by similar businesses in other jurisdictions. All of these factors contribute to TGI facing a higher degree of risk than utility operations in other provinces.

3.0 The Competitiveness of Natural Gas is Declining

As recently as 2005, as Figure 3.0 shows, both electricity and natural gas provided about the same amount of total energy in BC to end users in the residential, commercial and industrial sectors. The facts show conclusively that the competitiveness of natural gas has been declining since the early 1990s, and will likely continue to do so. This results in increased business risk to TGI.

The energy mix that will be used in BC in the future will be determined by a combination of energy costs, government policy, and available technologies. Given the provincial government leadership on GHG emissions reduction targets and implementation of the carbon tax, customer perception of natural gas is being, and will be, negatively impacted. TGI's market share of new energy requirement in its service area will decline compared to historical capture rates. With current customer use rates already on the decline, the combination of expected reduction in market share and reduced average usage leads to an increase the risk of non-recovery of, and appropriate return on, the capital invested over the long term.

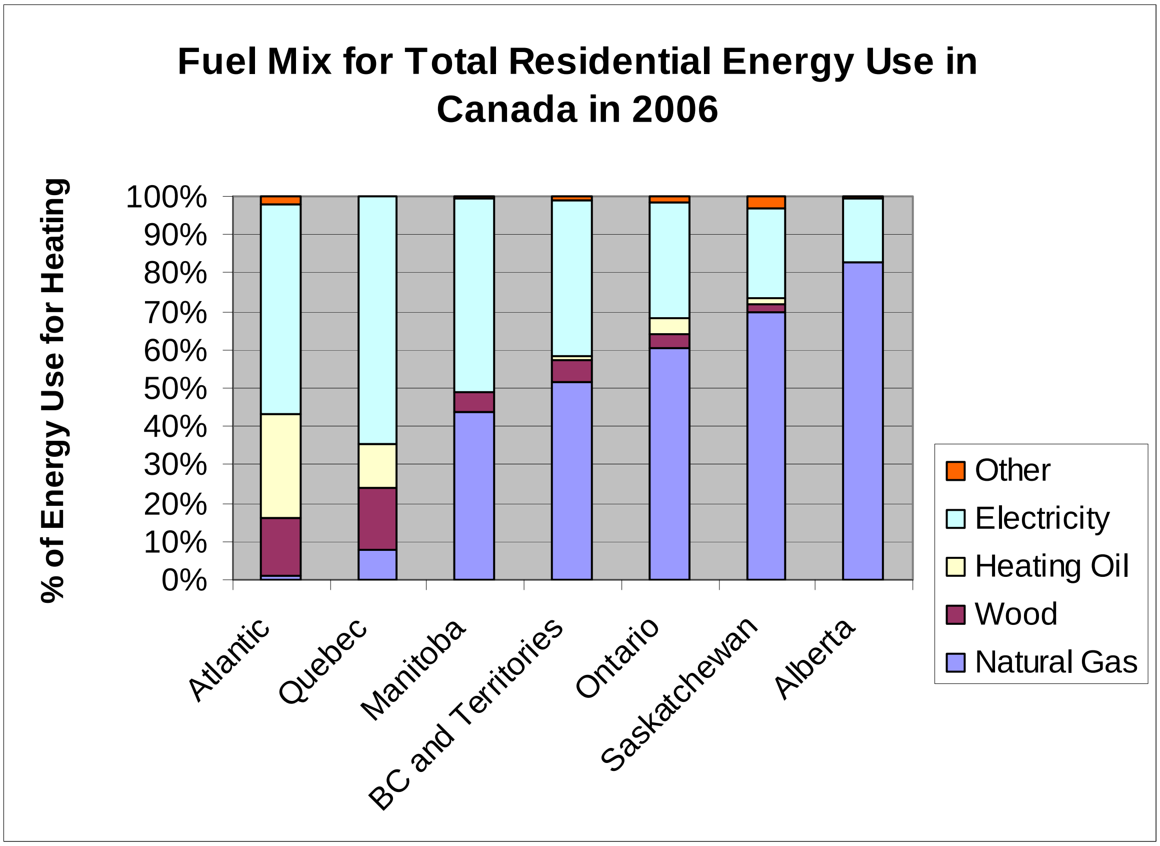
Figure 3.0: Annual Energy Consumption in BC across Energy Types



(Source: NRCan, BC Stats 2005)

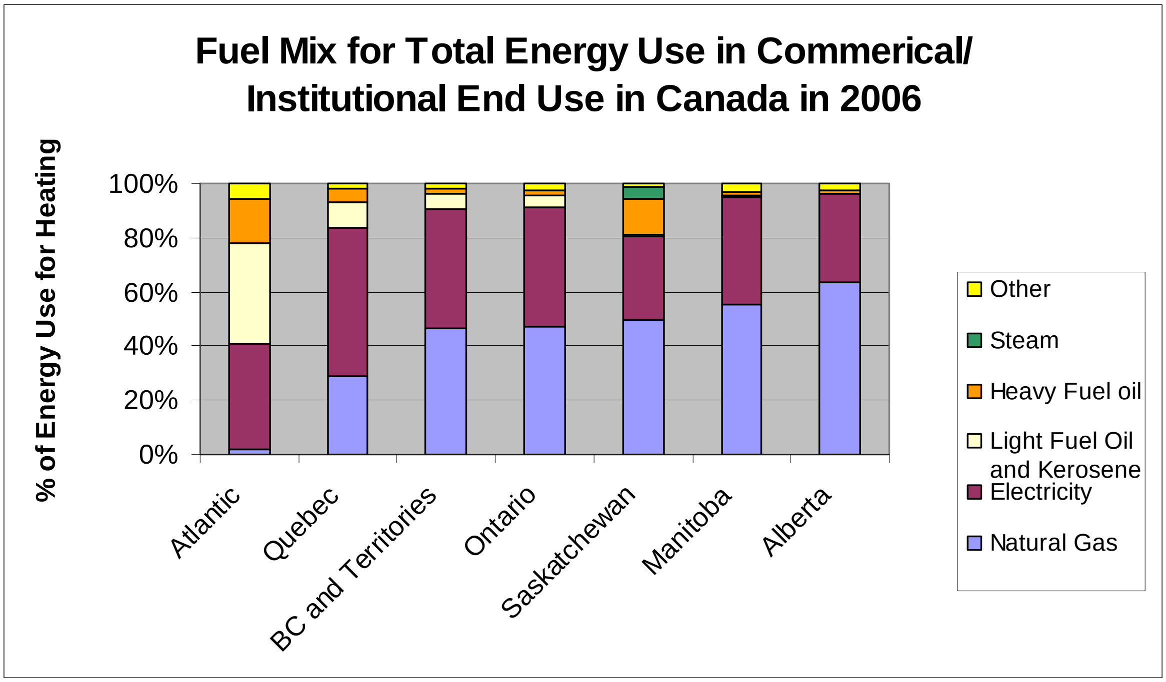
The two main energy sources used in end use applications in the residential and commercial sectors in BC have historically been electricity and natural gas (see Figures 3.1 and Figure 3.2). As these two Figures indicate, the fuel mix make up across the country is quite diverse from jurisdiction to jurisdiction. Some factors that drive these differences are: supply availability, established networks to deliver the product to customers, price of the product, size of the population to be served, and type of building stock being developed.

Figure 3.1: Fuel Mix for Total Residential Energy Use in Canada in 2006



Note: TGI service territory would be embedded into the BC and Territories column.
Source: http://www.oee.nrcan.gc.ca/corporate/statistics/neud/dpa/comprehensive_tables/index.cfm?attr=0

Figure 3.2: Fuel Mix for Total Energy Use in Commercial/Institutional End Use in Canada in 2006



Note: TGI service territory would be embedded into the BC and Territories column.
Source:
http://www.oee.nrcan.gc.ca/corporate/statistics/neud/dpa/comprehensive_tables/index.cfm?fuseaction=Selector.showTree

It is clear from the above figures that TGI's business can be differentiated from the natural gas distribution business in a number of other Canadian jurisdictions in two ways: (1) natural gas has a lower penetration rate in the TGI service territory than in other Canadian jurisdictions including Ontario, Saskatchewan, Manitoba, and Alberta; (2) TGI faces similar competition from electricity to that of Quebec.

Given this backdrop, three factors that influence natural gas use in space and water heating applications in the TGI service area are:

1) Historical operating cost advantages of natural gas versus other energy sources (which is in decline).
2) Terasen's competitiveness with electricity versus other jurisdictions (which is in decline).
3) Forward looking operating cost advantages of natural gas versus other energy sources (which are anticipated to decline).

These factors are discussed below.

3.1 Historical operating cost advantage of natural gas versus other energy sources is in decline:

One of the challenges that TGI has faced in recent years, and which it will continue to face, is the relative price advantage vis-a-vis electricity (the difference between natural gas rates and electricity rates) on an annual operating cost basis. Between 1998 and 2008, the price advantage of natural gas compared to electricity in B.C. declined from 63% to 18%[27].

Annual operating costs for natural gas applications such as space and water heating may improve versus electrical alternatives for these applications in the coming years with the establishment of the BC Hydro Residential Inclining Block ("RIB") rate that was implemented October 1, 2008. Natural gas requires an annual operating cost advantage compared to electricity to provide a payback on the up front equipment cost difference of a natural gas heated home and one that uses electric baseboards for space heating. As discussed above in Section 1.2, customers energy decision selection criteria is different than in the past and is evolving to the point where customers may be willing to forgo the potential economic benefit to them by using natural gas for space and water heating. Customers may select an energy alternative that cost more but is seen as helping to reduce the impacts of climate change.

As shown in Figure 3.1.1, Figure 3.1.2 and Figure 3.1.3 below, natural gas enjoyed a substantial price advantage versus electricity in the late 1990's throughout the three TGI regions (Lower Mainland, Inland and Columbia). In all three regions, the cost of natural gas to a customer in 1998 was less than half the cost of using electricity for the same applications.

This price advantage relative to electricity has gradually declined as natural gas rates increased with rising commodity costs, while electricity rates remained relatively constant.

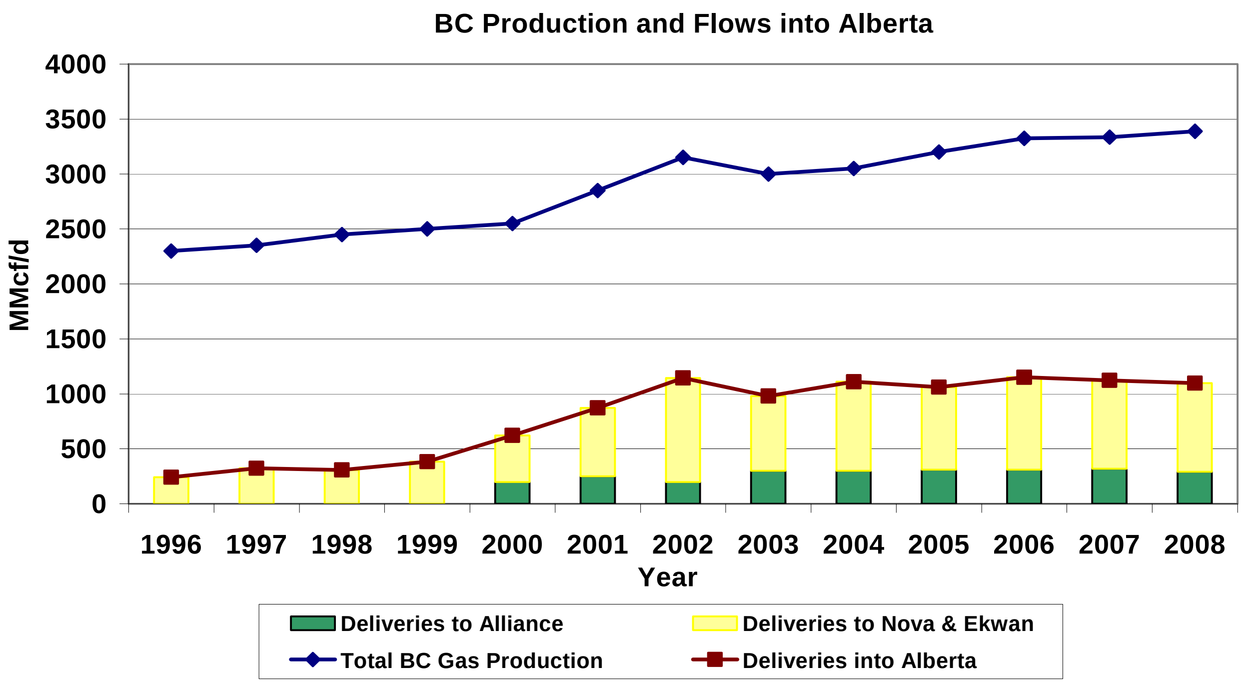
The fundamental reasons for the increase in natural gas commodity prices relates to the tightening of the supply/demand balance over the last 15 years.

In the 1990's, the Western Canadian Sedimentary Basin ("WCSB") experienced rapid growth in natural gas production capacity. This led to a "disconnect" in terms of lower prices in the WCSB as compared to other market prices in North America. The cause for this "disconnect" was that supply capacity growth in the WCSB outpaced the transportation capacity needed to move this new supply to market. This situation continued until new transportation pipelines were built with Foothills/Northern Border expansion projects in 1998 and the construction of the Alliance Pipeline in 2000. At this point, natural gas prices for the WCSB "reconnected" with prices in the rest of North America. This situation continues today as supply from WCSB lags behind the transportation capacity available to move gas out of this basin. In fact the WCSB is experiencing a decline in total natural gas supply.

Historically gas supply from Northeast BC has been the supply source in BC and the US Pacific Northwest ("PNW") region. Infrastructure has been built to move gas from Northern BC south via Westcoast Energy Inc. ("Westcoast") to Northwest Pipeline and the I-5 corridor. In the late 1990s producers with production in Northeastern BC signed long term contracts with the Alliance pipeline which move natural gas into the US Midwest markets. Northeastern BC natural gas production is no longer dependent on BC and PNW markets, instead it can flow into Alberta, and then to eastern Canada and the US Midwest. See Figure 3.1 for details.

[27] Figures 3.1.1, Figures 3.1.2, and Figures 3.1.3, show 2009 but 2009 is not reflected in this calculation as the year is not complete and gas commodity may changes in the remaining months for 2009.

Figure 3.1: BC Production Increases Result in an Increase of BC Natural Gas Flowing into Alberta (MMcf/d)



Natural gas production and processing in BC looks strong over the coming years with the recent discovery of shale and tight sands gas. In the past year Nova Gas Transmission Ltd. has announced three different proposals to move supply from BC into Alberta. These projects are projected, within five years, to transport as much natural gas as the Westcoast pipeline currently transports south. However, due to various pipeline expansion projects in the region that will move gas to Alberta and other eastern markets, there is a real danger that this new supply could bypass the Westcoast system. The resulting competition for commodity could lead to higher prices for the natural gas supplying BC and the US PNW.

The decrease in the price advantage of natural gas also results from the relatively flat BC Hydro's electricity rates over many years. Prior to 2004 BC Hydro was in an extended rate freeze period and its rates were not subject to BCUC oversight. During the rate freeze period BC Hydro was able to absorb its cost pressures with decreasing costs in other categories such as declining interest rates and with profits from electricity exports. In the meantime electric load has continued to grow beyond the supply capabilities of BC Hydro's Heritage resources, necessitating the acquisition in recent years of new more costly supplies from independent power producers. However, BC Hydro's rates are largely reflective of Heritage or historical costs of supply and continue to be among the lowest electricity rate in North America. With the establishment of the BC Hydro RIB rate, a customer's electricity rates will be determined based on the consumption level at the particular residential dwelling. In principle the RIB is a splitting of the allocated historical costs for the residential class into two rates, with the rate for the second step being higher, in order to promote energy conservation.

Customers reaction and concern to the recent high and volatile natural gas prices can be demonstrated by BCOAPO's recent statement in its final argument in the BC Hydro 2008 LTAP proceeding, which states:

> *"BCOAPO recognizes that Terasen's current rate compares favorably against BC Hydro's trailing residential rate. Right now, customers choosing natural gas for space and water heating are seeing a definite financial benefit as compared to their electricity-using counterparts. However, given the volatile natural gas prices, this could change at any time and customers would again find themselves in a situation where natural gas is no longer even the most economic choice*."[28]

This statement indicates that BCOAPO recognizes that its constituents could benefit from using natural gas in space and water heating now and possibly into the future but BCOAPO is worried about the long term cost and volatility of the natural gas prices.

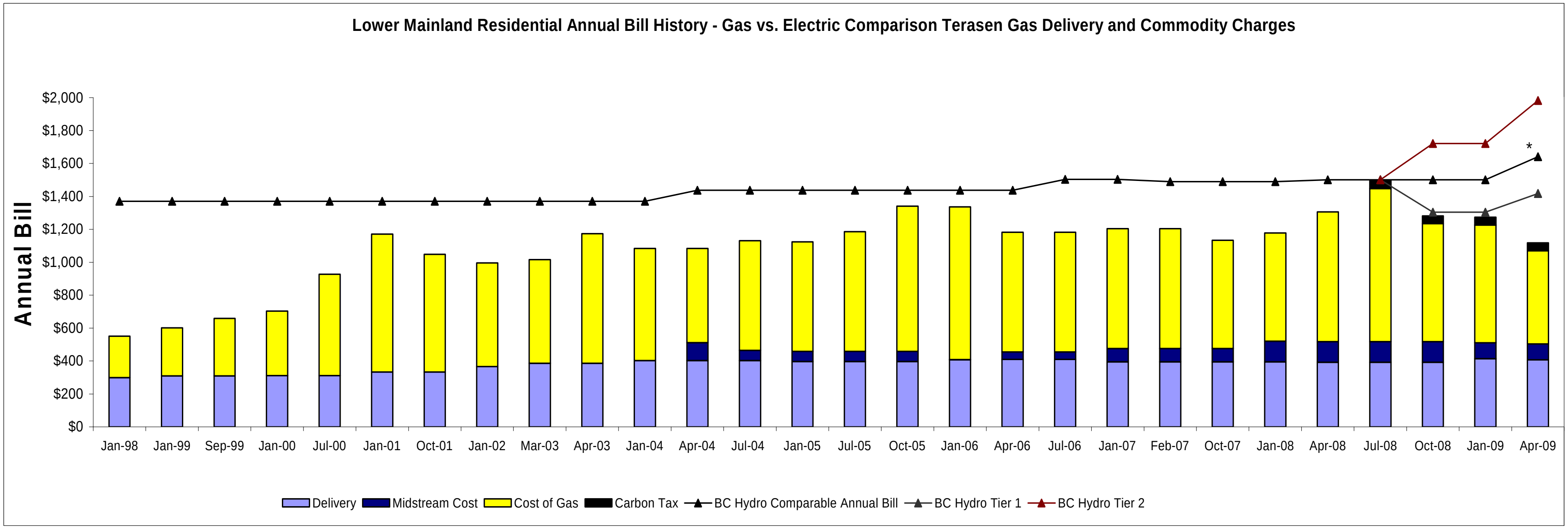
BCOAPO and other customers' perceptions of future natural gas prices may have been altered recently with the oil pricing scenario that unfolded in 2008. On July 3, 2008 the NYNEX oil futures contract for August 2008 deliveries hit an all time high of $145 US/barrel. This type of pricing event can shape customers perception of what the long term price for oil or natural gas may be and thus impact their investments and behavior towards energy choice.

The steady erosion of the natural gas cost advantage relative to electricity increases TGI business risk because growth in the customer base and throughput is more challenging to achieve. Increases in natural gas prices incent customers to reduce their energy consumption or look for cheaper alternatives to meet their energy needs. Furthermore, gas commodity costs are market based and regularly adjusted in customer rates based on quarterly reviews. Both cases lead to reduced consumption levels on the natural gas system which negatively impacts TGI's ability to recover its investment.

As an example, the BC Energy Plan: A Vision for Clean Energy Leadership has a strong focus on energy conservation and efficiency. The province, as part of its efforts to implement the Energy Plan, has established the publicly funded LiveSmart BC program that provides incentives and rebates to residential and commercial customers who make investments in energy conservation equipment. Through such programs as LiveSmartBC, new energy alternatives such as air source heat pumps and ground source heat pumps are being introduced to consumers as alternatives to their traditional natural gas furnace for applications such as space heating. These types of programs are directed at helping consumers reduce their energy consumption and emissions, but they also change public perception and attitudes toward the mature service offering of natural gas. The changed public perception increases business risk as people increasingly turn to other alternatives to meet their space and water heating requirements over time.

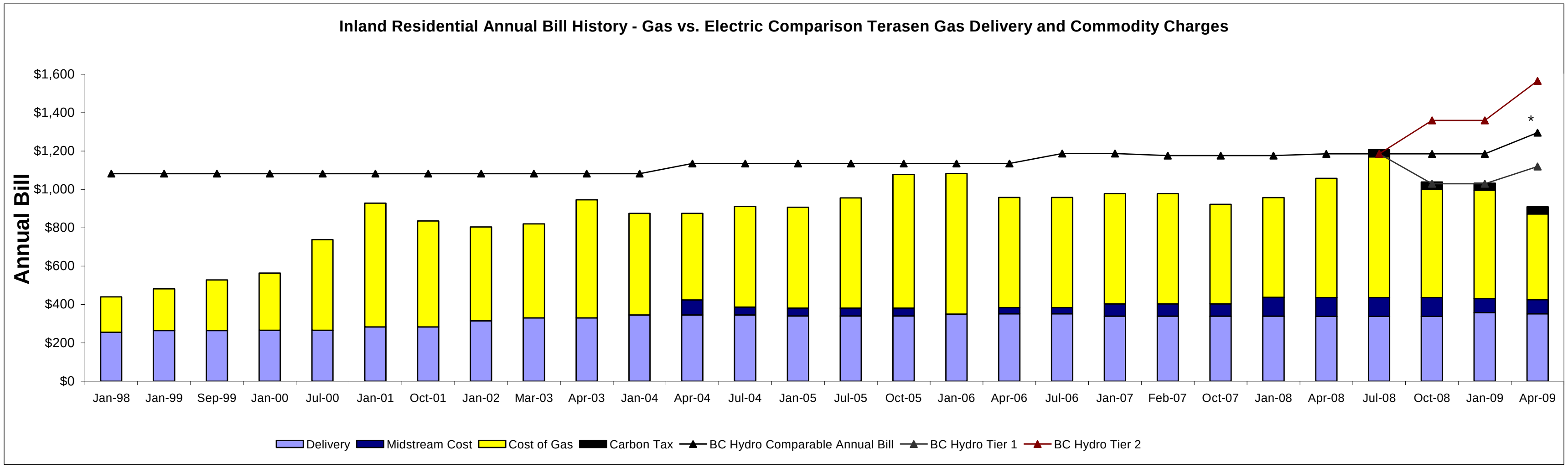
[28] BCOAPO, Final Argument in BC Hydro 2008 LTAP, dated April 27, 2009, page 8

Figure 3.1.1
Residential Annual Natural Gas and Electric Energy Costs in the Lower Mainland
1998 - 2009



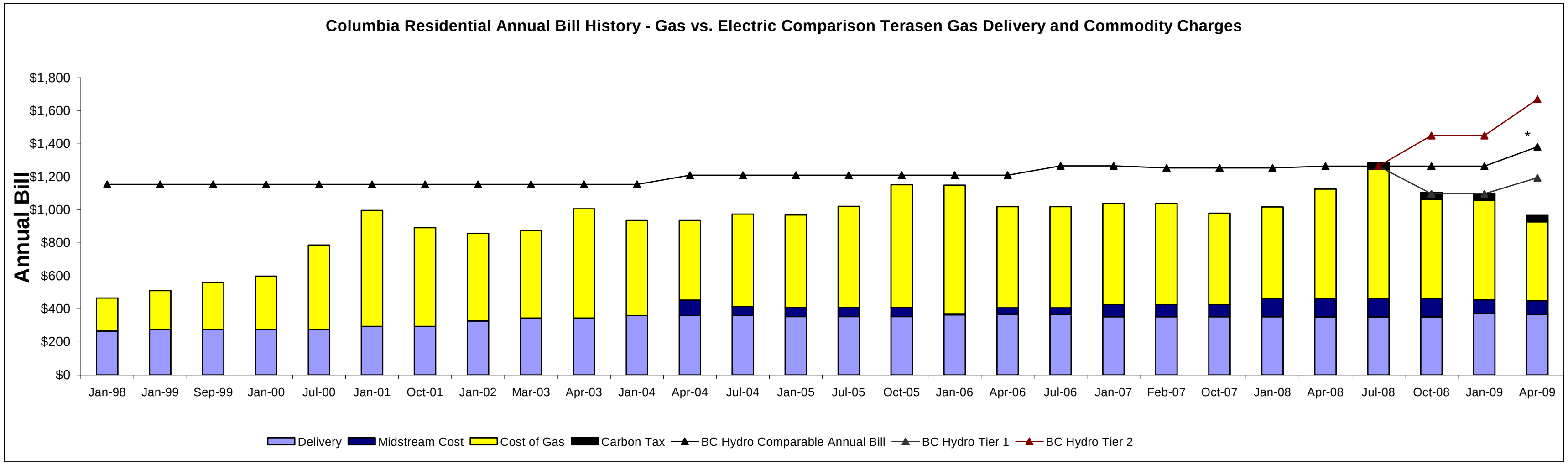
Assumes:
Natural gas use of 95 GJ
Efficiency of gas equipment is 90% relative to 100% for electricity
Terasen Gas amount includes the basic charge
BC Hydro amount does not include basic charge since a household already pays the basic electric charge for non-heating use
**Calculated BC Hydro rate based on the F2009-2010 RRA approved increase of 8.74% (inclusive of the applicable 1% rate rider)*

Figure 3.1.2
Residential Annual Natural Gas and Electric Energy Costs in the Interior
1998 - 2009



Assumes:
Natural gas use of 75 GJ
Efficiency of gas equipment is 90% relative to 100% for electricity
Terasen Gas amount includes the basic charge
BC Hydro amount does not include basic charge since a household already pays the basic electric charge for non-heating use
**Calculated BC Hydro rate based on the F2009-2010 RRA approved increase of 8.74% (inclusive of the applicable 1% rate rider)*

Figure 3.1.3
Residential Annual Natural Gas and Electric Energy Costs in the Columbia Region
1998 – 2009



Assumes:
Natural gas use of 80 GJ
Efficiency of gas equipment is 90% relative to 100% for electricity
Terasen Gas amount includes the basic charge
BC Hydro amount does not include basic charge since a household already pays the basic electric charge for non-heating use
**Calculated BC Hydro rate based on the F2009-2010 RRA approved increase of 8.74% (inclusive of the applicable 1% rate rider)*

The continued decline in the operating cost advantage from 63% in 1998 to just 18% in 2008 for natural gas versus its primary competition (electricity) combined with the lower capital and installation costs for electric baseboard heaters has created a challenging competitive market environment. The capital and installation costs for a new natural gas heating system typically range from three to four times higher than for electric baseboards. The difference in capital cost for heating equipment and ducting makes the simple payback to the potential natural gas customer extend over a long period of time or exceed the expected life of that equipment.

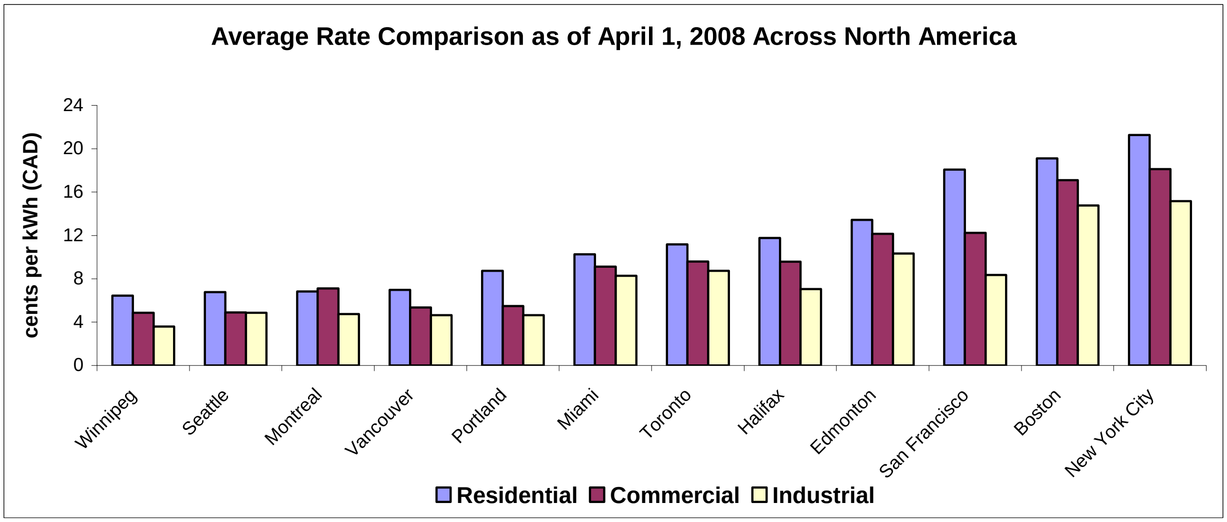
As an example, in the BC Hydro Conservation Potential Review Summary Report (Fuel Switching: Residential Sector) dated November 20, 2007, BC Hydro determined that no fuel switching (electricity to natural gas) measures were achievable.[29] In other words, the measure payback period either exceeds the life of the measure or the measure never pays back the original investment.[30] Although TGI expressed some concerns with the study's findings due to the methodology used in the study, BC Hydro has, in part due to the results contained in the study, changed its position on the use of natural gas for space and water heating. This is another example of how the actions and perceptions of others can increase business risk for TGI as the information provided to customers and potential customers affects how they perceive natural gas as an energy source.

One of the reasons for the decline in the price advantage that natural gas has had against electricity is the manner in which these products are priced in BC. Natural gas commodity pricing for consumers in BC is market-based; in contrast a large percentage of the costs making up electricity rates are the low embedded costs of BC Hydro's Heritage generation facilities. Please see Figure 3.1.4 below, which shows BC Hydro's electrical rates are among the lowest in North America.

[29] BC Hydro Conservation Potential Review 2007, Fuel Switching: Residential Sector, November 20, 2007, Page 112, Achievable Potential is defined: The portion of savings identified in the Economic Potential that could realistically be achieved within the study period through government and utility-led interventions and programs given institutional, economic and market barriers.

[30] BC Hydro Conservation Potential Review 2007, Fuel Switching: Residential Sector, November 20, 2007, page 89, study was for new and existing measures.

Figure 3.1.4: BC Hydro's Electricity Rates are Among the Lowest In North America



Rates are based on Hydro-Quebec's "Comparison of Electricity Prices in Major North American Cities"
Seattle rates are based on Seattle City Light

3.2 TGI competitiveness to electricity versus other jurisdictions in decline:

TGI faces a higher level of price competition than other gas distribution utilities in Canada and the Pacific Northwest. Figure 3.2 below shows the natural gas versus electric price differential for TGI in the Lower Mainland and six other gas distribution companies, based on current residential customer rates. Other than Gaz Metro, the other gas distribution companies enjoyed a price advantage ranging from approximately 25% to 74% as compared with a 32% price differential for TGI. Of the comparison group, Gaz Metro has slightly lower rates than its electric counterpart. Similar to TGI and TGVI, Gaz Metro competes with a major hydro generation-based electric utility, but has higher allowed returns and equity thickness than does TGI.

Figure 3.2
Comparison of Natural Gas versus Electric Price Advantage for Six Companies (2009)

	ANNUAL BILL - NATURAL GAS	ANNUAL BILL - ELECTRIC	GAS VS. ELECTRIC PRICE ADVANTAGE	
Terasen Gas (Lower Mainland)	$1,118	* $1,641	-32%	lower
Puget Sound Energy - Washington	$1,476	$2,530	-42%	lower
Northwest Natural Gas - Oregon	$1,604	$2,142	-25%	lower
Direct-Atco - Alberta	$775	$2,979	-74%	lower
Union Gas - Ontario	$1,010	$2,366	-57%	lower
Enbridge Gas - Ontario	$875	$2,366	-63%	lower
Gaz Metro - Quebec	$1,543	$1,574	-2%	lower

Notes:
**Calculated BC Hydro rate based on the F2009-2010 RRA approved increase of 8.74% (inclusive of the applicable 1% rate rider)*

Annual Bills for natural gas and electric, for all territories, are based on an annual use rate of 95 GJ.

The efficiency of gas equipment is assumed to be 90% relative to 100% for electricity to determine equivalent electricity. Lower gas efficiency appliances would result in lower gas price advantages than indicated above.

The annual electric rates do not include the fixed monthly charges since it is assumed that a household already pays the basic electric charge for non-heating use.

All rates are as at April 1, 2009.

All rates are exclusive of applicable franchise fees and/or taxes (with the exception of the Carbon Tax). Interior BC community customers pay a franchise fee of approximately 3%, which would reduce the indicated price advantage of gas by a like amount.

All annual bills are best estimates based on the information available from each utility.

3.3 Forward looking operating cost advantage of natural gas versus other energy sources is likely to decline:

Managing to remain competitive to the price of electricity in BC has become increasingly significant, particularly over the last few years with both increased natural gas prices and price volatility.

Near term economic realities have improved the competitiveness of natural gas at this time. Market prices are currently depressed due to declining industrial demand, high storage balances and weaker crude oil prices.

Yet it is long-term factors that will have a greater influence on prices and volatility in years ahead, and such factors suggest that the competitiveness of natural gas will continue to erode. As mentioned in Section 3.1, one factor that will influence prices and volatility is the declining natural gas production in the WCSB. Other factors include: increasing demand for electricity produced from natural gas outside of BC, the potential for active hurricane seasons affecting the Gulf of Mexico producing region, and the possible greater reliance on imported liquefied natural gas ("LNG") in the North American marketplace. Furthermore, future economic recovery and the associated increase in demand combined with the reduction in natural gas production forecast in 2009 could add to future market price volatility and potentially higher gas prices in the future. While the gap between forecast electricity rates and the current natural gas forward curve has widened in the short term, there is no guarantee that this widening gap will be permanent in nature, given the volatility in the North American energy markets and the fact that the actual costs of finding and development of new sources of natural gas exceeds current market prices.

In the short term natural gas price compression with electricity has eased – but evidence suggests this improvement may be unsustainable. With the recent BC Hydro F2009/2010 Revenue Requirements Decision, electricity rates have increased effective April 1, 2009, improving natural gas' competitive positioning with electricity, all else being equal. However, the magnitude of future electricity rate increases is uncertain as BC Hydro balances electricity self-sustainability and other government objectives going forward. Furthermore, while natural gas may be competitive with electricity rates on a variable basis, significantly higher capital costs for natural gas heating compared to electric space heating present a challenge for Terasen Gas in attracting new customers to offset the declining use rates of existing customers.

The following graphs (Figure 3.3 and Figure 3.3.1) illustrate the recent volatility in natural gas commodity prices compared to the commodity component of the electric equivalent.

Figure 3.3: AECO Prices vs. Electric Equivalent Commodity Component Current Prices as of May 11, 2009

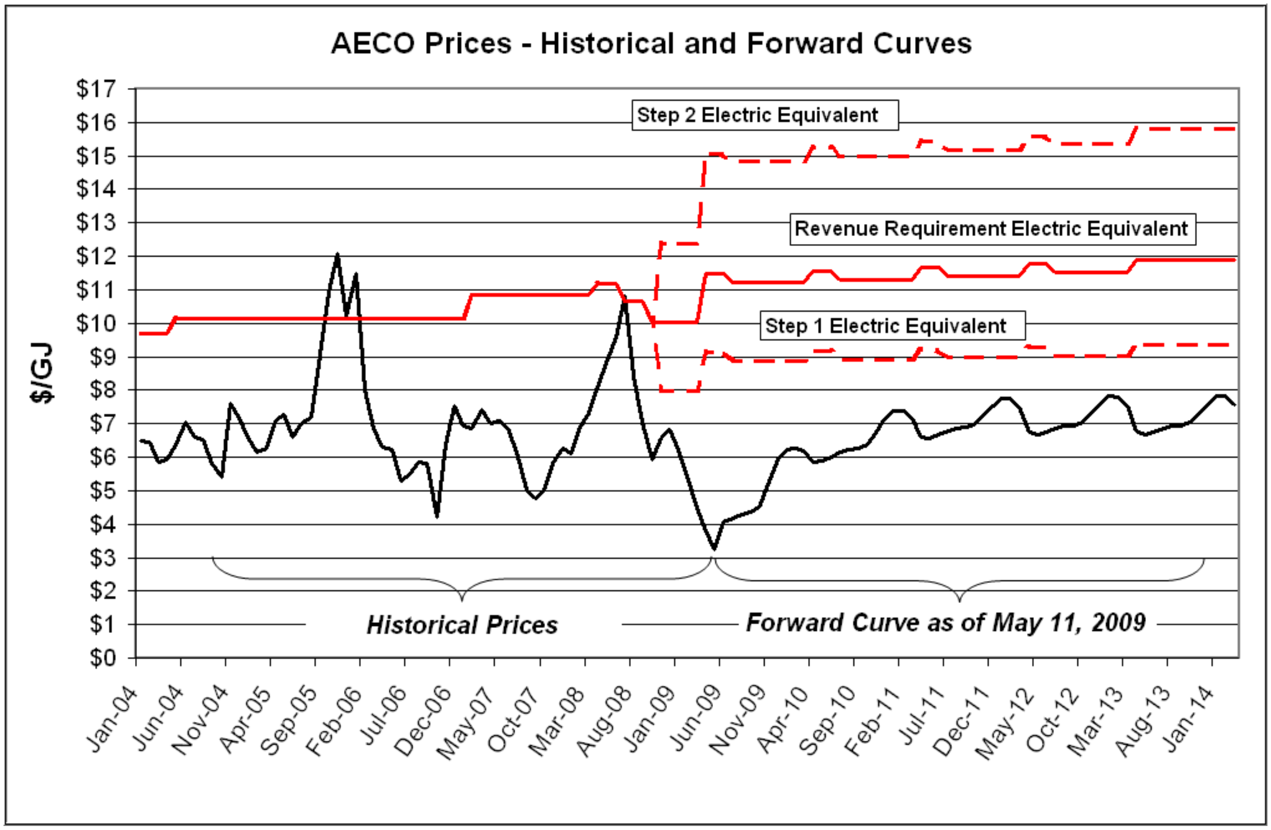


Figure 3.3 indicates that at the current gas commodity price, and the current forecast gas commodity prices (forward curve), TGI has a competitive advantage against electricity on an operating cost basis over the next five years. However, the comparison in prices is absent any consideration of the required recovery of the up front capital cost difference between a natural gas heated home and a home heated by electricity.

Figure 3.3.1: AECO Prices vs. Electric Equivalent Commodity Component Prices as of July 2, 2008

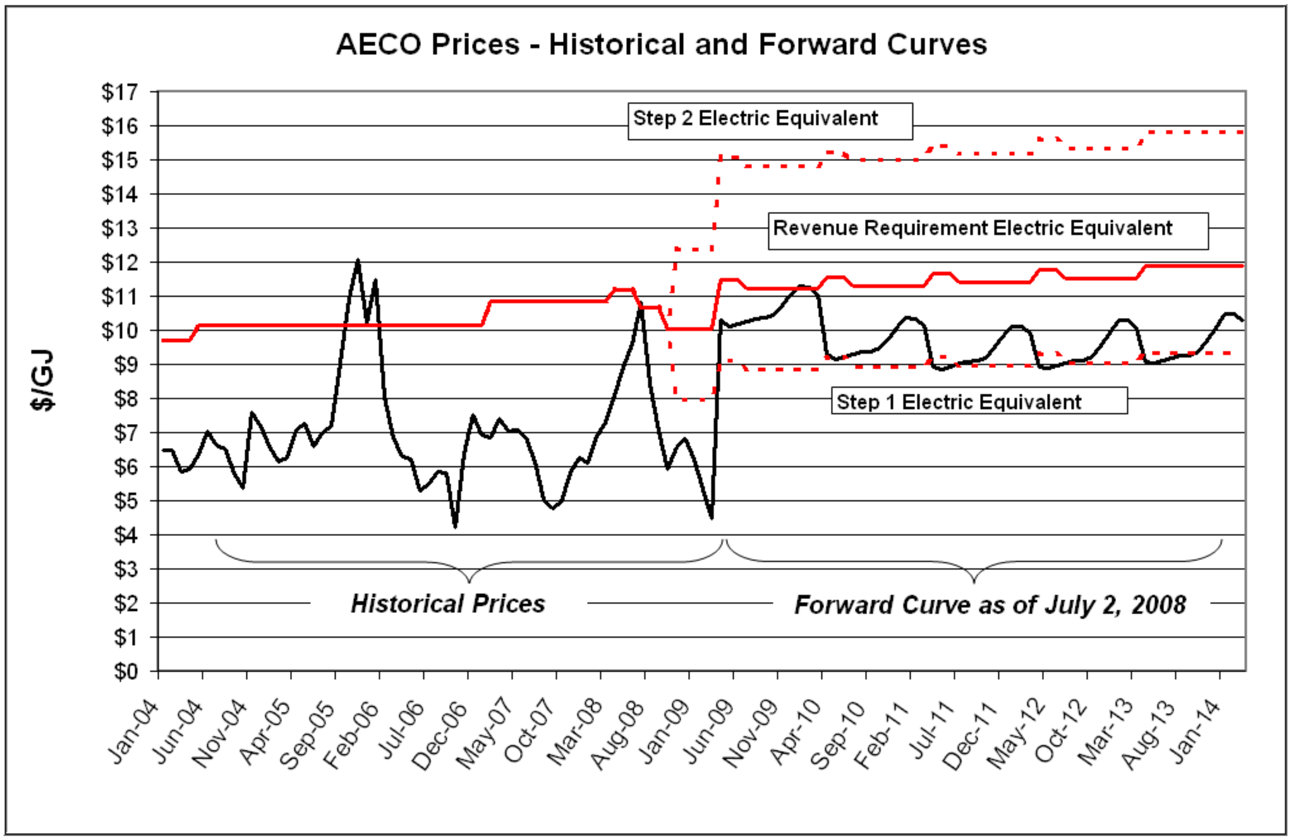


Figure 3.3.1 provides an indication of the volatility of natural gas commodity prices. The forward curve on July 2, 2008 was very different from and substantially higher than, the current forward curve. This graph illustrates the nature of the highly volatile natural gas marketplace in which Terasen Gas operates.

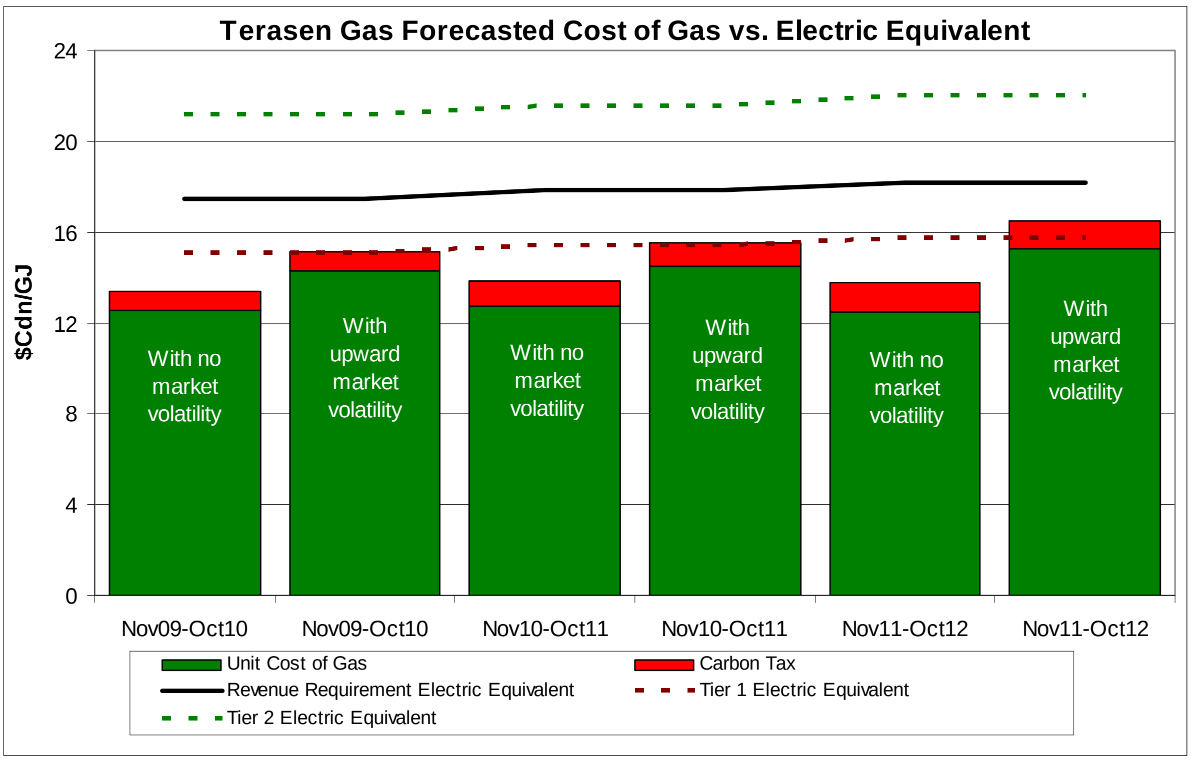
Consumers' energy sourcing decisions, and their perceptions of the relative merits of gas and electricity, are influenced by their views on price volatility and the possibility of significantly higher prices for fossil fuels in the future. This claim is support by BCOAPO's statements referenced in Section 3.1.[31]

A comparison of the total delivered cost of gas for TGI versus electricity (but excluding capital cost considerations) over a 36 month period is illustrated in Figure 3.3.2 below

[31] "BCOAPO recognizes that Terasen's current rate compares favorably against BC Hydro's trailing residential rate. Right now, customers choosing natural gas for space and water heating are seeing a definite financial benefit as compared to their electricity-using counterparts. However, given the volatile natural gas prices, this could change at any time and customers would again find themselves in a situation where natural gas is no longer even the most economic choice."

(based on current forward prices as of May 11, 2009 and standard market volatility assumptions). The gas cost projections in Figure 3.3.2 present the forecast cost of gas based on the current forward curve and reflect the existing hedged and un-hedged (floating) volumes in the portfolio for each gas year (Nov – Oct) shown. The chart provides two views for each gas year, the first bar in each pair ("With no market volatility") reflects only the forward curve pricing and the second bar in each pair ("With upward market volatility") adds a volatility adjustment factor of approximately 30 per cent to the floating volumes based on historical and current market conditions. As the graph illustrates, future market price volatility can have a significant impact on the unit cost of gas, as has been witnessed in the past, and therefore, adversely affect TGI's competitiveness with electricity rates.

Figure 3.3.2: Terasen Gas Current Forecast Cost of Gas and Volatility Potential



One might conclude from Figure 3.3.2 that at current forecast gas costs, TGI has a competitive advantage against the listed electricity equivalent rate comparisons on an operating cost basis.

3.4 Natural Gas Needs an Operating Cost Advantage to Payback the Difference in Upfront Capital Costs

As Figure 3.3 indicates TGI has a competitive advantage against electricity on an operating cost basis over the next five years using the current forward curve (as of May 11, 2009). What is not apparent from Figure 3.3 is that TGI requires a significant operating cost advantage to overcome the upfront capital cost differential for a natural gas versus an electrically heated home.

As Figure 3.4 shows, the annual energy cost differential between a natural gas heated home and an electrically heated home must be more than $500 per year or $10.31 per GJ over the life of the asset, in order to offset the capital cost differential for natural gas equipment versus electric baseboards. These calculations are based on the assumptions outlined in Figure 3.4.

Figure 3.4: Payback on Capital Costs Difference for a Natural Gas Heated Home[32]

Payback of Capital Costs (New Construction)

Space Heating Requirement Only
New Construction of home in Lower Mainland (2500 square feet in size)

Capital Costs for High Efficent Furnace (90%) and ducting/installations	$7,000.00
Capital Cost for Electric Baseboards	($2,500.00)
Difference in up front capital costs	$4,500.00
Interest Rate	0.06
Measureable Life of Furnace (years)	18
Amount that has to be recovered in operating cost annually to payoff difference in capital cost	$415.60
Add in furnace maintence costs per year	$100.00
Total ($)	**$515.60**
Energy consumptions for natural gas space heating (GJ's)	50
Difference in cost that needs to exist between natural gas heated home and electricity heated home in $/GJ over 18 years	**$10.31**

When the capital cost differential of $10.31 per GJ is added to the numbers outlined in Figure 3.3, natural gas for space heating applications is not competitive relative to any of the electric rates outlined in Figure 3.3, even the Step 2 RIB rate. The disparity in the overall competitiveness of natural gas taking into account upfront capital costs is very concerning given that natural gas commodity prices are lower today than in recent years and are actually below the costs of finding and developing new natural gas supply resources which suggests that natural gas prices are bound to increase in the future.

Natural gas used in space heating applications must have a significant operating cost advantage over a home heated with electricity, so that the difference in the up-front capital costs can be recovered. If natural gas does not have an operating cost advantage over electricity, natural gas will be challenged in being competitive with electricity over the long term.

[32] The 50 GJ used in this calculation relates to a new residential home located in lower mainland (2500 square feet). This 50 GJ is for space heating only and does not include other uses of natural gas in the home such as water heating or natural gas stoves. This 50 GJ is lower than the average Rate Schedule 1 use rate of 92.5 GJ for 2008 because the 92.5 GJ is related to the total demand not just the space heating load. Also it reflects a decrease for the higher efficiencies of the new home and new furnace as compared to the existing stock of houses and furnaces.

4.0 Ability to Attach New Customers and Retain Customer Base At Risk

A utility's ability to manage risk is in part dependent on its ability to attach and retain customers. These factors are a significant influence on the throughput volume that will flow across the utility's distribution system over the long term and will have a major effect on the long-term ability of the utility to recover its investment. In TGI's case, the Company is capturing a declining percentage of the new housing starts in BC, TGI is also experiencing declining use rates for existing customers. These factors were occurring even before the provincial Energy Plan was announced, which has a strong focus on energy conservation, and therefore, this trend can reasonably be expected to accelerate.

4.1 Housing Starts, Housing Mix, and Declining Net Customer Additions

Throughput levels will be determined over the long term by the mix of customers and their use rates, any decline of which can only be offset by new customer additions.

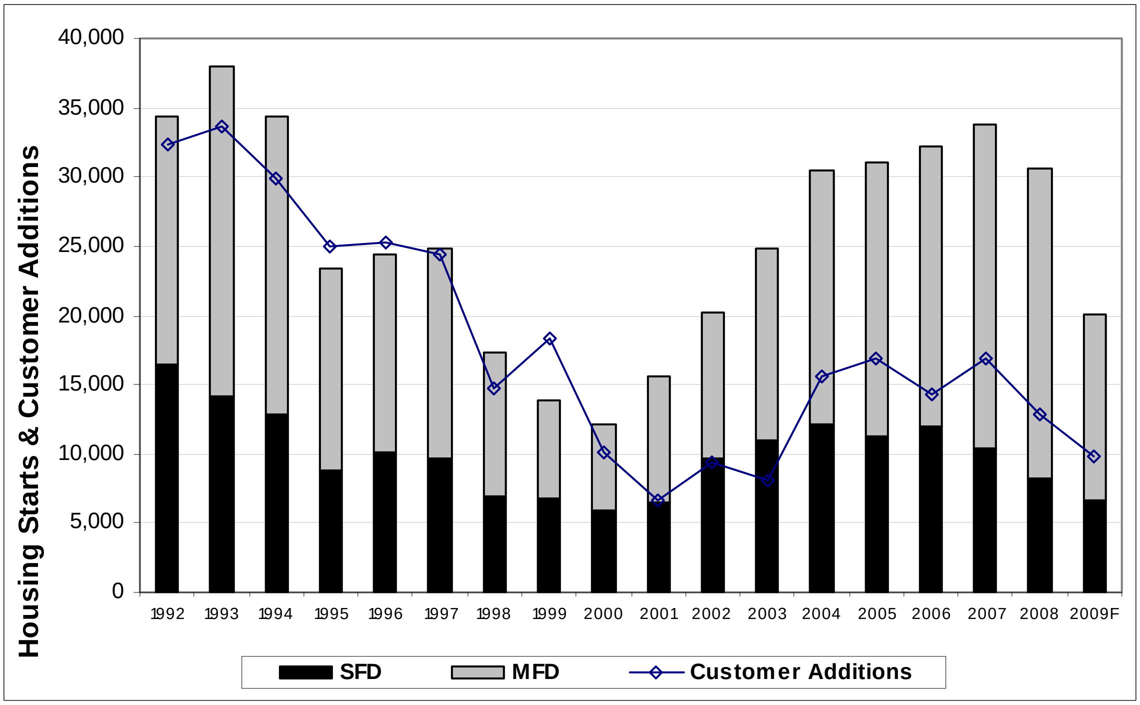
Customer additions are influenced by a number of factors, including the new construction market in British Columbia, and challenged by the shift in the housing market towards more higher-density housing types, and the price competitiveness trends discussed earlier. These factors contribute to the challenges TGI faces in maintaining its current customer base which contributes to an increased business risk.

Despite relatively low mortgage rates and a population that continues to grow, the U.S. slowdown and ensuing collapse of the financial markets have resulted in a dramatic recent decline in the British Columbia housing market.

Figure 4.1 below illustrates that housing starts declined steadily from 1993 to 2000, then began trending upward until reaching record levels in 2007. The decline in the US economy and global financial crisis that began in 2007 and accelerated during the latter half of 2008 has certainly impacted British Columbia, and more specifically the housing market. The Canada Mortgage and Housing Corporation ("CMHC") reported a 12% decline in housing starts from 2007 to 2008, and in the 2009 First Quarter Housing Market Outlook are projecting a one-third decline in housing starts for 2009 followed by an additional 9 per cent decline in 2010. In summary, the housing market has taken a significant turn for the worse, and a speedy recovery is not expected.

The current projection for housing starts (2009) is 22,800 for British Columbia, and in 2010 a further decline is expected. Since 1994, the annual number of housing starts in British Columbia has averaged approximately 25,000 units. Therefore, current and future expectations for housing starts are lower than the long-term average. When the ROE adjustment mechanism was introduced in BC in June 1994, annual new construction starts were in the 30,000 range (20% higher than the average experienced since 1994). And as noted, Terasen's throughput retention is highly affected by housing start levels.

Figure 4.1
New Construction Starts and Terasen Gas Net Customer Additions
TGI/TGVI Combined: 1992 – 2008



A shift in the housing market towards higher density housing types began in 1999, and multiple family dwellings have become the dominant housing type in BC (as illustrated in Figure 4.1 above). With high building material and land costs, and also declining affordability, the pool of potential single-detached new home buyers is shrinking. The average MLS price for the Greater Vancouver area is now almost $600,000 which puts this type of housing out of reach for many potential buyers, including first time buyers, especially in today's challenging economy. First time homebuyers are typically purchasers with modest budgets that push them into the multiple family dwelling segments. Selection of electric space heating reduces upfront "non-visible" construction costs and allows higher expenditure allocations to aesthetic items. Code changes due to recently introduced safety requirements have resulted in approximately a doubling of costs for gas hot water tanks. This puts further pressure on natural gas as a fuel choice. Over the past five years, approximately two-thirds of all housing starts have been multiple units and Terasen's capture rate in this segment is currently only 18%.

Figure 4.1.2
New Construction Proportion of Single versus Multi Family Dwellings
1999 – 2008

Year	Single Family	Multi-Family
1999	49%	51%
2000	49%	51%
2001	42%	58%
2002	48%	52%
2003	44%	56%
2004	40%	60%
2005	36%	64%
2006	37%	63%
2007	31%	69%
2008	27%	73%

In addition to price competitiveness, a significant driver of lower capture rates today versus the past is the higher proportion of new construction in multi-family versus single family units. While natural gas has experienced a high capture or penetration rate for single family units historically, electric baseboard heating has dominated multi-family construction units leading to lower capture rates in that market segment. With the supply of land on which to build new homes in urban centres diminishing, and with many single family dwellings being knocked down and replaced with multi-family dwellings (as they are demolished and rebuilt), there is a distinct trend towards more multiple family dwellings in the new construction housing mix (see Figure 4.1.2). Given this trend, it is reasonable to expect multiple family dwellings to become even more dominant in the future and with it further declines in customer capture rates.

Declining customer attachments are problematic for existing customers because new customers mitigate part of the impact of declining use rates, as discussed below. With customer attachments falling combined with declining average use per customer, Terasen is facing increased competitive challenges on a delivered unit cost basis. Speaking more generally, over the past decade the challenge to mitigate declining use per customer and throughput loss has become more pronounced, and the business risk profile has increased.

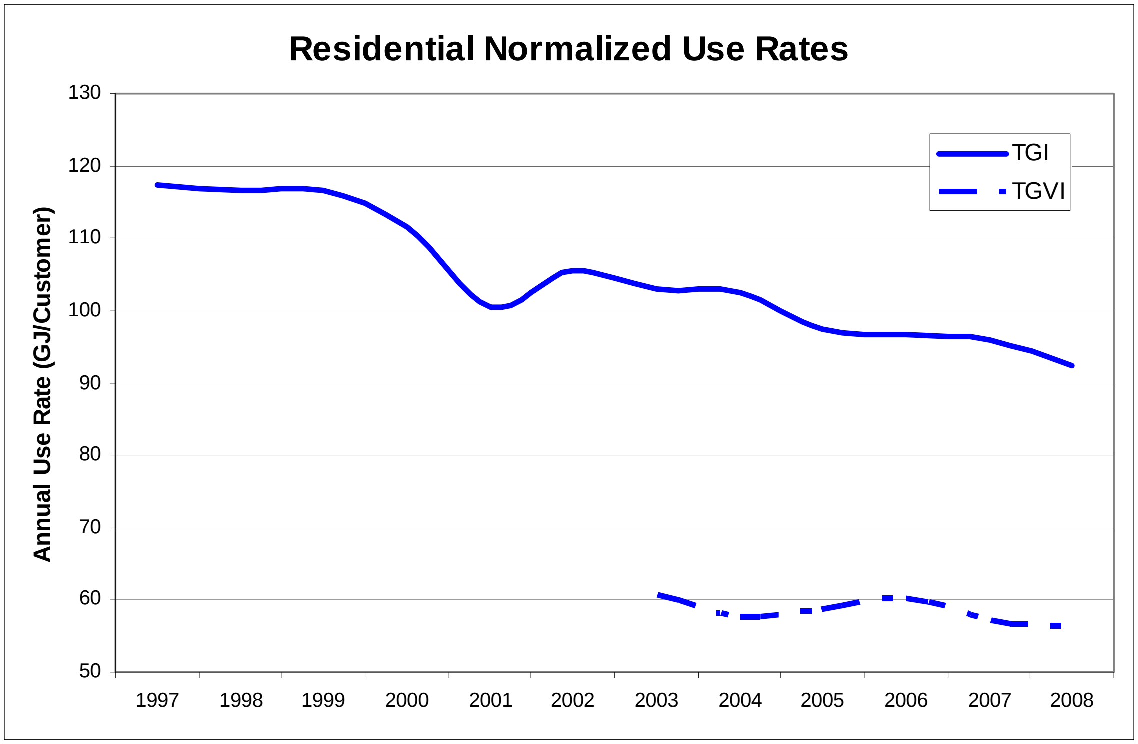
The price-driven competitive challenges are exacerbated by public policies such as the carbon tax and BC Energy Plan that, in the absence of comprehensive policies from government at all levels, discourage direct gas fired applications (even though they result in lower net emissions than applications where electricity is generated for space heating from far less efficient thermal generating stations). This also contributes to the increased business risk faced by the Company.

4.2 Shift in Annual Demand (Declining Annual Use Rates)

Even as Terasen's overall capture rate of new potential customers is in decline, the Company is also experiencing declining use rates from the existing customer base.

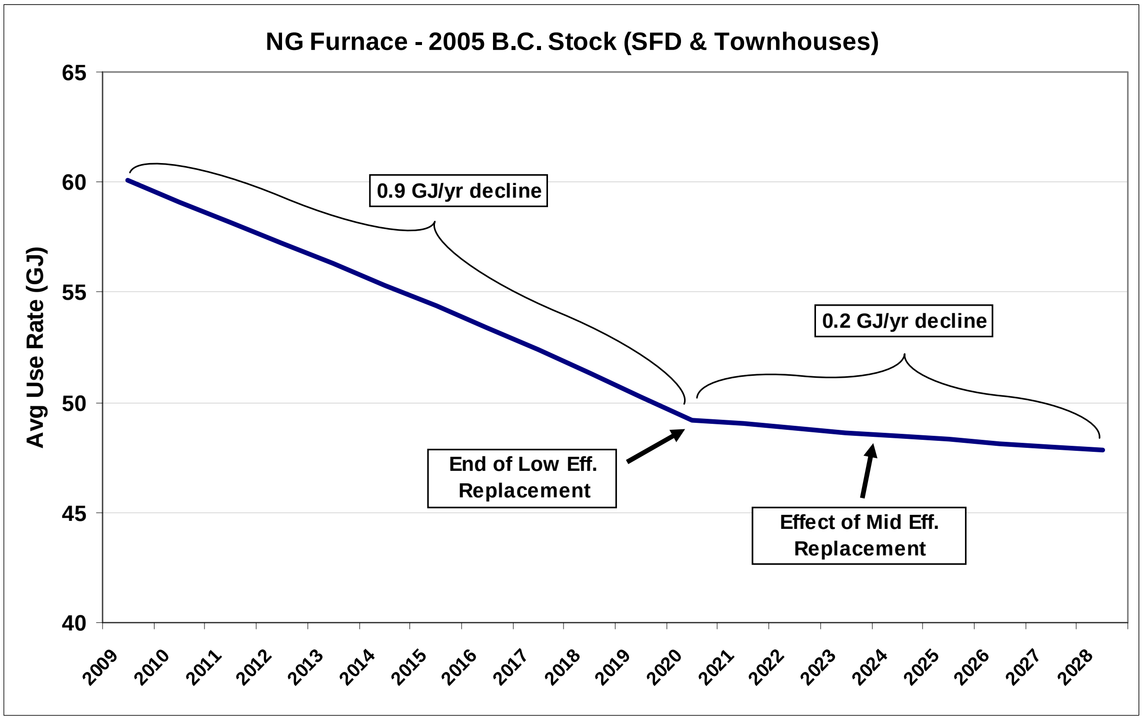
The annual use of natural gas by residential customers has declined steadily since the 1990s and is forecast to continue to decline in the future. This decline is the result of a combination of factors such as advances in gas appliance and construction technology, changes in housing and building space choice, increased volatility in the price of natural gas, and also customers increasing their awareness for the need of energy conservation. The chart below (Figure 4.2) shows the extent of this trend, where a reduction in TGI Residential use rates of 21.1% occurred between 1997 and 2008. A further decline of approximately 2% is forecast to occur by 2010. This decline in use rates places upward pressure on customers' delivery rates, and contributes to the compression of natural gas and electricity rates.

Figure: 4.2: Residential Use Rate in Decline



As discussed above, the trend of declining use rates is expected to continue into the foreseeable future. The main drivers for this trend are the replacement of lower-efficiency natural gas furnaces with higher efficiency models and the evolution of building codes from an energy efficiency perspective. Changes to the building code in 1990 mandated mid-efficiency furnaces as the minimum requirement for homes, and recent changes to building code legislation now stipulate that high efficiency furnaces are required for new construction as of 2008 and for furnace replacements beginning in 2010. If all other variables are held constant, the effect of retrofitting less efficient furnaces with new high-efficiency units can be estimated to cause an annual decline in use per customer rates of approximately 0.9 GJ per year. The annual decline is anticipated to slow to 0.2 GJ per year beginning in 2020, once the bulk of the low-efficiency units have been phased out, absent any further efficiency improvements. Figure 4.2.1 below illustrates this impact.

Figure: 4.2.1: Residential Use Rate Will Continue to Decline



Consumers' environmental awareness and their perceptions regarding fossil fuels and related climate change initiatives are also influencing energy choices. And these energy choices are being made by both the end users of natural gas and developers.

For end users, as existing appliances reach the end of their lifecycle, customers are faced with a fuel choice. For developers of multi-family dwellings, there are strong capital cost incentives to install electric baseboard heating, as it is cheaper to install than natural gas infrastructure. In both instances, with no formal government policies regarding the right fuel for the right application, inappropriate decisions can be made which could significantly impact the demand for natural gas, thereby increasing business risk.

TGI faces a considerable challenge in managing the effects of declining use rates that are caused by a combination of factors largely out the direct control of TGI, such as market forces (i.e. commodity price movement) and customer behavior (i.e. lifestyle choice and environmental and pricing perceptions) as noted above. The long-term trend in declining use rates coupled with the desire of communities and consumers to move towards alternative, sustainable energy sources place an increasing pressure on TGI's gas distribution business.

While the revenue stabilization mechanism of TGI provides short term intra-year relief from declining use, it does not offset the fundamental competitive pressure that results from declining use, particularly when electricity pricing based on a very large historic hydro component is the primary alternative fuel. There appears to be no relief on the horizon available to TGI to mitigate the business risks from these factors.

Summary

Climate change and energy consumption are subjects of enormous importance to British Columbians today and looking forward. In British Columbia the abundance and potential of renewable sources of electricity generation set the province apart from other jurisdictions where natural gas is distributed. Some have concluded by looking at BC in isolation that electricity should be used for space and water heating in the province and natural gas should be displaced from these applications. Based on structural changes in the marketplace and how customers and stakeholders perceive natural gas in this new environment, TGI's competitive position and future prospects as a natural gas distributor have deteriorated as compared to 2005.

British Columbians are presently not being encouraged by government policy or BC Hydro to use natural gas, and this increases business risks for TGI. Alternative energy sources such as ground source heat pumps and wind farm electricity generation, despite high capital costs, are being embraced by environmentally sensitive consumers and subsidized by governments. This is being done to reduce GHG emissions, and masks related costs to consumers through taxation. TGI supports sustainability initiatives through its Energy and Efficiency Conservation programs but sees a role for natural gas in the long term sustainability picture due to the advantages inherent in its physical properties, i.e. lowest emissions of the fossil fuels, no/low particulate matter, etc. Gas use should be encouraged, as the right fuel for the right application, but current government policies and initiatives provide consumers with a contrary message.

So the gas distribution sector in British Columbia is adversely affected in two ways. Competition from BC Hydro erodes market share on price and lower capital costs, and competition from alternative energy sources is subsidized by government climate change initiatives. Consumer misperceptions and misinformation provided to consumers must be overcome by the gas sector in order to retain existing business and to continue attracting new customers to mitigate the impacts of customer use rate reductions.

The competitive environment in which TGI operates today and expects to operate in the future, and the related business risks, are very different than those were when the automatic adjustment mechanism for ROE was introduced in 1994, and even since the business risks of TGI and the automatic adjustment mechanism were last reviewed by the Commission in 2005. TGI believes that its business risks have increased over the period and warrant both a higher return on equity than the current formula produces and a more robust capital structure containing more equity. Even in the absence of the problems with the formula, Terasen Gas requires higher returns due to increased business risk. The lower than warranted returns related to the increase in TGI's business risk are exacerbated by an automatic adjustment formula that has not produced appropriate results.

WRITTEN EVIDENCE

OF

DONALD A. CARMICHAEL

for

Terasen Gas Inc.

May 2009

Written Testimony of
Donald A. Carmichael

1) Introduction and Background:

Q1: Please state your name and business occupation.

A1: My name is Donald A. Carmichael and I am a financial consultant and advisor. Prior to becoming a financial consultant, I worked in the investment banking industry for more than 30 years with Scotia Capital Inc., Richardson Greenshields Limited and McLeod Young Weir Limited. My work was principally focused on natural gas transmission and distribution companies as well as electricity generation, transmission and distribution companies in both the public and private sectors. I was responsible for advising clients on the appropriate terms and pricing of debt and equity securities, providing strategic advice regarding mergers and acquisitions and executing business on behalf of some of the firms' most significant clients. This included advising both governments and corporations on strategic, regulatory and financing issues. I often participated in the marketing of debt and equity transactions to institutional investors, on behalf of my clients. I had extensive interaction with representatives of such lenders and investors in respect of the business profile of the issuer and the pricing of the issue.

Since forming my consulting and advisory business, I have advised the following clients:

In 2006, I appeared on behalf of the Coalition of Large Electricity Distributors (a group consisting of Toronto Hydro, Mississauga Hydro, Horizon Utilities, PowerStream Utilities, Ottawa Hydro and Veridian Corporation) before a Technical conference organized by the Ontario Energy Board (the "OEB") to discuss new processes to regulate Ontario's 90 local electricity distribution companies in a more streamlined fashion. I commented on the potential capital markets reaction to the OEB's proposals to streamline the determination of the ROE as well as necessary levels of equity capital to finance utility investment.

In 2007, I co-authored an expert report to the Nuclear Waste Management Organization regarding its long term funding program for the storage of nuclear waste produced by nuclear power reactors operating in Canada. In addition, I assisted Ontario Power Generation Inc. ("OPG") in negotiating the financial parameters of a long term power purchase agreement between OPG and the Ontario Power Authority. I advised Toronto Hydro Corporation regarding the financing of certain non-regulated activities through subsidiary companies on a limited or non-recourse basis.

During 2008, I advised OPG on various regulatory matters and strategies relating to its initial application to the OEB regarding the company's regulated nuclear and hydraulic generating assets. I provided an opinion to OPG's senior management team as to whether the applied for rate increase was reasonable in light of the risks which the regulated operations of the Company face and to provide on-going strategic and tactical input.

Q2: **What is your educational background?**

A2**:** I received my education at The University of Waterloo where I obtained an Honours Bachelor of Mathematics degree and at the Rotman School of Business at the University of Toronto where I achieved a Master of Business Administration with specializations in Finance and Operations Research.

Q3: **Have you appeared before regulatory boards in the past?**

A3: Over the course of my career, I have appeared before the National Energy Board (Interprovincial Pipe Lines Limited and Trans Mountain Pipe Line Inc.), the Canadian Radio-television and Telecommunications Commission (the BC Telephone Company Limited, Telesat and Teleglobe), the Alberta Energy and Utilities Board (AltaLink LLP), the OEB (Union Gas Inc., Ontario Hydro, Coalition of Large Distributors), the New Brunswick Public Utilities Board (New Brunswick Power Corporation) and the Board of Commissioners of Public Utilities of Newfoundland (Newfoundland and Labrador Hydro).

Q4: **What issues does your testimony address?**

A4: My evidence addresses the on-going concerns of debt and equity market participants regarding the method by which the return on common equity ("ROE") of Canadian utilities such as Terasen Gas Inc. ("Terasen Gas" or the "Company") is established. In particular, the determination of a utility's ROE in many Canadian jurisdictions is based on a formulaic approach which adjusts a base ROE, usually set following a generic hearing, by a proportion of the difference between the forecast yields in long term Canada bonds during the utility's test year to the forecast yield in the base year. In the case of utilities regulated by the British Columbia Utilities Commission (the "BCUC"), the formula is as follows:

$ROE_T = 9.145\% + .75 \text{ x } (YLTCB_{T+} – 5.25\%)$

Where

ROE_T is the return on deemed common equity in year T; and

$YLTCB_T$ is the forecast yield on Long Term Canada bonds in year T.

The BCUC adopted a formulaic approach in 1994 and has reviewed it periodically including 1997, 1999 and 2006 when it awarded an ROE of 9.145% to Terasen Gas based on a forecast long term Canada yield of 5.25%, an equity risk premium of approximately 390 basis points.

Similar formulas have been employed by the Alberta Utilities Commission, the National Energy Board, and the Ontario Energy Board. The National Energy Board decided on the use of a formula in Decision RH-2-94 which when applied in 1995 resulted in return on common equity of 12.25%. In concert with the almost continuous decline of yields on long Canada bonds, the RH-2-94 formula resulted in an ROE of 8.71% in 2008.

Even prior to the major decline of long Canada yields in 2008 and 2009, capital markets analysts and participants had commented that the ROEs resulting from the formulas and awarded in Canada have been at the lower end of the range of, or below, an acceptable rate of return on equity for utilities. This has resulted in less than adequate returns on common equity, insufficient equity risk premiums for common shareholders over the long term debt obligations of the utilities and weaker credit metrics for debt lenders. The erosion of the financial performance (lower returns on equity and cash flow generation) of Canadian utilities has been underway for an extended period of time without material changes to other important financial factors such as the degree of financial leverage.

Recently credit rating agencies have high lighted their concerns regarding the weak state of credit metrics achieved by utilities such as Terasen Gas that are regulated with an ROE formula and have compared such utility’s lower metrics with those of

U.S. utilities that the rating agencies believe to be comparable. Canadian utilities' financial performance lags the performance of U.S. based utilities. Analysis of utility ROEs in Canada and the U.S. indicates that Canadian utilities, on average, are awarded an ROE that is approximately 150 to 200 basis points lower than those of U.S. utilities of comparable business and financial risk, since the introduction of the formula approach in Canada.

Q5: Is there a second issue which concerns capital market participants?

A5: A second issue which has an impact on the utility's ability to attract capital is that the "fair return" awarded to the utility is the product of the ROE, currently determined using a formula, and the common equity base of the utility judged to be appropriate from time-to-time by the regulator. According to a debt and equity analysts, Terasen Gas has a low ROE produced by the BCUC formula and one of the lowest awarded common equity base for regulated operations of any utility in Canada. These two factors combine to produce some of the lowest credit metrics of a major utility operating in Canada. These lower credit metrics such as earnings (EBIT and EBITDA) and cash flow (FFO) coverage of interest on long term debt obligations weaken the Company's financial profile and can restrict its ability to access new long term debt and common equity capital. An increased common equity base would reduce the Company's financial risk and could potentially offset the decline in the Company's earnings and cash flow such that its access to debt funds remains relatively constant (i.e. earnings and cash flow coverage of interest obligations remain about the same and, with an increased common equity base, the debt to total capital and cash flow to total debt ratios may decline resulting in the

Company likely maintaining its existing credit rating). Lenders and investors believe this process has moved too slowly for regulated utilities in Canada and, particularly in the last one to two years. Awarded ROEs have continued to fall directly with declining forecast long term Canada yields; however, the cost of utility debt and common equity have increased substantially resulting in weaker credit metrics for lenders and inadequate returns for shareholders.

Utility equity bases in Canada have been consistently lower than those in the U.S. At this point, the financial performance of Canadian utilities, having lower ROEs and thinner common equity bases is significantly below the financial performance of U.S. based utilities. This puts Canadian utilities, such as Terasen Gas, at a distinct disadvantage in attracting funds as the Company must compete with these more highly equity capitalized U.S. and international utilities for debt and equity funding due to the globalization of and greater competition in the debt and equity capital markets.

The recent re-pricing of corporate business and financial risks has increased the risk premiums required by both debt lenders and common equity investors; however, increased ROEs and improved coverage will not be generated by the formulas currently in use by regulators in Canada, as forecast yields on ten and thirty year Canada bonds have fallen quite significantly and the formulas incorrectly assume that utility ROEs should decline proportionately with the forecast Canada long bond yields. Meanwhile credit spreads for 30 year Terasen Gas bonds have ranged from 285 to 420 basis points during 2009 compared to 113 to 128 basis points in 2005, dividend yields spreads for high quality preferred shares have increased from 150 basis points to approximately 400 to 425 basis points over 5 year Canada bonds and trailing earnings and dividend yields have increased on the Toronto Stock Exchange and in other global equity markets.

Certain equity analysts have suggested in the past that ROE formulas in use by regulators in Canada are “confiscatory and fail to meet the fair return standard” while others suggest that the formulas are now “broken”, in that under current financial market circumstances such formulas result in lower rates of return on common equity while all evidence indicates that capital markets require higher returns on corporate securities reflecting the re-pricing of risk which has taken place. Debt analysts have opined that ROE results produced by the formulas “have not reflected the real world increase in the cost of capital” and “the annual ROE adjustment is not even yielding the right direction of change in the cost of capital” under current capital market circumstances (see Stephen Dafoe, Director Corporate Bond Research, Scotia Capital Inc. in a letter to the Ontario Energy Board dated April 17, 2009).

Q6: Have other regulators in Canada addressed the inadequate ROE and common equity base issue?

A6: Yes. The recent National Energy Board decision regarding Trans Quebec and Maritimes Pipelines Inc. (RH-1-2008) reviewed the RH-2-94 formula, which is consistent with the BCUC formula, and addressed the issue of its continuing appropriateness. Under the RH-2-94 formula, TQM would have been awarded an ROE of 8.71% on a 30% common equity base for 2008. TQM applied to have the RH-2-94 formula set aside due to the fact that the formula produced unsatisfactory financial results for both lenders and shareholders. The resulting NEB decision states very clearly that:

> **"In the Board's view, changes that could potentially affect TQM's cost of capital may not be captured by the long Canada bond yields and hence, may not be accounted for by the results of the RH-2-94 Formula."**

The NEB then chose to set aside the RH-2-1994 formula and adopt an after tax weighted average cost of capital ("ATWACC") approach with no explicit common equity ratio assumed. However, based on a 40% common equity ratio (a 33.3% increase over TQM's previously approved common equity component of 30%), the awarded 6.4 % ATWACC for 2007 and 2008 equated to ROEs of 9.85% and 9.75%, respectively. If the previously awarded common equity base of 30% is assumed, an ATWACC of 6.4% implies an ROE of 11.6%. The awarded ATWACC of 6.4% compares to a 5.5% ATWACC that would have been generated if the RH-2-1994 formula had been applied for 2007 and 2008. The RH-2-1994 formula would have produced an ROE of 8.71% on a 30% common equity base or 289 basis points less than the implied 11.6% under the ATWACC methodology.

Q7: Has the NEB or any other provincial regulatory body taken steps to review the appropriateness of continuing to apply a formula to determine a utility's ROE?

A7: Yes. In light of the NEB's decision regarding TQM, it announced on March 23, 2009 that it was considering a review of the RH-2-94 decision and formula and asked that submission be made by May 25, 2009. Similarly the OEB sought comments from interested parties regarding the cost of long term corporate utility debt and the ROEs produced by its formula in a process which commenced on March 16, 2009 and was open for comment until April 17, 2009. The OEB noted that its formula had produced results which suggested the spread between utility debt and common equity had declined from 247 basis points in 2008 to 39 basis points in 2009 and asked for submission to address adjustments which should be made to these results, if any.

The Alberta Utilities Commission is undertaking a generic cost of capital hearing for 2008 to review the review the continuing appropriateness of a formula based approach.

Q8: Are there other financial issues related to a fair rate of return for Terasen Gas?

A8: An additional and related issue which must be addressed by the BCUC is the deemed common equity base of Terasen's utility operations, which at 35% is the lowest of major utilities in Canada, and which should be increased to at least 40%, as proposed by the Company, to reflect:

- its very weak financial performance and substandard credit metrics which are currently rated by Moody's as being below investment grade;
- greater concern regarding the business environment in which Terasen Gas operates including more difficult market conditions, limiting of system throughput growth due to public policy initiatives favoring conservation and efficiency, competition from other sources of "green" energy and the likelihood of very much weaker economic conditions in the province due to the onset of a global economic slowdown;

- the likelihood of a more negative view of the British Columbia regulatory environment developing particularly if a revised approach to the determination of an appropriate ROE and a significant increase in the Company's common equity base are not adopted by the BCUC; and
- heightened debt and equity capital market requirements including adequate returns and premiums for bearing risk, evidence of credit worthiness, financial strength (the ability to sustain unexpected events) and the stability of operating performance with adequate coverage for fixed obligations.

The recommended increase in common equity base is not a substitute for an improved or revised mechanism to determine an appropriate ROE for the Company's regulated operations. Both a higher ROE and a thicker common equity base are required for Terasen Gas in order to preserve its ability to attract capital on reasonable terms.

Q9: **How is your testimony organized?**

A9: My evidence is organized as follows:

1) Introduction and Background
2) Economic and Capital Market Conditions
3) Discussion and Implications
4) Conclusions

Economic and Capital Market Conditions:

Q10: Why is it necessary to review economic and capital market developments in order to consider the appropriateness of BCUC's ROE formula?

A10: The BCUC last considered the appropriateness of its ROE formula in the 2005 and rendered its decision in early 2006. Since then much has changed in the economic outlook, conditions in the capital markets and lenders' and investors' appetite for risk. These changes are significant and they are having a major impact on the capital market participants' view of the appropriateness of the ROE adjustment mechanism, the credit implications for utilities in Canada and ultimately these utilities' ability to access debt and equity capital on reasonable terms. In addition, capital markets have grown more competitive as Canadian investors have been given greater freedom to invest in the debt and equity securities of utilities based in foreign jurisdictions having the benefits of more liberal regulatory regimes and unregulated utility-like infrastructure companies offering higher returns and improved credit metrics.

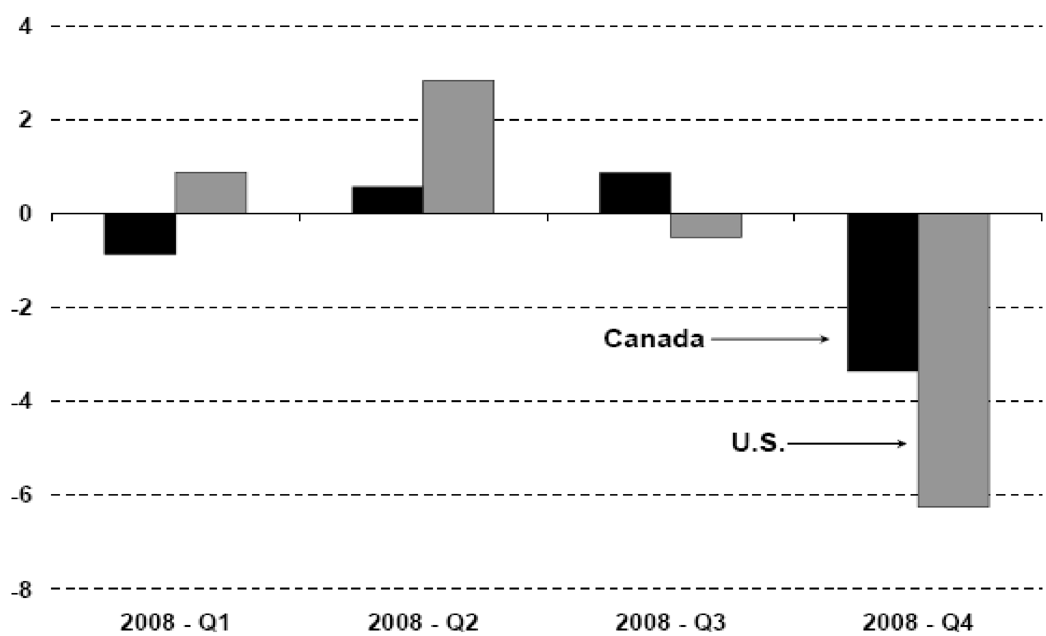
Q11: **Please describe recent economic conditions?**

A11: Figure 1 overleaf presents Canada and U.S. real GDP quarter-over-quarter growth rates through 2008. Over the first half of the year, U.S. real GDP growth outpaced Canada's growth, partly reflecting the impact of a temporary tax rebate in the U.S. Export growth also supported the U.S. economy over this period while Canadian exports declined significantly, reducing real GDP growth by approximately 1.4%. The weakness in Canadian exports stemmed from weak U.S. domestic demand and the impact of the appreciation of the Canadian dollar while the depreciation of the U.S. dollar lifted U.S. exports and reduced imports.

However, over the second half of 2008, Canadian real GDP growth exceeded U.S. growth as consumer spending in the U.S. collapsed, U.S exports stalled and then declined in the third and fourth quarters, respectively. In the fourth quarter of 2008, Canada's real GDP declined by 3.4% (its steepest decline since the first quarter of 1991) and U.S. real GDP declined by 6.2% (its steepest decline since the first quarter of 1982).

On a fourth-quarter-over-fourth-quarter (Q4/Q4) basis, which provides a better reflection of recent trend growth, Canadian real GDP declined by 0.7% and U.S. real GDP edged only slightly lower, declining by 0.8% in the final quarter of 2008. Thus, while the fourth quarter decline in the U.S was larger than Canada's, the relatively stronger U.S. performance in the first half of the year narrowed the gap between Canada and U.S. real GDP on a Q4/Q4 basis.

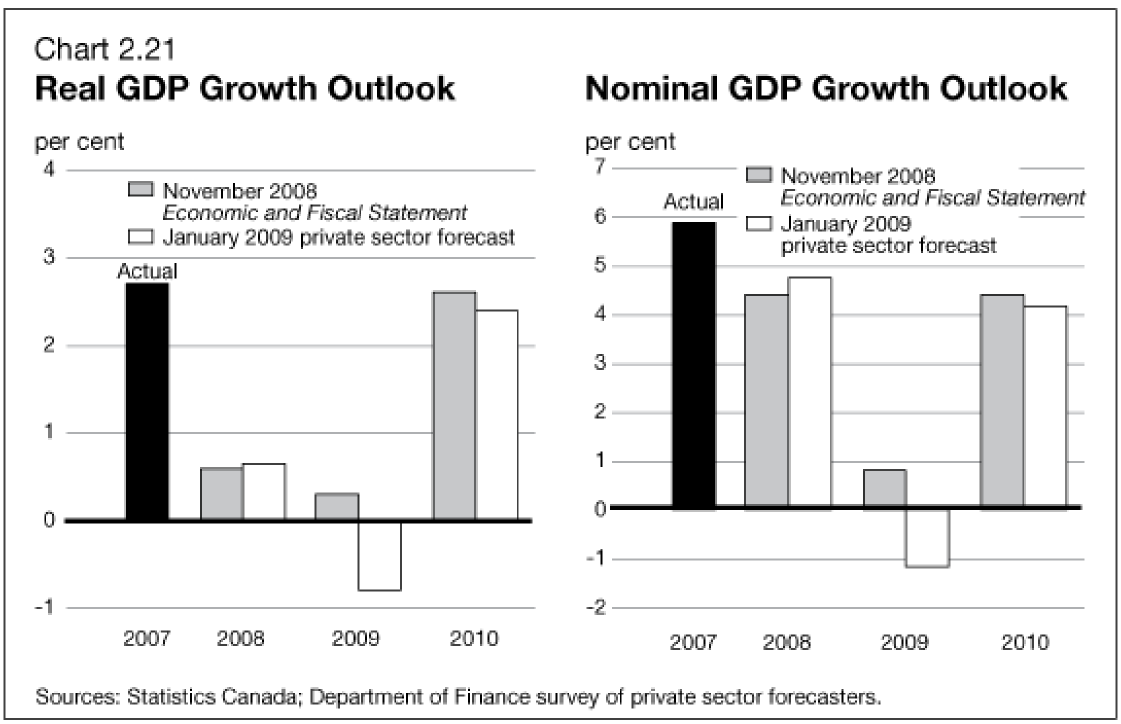
Figure 1: Real GDP Growth (%, quarter/quarter at annual rates)

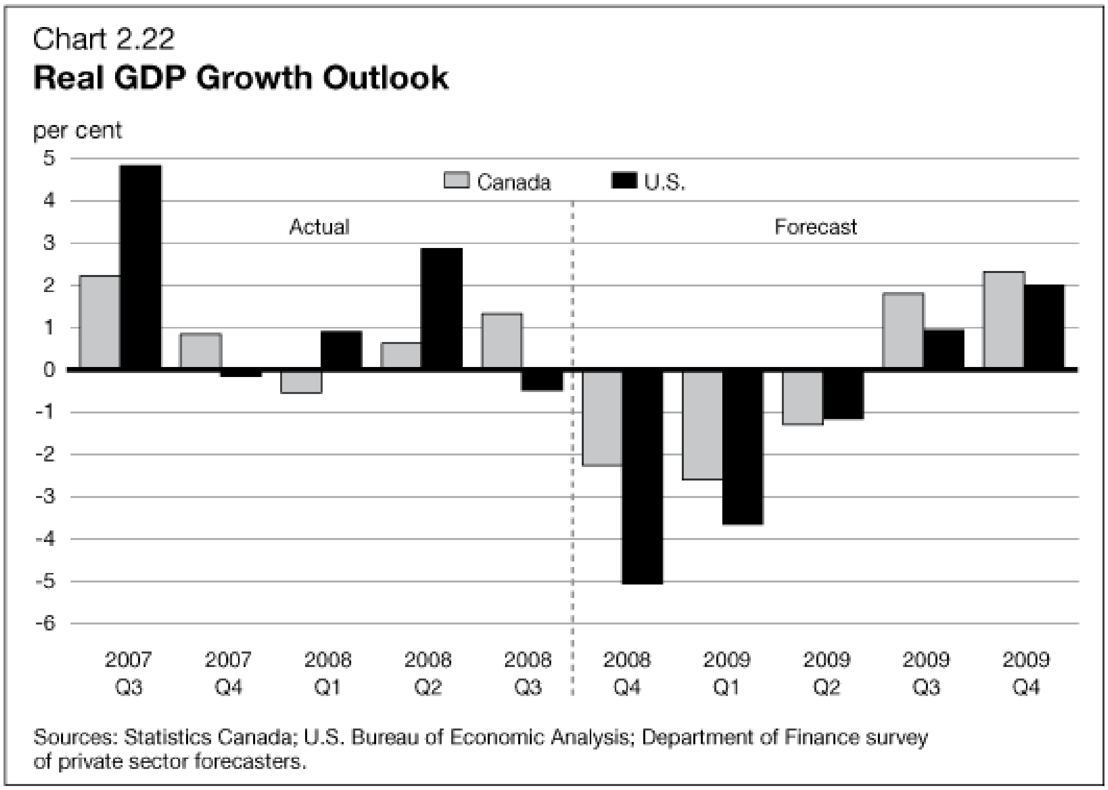


Sources: Statistics Canada and Bureau of Economic Analysis.

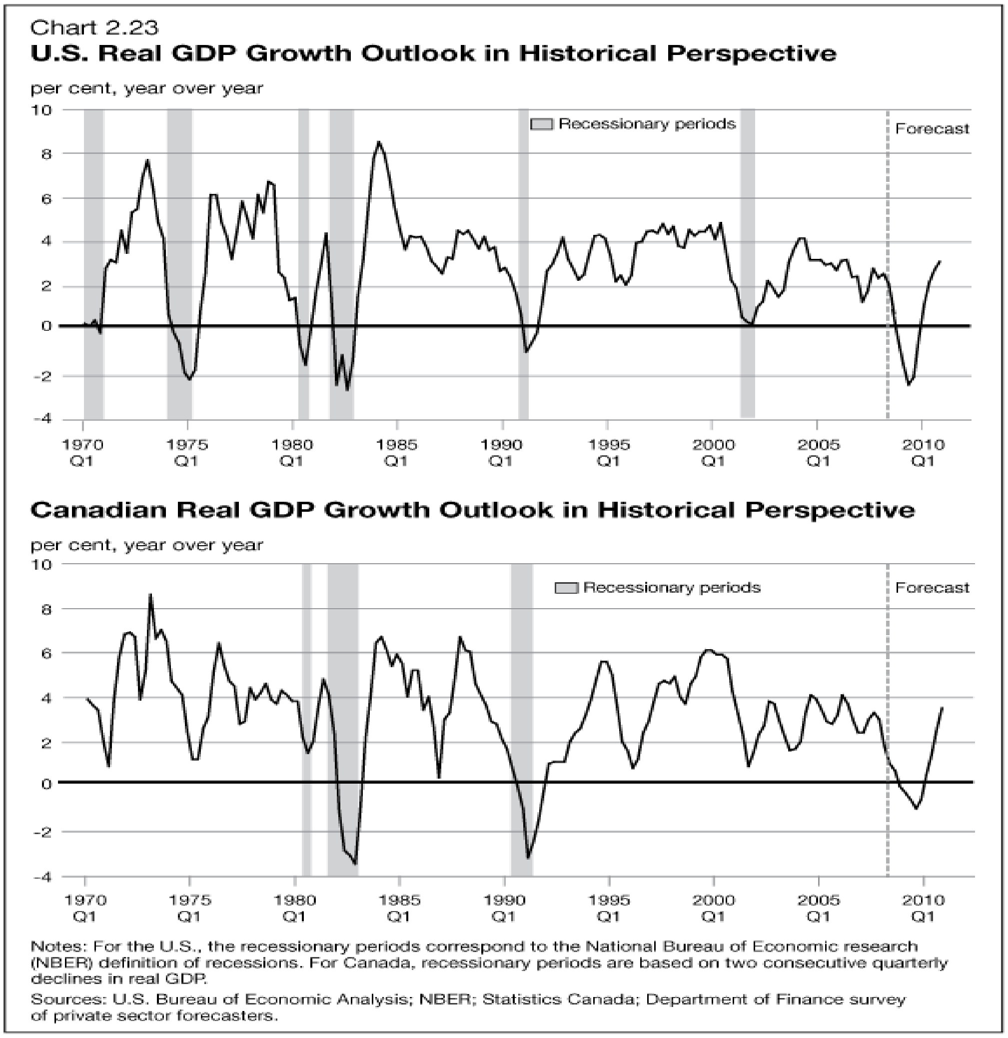
Q12: What is the outlook for the Canadian economy in 2009?

A12: In January 2009, private sector forecasters interviewed by the federal government expected that the Canadian economy would contract by 0.8 per cent in 2009. This compares to a forecast of 0.3 per cent growth at the time of the November *Economic and Fiscal Statement* (Chart 2.21). Private sector forecasters believe that the Canadian economy entered a recession in the fourth quarter of 2008 (see Chart 2.22 overleaf). Forecasters expect the recession to last three quarters with the deepest contraction occurring in the first quarter of 2009. Output is expected to reach bottom in the second quarter of 2009 and to start recovering thereafter.





The recession was expected to be somewhat milder than the last two Canadian recessions and significantly less pronounced than the U.S. recession, which was forecast to be one of the deepest recessions in U.S. post-war history (see Chart 2.23 overleaf). The outlook for GDP inflation in 2009 has been revised down to -0.4%. This mainly reflects downward revisions to the outlook for commodity prices stemming from the expected decline in global economic activity. The outlook for GDP inflation in 2010 has been revised down to 1.7%. Slower growth was expected to translate into an increase in the national unemployment rate to 7.5% and 7.7% in 2009 and 2010, respectively.



Q13: What economic conditions are expected in British Columbia?

A13: Scotia Economics expects the BC economy to be weak with Real GDP growth declining to -0.3% and -2.2% in 2008 and 2009, respectively while the unemployment rate increases from 4.6% in 2008 to 7.4% in 2009 (Global Forecast Update dated May 1, 2009).

Q14: Please describe developments in the debt capital markets since the Company's last cost of capital application in 2005?

A14: Since 2005, there have been two distinct phases of bond market trading. From the beginning of 2006 until September or October of 2008, the 30 year long Canada bond generally traded in a yield range of between 4.25% and 4.65%. These yields reflected a number of factors including experienced and anticipated low levels of inflation, a relatively strong Canadian dollar, continued improvement in the financial position and performance of the Government of Canada, actions taken by the Bank of Canada to improve the liquidity of the benchmark Canada bonds and the declining supply of such bonds due to the surpluses achieved by the federal government. In September and October 2008, yields on Canada bonds dropped significantly across the yield curve. This development in the bond market can be attributed to a so-called "flight to quality" as bond investors became substantially more pessimistic regarding the prospects for corporate credit. Lenders' unease regarding corporate credit had first been indicated by widening interest rate spreads between government and corporate credit in the summer of 2007. Many debt market observers attribute the spread widening to falling values and prices in the U.S. housing market and the associated bad debt problems created for the sub-prime mortgage market in the United States. These credit issues were imported into Canada and caused the asset backed commercial paper market to collapse due to the suspicion that a number of asset portfolios were tainted with sub-prime loans of little or no value. Lenders were now confronted with growing uncertainties, greater risk in financial markets and the potential for a decline in global economic activity with a corresponding negative impact on manufacturing activity and commodity prices. Lenders fled to more conservative investment vehicles.

Chart 3.1
30 Year Canada Bond Yield
From 04/2005 to 04/2009

This flight to quality generated the sales of corporate bond portfolios and the re-investment in and increased demand for Canada treasury bills and bonds. As a result, yields on all Government of Canada bonds generally declined throughout the period as indicated in Chart 3.1 and in the table below:

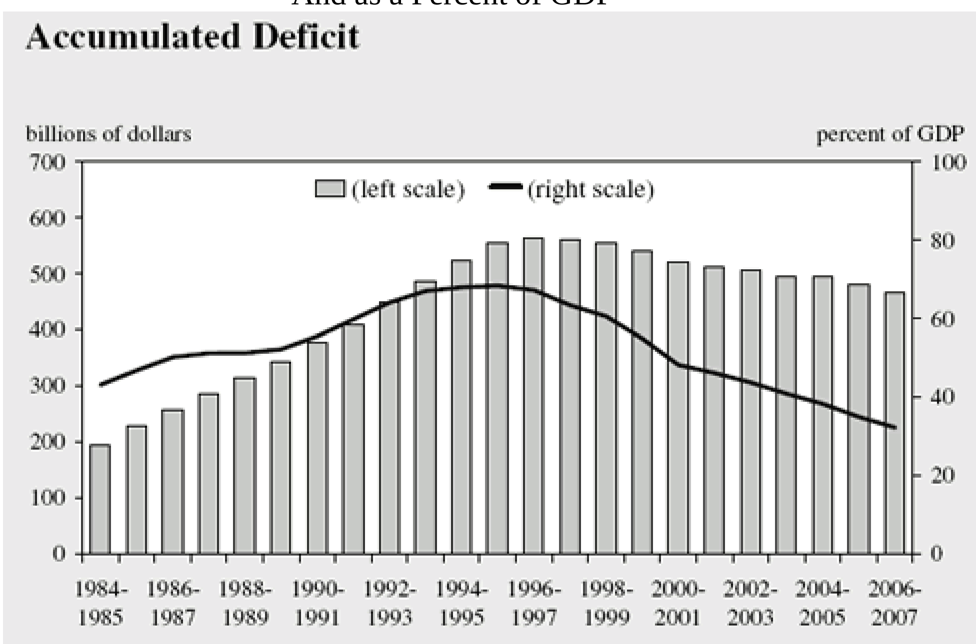
Average Canada Benchmark Yields

	5 Year Canada	10 Year Canada	30 Year Canada
2005	3.57%	4.11%	4.46%
2006	4.11	4.24	4.33
2007	4.23	4.29	4.35
2008	3.10	3.68	4.11
2009 (April 30)	1.82	2.92	3.70

Source: Scotia Capital Inc.

Government of Canada benchmark bond yields have now approached 65 year lows in the face of low (or negative) economic growth expectations, extremely modest inflationary expectations and a reduction of Government of Canada investable bond product, given nine years of federal government surpluses and strong financial performance (Chart 3.2). As the federal government reduced its presence, the market experienced significant growth in the corporate bond market, bonds issued by foreign corporations in Canada and the growth of term securitizations over the period.

Chart 3.2
Dollar Value of Canada Bonds Outstanding
And as a Percent of GDP



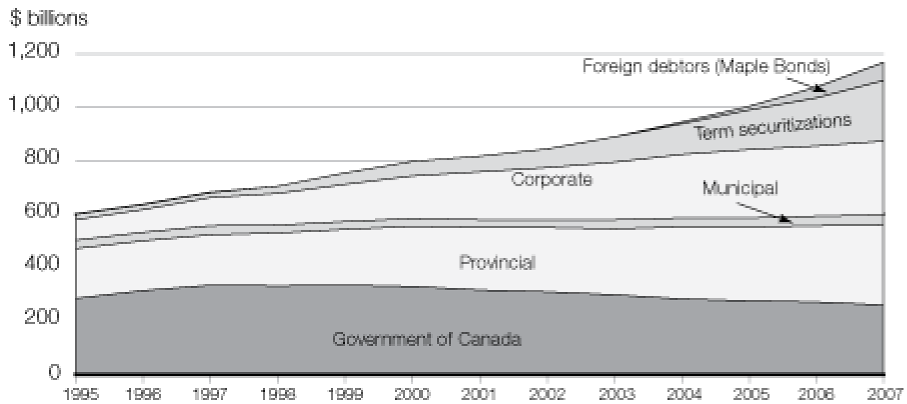
Source: Public Works Canada

Q15: Could you provide more details on the make-up of the Canadian bond market?

A15: At December 31, 2007, Government of Canada bonds represented 22% of the total bonds outstanding, compared to Government of Canada bonds representing approximately 50% of total bonds outstanding in 1996. The corporate bond sector has grown consistently, as can be seen in Chart 2.

Based on Statistics Canada surveys at December 31, 2007, life insurance companies and pension funds held about 24% of outstanding Canada bonds; other financial institutions, including investment dealers, mutual funds and property and liability insurance companies, held about 22%; followed by non-residents at 14% and chartered banks and near-banks at 12%. Non-resident holdings of Government of Canada bonds have declined by 10% in the period 1998 to 2007.

Chart 2
Amount of Domestic Bonds Outstanding by Issue Type, at December 31

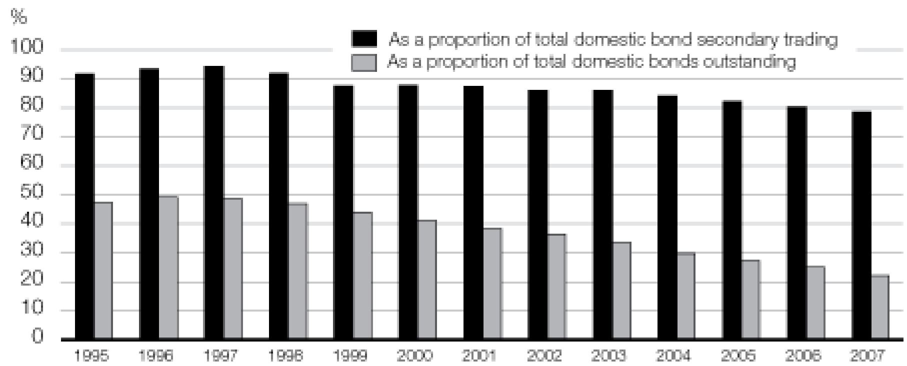


Source: Bank of Canada, *Banking and Financial Statistics*, Table K8.

Government of Canada bonds continue to be the most sought after and liquid investment in the market as 22% of the total bonds outstanding in the market account for approximately 80% of the secondary market trading (see Chart 18 overleaf).

Chart 18

Share of Government of Canada Bonds in the Domestic Market, at December 31



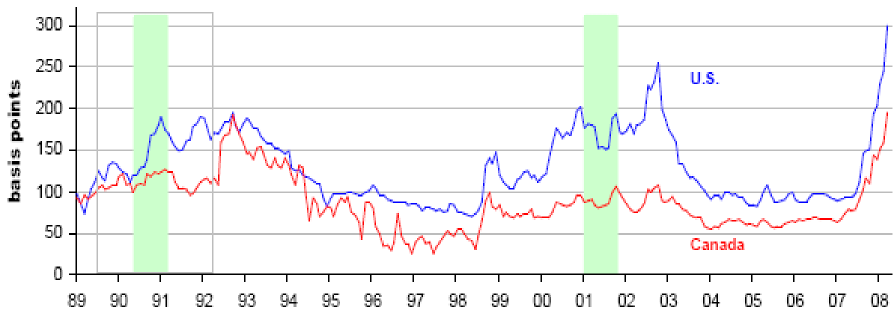
Source: Bank of Canada, *Banking and Financial Statistics*.

The share of secondary market trading of Government of Canada securities is highly concentrated, with primary dealers accounting for almost 90% of trading activity in 2007–08. The ten most active participants in the federal securities secondary market represented over 94 per cent of trading activity.

Q16: What has happened to corporate bond market conditions and spreads since 2005 and, in particular, have utility bond spreads for Terasen Gas increased or decreased over the period?

A16: Corporate bond spreads in Canada and the United States have widened particularly beginning in 2007 as the tightness in the credit markets began to develop reflecting major problems in the sub-prime mortgage market in the U.S. followed by lenders growing concern regarding a global economic slowdown and the slowdown's impact on creditworthiness of borrowers. For well regarded issuers having a credit rating of at least A(low), the widening of credit spreads has more than fully offset the decline in government bond yields such that the new issue cost of longer term debt funds increased (see Chart 4 overleaf).

Chart 4
Mid-Term Investment Grade
Corporate Bond Spreads



**1989 - 1996: Canada - Scotia Capital investment-grade index minus mid-term government yield, U.S. - Merrill Lynch investment grade index minus Merrill Lynch government bond index*
1997 - 2008: Merrill Lynch investment grade option-adjusted spreads
Grey shading: Canadian recession, green shading: U.S. recessions

Corporate yield spreads in Canada were somewhat tighter than those in the U.S. during 2007 and 2008 as credit issues were a much greater concern in the U.S., due to sub-prime mortgage issues, the collapse of housing prices and the stronger performance of the Canadian economy in the first half of 2008 compared to the U.S. As exports to the United States collapsed, the Canadian manufacturing sector slowed significantly and many commodity prices collapsed in the second half of 2008, credit spreads in Canada continued to escalate and market conditions became very difficult for lower grade credits. At times in late 2008 and early 2009, the bond market was closed to issuers rated less than A- as credit concerns gripped the market and liquidity virtually disappeared.

Utility bonds experienced a similar widening of credit spreads reflecting the re-pricing of risk by lenders. The following table sets out Terasen Gas average new issue credit spreads from 2005 to 2009:

Terasen Gas Inc.
Indicative New Issue Credit Spreads

	5 Year	10 Year	30 Year
		(Basis points)	
2005	42	70	120
2006	49	75	134
2007	67	91	128
2008	164	182	202
2009 (April 30)	274	283	305

Source: Scotia Capital Inc.
Each week, Terasen Gas obtains estimates of the prospective new issue spreads for its bonds from four of the primary investment dealers it utilizes for debt issuance. The banks provide estimates of the new issue credit spreads based on their analysis of the secondary trading spreads for existing issues and discussions with institutional investors who buy such debt to estimate the current credit spreads on new debt issuance by the major utilities including Terasen Gas. Terasen Gas relies on this information to time the launch of its credit issuance in the market as well as to set the offered yield.

The interest rate spread on Terasen Gas bonds was relatively constant during 2005, 2006 and 2007 but escalated in 2008. By 2009, the spread on 10 year bonds had increased by more than 250% while the spread on Terasen Gas 30 year bonds increased by more than 140%.

From 2005 to 2009, Terasen Gas executed four long term debt financings. The first financing occurred on September 25, 2006 for an amount of $120 million at a yield of 5.55% or 136 basis points over the long Canada yield of 4.19% and a differential of 325 basis points between the awarded ROE of 8.80% and the yield on the debentures issued by Terasen Gas. The second 30 year debt financing occurred on October 2, 2007 for an amount of $250 million at a yield of 6.00% or 148 basis points over the long Canada yield and a differential of 237 basis points between the awarded ROE of 8.37%. An additional $250 million was raised on May 13, 2008 at a yield of 5.80% and a spread of 163 basis points over the 30 year long Canada yield and a differential of 282 basis points between it and the awarded ROE for 2008 of

8.62%. The final long term debt financing occurred February 24, 2009 for an amount of $100 million with a yield of 6.55% or 285 basis points over the long Canada yield and a differential of only 192 basis points between the awarded ROE and the new issue debt yield. Notwithstanding the fact that Terasen Gas had maintained it's A- bond rating throughout the period, its borrowing spread over the long Canada bond increased by approximately 150 basis points (285 basis points versus 136 basis points), the new issue cost of its long term debt increased from 5.55% in 2006 to 6.55% in 2009 and the differential between its awarded ROE and the long term debt new issue yield fell from 325 basis points to 192 basis points.

The average required new issue yields for Terasen Gas increased over the 2005 to 2009 period as set out below:

	Average Required New Issue Yield		
	5 Year	10 Year	30 Year
2005	3.99%	4.81%	5.66%
2006	4.60	4.99	5.67
2007	4.90	5.20	5.63
2008	4.74	5.50	6.13
2009 (April 30)	4.56	5.81	6.80

Source: Scotia Capital Inc.

At the long term end of the yield curve, the required average yield on 30 year debt financing has increased by approximately 114 basis points or 20% over the period 2005 to 2009 while the Terasen Gas credit rating has remained constant. This reflects the re-pricing of risk by lenders.

Q17: Does the flight to quality re-occur from time to time in the bond market?

A17: Yes, such conditions occur with some regularity. A flight to quality occurred in 1998 following the collapse of Long Term Capital Management, a United States based hedge fund and in 2002 following the sell off caused by the so-called tech bubble in Canada and the United States.

Q18: Please describe conditions in the preferred share market, the direction of yields and the type of preferred share structures that have been issued in the period 2006 to 2008?

A18: There was a significant increase in the net new issuance of preferred shares in 2008 compared to 2006 and 2007. In 2008, net new issuance amounted to $5.5 billion of preferred shares compared with $2.0 billion issued in 2007 and $2.2 billion in 2006. Virtually all preferred share financing in 2008 was carried out by financial institutions (banks and insurance companies) and, in the case of banks, such issuance was structured to increase their regulated Tier 1 capital without having to issue common shares. At the beginning of 2008, the preferred market was willing to accept perpetual preferred shares at increasing pre-tax equivalent spreads that reflected the growing concerns regarding the creditworthiness of the banking system in North America. As pre-tax equivalent spreads continued to widen throughout the year, the Rate Reset perpetual preferred share was re-introduced to the market. This structure offers investors an attractive dividend rate at the date of issue and an option at the call date if the shares are not called for redemption to convert to a new preferred share at a stated fixed reset rate expressed as a spread over the yield of a 5 Year Canada bond on the reset/call date or to convert to a floating rate preferred share. For the eighteen Rate Reset preferred share transactions carried out in 2008, Reset Rates ranged from 1.60% to 3.83% and averaged 2.40%, all over the 5 year Canada bond. By year end 2008, the initial preferred share coupons ranged from 6.00% (Great West Lifeco, November 27, PFd1L to 6.50% (Bank of Montreal, December 11, PFD-1) with corresponding reset spreads of 3.07% and 3.83%, respectively. The most recently completed rate re-set preferred share transaction was carried out by Royal Bank of Canada (Pfd-1) at an initial dividend yield of 6.1% for the initial 5 years of the transaction (a spread of 413 basis points over the 5 year Canada bond) with an option to convert to a preferred share yielding 4.13% over the benchmark 5 year Canada bond, if the initial share is not called for redemption at that time.

A key development in the preferred share market during 2008 was the widening of credit spreads in the bond market and a corresponding adjustment of offering and trading yields in the preferred share market. Preferred shares have historically been priced on a pre-tax equivalent yield, that is, on a pre-tax equivalent basis, does the yield on the new issue of preferred shares compensate the investor for the additional business and financial risk of the issuer when compared with the yield on equivalent term government of Canada bonds and when compared with the yield on similar term debt obligations of the issuer if such instruments are outstanding.

In the past, investors in preferred shares of high quality issuers (Pfd-1) have required a spread of at least 150 basis points above the yield on similar term Canada bonds. During 2008, spreads have widened out materially to the 300 to 400 basis point range and currently utility preferred shares are trading to provide a yield to retraction of between 400 and 500 basis points.

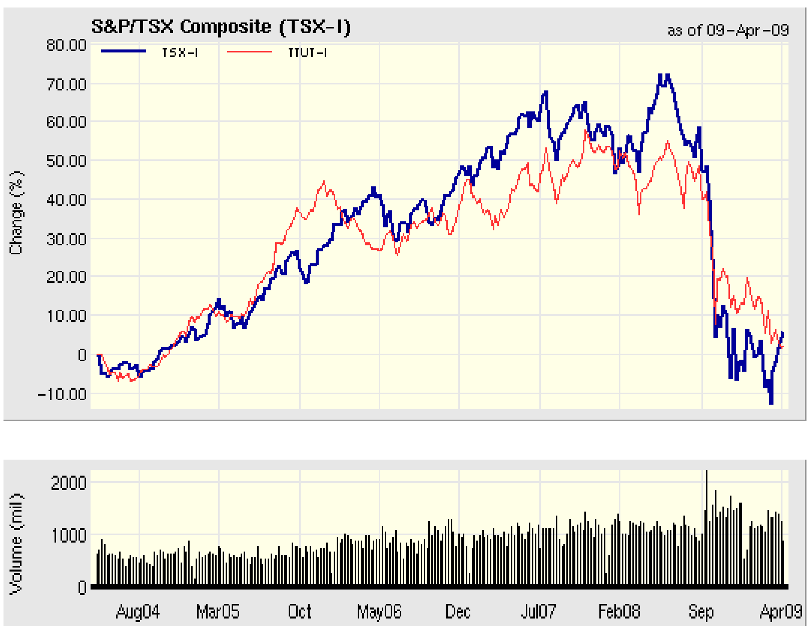
Another notable feature of the preferred share market in 2008 and 2009 was the fact that it was very credit sensitive allowing only highly rated issuers (Pfd-1 and Pfd-2) to attract new capital in the market place. These developments reflect investors' re-pricing of the risk and are consistent with the widening of spreads in the bond market as well as the more junior position of preferred shares relative to the issuer's debt securities.

Q19: Please describe recent developments in Canadian and international stock markets?

A19: The Toronto stock exchange enjoyed robust growth commencing in 2002, after correcting from the over-exuberant tech company valuations. In an environment of growing international trade, rising commodity prices, an appreciating Canadian dollar, historically low interest rates, excess capital markets liquidity, low inflation rates and stronger than expected corporate earnings growth, the S&P/TSX Composite Index rose from 7,648 on January 1, 2002 to a peak of 15,073 on June 18, 2008, a compound annual growth rate of approximately 11%.

The stock market then commenced a rapid and volatile collapse as the U.S. credit crisis which had emerged in early 2006 became much more serious, the outlook for the global economy diminished, commodity prices fell rapidly, international concerns regarding U.S. banks and financial institutions impacted the valuation of Canadian financial institutions and the Canadian industrial sector slowed dramatically reflecting a significant downturn in the economy of our largest trading partner. At March 26, the S&P/TSE Composite Index closed at 8,797, a decline from the peak of more than 41% in less than nine months (see Chart 5 below). The collapse of the market essentially erased the gains achieved over the previous six and one half years. The decline in the market was volatile and characterized by significant and sometimes record setting one and two day declines.

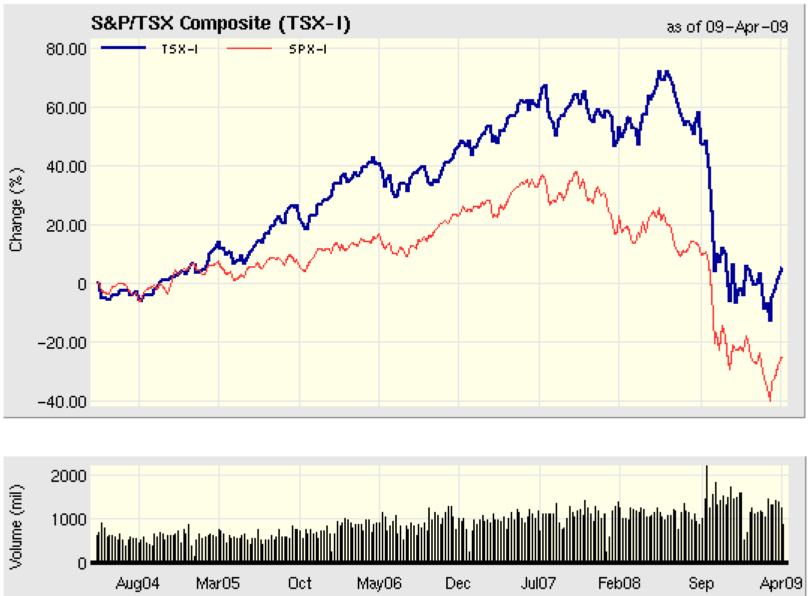
Chart 5
TSE Composite and Utility Index
2004 to 2009



Q20: Was the performance of the S&P/TSE Composite Index mirrored in the United States?

A20: Yes; however, the loss of wealth has been greater in the U.S. as the S&P 500 Index has declined by approximately 25% over the 2004 to 2009 time frame (see Chart 6 overleaf).

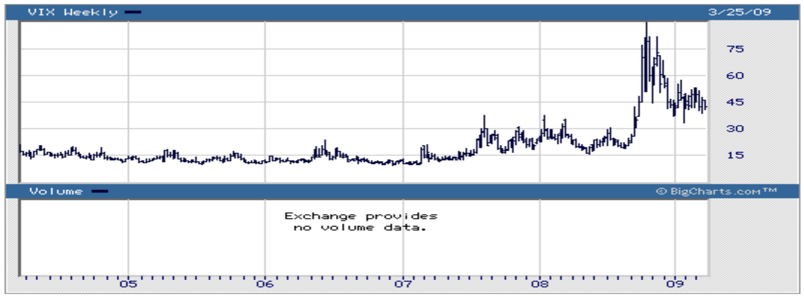
Chart 6
TSE Composite versus S&P 500 Index
2004 to 2009



Q21: Has the volatility of stock markets increased with the declines experienced in the last nine months?

A21: Yes. The volatility has clearly increased. The Chicago Board of Options Exchange Volatility Index ("VIX") measures the implied market volatility of S&P 500 index options (see graph overleaf). "Implied Volatility" represents the volatility built into the price of an option in the market. Implied volatility is particularly important because it determines market consensus about the probable volatility of the underlying stock in the future. The higher the value of the index, greater the market volatility is implied and the higher the degree of market uncertainty.

Weekly VIX Index Performance
March 2005 to March 2009



Source: Chicago Board of Options Exchange

A significant escalation in the implied volatility has taken place in the last nine months with the index escalating from an average of approximately 15, during 2004 to 2007, to a high of 89.5 in October 2008. This represents an increase of about 6 times over the previous levels of implied volatility. Since the peak in October 2008, the implied volatility of the market has declined somewhat to approximately 45 or 3 times the previous average.

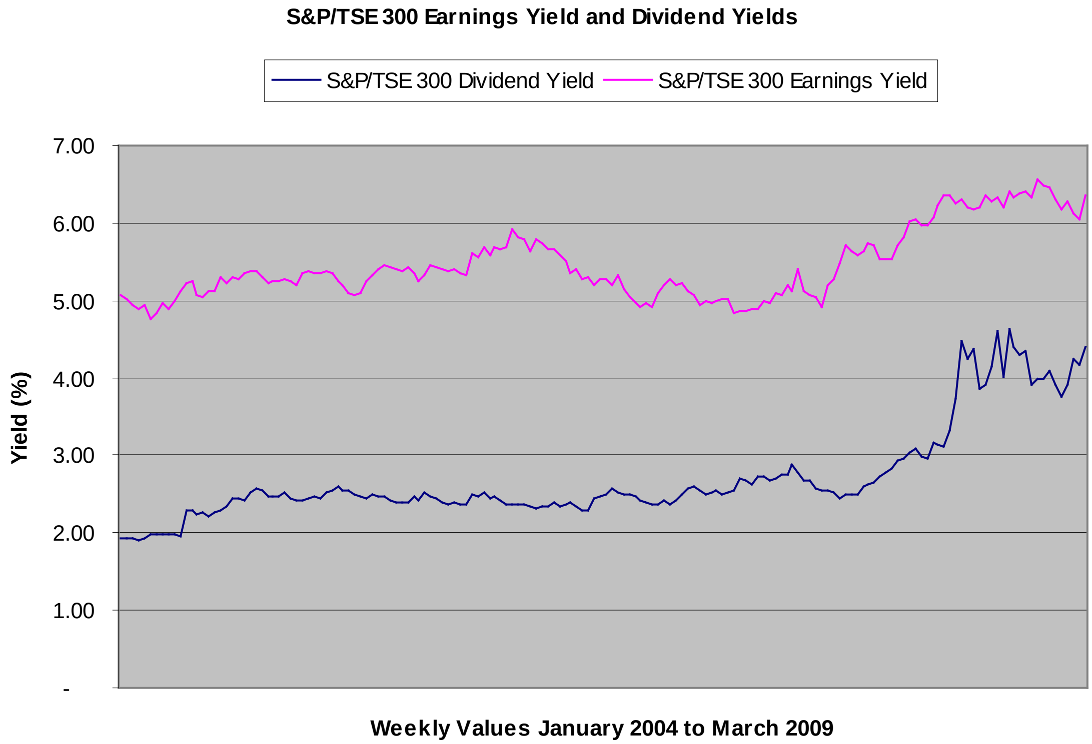
Q22: Is there a similar measure of volatility for the Toronto Stock Exchange?

A22: The Montréal Exchange has introduced a new Implied Volatility Index (“MVX”) reflecting the market's expectation of how relatively volatile the stock market will be over the next month. MVX is calculated from current prices of at-the-money options on the iShares of the CDN S&P/TSX 60 Fund (XIU). The Montreal Exchange believes MVX is a good proxy of investor sentiment for the Canadian equity market: the higher the Index, the higher the risk of market turmoil. A rising Index therefore reflects the heightened fears of investors for the coming month.

The MVX shows a very similar pattern as the VIX and, in particular, there is a significant upward move in implied volatility in September 2008 consistent with volatility in the United States.

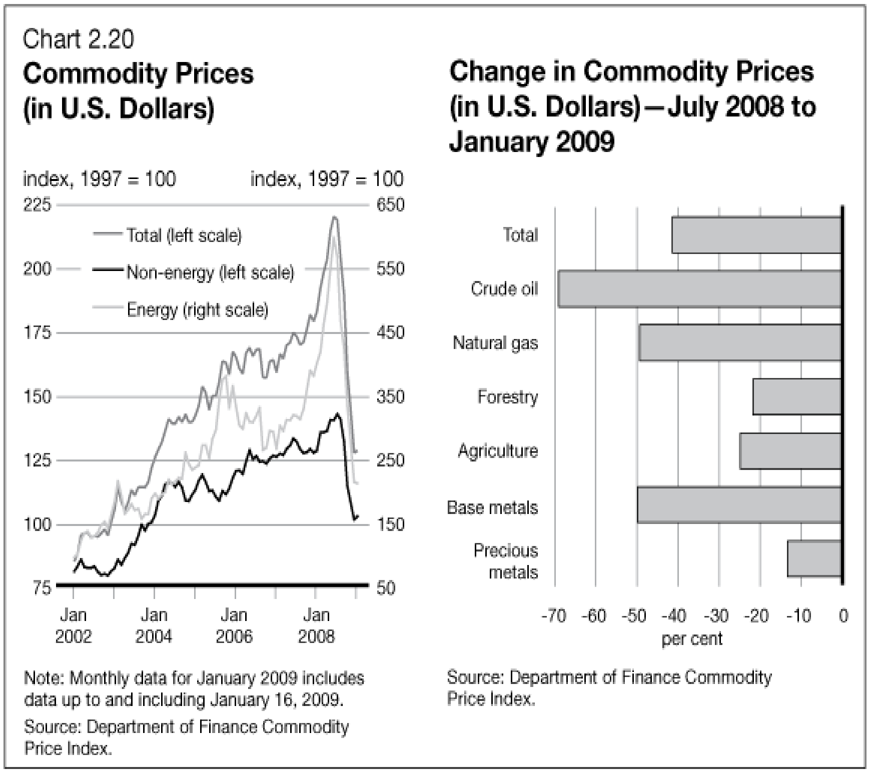
Q23: Has the greater volatility in the markets effected investors' valuations of common shares?

A23: I believe that the increased volatility in the market and economic uncertainty has resulted in the decline of the market price/earnings ratio in Canada and the corresponding increase of the earnings yield (earnings/market price) over the last five years. The price/earnings ratio indicates what investors are willing to pay for a company's earnings. Conversely the earnings yield indicates a stock's return on market value. As the earnings yield increases, the cost of common equity increases. Conversely, as the earnings yield declines, the cost of common equity declines. The graph below indicates the earnings yield and the dividend yield for the S&P/TSE 500 Composite Index have generally been rising since 2003 with marked increases in 2003 (following the collapse of the tech bubble), 2006 and 2008 (after the emergence of credit concerns, the broad decline of commodity prices and the outlook for global economic growth became decidedly negative). This trend indicates investors' greater uncertainty regarding the economic outlook and the perception that companies are facing greater business and financial risks. For TSE composite companies, business risks have increased with greater global competition in the manufacturing sector, the rising value of the Canadian dollar which has impacted profitability in many industries and the rising cost of doing business in Canada.



Q24: Even with the rising cost of common equity capital, valuations in the stock market continued to increase until mid-2008. Why did the increase in value continue?

A24: A number of factors lead to higher valuations in Canada including continuously rising commodity prices for oil, gas, potash, base metals and precious metals (see Chart 2.20 on next page). Companies involved in these industries make up more than 45% of the value of the 300 Composite Index. Continued merger and acquisition activity in Canada based on the consolidation of various industries and hedge fund and private equity purchases funded by the liquidity of the domestic and international banking system (in particular, the proposed purchase of Bell Canada by the Teachers Pension Fund and others at a price that was substantially above the public market price of BCE). Prior to 2008, the strong growth of earnings of Canada's financial sector and other success stories such as the world wide acceptance of the "BlackBerry" also contributed to expanded valuations.



Q25: Have any other major changes impacted Canadian investors and domestic capital markets in the last five years?

A25: The globalization of Canadian capital markets and the removal of various personal and institutional restrictions on foreign investment have caused the Canadian and international capital markets to become substantially more integrated than in the past. Canadian institutional and retail investors have been freed from restrictions regarding their ability to invest in foreign securities as a result of pension fund legislation passed in 2005.

Foreign property restrictions for Canadian pension funds, pension real estate and investment corporations, deferred income plans (including individual registered retirement savings plans) and other tax-exempt entities were introduced in 1971. Such restrictions limited the amount of “foreign property” these tax exempts could hold. Foreign property generally consists of shares, units and debt issued by non-resident entities, investments in most trusts and investments in most partnerships. The foreign property limit, which was originally set at 10%, was raised to 20% in 1994 and then to 30% in 2001. The Income Tax Act (Canada) provided that tax exempts holding assets in excess of these foreign property limits were subject to a 1% per month penalty tax.

Following the changes in 2005, many of Canada’s largest institutional investors could invest in foreign securities without limit and, as a result, have become major players on international stock markets and non-Canadian private equity situations. Investors, such as the Ontario Teachers Pension Fund (“Teachers”), The Ontario Municipal Employee Retirement System (“OMERS”), The British Columbia Investment Management Corporation (“BCIMC”), the Canada Pension Plan Investment Board (“CPP”) and Alberta Investment Management (“AIM”), have bid for and won private equity opportunities in regulated utilities and utility-like but non-regulated situations in the U.S. and Europe. OMERS has announced its intention to diversify into private equity to reduce its exposure to the volatility of public stock markets and to increase its exposure to long term investments in utility-like infrastructure projects. To date, many of these infrastructure investment opportunities have been outside of Canada and have included assets such as gas and electricity transmission, gas and electricity distribution systems in the United States, Europe and South America, airports in the United Kingdom, regulated drinking water and sewage water utilities in the U.K., container terminals in the United States and Canada and the Ontario land registry system.

Retail investors were also granted much greater freedom to invest their self managed retirement savings plans in foreign equities under the same legislation.

Greater competition has also emerged in the Canadian bond market as foreign issuers increased their issuance activity following the removal of limitations on foreign investments. The market in Canada for the new issuance of foreign bonds and debentures has grown rapidly reflecting the Canadians lenders desire to diversify their portfolios with new issuers and to achieve higher returns with similar or, in some cases, stronger credit metrics than those available from domestic issuers. Foreign issuance in the Canadian bond market has represented approximately 18.9% of the domestic new issue market from 2005 to 2008.

In 2007, foreign issuance in the Canadian domestic bond market peaked at approximately 29%. The market was driven by Canadian lenders willingness to invest in these issues to broaden the diversification of their fixed income portfolios with new foreign names and by attractive Canadian dollar U.S. dollar swap spreads which made the transaction economic for treasurers of U.S. issuers to issue in Canadian dollars.

Q26: Is there another issue that may affect regulated utilities access to long term funding going forward?

A26: The funding requirements for announced infrastructure projects in Canada will be massive and will compete with utility funding going forward. It is reasonable to anticipate that projects such as toll roads, bridges and urban transportation systems will be privately debt financed with some limited support by governments and will be directly competitive with debt and equity financing for utilities.

2) <u>Discussion and Implications:</u>

Q27: Given current and expected capital market conditions, please discuss the appropriateness of the BCUC's current approach to setting ROEs for Terasen Gas Inc?

A27: The formula used to determine Terasen Gas's ROE for test year T is the ROE in the base year of 9.145% plus 75% of the difference of the forecast yields for a 30 year long term Canada bond in test year T minus the yield of the same 30 year bond in the base year (5.25%) or:

$$ROE_T = 9.145\% + .75 \times (YLTC_T - 5.25\%)$$

Where,
ROE_T is the return on utility common equity in year T, and
$YLTC_T$ is the forecast yield on a 30 year long Canada bond in year T.

The initial ROE for Terasen Gas under the current formula was based on a 3.895% equity risk premium and a long term Canada yield of 5.25% for the test year 2006 and was 9.145%. Since the March 2006 BCUC decision, the ROE has declined further to 8.47% in 2009 reflecting the decline of forecast long Canada yields of approximately 90 basis points over the period. However, since the 2009 ROE was set in November 2008, long Canada yields have declined significantly beyond the forecast yield of 4.35% for 2009 and are currently in the range of 3.60% to 3.65% (average of 3.67% in April 2009). This yield on 30 year Canada bonds would result in the BCUC formula producing an ROE ranging from **7.90% to 7.95%** under current market conditions.

Meanwhile returns required on corporate securities have risen significantly reflecting the substantial increase in corporate interest rate spreads over Government of Canada bonds and a major increase in earnings yield experienced on the Toronto Stock Exchange and other major exchanges in the second half of 2008. These higher returns are required by utility investors and lenders in order to attract capital on reasonable terms. Terasen Gas long bond interest rate spreads peaked in January 2009 at approximately 390 to 400 basis points over the 30 year long term Canada bond. This interest rate spread was roughly equivalent to the equity risk premium judged to be appropriate by the BCUC in its ROE decision for Terasen Gas in 2006. Interest rate spreads have eased recently to the area of 280 to 290 basis points over the long Canada bond or about 150 basis points more than interest rate spreads in 2006. The increase in corporate utility bond spreads has more than fully offset the decline in long Canada yields resulting in Terasen Gas having to pay 100 to 125 basis points more for long term debt capital at the present time (Terasen Gas issued a thirty year bond in 2006 at a yield of 5.55% and completed a similar term financing in 2009 at a yield of 6.55%).

High quality preferred share yields have increased from a pre-tax equivalent spread of 150 basis points over appropriate term Canada bonds in 2006 to a pre-tax equivalent spread of 400 to 425 basis points under current conditions. Investors' return requirements for common equity investments have also escalated reflecting economic developments over the past year including the credit crisis, the diminished outlook for growth in the global economy, the collapse of commodity prices and the much higher volatility of and the dramatic sell-off in global equity markets. The S&P/TSE 300 price/earnings ratio has declined substantially (from approximately 21 times in 2006 to approximately 12.5 times in 2009, or about 40%) and the required earning yield for the S&P/TSE 300 common stocks has increased from 4.75% to approximately 8.00%. The S&P/TSE 300 dividend yield has risen from a low of 1.93% in 2006 to a current level of 3.7%. These developments demonstrate that the cost of common equity capital is rising.

With regard to the BCUC's ROE formula, there have been concerns for some time that the formulistic approach, employed by regulators in British Columbia and other jurisdictions in Canada, has been producing results that have not been high enough to preserve the financial integrity of utilities being regulated. BMO Capital Markets, in a research analysis dated December 7, 2006 entitled "2007 ROEs Decline to Unprecedented Levels" commented that an ROE produced by the formula based ROE adjustment mechanism likely "violates the Fair Return Standard and is confiscatory". The author of this report, Karen Taylor of BMO Capital Markets, has recently become an executive advisor to the Chair of the Ontario Energy Board.

Q28: Do the credit rating agencies and lenders in the debt capital markets have similar views regarding the financial performance of utilities regulated under an ROE formula?

A28: Yes. Credit rating agencies have characterized the resulting ROEs as lower than comparable investments in other jurisdictions. Moody's published the following table in 2008 reflecting the achieved financial performance of gas distribution companies that Moody's rates as A3 in North America:

	Avg Rating		FFO / Debt	(FFO+Int)/Int	RCF / CAPEX
LDC	A3	2006 avg	19%	4.3x	93%
		2007 avg	20%	4.4x	89%
		LTM avg	24%	4.7x	80%
		3 yr avg	21%	4.5x	87%

Source: Moody's FM, ratios calculated with Moody's standard adjustments

Over the past three years, Terasen Gas has averaged an FFO (Funds from Operations) to Debt Ratio of 9.5%, an (FFO + Interest) to Interest ratio of 2.4x and an RCF (Retained Cash Flow) to Capex (Capital expenditures) ratio of 70%, which are clearly substantially below the levels achieved by other A3 utilities. Moody's classifies Terasen Gas financial performance in the Ba credit category and indicates its methodology implied credit rating is Baa1. In its most recent credit rating report (dated May 27, 2008), Moody's made the following comments regarding the financial performance of Terasen Gas:

> **"TGI's financial metrics are generally weaker than those of its A3 rated global LDC peers such as Piedmont Natural Gas Company, Inc., Northwest Natural Gas Company, Connecticut Natural Gas Corporation, Public Service Co. of North Carolina, UGI Utilities and sister Company, TGVI. Moody's recognizes that *TGI's relatively weaker financial metrics are largely a function of the relatively low deemed equity and allowed ROE permitted by the BCUC*. In general, *Canadian deemed equity ratios and allowed ROEs are low relative to those of other jurisdictions and TGI's are among the lowest in Canada*. However, TGI's A3 senior unsecured rating reflect Moody's view that TGI's relatively weaker financial metrics are offset to a significant degree by the supportiveness of the business and regulatory environments**

in which TGI operates. *Moody's rating methodology model for North American LDCs indicates a Baa1* rating for TGI which is one notch below the company's A3, senior unsecured published rating assigned by Moody's rating committee. TGI's published rating exceeds the methodology-implied rating because Moody's rating committee places greater emphasis on the supportiveness of TGI's regulatory and business environments than the rating methodology model does. The methodology-implied rating falls within the one to two notch band that Moody's rating methodologies aim to achieve."*(Emphasis added)*

Q29: Is a credit downgrading a significant risk for Terasen Gas and, if it did occur, what would be the consequences to the company?

A29: The potential for a credit downgrading is an increasing risk for Terasen Gas, given its weak financial metrics and the heavy reliance by Moody's and other analysts and credit rating agencies on the regulatory environment and the supportive business environment in British Columbia. Credit rating agencies and sophisticated lenders rank changes to the regulatory environment as the single largest risk faced by a utility. Therefore, major changes to regulatory methodologies which have been used for some time, whether such changes are positive or negative, often give rise to credit rating agencies and lenders doing a full review of the regulatory environments and policies used in different jurisdictions across the country. Moody's and other debt market participants would likely question the regulatory supportiveness of a jurisdiction that would allow utility ROEs to decline below 8.00% as currently suggested by the BCUC formula, particularly if utilities in other jurisdictions in

Canada of similar risk are awarded ROEs, consistent with the TQM decision, ranging from 10.00% to 11.00% with substantially greater common equity under a different model. In particular, the British Columbia regulatory environment and the potentially weak credit metrics that could be awarded Terasen Gas will be viewed by lenders and credit rating agencies in light of the National Energy Board's decision to set aside the RH-2-94 formula in determining the rates for TQM in its decision. The implied 9.75% ROE on a common equity base of 40% awarded to TQM indicates to investors and lenders how apparently out-of-touch with current realities the application of BCUC's formula would be. Following the National Energy Board decision on TQM and the likely recognition by the NEB, OEB and AUC of the financially unacceptable results of the formulaic approach, credit rating agencies, lenders and investors would look for similar regulatory innovation and commensurate regulatory awards in British Columbia. If such innovation and increased awards are not forthcoming, the possibility of a credit downgrading for Terasen Gas and the migration of utility debt and equity capital from British Columbia to other more investor friendly jurisdictions increases.

If, concurrent with questions arising about the quality of the regulatory environment, the business environment in British Columbia deteriorated significantly, as it has in the past two major recessions and as is currently forecast for 2010, credit rating agencies and lenders could re-consider the supportiveness of the business environment in British Columbia and could potentially reduce the credit rating of Terasen Gas or demand a higher interest rate spread.

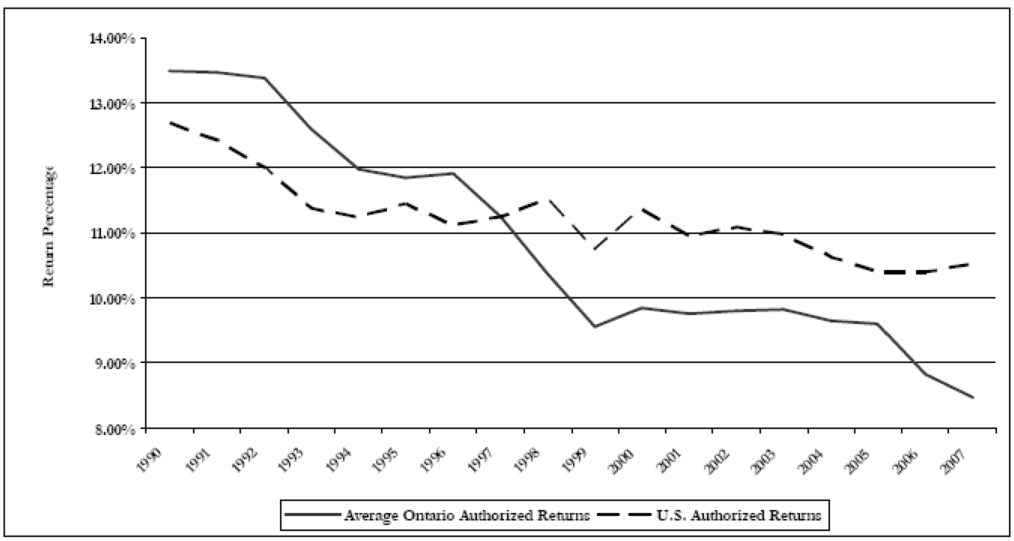
The loss of even one-third of a credit rating grade (i.e. one notch) would reduce Terasen Gas to a Baa1 credit category and, under current credit market conditions, its new issue spread would expand significantly (the ten year spread would increase by approximately 50 to 75 basis points), the available term to maturity would likely decline from thirty years to ten years and, even with the more onerous terms (shorter term to maturity and higher new issue yield), the availability of debt funds would likely be reduced. Many institutional lenders are restricted from investing in Baa credits or simply chose not to, as a matter of investment policy.

Prior to the globalization of the capital markets, Canadian lenders, wanting long term utility bonds, had limited investment choices and were obliged to accept the weaker financial performance of Terasen Gas. Now the range of choices for Canadian lenders is much broader and includes, according to Moody's, many utilities operating in the U.S. Canadian lenders' now have an unlimited ability to invest in utility bonds issued by companies from the United States, many of which have much stronger credit metrics than utilities in Canada.

Q30: Is there a similar dilemma for common equity investors in Canada?

A30: Yes, there is. Utility rates of return on common equity in Canada have generally been less than those in the United States since the late 1990s, following the adoption of a formula based on long term Canada bond yields to determine utility rates of return by regulatory bodies in Canada. In a recent study commissioned by the OEB in June 2007, Concentric Energy Advisors ("Concentric") reported that **"the current ROE differential between Canada and the U.S. is in the range of 1.5% to 2.0% (i.e. 150 to 200 basis points)."** Concentric found that, prior to the shift to a formula derived ROE in Canada beginning in 1997 (Chart 2), Ontario and American **"ROEs were in approximate parity"** and that **"while the specific characteristics of individual gas utilities and their respective regulatory environments can lead to differences in allowed returns, there are no apparent fundamental differences between gas utilities in Ontario and those in the U.S. that would cause the sizeable gap in ROEs. U.S. gas utilities are not demonstrably riskier than Canadian gas utilities."**

CHART 2: U.S. AUTHORIZED RETURNS VS. ONTARIO AUTHORIZED RETURNS – GAS DISTRIBUTION UTILITIES 1990 - 2007[6]



These findings strongly suggest that utility common share investors in Canada, if acting prudently, should choose to invest in gas distribution utilities in the U.S. rather than similar utilities in Canada so long as their ROE is determined by a formula based only on forecast long term Canada yields.

Q31: Do recent changes in Canadian capital markets improve or exacerbate the problems with the BCUC's formula?

A31: Under current market circumstances, the BCUC's return on equity formula would result in a further decline in the rate of return on common equity for Terasen Gas from 8.47% to a range of 7.90% to 7.95% (based on Q1 2009 Consensus Forecasts of Long Canada bond yields) while all factual information from the capital markets indicates that investment risk has been re-priced at a higher level by investors. The re-pricing has resulted in credit spreads on high quality utility corporate bonds and high quality preferred shares increasing substantially. Investors are demanding higher returns in the form of higher earnings and dividend yields and lower price/earnings multiples to attract new common share investments. Stock markets have sold off dramatically to achieve investors' escalated return requirements. These developments all indicate that the cost of common equity capital for Terasen Gas has risen.

Q32: Please discuss the trend of the differential between the ROE awarded to Terasen Gas since 2006 and its cost of long term debt funds?

A32: The table below sets out the trend of the differential between the ROE of Terasen Gas and it debt new issue cost for thirty year long term debentures:

Year	ROE Awarded	Debt New Issue Yield	Differential
2006	9.15%	5.55%	3.60%
2007	8.37	6.00	2.37
2008	8.62	5.80	2.82
2009	8.47	6.55	1.92
2010F	7.95(1)	6.40(2)	1.55

(1) Based on long Canada yield of 3.60% to 3.65% (average yield of 3.67 in April 2009).

(2) Based on long Canada yield of 3.67% and Terasen Gas spread of 273 bps (average for April 2009).

If used to determine the ROE for Terasen Gas under current market conditions, the BCUC formula would require common share investors to accept a dramatically reduced differential of approximately 155 basis points between the yield on newly issued Terasen Gas debt (currently requiring a new issue yield in the range of 6.35% to 6.40%) and the ROE on its regulated equity (based on current long Canada yields, the return on equity would be 7.90% to 7.95%). This infers that long term debenture holders, at a more senior position in the capital structure compared to common shareholders, are able to negotiate a higher yield and risk premium (increasing from 135 basis points to approximately 275 basis points) while the rate of return and risk premium for common shareholders over utility bond investors is contracting, as demonstrated in the following chart.

The prospect of declining ROEs, declining spreads between debt and equity securities of the same utility issuers and the associated weakened financial performance of utility issuers during a period of difficult capital markets and restricted liquidity in the financial system, likely caused the National Energy Board to conclude in RH-1-2008:

> **"In the Board's view, changes that could potentially affect TQM's cost of capital may not be captured by the long Canada bond yields and hence, may not be accounted for by the results of the RH-2-94 Formula."**

The NEB then set aside the results of the RH-2-94 formula and accepted an entirely different regulatory framework for TQM.

Q33: Is the formulaic approach supported by debt and equity analysts in the capital markets?

A33: Capital markets observers and analysts have reached similar conclusions regarding the inadequacies of determining utility ROEs on the basis of formulas.

RBC Capital Markets has published three different recent comments on ROEs expected to be derived from the return on equity formulas. RBC expects a 14 to 15 basis point decline in awarded ROEs for 2009 followed by a much larger decline of approximately 67 basis points in 2010. RBC has stated that in its view "**The Formula is Broken**" and it recommends that investors should focus their investments in companies with the least exposure to an ROE that is derived from a formula based on changes to the forecast long Canada yield from a risk-reward perspective (January 16, 2009).

Scotia Capital has written extensively (five separate commentaries commencing in June 2008) regarding what it considers to be the drawbacks of the existing formulistic approach. Scotia Capital has called for changes due to the weak credit metrics produced by the formula and has pointed out the narrowing of the differential between utilities' ROEs and their new issuance costs of long term debt financing. Scotia Capital points to the reduction of long Canada yields, in part, being caused by the reduction in the supply of ten and thirty year Canada bonds. In a letter to the OEB dated April 17, 2009, Scotia Capital commented that the ROEs formulas "**have not reflected the real world increase in the cost of capital**" and "**the annual ROE adjustment is not even yielding the right directional change in the cost of capital**".

Q34: Has there been additional capital markets commentary regarding the appropriateness of formula derived ROEs?

A34: BMO Capital Markets commented positively on the recent National Energy Board ruling for Trans Quebec and Maritimes Pipeline Inc. (March 23) as follows:

"The NEB's decision equates to 9.85% and 9.75% returns on 40% deemed equity in 2007 and 2008, respectively."

"We view the NEB's decision as positive from a corporate debt perspective, as it increases the company's return on equity to 9.75% on 40% deemed equity. The increase in ROE should strengthen the financial profile of companies operating under this methodology, as cash flow generation should improve."

"We applaud the NEB for acknowledging that the RH-2-94 formula is no longer applicable given changes in business risk, financial markets and economic conditions." and finally,

"Overall, we view the NEB's decision as positive from a corporate debt perspective, as it increases the company's return on equity to 9.75% on 40% deemed common equity or 11.6% on 30% deemed equity, which is significantly above the 8.71% (on a 30% common equity base) it would have obtained under the historical formula in 2008. The new methodology takes into account changes in economic and industry conditions and does not depend solely on the forecast of the Government of Canada bond yield. Furthermore, the increase in ROE should strengthen the financial profile of companies operating under this methodology over the medium term, as cash flow generation should improve."

Q35: Have other capital market concerns been identified for utilities subject to determination of their ROE based on a formula?

A35: Yes. With the continuing decline of long Canada yields and resulting decline of awarded ROEs, the utilities' cash flow has fallen due, in part, to the fact that common equity bases for regulatory purposes have increased only slightly when compared to the decline in ROEs. The decline in cash flow generated by the utility leads to weaker credit metrics (in particular, ratios based on Funds Flows from Operations) and the value of the business as the discounted value of future cash flows declines as well.

Dominion Bond Rating Service ("DBRS") made the following comment (March 20, 2009) following the release of the recent TQM decision:

> **"In the Decision, the NEB deviated from its previous methodology (see below), by setting a 6.4% after-tax weighted-average cost of capital (ATWACC) return (with no explicit deemed capital structure) for each of 2007 and 2008. This compares to the 6.9% ATWACC return requested by TQM and the 5.5% ATWACC return that would have resulted if the NEB had retained its previous methodology. TQM agreed to assume the risk that the imbedded cost of debt could exceed the market-based cost of debt, which is relatively small at this time.**
>
> **Under the previous methodology, the Company had a relatively *weak financial profile largely due to its low deemed equity component (30%) and low allowed return on equity (ROE) (8.46% in 2007 and 8.71% in 2008)*. In its application, TQM requested an increase in its deemed equity component to**

40%, which is in line with other Canadian pipelines regulated by the NEB, as well as an increase in allowed ROE to 11%, translating into a 6.9% ATWACC return." (*Emphasis added*)

At a deemed common equity base of 35%, Terasen Gas suffers from these same problems, namely a low ROE and an inadequate common equity base. This results in some of the lowest credit metrics for a major utility in Canada and a very wide discrepancy between utilities in the U.S. and Terasen, as noted by Moody's analysis. In its 2005 Decision, the BCUC commented that an appropriate equity base for Terasen Gas fell in the range of 35% to 38% and determined that an appropriate level was 35% based on an awarded return of 8.80%. This decision has produced credit metrics equivalent to a **Ba** credit rating according to Moody's and with a 35% common equity ratio, Terasen is the thinnest equity capitalized major utility in Canada. The BCUC should consider increasing Terasen Gas's deemed equity base to at least 40% to achieve an appropriate stand alone financing structure for Terasen Gas. Such an increase would be consistent with decisions in other Canadian regulatory jurisdictions (in particular, Ontario) which have chosen to increase the common equity bases of gas (36% common equity bases for Union Gas and Enbridge plus additional total equity in the form of preferred shares) and electric distribution companies (40%) for Toronto Hydro and other major LDCs). The increase would also recognize that Terasen Gas must compete for debt and equity funds against more thickly equity capitalized gas distribution companies from the U.S.

3) **Conclusions:**

Q36: What conclusions have you drawn regarding the ROE formula employed by the BCUC?

A36: Under current market conditions, the formula results are directionally incorrect. It would suggest that the ROE for Terasen Gas should be reduced to below 8.00%, notwithstanding the re-pricing of risk which the capital markets have carried out over the past twelve to eighteen months. The re-pricing of risk has increased corporate costs of capital in the corporate bond market, the preferred share market and the market for common stock investments. While corporate costs of capital increased, yields on long term Canada bonds have declined reflecting the general scarcity of such bonds and lenders eagerness to cut their risk exposure by selling corporate bonds and buying Canada bonds.

The resulting declining yields in the long Canada market result in the BCUC's formula producing a declining ROE. The difference between the formula derived ROE and the cost of newly issued debt by Terasen Gas has been reduced from approximately 360 basis points in 2006 (9.145% - 5.55%) to approximately 192 basis points in 2009 (8.47% - 6.55%), a reduction of almost 47%. The notion suggested by the formula that the debt risk premium for a particular issuer can be rising while at the same time the issuer's cost of common equity capital is falling would cause the capital markets to re-examine the proposition that Terasen Gas is subject to fair and stable regulation, particularly in light of the recent TQM decision by the National Energy Board, the anticipated broader application of the NEB approach to other utilities subject to its jurisdiction and expected changes to the calculation of an appropriate ROE in Alberta and Ontario by the capital markets.

Q37: What are your conclusions regarding an appropriate common equity base for Terasen Gas?

A37: I believe that the common equity base of Terasen Gas should be increased to at least 40% in order to achieve reasonable credit metrics and maintain the current A- credit rating. This equity capitalization is still well below comparable gas distribution utilities in the U.S. with which the Company competes for debt and equity funding. Investors and credit rating agencies have historically been willing to accept the weaker financial performance of Terasen Gas due to relatively strong business conditions in British Columbia and a regulatory environment viewed to be somewhat supportive. With the likely decline in the BC economy in 2009 and 2010 and the adoption of new and increased ROEs and capital structure levels by regulators in other Canadian jurisdictions to bring Canadian utilities more in line with U.S. based utilities as reflected in the NEB's TQM decision, providers of long term capital and analysts will expect similar changes in the British Columbia regulatory regime.

Opinion

on

Capital Structure and Fair Return on Equity

Prepared for

TERASEN GAS INC.

Prepared by

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.

May 2009

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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 190 proceedings in Canada and the U.S. My professional experience is provided in Appendix G.

I have been asked by Terasen Gas Inc. (TGI) to: (1) assess the reasonableness of the Company's proposed capital structure; and (2) recommend an allowed return on equity for TGI; and (3) to address the reasonableness of TGI's proposal to fix the ROE for a period of time rather than propose an automatic adjustment mechanism at this time.

B. EXECUTIVE SUMMARY

My conclusions are as follows:

1. The existing automatic adjustment formula is clearly not producing returns that meet the fair return standard. The fair return and any automatic adjustment mechanism which is adopted for setting the allowed return on equity both need to be recalibrated.

2. The sensitivity of the cost of equity to government bond yields is materially lower than the existing automatic adjustment mechanism implies. In addition, the cost of equity moves in the same direction as the utility cost of debt; this relationship has not been reflected in the automatic adjustment mechanism. As a result, the allowed ROEs have decreased over time to a much greater extent than is justified and recently have moved in the wrong direction. The application of the formula in current circumstances would produce a lower ROE at the same time that the utility debt costs and required credit premiums have increased, an outcome which is illogical.

3. The allowed return for TGI must meet all three criteria of the fair return standard, including the comparable return standard. The fair return extends to both the capital structure and return on equity, that is, the overall return allowed must satisfy the fair return standard.

4. Satisfying the comparable return standard requires consideration of returns available to comparable utilities in the U.S., given the similarity of operating and regulatory environments, the integration of the two capital markets, the small number of Canadian utilities with equity market data and the obvious circularity of comparisons limited to utilities that are all subject to the same ROE automatic adjustment mechanism.

5. The capital structure and the return on equity are inextricably linked; the fair return on equity cannot be established without reference to the level of financial risk inherent in the capital structure adopted for regulatory purposes.

6. TGI has proposed a capital structure with a common equity ratio of 40.0%. The proposed capital structure is reasonable in light of the increase in the Company's business risks, the importance of maintaining the existing credit ratings, the trend toward stronger capital structures among other Canadian utilities, and the stronger capital structures and credit metrics of TGI's U.S. peers, with whom TGI competes for capital and whose total returns form a basis for satisfying the comparable returns standard.

7. The fair return on equity for TGI is estimated at 11.0%. The fair return for TGI 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 tests indicate the following costs of equity before adjustment for financing flexibility:

Risk Premium Test	**Cost of Equity**
Risk-Adjusted Equity Market	8.75%
DCF-Based	10.00%
Historic Utility	10.5%
Average	**9.75%**

   c. The discounted cash flow test, applied to a sample of benchmark low risk U.S. utilities, supports a cost of equity of 10.5-11.0% (midpoint of 10.75%).

d. The allowance for financing flexibility should be, at a minimum, 0.5%. The addition of a 0.5% financing flexibility adjustment results in a cost of equity based on the market-based equity risk premium and DCF tests of approximately 10.25-11.25%.

e. The comparable earnings test shows that, based on the achievable earnings returns of low risk competitive unregulated Canadian firms, whose reasonableness was corroborated by the returns of a sample of unregulated U.S. firms, a fair return applicable to a benchmark utility would be approximately 11.5-11.75%.

f. With primary weight given to the capital market-based tests, equity risk premium and discounted cash flow, the fair return on equity for TGI is 11.0%.

8. TGI is proposing not to implement an automatic adjustment mechanism at this time. This proposal is reasonable given (1) the abnormally low Government of Canada bond yields and (2) the critical importance of the relationship between the base ROE and the construction of the formula.

II. TIME FOR A NEW BENCHMARK ROE

For 15 years, the allowed ROEs for the utilities regulated by the BCUC have been set using an automatic adjustment formula. While the formula has been amended several times, its defining element has consistently been its reliance on long-term Canada bond yields to set allowed ROEs. As most recently amended in March 2006, the automatic adjustment formula changes the allowed ROE by 75% of the change in forecast long-term Canada bond yields. If the formula were applied using the long-term government of Canada bond yield of 3.6% based on the March 2009 Consensus Forecast, the benchmark low risk utility allowed ROE would be 7.9%. In its ROE and Capital Structure Decision dated March 2006, the BCUC concluded that, should the automatic adjustment mechanism result in an ROE for the low risk benchmark utility of less than 8%, the Commission would canvass the views of the parties on whether the automatic adjustment mechanism should be reviewed.

Since the inception of the formula in Canada in the mid-1990s,[1] the allowed ROEs for BC utilities, as well as for utilities in other Canadian jurisdictions, have tracked the downward trend in long-term Canada bond yields. Although the formula has been reviewed three times, comprehensively, by the British Columbia Utilities Commission (BCUC) since the formula was originally adopted (in 1997, 1999 and 2006), the overriding factor determining the allowed ROE has been the downward trend in long-term Canada bond yields, rather than factors which directly drive equity return requirements. Between 1995 and 2009, the forecast long-term Canada bond yield has fallen by 475 basis points; the corresponding allowed ROE for the benchmark BC utility has fallen by 350 basis points, that is, by approximately 75% of the decline in long-term Canada bond yields. With the widespread adoption of similar automatic adjustment formulas, allowed ROEs in Canada have converged to a relatively narrow range. Moreover, with virtually all major Canadian utilities

[1] The British Columbia Utilities Commission introduced the first formula (Order G-35-94, *In the Matter of Return on Common Equity BC Gas Utility, Pacific Northern Gas, West Kootenay Power*, June 1994).

subject to a similar formula, comparisons among the ROEs as a “reasonableness check” are subject to such an extensive degree of circularity as to make such comparisons of little or no value.

The decline in long-term Canada bond yields experienced during the past 15 years reflects in large part a sea change in the Canadian economy characterized by a shift from huge government deficits and indebtedness to an unbroken string of government surpluses (commencing in 1997) and a steady reduction in the relative (to the size of the economy) amount of debt outstanding.[2] With the vast improvement in the government’s finances and the reduction in government debt outstanding relative to the size of the economy came the decline in long-term Canada bond yields. The secular decline in long-term Canada bond yields reflects three factors: a reduction in the expected rate of inflation over the longer-term, the waning of investors’ fear that inflation would reignite to levels experienced in the 1980s decade, and a declining supply of long-term government debt relative to demand.

Of these three factors, only the decline in the expected rate of inflation over the longer-term would directly translate into a corresponding decline in the cost of equity. The fear that inflation would reignite had taken the form of a premium that investors required to “lock in” investment in long-term bonds with fixed coupon rates. Investors in equities, in contrast, are not similarly locked in and thus equity investors did not demand the same “lock in” premium. In contrast to the fixed rates on debt, corporate earnings, which ultimately determine the returns to equity investors, are better able to keep pace with the rate of inflation. The elimination of the “lock in” premium as inflationary fears waned lowered the risk associated with investment in long-term government bond yields. In the absence of a commensurate decline in the cost of equity, the result was an increase in the market equity risk premium.

With respect to the third factor, strong demand for long-term government debt by institutions, particularly those seeking to match the duration of their assets and liabilities,

[2] The Federal government is anticipating budget deficits for fiscal years 2009/10-2012/13.

creates an imbalance in the supply of and demand for long-term government securities. The scarcity factor, in turn, leads to abnormally low long-term government bond yields. The reduction in long-term government bond yields arising from a demand/supply imbalance has no bearing on the cost of equity.

Layered over the secular decline in long-term Canada bond yields have been periodic "flights to quality" throughout the period the formulas have been in effect. A "flight to quality" occurs when investors flee from risky securities to the safe haven of the safest securities, long-term government securities. A "flight to quality" puts downward pressure on the yields of default-free securities, e.g. long-term government bond yields, and a corresponding increase in the cost of risky forms of capital. Since the introduction of automatic adjustment formulas, the capital markets have been characterized by multiple crises of varying proportions, including the "Asian Contagion" and ensuing Russian sovereign debt default in 1997-1998, the dot.com bust in 2000, the Enron bankruptcy in 2001, 9/11, the run-up to and the outbreak of the Iraq War in March 2003, and the global financial crisis dating from August 2007. The series of market crises and flights to quality during the period the formulas have been in operation has kept downward pressure on the level of long-term Canada bond yields, which in turn has suppressed the level of allowed ROEs.[3]

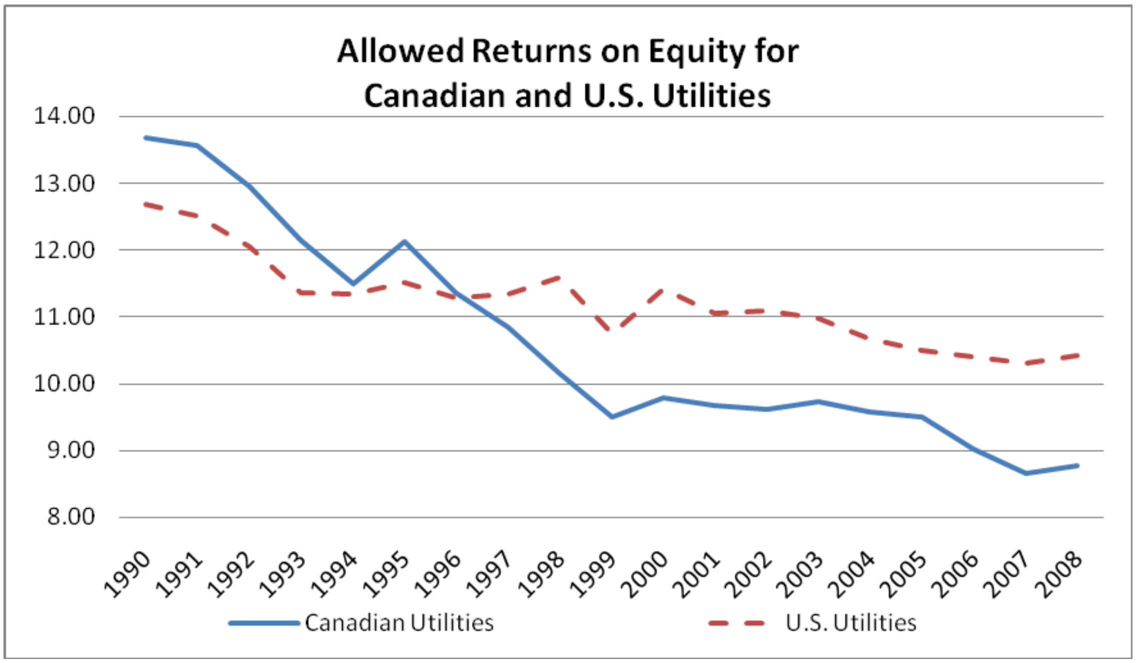
As a result of reliance on a formula which has been governed solely by changes in the long-term Canada bond yield, rather than the composite of factors that bear on equity return requirements, the allowed ROEs have fallen below levels commensurate with a fair return. The extent to which the formula ROEs have diverged off course from a fair and reasonable level over time can be assessed by a comparison of the allowed ROEs of Canadian and U.S. utilities.

[3] To put this in some perspective, Consensus Economics, *Consensus Forecasts* estimates the long-run average yield on 10-year Canada bonds twice annually, in April and October. Since 1997, the forecast yield in October for the subsequent 11 year period has averaged 5.5%. By comparison, the actual yields on 10-year Canada bonds during 1998 to 2008 have averaged 4.8%, or approximately 0.7 percentage points lower than the long-term forecast yield.

This comparison is germane given (1) the significant integration of the Canadian and U.S. capital markets, (2) the similarity in the business (or operating environments) for distribution utilities in Canada and the U.S., and (3) the similarity in the regulatory models in the two countries.

Figure 1 below compares the allowed ROEs in Canada and the U.S. since 1990.

Figure 1



Source: Schedule 22

Figure 1 shows that allowed returns in the U.S. and Canada were comparable until automatic adjustment formulas tied to government bond yields became the norm (approximately 1997-1998) in Canada. With the widespread adoption of automatic adjustment formulas in Canada, a significant gap between the allowed ROEs in the two countries emerged, a gap which has persisted through 2008. Between 1998 and 2008, Canadian utilities' allowed ROEs have averaged close to 1.4 percentage points lower than those of their U.S. peers, whose allowed ROEs continue to be set using various tests and informed judgment. The average yield on long-term government bonds in the two countries over the same period differed by less than 0.1% (10 basis points).

As of 2008, the differential between the allowed ROE for the benchmark BC utility (8.47%) and the average ROE adopted for U.S. gas distributors (10.37%) was 1.9 percentage points despite a differential between long-term government bond yields in the two countries of less than 0.2%. The magnitude of the differential of the overall return in favour of the U.S gas distributors is substantially greater given the difference between the allowed common equity ratios: currently 35.01% for TGI versus 50% for its U.S. LDC peers. In the absence of compelling evidence that TGI faces a materially lower level of business risk than its U.S. peers, the significantly lower financial risk (higher common equity ratios) of the U.S. gas distributors relative to that of TGI requires a higher ROE for TGI to result in an allowed return which satisfies the fair return standard.

Since allowed ROEs in the U.S. are determined using various cost of equity tests, they can be used, retrospectively, to test the sensitivity of the utility cost of equity to changes in long-term government bond yields. When the quarterly allowed ROEs from 1994 (the year the formula was first introduced in Canada) to 2008 are regressed against long-term Treasury bond yields and utility/Treasury bond yield spreads lagged by six months,[4] the result indicates that the allowed ROEs changed by approximately 55 basis points for every one percentage point change in long-term government bond yields and was positively related to the utility/government bond yield spread. By comparison, the typical automatic adjustment formula relied upon in Canada assumes that the ROE changes by 75 basis points for every one percentage point change in long-term government bond yields and includes no other explanatory variables. The analysis strongly indicates that, with the benefit of hindsight, the cost of equity is significantly less sensitive to changes in long-term government bond yields than the automatic adjustment formulas assume.

The evidence that the formulas have not been producing returns that meet the fair return standard has been mounting for some time.

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[4] To take account of the fact that the date of the decision lags the period covered by the market data on which the ROE decision was based. Excluding the spread as a second explanatory variable, the regression indicates that the allowed ROEs changed by approximately 40 basis points for every one percentage point change in long-term government bond yields.

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.

In its June 2006 *Canadian Hydrocarbon Transportation System* report, the National Energy Board (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 had "Buy" recommendations on utility stocks, the recommendations tended to reflect the prospects of the unregulated operations. Analysts also commented that companies had 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.[5] Some market participants 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,

[5] The NEB did not consult with analysts for the purpose of their 2008 report, in light of its then ongoing cost of capital proceeding for TransQuébec and Maritimes Pipeline.

> 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.

In *Pipelines/Gas & Electric Utilities*, dated December 7, 2006, Karen Taylor, then equity analyst for BMO Capital Markets, concluded, "We believe on a collective basis, that the allowed returns as established by the formulas highlighted above [referring to the NEB, EUB,[6] BCUC and OEB[7] formulas] are confiscatory and likely violate the Fair Return Standard."[8]

With the application of the formula for 2009, the resulting allowed ROEs were not only too low to be fair to investors, they had clearly moved in the wrong direction. While flight to quality had pushed the actual yields and forecast yields on long-term government bonds lower during 2008, other indicators were signalling a higher cost of capital. Between November 2007 and November 2008, the yield on long-term TGI bonds had jumped over 150 basis points, from approximately 5.6% to 7.2%.[9] Over the same period, the yield on the TSX Composite had also risen by more than 1.5 percentage points as the equity market plunged. The higher dividend yield, similar to the increase in corporate debt yields, points to a higher cost of capital. Yet the application of the formula, tied solely to government bond yields resulted in a lower allowed ROE for TGI 2009 than in 2008 (8.47% versus 8.62%).

Were the BCUC to set the allowed ROE using the March 2009 consensus forecast, it would be lower still, at 7.9%. Yet the cost of debt for TGI remains a full percentage point above

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[6] Alberta Energy and Utilities Board
[7] Ontario Energy Board
[8] Studies commissioned by the Canadian Gas Association and the Canadian Energy Pipeline Association published in 2008 also came to the conclusion that the ROEs produced by the automatic adjustment formulas did not meet the fair return standard.
[9] Yield on Terasen Gas 6.95% coupon bond due September 2029; data provided by RBC Capital Markets.

the yield prevailing when the Commission last reviewed the formula and set the benchmark utility allowed ROE at 8.8% for 2006. In March 2006, the cost of new long-term debt for TGI was approximately 5.5%; at the end of March 2009, it was 6.5%. It makes no logical sense that equity investors, who are subordinate to debt investors in terms of their claims on the assets of the utility, would demand a lower return when debt investors are demanding a higher return. The divergence between the observed trends in the cost of utility long-term debt and the automatic adjustment formula ROE result provides a strong signal that the automatic adjustment formula is not working properly.

As a further perspective, an allowed ROE of 7.9% would represent a significant narrowing of the premium between the allowed ROE and the coincident cost of new 30-year debt to TGI. An allowed ROE of 7.9% would equate to a premium of only 1.4 percentage points above the prevailing cost of new long-term debt. By comparison, when the BCUC reviewed the formula in 1999 and 2006, the allowed ROEs were approximately 2.4 and 2.7 percentage points respectively higher than the corresponding cost of long-term utility debt. There is no logical reason that the differential between the returns required by investors to invest in the common equity of utilities like TGI rather than the Company's long-term debt would have declined between 2006 and 2009 as the operation of the automatic adjustment formula implies. The material narrowing of the spread between the cost of new utility long-term debt and the automatic adjustment formula ROE result provides further support for the conclusion that the automatic adjustment formula is not producing reasonable results.

In March 2006, the yield on the TSX Composite Index was 2.3%; at the end of March 2009 it was 4.2%. It makes no logical sense that utility equity investors would demand a lower return when the virtual doubling of the market dividend yield (reflecting a 30% price decline) is signalling an increase in the cost of equity and the equity risk premium. The divergence between the observed trends in the market cost of equity and the automatic adjustment formula ROE result is provides an additional strong signal that the automatic adjustment formula is not working properly.

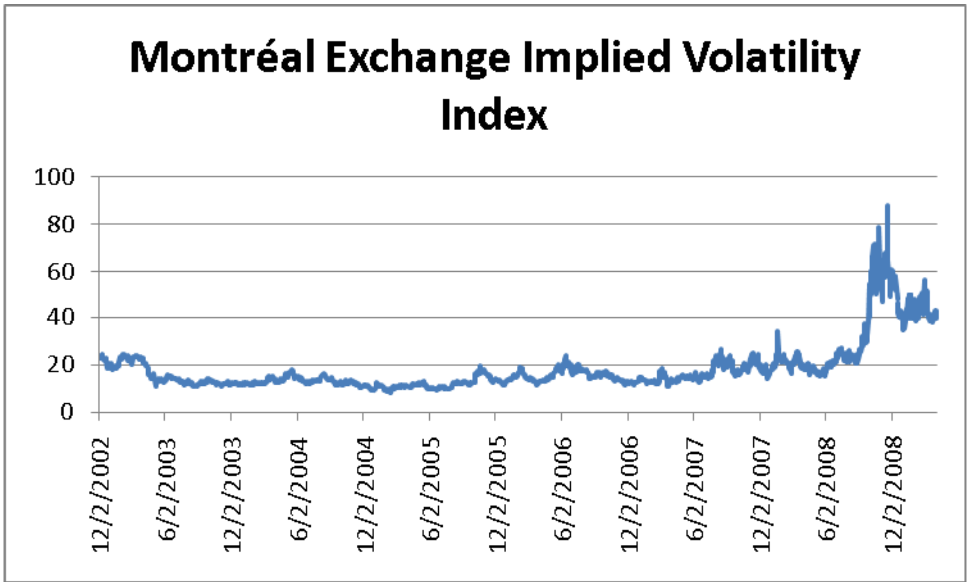
In addition to the increase in the market dividend yield, the increase in the cost of equity, and the widening of the equity risk premium, is reflected in the significant increase in the volatility in the equity markets, as represented by Implied Volatility Index ("MVX") introduced by the Montréal Exchange in 2002. The Montréal Exchange states that the "MVX is a good proxy of investor sentiment for the Canadian equity market: the higher the Index, the higher the risk of market turmoil. A rising Index therefore reflects the heightened fears of investors for the coming month."[10] In other words a rising MVX is an indicator of rising investor risk aversion and a rising market risk premium.

As shown in Figure 1 below, during much of 2002-2007, prior to the onset of the financial crisis, the MVX was relatively stable, trading within a range of 8 to 24, and averaging 15. During 2008, the MVX rose sharply, peaking at almost 90 in November 2008, its highest level since inception, and averaging close to 60 during the 4th quarter. While volatility has declined, the MVX has continued to trade substantially above its 2002-2007 levels, averaging over 40 in the first quarter of 2009. To put this in perspective, the MVX never exceeded 25 prior to August 2007. Since mid-2008, the MVX has signaled higher risk aversion and, therefore, an increase in the equity risk premium.[11]

[10] www.m-x.ca/indicesmx_mvx_en.php

[11] Similarly, in the U.S. the VIX index, an equity volatility index introduced in 1993 by the Chicago Board Options Exchange (often referred to as the "Fear Gauge"), is an indicator of investor risk aversion. The index indicates that, during much of 2004-2006, the equity market was perceived as unusually stable; trading within a range of 10 to 19, and averaging 13.5. The VIX index rose steadily throughout much of 2007, averaging 100% higher during the 4th quarter than during the 4th quarter of 2006. During the fourth quarter of 2008, as the depth of the financial crisis was revealed, the index jumped sharply, peaking at almost 80 in October 2008, its highest level since inception, and averaging close to 60 during the entire 4th quarter. At the end of March 2009, it was trading around 45, levels not experienced previously. On only six days prior to the current financial market crisis, four during the 1998 global market crisis and two times in 2001-2002 in the wake of the recession in the U.S., has the index traded at or above 40. However, at no time prior to this financial crisis has it touched 45.

Figure 2



Source: Montréal Exchange

The unambiguous divergence between the trends in long-term government bond yields on the one hand and utility bond yields and the market cost of equity on the other has led equity analysts to reach the conclusion that the formula is broken. In RBC Capital Markets' January 16, 2009 *Industry Comment* entitled "Allowed ROEs: The Formula Is Broken, but Will Regulators Fix It?", analyst Robert Kwan commented,

> With higher equity risk premiums and higher long bond yields for Energy Infrastructure companies that are trading at levels close to the allowed ROEs, it appears that the formula is broken. Forgetting the magnitude of change, it appears that the formula is producing a result that is directionally incorrect (i.e., ROEs declining yet corporate bond yields and equity risk premiums are rising).

Mr. Kwan recommended from a risk/reward perspective

> We would focus on companies with the least exposure to the formula.

A February 23, 2009 report by Macquarie Research entitled *ROE Formula May Finally Bite the Dust* concluded that government bond yields bear little resemblance to any private company's cost of capital. The report also concluded that:

> Lack of comparability between allowed utility ROEs and returns on similar investments is driving the emerging capital access problem. In support of the argument the comparability criterion is not being met, utility customers and their expert witnesses like to point out that allowed returns for U.S. utilities are considerably higher than allowed returns in Canada. No matter how we slice the data, we concur with this opinion.

On March 19, 2009 the National Energy Board released its cost of capital decision for TransQuébec and Maritimes Pipeline (TQM). In that decision, the NEB expressed the view that

> there have been significant changes since 1994 in the financial markets as well as in general economic conditions. More specifically, Canadian financial markets have experienced greater globalization, the decline in the ratio of government debt to GDP has put downward pressure on Government of Canada bond yields, and the Canada/US exchange rate has appreciated and subsequently fallen. In the Board's view, one of the most significant changes since 1994 is the increased globalization of financial markets which translates into a higher level of competition for capital. When taken together, the Board is of the view that these changes cast doubt on some of the fundamentals underlying the RH-2-94 Formula as it relates to TQM.

The NEB also noted that

> The RH-2-94 Formula relies on a single variable which is the long Canada bond yield. In the Board's view, changes that could potentially affect TQM's cost of capital may not be captured by the long Canada bond yields and hence, may not be accounted for by the results of the RH-2-94 Formula. Further, the changes discussed above regarding the new business environment are examples of changes that, since 1994, may not have been captured by the RH-2-94 Formula. Over time, these omissions have the potential to grow and raise further doubt as to the applicability of the RH-2-94 Formula result for TQM for 2007 and 2008.

The NEB's decision for TQM replaced the automatic adjustment formula ROE and deemed capital structure with an after-tax weighted average cost of capital (ATWACC) of 6.4%. Although the decision specified neither a capital structure nor allowed ROE, it provided some alternative combinations of common equity ratio and ROE equivalent to the 6.4%

ATWACC so as to facilitate comparisons. The 2007/2008 ROE at the TQM and Intervenor recommended equity ratios of 40% and 32% would be 9.7% and 11.2%, respectively. At the same common equity ratio last approved for TQM of 30%, the return adopted by the NEB for TQM is more than 250 basis points higher than the corresponding 2007 and 2008 ROEs of 8.46% and 8.71% if determined by the NEB's multi-pipeline formula. In coming to its decision, the NEB concluded that market returns of U.S. companies were relevant to the cost of capital of Canadian firms, as U.S. market returns can be a useful proxy for investment opportunities in the increasingly integrated global capital markets. Following its decision for TQM specifically, the NEB has decided to consider whether it should initiate a full review of its RH-2-94 decision which adopted the automatic adjustment formula.[12]

BMO Capital Markets analyst George Lazarevski in *Pipelines and Utilities* (March 30, 2009) stated,

> We applaud the NEB for acknowledging that the RH-2-94 formula is no longer applicable given the changes in business risk, financial markets and economic conditions. In particular, the globalization of financial markets made it difficult for Canadian operators to compete for capital with such low ROE.

On April 24, 2009, Scotia Capital commented,

> The turmoil in financial markets over the last 18 months has had a material knock-on effect on a sector typically seen as a safe haven from adverse equity market volatility and valuations. Energy utilities across Canada have seen their regulated returns on equity squeezed by falling Government of Canada bond yields, even as the real-world cost of equity capital has risen dramatically.
>
> Beginning with the National Energy Board in early 1995,[13] Canadian energy regulators have largely adopted formula-based annual adjustments to utilities' allowed return on equity. These formula have been based on the capital asset pricing model. A base "risk-free" rate, represented by long Canada bond yields, is augmented by an equity risk premium, chosen to represent the business and financial

[12] The potential NEB review is part of a broader movement to address the failings of the existing automatic adjustment formulas. The Alberta Utilities Commission is in the process of reviewing the automatic adjustment formula, the Ontario Energy Board has initiated a more limited review of the reasonableness of the 2009 values produced by its formulaic approach to setting the cost of capital for electricity distributors, and Gaz Metro is applying to the Régie for a change in cost of capital methodology.

[13] As noted earlier, the BCUC was actually the first Canadian regulator to adopt an automatic adjustment mechanism in 1994.

risk of the utilities. The NEB's formula was created in 1994 and 1995, when Canada long bond yields reached over 9% at times, due to a range of factors, including ratings downgrades, large public sector deficits, and bearish domestic and international market sentiment towards Canadian government debt.

As Canada's public sector reformed its finances, long Canada yields have come down, gradually but steadily, since early 1995. This led to a gradual decline in utility allowed ROEs, which has been a challenge for equity holders, and a challenge for utility management to offset by trying to "over-earn" the regulatory target, which is used to set rates.

The onset of economic and financial market turmoil in late 2007 led to a further, more rapid decline in Canada yields, mimicking the global flight to the safety of top-quality sovereign debt, and reflecting widespread investor aversion to risk of all kinds. This triggered a decrease in Canadian utility regulators' formula-driven ROEs, to unprecedented low levels. However, utility bond spreads, and their cost of equity capital, were rising.

Very recently, the NEB recognized these adverse and undesirable results, in what we view as a very significant Decision in the case of Trans Québec & Maritimes Pipeline. The NEB varied from its formula, which it had applied virtually universally to utilities in its jurisdiction since 1995. The ROE relief was material, lifting TQM's ROE from the formula-set 8.46% and 8.71% in 2007 and 2008 (on the NEB's deemed equity capitalization of 30%) to roughly 11.6% to 11.8%, based on the same capital structure and the embedded cost of debt.[14]

With this backdrop, it is apparent that a review from first principles of the cost of capital (capital structure and ROE) for TGI is warranted and the allowed return rebased at a level which satisfies the fair return standard.

[14] Stephen Dafoe, "Falling Canada Yields and Utility ROEs", *Capital Points*, ScotiaBank Group, April 24, 2009.

III. THE FAIR RETURN STANDARD

The standards for a fair return arise from legal precedents[15] which are echoed in numerous regulatory decisions across North America, including the BCUC's August 26, 1999 decision entitled *In the Matter of Return on Equity for a Benchmark Utility*.[16] 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.

The legal precedents make it clear that the three requirements are separate and distinct. Moreover, none of the three requirements is given priority over the others. The fair return standard is met only if all three requirements are satisfied. In other words, the fair return standard is only satisfied if the utility can attract capital on reasonable terms and conditions,

[15] 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))*.

[16] The three requirements were summarized by the National Energy Board (RH-2-2004, Phase II) as follows:

> "The Board is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:
> - be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);
> - enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
> - permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard)."

The three requirements were reiterated in the March 19, 2009 TQM decision (pages 6-7).

In EB-2005-0421(Toronto Hydro), dated April 12, 2006, the Ontario Energy Board 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) its financial integrity can be maintained ***and*** the return allowed is comparable to the returns of enterprises of similar risk.[17]

In Commission Order G-14-06 (March 2, 2006) the BCUC recognized “the relevance of two separate standards namely the capital attraction standard and the comparable returns standard in establishing a fair return on equity for a benchmark low-risk utility. One standard does not trump the other, neither is one subsumed by the other.”

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. A fair return preserves the financial integrity of the utility, that is, it permits the utility to maintain its creditworthiness, as demonstrated by the level of its credit metrics and debt ratings. 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.

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.

[17] See Appendix A for further discussion of the distinction between the capital attraction and comparable returns standards.

IV. FRAMEWORK FOR EVALUATION OF CAPITAL STRUCTURE AND ROE FOR TGI

A. RELATIONSHIP BETWEEN CAPITAL STRUCTURE AND ROE

The overall cost of capital to a firm depends, in the first instance, on business risk. Business risk comprises the fundamental characteristics of the business (e.g., demand, supply and operating factors) that together determine the probability that future returns to investors will fall short of their expected and required returns. Business risk thus relates largely to the assets of the firm. For utilities, the business risks also include regulatory risks, i.e., the regulatory framework under which the utility operates. The prevailing regulatory framework effectively represents the current allocation of the fundamental business risks between investors and ratepayers. Regulatory risk can be considered either as a component of business risk or as a separate risk category along with business and financial risk.

The cost of capital 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 shares and common equity, can be viewed as a summary measure of the financial risk of the firm. The use of debt in a firm's capital structure 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.

There are effectively two approaches that can be used to determine the fair return. The first approach entails acceptance of the utility's actual capital structure for regulatory purposes or deeming a capital structure that adequately protects bondholders but does not necessarily equate the total (fundamental business, regulatory and financial) risk of the regulated company to those of the proxy companies used to estimate the cost of equity. If the total risk of the proxy companies is higher or lower than that of the specific utility, the proxies' estimated cost of equity needs to be adjusted upward or downward to arrive at the cost of equity of the specific utility.

The first approach, varying both capital structures and ROEs, is used by the BCUC. The combination of capital structures and ROEs is also used by the OEB and the Régie de l'Énergie de Québec (Régie).

The second approach assesses the utility's fundamental business and regulatory risks, and then establish a capital structure that is both compatible with those risks and that permits the application of a cost of equity determined by reference to proxy companies, with no adjustment to that cost. This approach can be applied to a spectrum of regulated companies within a range of combined fundamental business and regulatory risks.

The NEB employed the second approach when it established its automatic adjustment mechanism for a number of oil and gas pipelines in 1995.[18] It is also the approach that was adopted by the former Alberta EUB in its Generic Cost of Capital Decision 2004-052 in 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 return on equity to be applied to each of the utilities under its jurisdiction.

In summary, the various components of the cost of capital are inextricably linked; it is impossible to determine if the return on equity is fair without reference to the capital structure of the utility. Thus, the determination of a fair return must take into account all of

[18] In its Reasons for Decision RH-1-2008 (March 2009), the NEB recognized the inextricable link between ROE and capital structure. However, it did not specify either an ROE or a capital structure for TQM. Instead, it adopted an overall cost of capital and left it to TQM to choose its optimal capital structure. The NEB also noted that the overall cost of capital approach enables comparisons of returns on an equal footing between companies of comparable risk.

the elements of the cost of capital, including the capital structure and the cost rates for each of the types of financing. It is the overall return on capital which must meet the requirements of the fair return standard. Both approaches used by Canadian regulators are equally valid as long as the combination of capital structure and return on equity result in an overall return which satisfies all three fair return standards.

B. CONCEPT OF BENCHMARK UTILITY AND BENCHMARK ROE

The concepts of a benchmark utility and benchmark return on equity have been used by the BCUC to establish allowed ROEs for each of the utilities under its jurisdiction. Essentially, this approach (1) designates one of the utilities as the "benchmark" utility, (2) estimates that utility's cost of equity, and then (3) establishes the cost of equity for the other BCUC-regulated utilities by reference to the benchmark utility's cost of equity. With regard to (3), the costs of equity (and allowed ROEs) for the utilities other than the designated benchmark have been estimated and expressed as a premium above the benchmark ROE. TGI has historically been designated the benchmark utility and each of the other BC utilities' allowed ROEs, have reflected a premium to TGI's allowed ROE.

The approach taken by the BCUC, as noted in Section A, has also adopted different deemed capital structures for the utilities, ranging from a 35% common equity ratio for TGI to 40% common equity ratios for Terasen Gas (Vancouver Island), FortisBC, and Pacific Northern Gas-West. To assess whether the utilities' allowed returns are fair returns, i.e., ones that meet all three criteria of capital attraction, financial integrity and comparability, both the capital structure and ROE have to be taken into account. To illustrate, assume that Utility A and Utility B have similar business and regulatory risks, which means their costs of capital should be similar. Both utilities are allowed the same ROE. However, Utility A has a lower deemed common equity ratio than Utility B and thus is being allowed an overall return which is lower than that of Utility B. As both utilities are of similar business risk, this outcome would not be fair and reasonable. Consequently it is critical to ensure that the **overall** allowed returns for each utility meet the fair return standard.

It is perhaps obvious that the same is true when establishing the allowed return for the utility which is to be designated as the benchmark. The ROE applicable to the benchmark utility (i.e., the benchmark ROE) is derived from market data which includes utilities from various industries (electric, gas distribution and gas pipeline). The cost of equity, as estimated using tests applied to samples of proxy companies, reflects the composite of those proxy companies' business, regulatory and financial risks. For the proxy companies' cost of equity to be equivalent to the "benchmark cost of equity" applicable to the "benchmark utility", the benchmark utility's total risk needs to be similar to that of the proxy companies. If it is not, the solutions include (1) changing the benchmark utility's capital structure; (2) making an adjustment to the proxy companies' cost of equity to reflect the relative total risk of the benchmark utility; or (3) some combination of (1) and (2).

To minimize the extent to which such adjustments are required, the point of departure should be the selection of companies that are of relatively similar total risk to the benchmark utility. In the Canadian context, there are only seven[19] publicly-traded Canadian utilities. These companies are relatively heterogeneous in terms of both operations[20] and size.[21] While the Canadian utilities provide some perspective, a more accurate assessment of the cost of capital for the benchmark utility can be made by reliance on a sample of comparable risk U.S. utilities drawn from a much broader universe. The selection of the sample relies on criteria designed to (1) identify companies that are of relatively similar risk to the benchmark utility and (2) produce a large enough sample of companies to ensure reliable cost of equity test results.

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[19] AltaGas Utility Group (spun off from AltaGas Income Trust in late 2005), Canadian Utilities, Emera, Enbridge, Fortis, Pacific Northern Gas and TransCanada Corporation.

[20] Their operations span all the major utility industries, including electricity distribution, transmission and power generation, natural gas distribution and transmission, and liquids pipeline transmission, as well as unregulated activities in varying proportions of their consolidated activities.

[21] Ranging from an equity market capitalization of approximately $40 million (AltaGas) to $20 billion (TransCanada).

Further, it is important to recognize that, while it may be administratively efficient to designate one utility as the "benchmark", it does not necessarily follow that (1) the designated benchmark is the lowest risk utility, or (2) that the risk of the designated benchmark utility does not change over time relative to its peers.

V. CAPITAL STRUCTURE FOR TGI

A. PROPOSED CAPITAL STRUCTURE OF TGI

TGI is requesting that the Commission approve a regulated common equity ratio of 40.0%.

B. PRINCIPLES FOR CAPITAL STRUCTURE DETERMINATION

The following principles should be respected when establishing both the cost of capital generally and a reasonable capital structure for TGI:

1. The Stand-Alone Principle
2. Compatibility of Capital Structure with Business Risks
3. Maintenance of Creditworthiness/Financial Integrity
4. Ability to Attract Capital on Reasonable Terms and Conditions
5. Comparability of Returns

Each of these five principles is defined below. The five principles which apply to the determination of a reasonable capital structure include the three standards (Principles 3 to 5) which govern a fair return identified in Section III above, reflecting the interdependence between capital structure and ROE.

B.1. <u>The Stand-Alone Principle</u>

The stand-alone principle encompasses the notion that the cost of capital incurred by a utility should be equivalent to that which would be faced if it was raising capital in the public markets on the strength of its own business and financial parameters; in other words, as if it were operating as an independent entity. The cost of capital for the company should reflect neither subsidies given to, nor taken from, other activities of the firm.[22] Respect for the stand-alone principle is intended to promote efficient allocation of capital resources among the various activities of the firm. As TGI is a stand-alone regulated entity which raises its own debt on the strength of its own business and financial risk profile, the application of the stand-alone principle is not an issue.

B.2. Compatibility of Capital Structure with Business Risks

The capital structure of a utility should be consistent with the business and regulatory risks of the specific entity for which the capital structure is being set. The business risk of a utility is the risk of not earning a compensatory return on the invested capital and of a failure to recover the capital that has been invested. The fundamental business risks of a utility include demand, competitive, supply, operating, technology-related and political risks. Regulatory risk relates to the framework that determines how the fundamental business risks are allocated between the utility's customers and its investors.

B.3. Maintenance of Creditworthiness/Financial Integrity

A reasonable capital structure for TGI, in conjunction with the returns allowed on the various sources of capital, should provide the basis for stand-alone investment grade debt ratings in the A category. Debt ratings in the A category assure that the utility would be able to access the capital markets on reasonable terms and conditions during both robust and difficult, or weak, capital market conditions. In contrast to unregulated companies, utilities do not have the same flexibility to defer financing new assets. Utilities are required to provide service on demand, and must access the capital markets when service requirements demand it.

[22] In a similar vein, in setting the allowed return, the availability of incentives through a performance-based regulation plan should not be viewed as an "offset". Performance-based regulation is intended to provide the basis for incenting the utility to achieve efficiencies in order to benefit customers and to be able to earn a return in excess of the cost of capital. Setting the allowed return below the cost of capital with the expectation that incentive returns will be achieved undermines the objective of performance-based regulation.

The critical nature of maintaining credit ratings in the A category arises from two factors: market access and cost. Even a utility with split-ratings (that is, one debt rating in the A category and one rating in BBB category) would face a higher cost of debt and lesser market access relative to a utility with all debt ratings in the A category. Regulated issuers with BBB ratings can be closed out of the market at times, particularly at the longer end (20-30 year term) of the debt market. TGI is principally financing long-term assets. Thus the Company needs to maintain the financing flexibility required to be able to access debt with terms to maturity in the range of 10 to 30 years in both strong and weak capital market conditions.

If a utility experiences a downgrade, the downgrade would not only result in an increase in the cost of the additional debt that the company needs to raise, but it will affect all of the outstanding debt. An increase in the cost of debt to a utility increases the required yield on the outstanding debt and reduces the value of that debt. Since existing debt holders are the most likely purchasers of future issues, a debt rating downgrade, with the resulting negative impact on the value of their existing holdings, would likely make them less willing to purchase future issues.

B.4. Ability to Attract Capital on Reasonable Terms and Conditions

A higher cost of debt to the utility translates into a higher cost of debt to ratepayers. The relative cost of A rated debt versus BBB rated debt varies with market conditions, but ratings in the BBB category can be very costly to ratepayers. As the recent global market crisis has demonstrated, capital markets can deteriorate rapidly.

In September 2006, TGI issued 30-year debt at a spread of 123 basis points over the benchmark long-term Government of Canada bond yield. When spreads peaked in early January 2009, the indicated spread for a new 30-year TGI debt issue was 380 basis points, close to 260 basis points higher than the spread that prevailed when the ROE was last calibrated by the BCUC. Since the beginning of 2007, spreads for companies with ratings in the BBB category had increased by an even greater amount, as shown in the table below.

The lack of an indicated 30-year new issue spread in January 2009 for TransAlta in that table signifies that TransAlta would likely not have been able to raise 30-year debt at that time.

Table 1

	Debt Ratings DBRS/Moody's/S&P	**Term of Issue**	**Indicated Spread at 1/1/2007**	**Indicated Spread at 1/8/2008**	**Indicated Spread at 1/5/2009**	**Change in Indicated Spread 2009/2007**
TGI	A/ A3 / A	10 yr	70	100	355	+285
		30 yr	130	125	380	+250
Epcor Utilities	A(low) / - / BBB+	10 yr	75	140	480	+405
		30 yr	135	195	505	+370
Nova Scotia Power	A(low) / Baa1 / BBB	10 yr	75	140	420	+345
		30 yr	138	170	445	+307
TransAlta	BBB / Baa2 / BBB	10 yr	135	355	600	+465
		30 yr	300	380	N/A	N/A
Union Gas	A/ - /BBB+	10 yr	57	130	370	+313
		30 yr	107	150	395	+288
Westcoast	A(low)/ - /BBB+	10 yr	63	135	410	+347
		30 yr	118	155	435	+317

Source: RBC Capital Markets, *Indicative New Issue Pricing*, various issues.

While credit spreads have narrowed since January,[23] this table underscores the potential magnitude of the incremental costs that are associated with being a BBB rated issuer, and the importance from both a cost and market access perspective of maintaining ratings in the A category. It bears noting that, in the case of a downgrade, the increased cost of debt would be borne by ratepayers over the full life of the issues.

In assessing the importance of maintaining strong A ratings, it is important to consider the relatively small size of the BBB market in Canada. As reported in "Back to Basics" by Marlene K. Puffer, *Canadian Investment Review*, Fall 2006, the BBB corporate debt market is only 4% of the total market and it is mainly limited to issues with terms under 10 years. Many institutional investors such as pension funds face limits on the proportion of BBB

[23] In early February 2009, TGI issued 30-year debt at a spread of 285 basis points, or more than 160 basis points higher than the spread of its 2006 debt issue.

rated debt they are allowed to hold in their portfolios or cannot invest in BBB rated debt at all.[24] The small size of the Canadian market for BBB rated debt and the limitations on the ability of BBB issuers to raise debt in the long-term end of the debt market underscore the importance of A credit ratings.

From January 2006 to March 2009, RBC Capital Markets[25] recorded $164 billion (452 issues) of corporate debt financing in Canada. Of that amount, companies all of whose ratings were in the BBB category or below accounted for approximately 6% and 9% of the total dollar value and number of issues respectively. Even including companies with one rating in the A category (i.e., split-rated A/BBB category or lower) are included, those issues account for only 13% and 17% of the total value and number of issues respectively. From mid-2007 to March 2009, during which the credit markets have been experiencing various degrees of turmoil, of 189 reported issues, only seven were by companies with all ratings in the BBB category or lower, none of which was for a term in excess of 10 years.

Utilities need to be able to raise capital on demand. While the capital markets were very robust and open to new utility issues at the time of the last Commission decision on TGI's capital structure in early 2006, the current financial crisis underscores how quickly markets can change.

TGI will be competing for capital in markets that may be characterized by an unprecedented requirement for regulated infrastructure capital. Its peers are increasingly global, not solely Canadian.[26] In its 2008 *World Energy Outlook*, the International Energy Agency estimated

[24] 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.
[25] RBC Capital Markets, *Credit Weekly*, various issues.
[26] Comparisons among utilities across borders, particularly by the bond rating agencies, are common. For example, S&P's peer comparison for AltaLink includes American Transmission Company and International Transmission Company, both U.S. companies (Standard and Poor's, *Research: Peer Comparison: North American Stand-Alone Transmission Companies Deliver Electricity… and Profits*, April 26, 2006). Hydro One's peers include Consolidated Edison and National Grid, one a U.S. company and one a U.K. company with extensive U.S. holdings (Standard & Poor's *Peer Comparison: Consolidated Edison Inc., Hydro One Inc. and National Grid PLC – Same Ratings, Different Basis*, October 11, 2005). TransAlta Corporation's peers include PPL Corporation and Constellation Energy, both U.S. electric utilities (Standard and Poor's, *TransAlta Corp*, October 22, 2008). Ontario Power Generation's peers have included two Canadian companies

that between 2007 and 2030 close to $4.3 trillion in investment would be required by the gas transmission and distribution ($1.6 trillion) and electricity ($2.6 trillion) industries in North America.[27] To compete successfully for the required capital, that is, to continue to be able to attract capital on flexible terms and conditions, TGI will require financial metrics (which reflect the combination of capital structure and ROE) that are competitive with those of their peers. Competition for capital to address infrastructure investment requirements in North America (and globally) supports a strengthening of TGI's financial parameters.

B.5. <u>Comparability of Returns</u>

The combination of the adopted capital structure and return on capital should be comparable to the returns of comparable risk companies.

In order to be competitive in the capital markets, a regulated utility's financial parameters – which encompass both capital structure and ROE – need to be comparable to those of its peers. In this regard, it is important to recognize that TGI competes for capital not only with other Canadian regulated companies, but with regulated companies globally, as well as with unregulated companies, both within Canada and globally. The achievement of comparability requires explicit recognition of the financial parameters of the companies of comparable risk to TGI, including regulated companies throughout North America.[28]

(TransAlta and Emera) and a U.S. company, Exelon (Standard and Poor's, *Research: Ontario Power Generation Inc.*, December 9, 2005).

[27] Approximately $19 trillion world-wide (Table 2.4).

[28] The Conference Board of Canada has pointed out the importance of comparable returns for electric 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."*

The comments of the Conference Board with respect to electric transmission are no less true of other utility sectors, including natural gas distribution.

C. TRENDS IN BUSINESS RISK AND RELATIVE BUSINESS RISK OF TGI

In the last cost of capital proceeding in 2005-2006, TGI applied for a common equity ratio of 38%, in part based on the increased longer-term risks that it was facing, largely related to a more competitive business environment. Since that proceeding, the competitive environment in which TGI operates has continued to evolve. As described in more detail in the Company's testimony:

(1) The provincial energy policy introduced in early 2007 discourages the use of fossil fuels, including natural gas, and has imposed a carbon tax on the consumption of natural gas;

(2) The competitive advantage of natural gas in British Columbia has been eroding over the past 15 years (since the BCUC first introduced the automatic adjustment formula);

(3) The new construction market has been shifting from single-family to multi-family dwellings, for which electricity is the energy source of choice;

(4) Alternative energy sources have become increasingly available to customers (e.g., ground source heat pumps);

(5) Per customer usage has continued to decline.

The increased longer-term business risk which TGI faces supports an increase to the 35% common equity ratio which the BCUC approved in 2006.[29]

[29] The current allowed equity ratio of 35.01% incorporates the impact of the amalgamation of TGI and Squamish Gas effective January 1, 2007.

D. CHANGES IN REGULATED CAPITAL STRUCTURES OF CANADIAN UTILITIES

Since the Commission last reviewed the appropriate capital structures for TGI, there have been a number of changes in the deemed capital structures adopted for other Canadian regulated companies with which the Terasen utilities would have been compared.

Since the Commission's last review, the allowed common equity ratios for a number of the NEB-regulated pipelines have increased. Both Foothills and TCPL-BC System have since negotiated common equity ratios of 36%, or six percentage points higher than they were when the Commission conducted its analysis of TGI in 2005.[30] In May 2007, the NEB approved a multi-year settlement between TCPL and shippers that increased TCPL's deemed common equity ratio from the 36% which existed in 2005 to 40%. Westcoast has also negotiated increases in its deemed common equity ratio for its transmission mainline since the Commission last reviewed TGI's capital structure. In 2005, the deemed common equity ratio was 31%. For 2007, the deemed common equity ratio was 36%. Westcoast filed a negotiated settlement with the NEB in August 2008 which would maintain the transmission mainline common equity ratio at 36% from 2008-2010.[31]

In isolation, the increases in the deemed common equity ratios of the NEB regulated pipelines (and maintaining the same differential with TGI) would increase the common equity ratio for TGI by approximately five percentage points, i.e., to 40%.

[30] Foothills Pipe Lines Ltd., Order TG-08-2005, December 21, 2005; TransCanada PipeLines Limited, Order TG-02-2006, February 22, 2006.

[31] As noted earlier, in its Reasons for Decision RH-1-2008 (March 2009), the NEB did not specify a capital structure for TQM. Instead, it left it to TQM to choose its optimal capital structure, concluding "The Board is of the view that while estimating the equity ratio based on business risk, separately from the determination of the return on equity, can be useful in a regulatory context, it does not reflect the way that much of the business world approaches capital structure and capital budgeting decisions." (page 17) TQM had specified a common equity ratio of 40% in its tolls application.

The Ontario Energy Board has also approved increases for a number of the gas and electric utilities under its jurisdiction since the Commission's last review.

Table 2

Company	Decision Date	Equity Ratio	Change in Equity Ratio
Union Gas	5/06	36%	+1%
Toronto Hydro	12/06	40%	+5%
Enbridge Gas Distribution	7/07	36%	+1%
Hydro One Transmission	8/07	40%	+4%

Consideration of all the increases in the allowed common equity ratios for other Canadian regulated companies with which TGI would be compared supports an increase in the common equity ratio of TGI of approximately four percentage points.

E. BOND RATINGS AND CREDIT METRICS

TGI's debt is currently rated by all three major debt rating agencies, DBRS, Moody's and Standard & Poor's.[32] TGI's Moody's debt rating, at A3 for senior unsecured debentures, is only one notch from the Baa rating category. Since bond investors are more likely to focus on the lowest rating, it is appropriate to focus on the Moody's ratings and guidelines.

Moody's ratings from highest to lowest are as follows:

[32] TGI's S&P ratings are unsolicited ratings.

Table 3

Rating	Rating Definition
Aaa	Highest quality with minimal credit risk
Aa	High quality with very low credit risk
A	Upper medium credit with low credit risk
Baa	Medium grade with moderate credit risk; may possess certain speculative elements
Ba	Have speculative elements and are subject to substantial credit risk
B	Speculative and subject to high credit risk
Caa	Of poor standing and subject to very high credit risk

To ratings within each major category, a modifier of 1 to 3 is appended, with 1 meaning that the obligation ranks in the upper end of its generic rating category and 3 means that the obligation ranks at the lower end of its generic rating category. Ratings of Baa3 or higher are considered investment grade.

Moody's quantitative methodology for rating North American natural gas distributors considers four main factors: sustainable profitability (20% weight); regulatory support (10% weight); ring-fencing (10% weight); and financial strength and flexibility (60% weight). The sustainable profitability and financial strength and flexibility factors are divided into sub-categories with individual weights assigned to the sub-categories. The table below shows where TGI scored[33] in each of the categories in the most recent Moody's Credit Opinions and compares them to the median indicated ratings of the natural gas distribution utilities which are included in my sample of low risk U.S. utilities used to estimate the cost of equity for TGI.

[33] Based on expected implied ratings levels where different from historic levels.

Table 4

Factor	Weight	Rating on Factor	
		TGI	Proxy LDCs [1/] (Median)
Sustainable Profitability:			
ROE	15%	Baa	A
EBIT/Customer Base	5%	A	A
Regulatory Support	10%	Aa	Aaa/Aa
Ring-Fencing	10%	Aa	A
Financial Strength and Flexibility:			
EBIT Interest Coverage	15%	Ba	Aa/A
Retained Cash Flow/Debt	15%	Ba	Baa
Debt/Book Capitalization	15%	Ba	A
Free Cash Flow/Funds from Operations	15%	Aa	Aa/A
Actual Rating		A3	A3

[1/] AGL Resources, Indiana Gas, New Jersey Resources (New Jersey Natural Gas), Northwest Natural Gas, Piedmont Natural Gas, Vectren Corporation (Indiana Gas) and WGL Holdings.

Sources: Moody's, *Rating Methodology: North American Regulated Gas Distribution Industry (Local Distribution Companies)*, October 2006 and *Credit Opinion: Terasen Gas Inc*., May 27, 2008.

Table 4 shows that TGI's implied ratings in three of four of the Financial Strength and Flexibility categories, including capital structure, are below investment grade; on average, it is Baa rated on Financial Strength and Flexibility.

Moody's noted with respect to TGI that "Notwithstanding TGI's relatively low risk business profile, its financial profile is considered weak at the A3, senior unsecured rating level. Accordingly, further sustained weakening of TGI's financial metrics, for instance ROE below 8%, EBIT/Interest below 2x, RCF/Debt below 5% and/or Debt/Book Capitalization (Excluding Goodwill) above 65%, would likely lead to a downgrade of TGI's rating."[34]

[34] Both DBRS and Standard & Poor's consider the equity ratios adopted for Canadian utilities to be thin (and the allowed equity returns relatively low).

For example, in reference to FortisAlberta, DBRS commented that:

TGI's weak financial profile for the rating, with all four factors already at the lower limits cited by Moody's, warrants an increase in the common equity ratio, which in turn, would improve the EBIT Coverage and Retained Cash Flow/Debt ratios.

With its existing approved regulated capital structure of 64.99% debt and 35.01% common equity ratio, TGI falls below Moody's investment grade guideline range (50-65% for a Baa rating on the Debt/Book Capitalization factor).[35] An increase to the common equity ratio to 40.0% (debt ratio of 60.0%) would, in isolation, place TGI within the investment grade guidelines.

With respect to EBIT interest coverage, Moody's guideline ranges for A and Baa ratings are 3-5X and 2-3X times respectively. TGI's EBIT interest coverage has been just at or below 2X since 2000, i.e., in the Ba guideline range (below investment grade). Since the Company's embedded cost of debt has declined by close to 1.3 percentage points since

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> In Alberta, as well as in many other jurisdictions in Canada, the rates of return and equity capitalization for ratemaking purposes allowed by regulators have been low in recent years, largely as a result of the low interest rate environment. This has had a negative impact on earnings and cash flows. FortisAlberta's equity thickness at 37% and low ROE's directly impact shareholder returns, hindering the ability to attract capital for capital expenditure purposes. In addition, the allowed ROEs are significantly below those allowed for similar operations in the U.S. This acts as a disincentive for investors to allocate capital to Canadian utilities because they can earn higher rates of return in the U.S. from businesses having similar business risk profiles. (DBRS, *Credit Rating Report: FortisAlberta*, November 25, 2005).

In general, S&P considers that Canadian utility financial policies tend to be aggressive with leverage, and regulators parsimonious with returns. (Standard & Poor's, *Industry Report Card: Regulatory Rulings, M&A, and Fuel Cost Recovery Dominate Global Utilities Credit Environment*, November 21, 2006. The "aggressive leverage" is largely a result of regulatory directives, as noted by S&P in its March 2003 report entitled *Canadian Regulation Reassessed as a Ratings Factor*. In that report S&P had 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.

As a specific example, in its report for Union Gas issued subsequent to the utility's 2006 settlement raising the allowed common equity ratio to 36%, the two weaknesses referred to 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).

[35] In calculating the debt ratio for debt rating purposes, Moody's, and Standard & Poor's, make adjustments to the reported amounts of debt and equity on the financial statements to capture debt-like elements of balance sheet items. Moody's for example adjusts the reported debt and equity amounts for operating leases. The adjustments typically result in an adjusted debt ratio for debt rating purposes that is higher than the ratio deemed for regulatory purposes.

1999/2000, it would have been reasonable to expect a "natural" improvement in interest coverage as interest rates fell and older higher cost debt was retired. Instead, the interest coverage has remained essentially flat, despite the increase in the allowed common equity ratio in 2006. In part the lack of improvement in the interest coverage ratio reflects the decline in allowed ROE, which has fallen close to 1% between 1999/2000 and 2009.

The level of pre-tax interest coverage is also a function of the corporate income tax rate. All other things equal, the lower corporate income tax rates reduce pre-tax interest coverage. Since the automatic adjustment formula has been in place, the combined provincial/federal corporate income tax rate has declined from over 45% in the mid-1990s to 28.5% in 2010. In 2005, the last time the BCUC reviewed the capital structure for TGI, the combined rate was 34.1%. At the 2009 allowed ROE of 8.47%, the approved capital structure and embedded debt costs, the reduction in the corporate income tax rate from 33.97% to 28.5% lowers the pre-tax interest coverage by approximately 0.08 times.[36] In isolation, the lower corporate income tax rate in 2010 indicates that an increase in common equity ratio from the current 35.01% would be warranted simply to maintain the same level of pre-tax coverage ratios achievable at the 2005 corporate income tax rate.[37]

In comparison to the U.S. gas distribution utilities which are included in the proxy sample of U.S. utilities used to estimate the cost of equity (See Chapter VI), TGI compares unfavourably in Moody's Financial Strength and Flexibility Factors. On average, the implied Financial Strength and Flexibility rating for the proxy LDCs is A, compared to the Baa implied ratings of TGI. It is also of note that, while superior regulatory support is frequently cited as the reason Canadian utilities are rated higher than their U.S. peers, the

[36] The lower tax rate also raises the potential variability in after-tax equity returns. Effectively, a taxable utility can share downside business risk with the Canada Revenue Agency (CRA). The lower the corporate income tax rate, the larger will be the decline in the achieved return for a given percentage decline in operating income. In the Alberta Generic Cost of Capital Decision 2004-052, the EUB recognized this principle when it adopted a higher deemed common equity ratio for non-taxable than taxable utilities. The reduction in the corporate income tax rate in British Columbia from approximately 34% in 2006 to 28.5% in 2010 and to 25% by 2012 increases the variability of after-tax ROEs marginally.

[37] By 2012, the combined federal/provincial corporate income tax rate is expected to decline to 25%, which, all other things equal, would further reduce EBIT interest coverage.

median regulatory support rating of the proxy U.S. LDCs, at Aaa/Aa, is higher than the Aa implied rating of TGI.

The table below compares key credit metrics of TGI with those of the universe of Canadian utilities with rated debt and with those of A rated U.S. electric and gas utilities.

Table 5

Company/Sample	Ratings DBRS/Moody's/S&P	Common Equity Ratio (2008)	EBIT Interest Coverage (2005-2007)	FFO to Total Debt (2005-2007)	FFO Interest Coverage (2005-2007)
TGI	A/A2/AA-	34.8%[1/]	2.0x	9.1%	2.4x
All Canadian Utilities with Rated Debt	A/A3/A-	40.4%	2.5x	14.5%	3.2x
U.S. A-Rated Gas Distribution (All)	-/A3/A	46.7%	3.7x	20.2%	4.5x
U.S. Proxy Utility Sample	-/A3/A	41.9%	3.6x	21.3%	4.4x
U.S. Proxy Utility Sample-LDC Only	-/ A3 / A	45.3%	3.8x	21.7%	4.7x

Definitions:

Earnings before Interest and Taxes (EBIT) Interest Coverage: Operating income divided by interest expense.

Funds from Operations (FFO) to Total Debt: FFO equals net income plus depreciation, amortization and deferred taxes. FFO to debt equals FFO divided by total debt.

Funds from Operations (FFO) Interest Coverage: FFO plus interest expense divided by interest expense.

[1/] The 2008 common equity ratio of 34.8% includes Construction Work In Progress financed 100% with debt.
Source: Schedules 4, 5, 6 and 15

As the table above demonstrates, the credit metrics of TGI and Canadian utilities generally compare unfavourably to their U.S. peers. In other words, they are competing for capital with U.S. utilities with stronger financial metrics. Moreover, as utility debt yield spreads between Canada and the U.S have converged, Canadian utilities no longer have a built-in domestic cost advantage in raising capital.[38] In setting the allowed return, (the capital structure as well as the ROE), the BCUC needs to recognize that Canadian utilities generally and TGI specifically should be allowed to achieve a degree of financing flexibility which is comparable to that of its North American peers.

The actual credit metrics of U.S. utilities reflect the returns (a combination of the ROE and capital structure) that are awarded by regulators. From 2006-March 2009, the average common equity ratio adopted by U.S. regulators for gas distribution utilities with weather normalization clauses and/or decoupling was approximately 48% with corresponding awarded ROEs averaging 10.2%.

F. REASONABLENESS OF PROPOSED CAPITAL STRUCTURE

Within a reasonable range, the capital structure for a particular utility is appropriately a decision for management, because management is in the best position to assess its business risks, financing requirements and access to debt and equity capital. In my opinion, the capital structure proposed by TGI, containing 40.0% common equity, is within a reasonable range, albeit at the lower end, for the reasons summarized below.

1. The level of business risk to which TGI is exposed has risen since the BCUC set the allowed common equity ratio at 35% in 2006.

2. There have been material increases in the allowed common equity ratios of some of TGI's Canadian utility peers, in particular the NEB-regulated gas pipelines, with whom TGI competes for capital.

[38] Over the ten year period ending December 2005, for example, the average yield spread between long-term A rated Canadian utility and long-term Canada bonds was approximately 40 basis points lower than the corresponding yield spread between U.S. long-term A rated utility and Treasury bonds. Since the elimination of the Foreign Property Rule (FPR) in 2005, the spreads have converged. From January 2006 to the end of March 2009, on average the spreads in Canada and the U.S. have been virtually identical (differential less than 10 basis points).

3. TGI's credit metrics are weak for its credit ratings, and in isolation fall below investment grade guidelines;

4. Lower allowed ROEs and lower corporate income tax rates have placed downward pressure on what otherwise would be improving interest coverage ratios; further expected reductions in income tax rates will continue to lower coverage ratios, all other things equal.

5. The debt rating agencies continue to view the capital structure ratios of Canadian utilities as weak. A 40.0% common equity ratio for TGI lies at lower end of Moody's guideline range for an investment grade rating on this credit metric.

6. The further global integration of the Canadian capital markets, particularly with the termination of the Foreign Property Rule warrants a strengthening of TGI's financial parameters to provide the ability to offer a return compensatory with its risk and comparable to those of its global peers.

7. The forecast North American and global investment requirements for infrastructure point to significant competition for capital going forward. TGI should be positioned so that it can compete successfully, that is, continue to obtain capital as required on reasonable terms and conditions. At the existing capital structure, TGI's credit metrics compare unfavourably to those of its U.S. peers.

While the proposed increase in common equity ratio will lower TGI's financial risks, a 40.0% common equity ratio is still materially lower than that maintained by its U.S. peers. The lower common equity exposes TGI to higher financial risks, which need to be recognized when setting the allowed ROE.

The recommended ROE which is developed in Section VI is premised on a deemed common equity ratio for TGI of 40.0%. If a lower common equity ratio were approved, the required ROE would be higher to compensate for the higher financial risks. At the existing common equity ratio of 35%, the recommended ROE would be approximately 55-90 basis points higher than the ROE at a 40.0% common equity ratio.[39]

[39] It bears noting that the proposed increase in the common equity ratio is predicated on TGI being awarded a fair return. Investors have no incentive to commit further equity to any enterprise if the expected return is inadequate.

VI. FAIR RETURN ON EQUITY

A. APPROACH TO ESTIMATION OF RETURN ON EQUITY

The key to determining the fair return on equity (i.e., ensuring that all three requirements of the fair return standard are met) is reliance on multiple tests. There are three different types of tests that have traditionally been used to estimate the fair return on equity: equity risk premium, discounted cash flow and comparable earnings tests. Each of the tests is based on different premises and brings a different perspective to the fair return on equity. None of the individual tests is, on its own, a sufficient means of estimating the fair return; each of the tests has its own strengths and weaknesses. Individually, each of the tests can be characterized as a relatively inexact instrument; no single test can pinpoint the fair return.[40] Moreover, different tests may be more or less reliable depending on prevailing economic and capital market conditions.[41] These considerations not only emphasize the importance of reliance on multiple tests, but also of benchmarking, or testing the reasonableness of the test results themselves against other relevant information.

Moreover, the criteria that define a fair return, set forth in Chapter II, give rise to separate standards of capital attraction and comparable returns. A fair and reasonable return gives weight to both the cost of attracting capital standard and comparable returns standard.[42] The

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[40] For example, Bonbright states, "No single or group test or technique is conclusive. Therefore, it is generally accepted that commissions may apply their own judgment in arriving at their decisions." (James C. Bonbright, Albert L. Danielsen, David R. Kamerschen, *Principles of Public Utility Rates*, 2nd Ed., page 317, Arlington, VA.: Public Utility Reports, Inc., March 1988).

[41] For example, see Federal Communications Commission, Report and Order 42-43, CC Docket No. 92-133 (1995).

> "Equity prices are established in highly volatile and uncertain capital markets... Different forecasting methodologies compete with each other for eminence, only to be superseded by other methodologies as conditions change... In these circumstances, we should not restrict ourselves to one methodology, or even a series of methodologies, that would be applied mechanically. Instead, we conclude that we should adopt a more accommodating and flexible position."

[42] Appendix A discusses the distinctions between the two standards.

requirements of the two standards are met using different types of tests. The equity risk premium and discounted cash flow tests establish the cost of attracting capital. The comparable earnings test is one measure of the comparable returns standard. To establish a fair return on equity for TGI, I have applied all three. The application of each of the tests is discussed in the sections below.

B. EQUITY RISK PREMIUM TESTS

B.1. Conceptual Underpinnings

An 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. Equity risk premium tests are 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.

Equity risk premium tests, similar to the other tests used to arrive at a fair return, are forward-looking, that is, they are 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[43] and their views of such key factors as inflation, productivity and profitability. Because equity risk premium tests are 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.

[43] To illustrate, as discussed in Section II above, as demonstrated by the MVX index in Canada, equity market volatility has picked up significantly and investor risk aversion has increased in the period since TGI last appeared before the BCUC as investors have become less sanguine about the future of the equity market.

B.2. Risk-Free Rate

The application of equity risk premium tests require 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.

For the purpose of applying the equity risk premium tests, the estimated long-term Canada bond yield is 4.25%. The estimate relies as a point of departure on the April 2009 Consensus Forecasts' 3.1% 10-year Canada bond yield forecast for April 2010,[44] which, with a current 0.75% spread between 10-year and 30-year Canada bond yields, results in a yield of 3.85%. It is reasonable to expect that long-term Canada bond yields will rise during 2010 as the economy strengthens. A 4.25% long-term Canada bond yield forecast for 2010 reflects increases in yield of approximately 0.2% per quarter throughout the year, and is consistent with a gradual upward trend toward the forecast yield expected to prevail over the longer term of approximately 5.25%.[45]

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

B.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; and (3) applying the relative risk adjustment to the equity market risk premium, to arrive at the required utility equity risk premium. The cost of equity is thus estimated as:

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[44] Consensus Economics does not provide a forecast of the 30-year Canada bond yield, nor does it provide a forecast of 10-year Canada bond yields for all of 2010.

[45] Consensus Economics, *Consensus Forecasts*, April 2009 forecast the average 10-year Canada bond yield from 2011-2019 at approximately 5.0%. The spread between 10-year and 30-year long term Canada bond yields has historically averaged approximately 35 basis points.

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

The risk-adjusted equity market risk premium test is a variant of the Capital Asset Pricing Model (CAPM). The CAPM attempts to measure, within the context of a diversified portfolio, what return an equity investor **should** require (in contrast to what the investor **does** require). 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 returns, as proxied in Canada by the returns on S&P/TSX Composite, and the returns on 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 B.

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

B.3.b.(1) Globalization and Relevance of U.S. Equity Market Experience

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 expected 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). These factors are set out in Appendix B.

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 had 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 2005.[46] Historic Canadian equity returns therefore are likely to understate investor return requirements.

Investor reaction to the increasingly less restrictive FPR supports that conclusion. Equity investment outside of Canada grew rapidly as the barriers to foreign investment (in terms of transactions and information costs as well as the foreign investment cap) declined. Foreign stock purchases by Canadians increased almost ten-fold between 1995 and 2007. Purchases of foreign stocks in 1995 were $83 billion; in 2007, they were $915 billion. Although purchases declined in 2008, they were still almost $750 billion during the first eleven months of the year. In mid-2008, although the total percentage of foreign assets in trusteed pension funds was less than 30%, the percentage of foreign equity to total equity was close to 45%.[47] [48]

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

[47] Based on market value. On a book value basis, the proportion of foreign assets in the pension funds is closer to 33% and over 50% of all equity investment is foreign. Statistics Canada, Table 280-0003.

[48] Pension funds are increasingly investing in infrastructure assets outside of Canada. For example, a consortium of investors including the British Columbia Investment Management Corporation, the Alberta Investment Management Corporation and the Canada Pension Plan Investment Board are in the process of acquiring Puget Energy, an electric and gas utility serving northern Washington state. The most recent allowed returns for Puget Sound Energy (both electric and gas) were 10.15% on a 46% common equity ratio, adopted in October 2008.

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. Historically, much of the difference between the achieved risk premiums in Canada and the U.S. arises from higher interest rates in Canada. With the vastly improved economic fundamentals in Canada (e.g., lower inflation, balanced budgets), the relative risk of investing in Canadian government bonds has declined. Consequently, the differential between Canadian and U.S. government bond yields and returns that existed historically has been substantially reduced. Over the period 1926-1996, the difference between long-term government bond yields in Canada and the U.S. averaged close to 100 basis points. Between 1997 and 2008, the difference was approximately -20 basis points.

The most recent consensus of long-term forecasts of government bond yields anticipates that 10-year government bond yields will be virtually identical in the two countries, at approximately 5.0% for Canada and 5.2% for the U.S. over the period 2011-2019 (Consensus Economics, *Consensus Forecasts,* April 2009).[49] With similar interest rates in the two countries going forward, 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 57% of the total market capitalization of the S&P/TSX Composite at the end of December 2008. 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 47% of Canadian portfolio investment in foreign equities at the end of 2007 was in the U.S.[50] The diversified nature of the U.S. equity

[49] Blue Chip *Economic Indicators* (March 2009), which canvasses economic forecasters at 50 financial institutions, anticipates a 10-year U.S. Treasury yield of 5.25% from 2011-2020.
[50] Statistics Canada, *Canada's International Investment Position – Fourth Quarter 2008.* Of the remaining 53%, the next largest allocation of foreign portfolio equity investment is the U.K., which accounted for 11%.

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 Canadian utilities, e.g., TGI.

B.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, 1947-2008, a period more closely aligned with what today's investors are likely to anticipate over the longer-term.[51] I have also taken account of achieved returns and risk premiums over longer periods.

B.3.b.(3) Historic Risk Premiums from 1947-2008

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:

[51] 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 6

Historic Risk Premiums Arithmetic Averages (1947-2008)		
	Versus Bond Total Returns	**Versus Bond Income Returns**
Canada	4.6%	4.4%
U.S.	5.6%	6.2%

Source: Schedule 8.

B.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. (See Appendix B for further discussion).

B.3.b.(5) Income Returns versus Total Bond Returns

The application of the CAPM requires the estimation of the market return in relation to the risk-free rate. While government bonds are considered default-free, they are not risk-free; they are subject to interest rate risk. The total bond returns experienced include capital gains and losses resulting from changes in interest rates over time. The bond income return, in contrast, reflects only the bond coupon payment portion of the total bond return; it represents the riskless component of the bond return. In principle, using the bond income return more accurately measures the historic equity risk premium above the risk-free rate.

B.3.b.(6) Historic Risk Premiums and Price/Earnings Ratios

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.[52] That analysis demonstrates:

(1) 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 1947-1988 (prior to the increase in P/E ratios commencing in 1989) are actually higher than the average returns for the full 1947-2008 period.

(2) An analysis of rolling 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.

(3) The observed decline in the experienced risk premium over the 1947-2008 period, particularly in Canada, is due largely to an increase in bond returns, not a decline in equity returns. The historic bond returns in Canada (both total and income returns) are significantly higher (at approximately 7.0%)

[52] See Appendix B for further discussion.

than the forecast yields on long-term Canada bonds of 4.25% for 2010 and 5.25% over the longer-term.

In summary, the historic equity market returns in both Canada and the U.S. provide a reasonable estimate of the forward looking equity market return. In contrast, the Canadian historic bond returns are materially higher than the expected returns. Thus, the historic measured risk premium in Canada understates a reasonable estimate of the forward-looking equity market risk premium.

B.3.b.(7) Comparison of Longer-Period Returns to Post-World War II Returns

A comparison of the longer-term returns and equity risk premiums in Canada and the U.S. to the post-World War II returns demonstrates that the average returns for the equity markets have not changed materially. Over the long-term, on average, the equity market return in both countries has been in the range of 11.0%-12.0%.

Table 7

	Canada		U.S.	
	1924-2008	1947-2008	1926-2008	1947-2008
Equity Market Return	11.3%	11.6%	11.7%	12.2%

Source: Schedule 8.

B.3.b.(8) Estimate of Equity Market Risk Premium

Given the absence of any material upward or downward trend in the historic equity market returns, a reasonable expected value of the future equity market return is a range of 11.0%-12.0%, based on both the Canadian and U.S. equity market returns. Based on both the near-term (2010) and the longer-term forecasts for long-term Canada bond yields of 4.25% and 5.25% respectively, and an expected equity market return in the range of 11.0%-12.0%, the indicated equity market risk premium is approximately 6.75%.

B.3.c. Relative Risk Adjustment

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

The market risk premium result needs to be adjusted to recognize the relatively lower risk of utilities. 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 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[53] 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 B).

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 standard deviations of monthly total market returns for each of the 10 major Sectors of the S&P/TSX Index, over five-year periods ending 1997 through 2008 (Schedule 10).

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 10 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

[53] 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).

to the mean and median standard deviations of the 10 major Sector Indices suggests a relative risk adjustment for a Canadian utility in the range of 0.55-0.85, with a central tendency of approximately 0.65-0.70.

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

Since beta is the risk measure that underpins the application of the CAPM, I also took account of utility betas to estimate the relative risk adjustment. Schedule 11 summarizes the "raw" betas I calculated for individual publicly-traded Canadian regulated gas and electric companies, the TSE Gas/Electric Index, and the S&P/TSX Utilities Sector using monthly price data calculated over five-year periods ending 1993 through 2008.[54]

As Schedule 11 indicates, there was a significant decline in the calculated "raw" betas of the individual Canadian utilities between 1993-1998 and 1999-2005 (from approximately 0.50-0.60 to 0.0 and slightly negative). Following an increase in 2007 to 0.50, the utility betas again declined in 2008 to approximately 0.25. The observed levels and pattern of the calculated "raw" utility betas in 1999-2008 can be traced to four 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 fallout of the subprime mortgage crisis; and (4) the greater sensitivity of utility stock prices relative to the equity market composite to rising and falling interest rates (e.g., during the equity market "bubble" of 1999 and early 2000 and during the first half of 2006). Over the longer-term (1970-2008), the "raw" beta of the TSX Utilities Index was 0.50, as indicated below.

[54] 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.

B.3.c.(3) Canadian Utility Returns and "Raw" Betas

The equity betas of traded Canadian utility shares and of the utility index explains a relatively small percentage of the actual achieved market returns over time. A regression of the monthly returns on the TSX Utilities Index against the returns on the TSX Composite, for example, over the period 1970-2008[55] shows the following:

$$\begin{array}{lcl} \text{Monthly TSX Utilities Index Return} & = & 0.0056 + 0.50 \left\{ \text{Monthly TSE Composite Return} \right\} \\ \text{t-statistic} & = & \qquad\qquad 14.9 \\ R^2 & = & 32\% \end{array}$$

The relationship quantified in the above equation suggests a beta of close to 0.50. 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 32%. That means 68% of the monthly volatility in share prices remain unexplained.

Since utility shares are interest sensitive, the regression was expanded to capture the impact of movements in long-term Canada bond prices on utility returns. The addition of monthly long-term Canada bond returns to the analysis indicates the following:

$$\begin{array}{lcl} \text{Monthly TSX Utilities Index Return} & = & 0.00185 + .42 \left\{ \text{Monthly TSE Composite Return} \right\} + .53 \left\{ \text{Monthly Long Canada Bond Return} \right\} \\ \text{t-statistics} & = & \qquad\qquad 13.3 \qquad\qquad\qquad\qquad\qquad 9.3 \\ R^2 & = & 43\% \end{array}$$

When government bond returns are added as a further explanatory variable, somewhat more of the observed volatility in utility stock prices is explained (43% versus 32%). The second

[55] The Monthly TSX Utilities Index Returns are comprised of the monthly returns on the TSE Gas & Electric Index for period January 1970 to April 2003 and the monthly returns on the S&P/TSX Utilities Index for the period May 2003 to December 2008.

regression equation suggests that utility shares have had approximately 40% of the volatility of the equity market and over 50% of the volatility of the bond market, the latter consistent with utility common stocks' interest sensitivity. Nevertheless, the equation still leaves more than half of the utility shares' volatility unexplained. To provide some perspective, the average actual annual return for the index over the 1970-2008 period was 12.2%. Of this average annual return, 2.25 percentage points was explained neither by volatility in the equity market nor returns of the government bond market.

Using an expected annual equity market return of 11.5%, an annual long-term Canada bond return equal to the forecast longer-term 30-year Canada yield of 5.25%, and a annual "unexplained"[56] return component equal to that achieved in the past (2.25 percentage points), the indicated utility return going forward is 10.0%. If, instead, the "unexplained" return component is assumed to be equal to the same proportion of the total return as was the case historically (18.5%), the expected utility return is approximately 9.3%. When the average of the two utility returns (9.6%) is expressed as an equity risk premium above the 5.25% forecast long-term Canada bond yield, the indicated relative risk adjustment is approximately 0.70.[57]

B.3.c.(4) Use of Adjusted Betas

From the calculated "raw" betas, the inference can readily be made that utilities are less risky than the equity market composite, which by construction has a beta of 1.0. The more difficult task is determining how the "raw" beta translates into a relative risk adjustment that captures utility investors' return requirements. In order to arrive at a reasonable relative risk adjustment, the normative ("what should happen") CAPM needs to be integrated with what has been empirically observed ("what does or has happened"). Empirical studies have shown that stocks with low betas (less than the equity market beta of 1.0) have achieved returns higher than predicted by the single variable (i.e., equity beta) CAPM. Conversely,

[56] Represented by the intercept in the equation.

[57] $\frac{9.6\% - 5.25\%}{11.5\% - 5.25\%} = .70$

stocks with betas higher than the equity market beta of 1.0 have achieved lower returns than the model predicts.

The use of betas that are adjusted toward the equity market beta of 1.0, rather than the calculated "raw" betas, takes account of the observed tendency of low (high) beta stocks to achieve higher (lower) returns than predicted by the simple CAPM. Adjusted betas are a standard means of estimating betas, and are widely disseminated to investors by investment research firms, including Bloomberg, *Value Line* and Merrill Lynch. All three of these firms use a similar methodology to adjust "raw" betas toward the equity market beta of 1.0. Their methodologies give approximately 2/3 weight to the calculated "raw" beta and 1/3 weight to the equity market beta of 1.0.

The following table compares the three-year Bloomberg betas ending March 27, 2009 for the five major Canadian utilities to the calculated "raw" betas for the same three-year period. The Bloomberg betas suggest that the relative risk adjustment based on recent Canadian utility betas would be approximately 0.65. The application of the same adjustment formula to the recent three-year raw betas and the long-term calculated "raw" beta of 0.50 for Canadian utilities estimated above results in a similar relative risk adjustment of 0.67.[58]

Table 8

Company	"Raw" Beta	Bloomberg Beta
Canadian Utilities	0.41	0.61
Emera	0.38	0.59
Enbridge	0.56	0.71
Fortis	0.49	0.66
TransCanada	0.47	0.65
Average	**0.47**	**0.65**

Source: Schedule 11 and Bloomberg

A comparison of the reported *Value Line* betas for the sample of low risk U.S. utilities relied upon in the application of the discounted cash flow (DCF) and DCF-based risk premium test

[58] Adjusted beta = 0.67 x "Raw" Beta + 0.33 x Market Beta of 1.0.

shows a similar relationship. The "raw" calculated betas for the five-year period ending March 2009 averaged 0.41; the average reported *Value Line* beta for the sample, and the beta more likely to be relied upon by analysts and investors, was 0.66 (Schedule 15).

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

The preceding analysis of standard deviations of market returns and betas supports a relative risk adjustment in the range of 0.65-0.70.

B.3.d. Utility Risk Premium and Cost Of Equity

I previously estimated the equity market risk premium at the 2010 forecast long Canada yield of 4.25% and at the longer-term yield of approximately 5.25% at approximately 6.75%. At an equity market risk premium of 6.75% and a relative risk adjustment of 0.65-0.70, the indicated utility equity risk premium is approximately 4.5%. The cost of equity based on the risk-adjusted equity market risk premium test at the 2010 forecast long-term Canada bond yield of 4.25% is 8.75%, before any adjustment for financing flexibility.

B.4. DCF-Based Equity Risk Premium Test

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 the utility. The DCF-based risk premium test, discussed in this section and the equity risk premium test discussed in Section B.5, estimate the utility equity risk premium directly, by analyzing utility equity return data.

The DCF-based equity risk premium is a forward-looking test which uses the discounted cash flow model (DCF) and long-term government bond yields to estimate expected utility returns and risk premiums over time. Monthly cost of equity estimates were constructed for the period 1991-March 2009[59] using the DCF model and a sample of low risk U.S. gas and electric utilities as a proxy for TGI.[60] The reasons for choosing U.S. utilities are as follows:

First, there are only six publicly-traded Canadian utilities with conventional corporate structures and with a long-term stock trading history. Second, there are insufficient forward-looking estimates of long-term growth rates for these companies that would permit the creation of a consistent series of DCF costs of equity and corresponding risk premiums. A consensus estimate of investors' growth expectations is critical 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.

Third, U.S. utilities are reasonable proxies for estimating the cost of equity for TGI. As noted in Section II, the operating environments are similar, the regulatory model in the U.S. is similar to the Canadian model,[61] and the Canadian and U.S. capital markets are significantly integrated.[62] Only relatively pure-play U.S. utilities were selected; these utilities are in the same business risk category as TGI (as well as of the typical Canadian utility)[63] and have S&P debt ratings of A- or better, similar to those of TGI and the universe of Canadian utilities with rated debt (Schedules 6, 7 and 15). The sample contains 13 utilities, and is the same sample of companies used to perform the discounted cash flow test (Section VI.C.).

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[59] The period 1991-March 2009 encompasses both a full business cycle (1991-2007) as well as data through the most recent full quarter available.

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

[61] As noted earlier, the LDCs which are included in the proxy sample are considered by Moody's to have slightly better regulatory support, on average, than TGI.

[62] A June 2007 study prepared on behalf of the Ontario Energy Board entitled *A Comparative Analysis of Return on Equity of Natural Gas Utilities* by Concentric Energy Advisors compared the gas distribution industry and capital markets in Canada and the U.S. and concluded (1) taken as a whole, U.S. gas utilities are not demonstrably riskier than Canadian gas utilities; and (2) As a result of the interplay between the Canadian and U.S. markets, Canadian utilities compete for capital essentially on the same basis as utilities in the U.S. In the current market environment, no fundamental differences were identified that would indicate a significant difference in investor required returns between the two markets.

[63] S&P considers TGI to have an "Excellent" business profile; all of the utilities in the proxy sample of U.S. utilities also have an "Excellent" business profile.

The monthly DCF costs of equity were estimated as the sum of the consensus of analysts' forecasts of long-term normalized earnings growth,[64] plus the expected dividend yield. The equity risk premium is equal to the difference between the sample average DCF cost of equity and the corresponding month-end 30-year Treasury bond yield.

For the sample of U.S. utilities, the DCF-based risk premium test indicates an average risk premium over the full 1991-March 2009 period of 4.3% (Schedule 12); the corresponding average long-term government bond yield was 5.9%, approximately 175 basis points higher than the 2010 forecast long-term Canada bond yield of 4.25%.

The data suggest that there has been an inverse relationship between the long-term government bond yield and utility equity risk premiums over the 1991-March 2009 period. A simple regression analysis between the monthly 30-year Treasury bond yields and the corresponding equity risk premiums over the entire 1991-March 2009 period indicates that, on average, over the full period, the equity risk premium rose by 70 basis points when the long-term government bond yield fell by 100 basis points and, conversely, the equity risk premium fell by 70 basis points when the long-term government bond yield rose by 100 basis points. Expressed in terms of ROE, the equity return rose by 30 basis points when the long-term government bond yield rose by 100 basis points. Conversely, the equity return fell by 30 basis points when the long-term government bond yield fell by 100 basis points.

This analysis indicates that the ROE is much less sensitive to changes in the long-term Canada bond yield that the existing formula assumes. The existing formula assumes that the ROE increases or decreases by 75% of the increase or decrease in the long-term Canada bond yield. The DCF-based risk premium analysis indicates that the increase or decrease in ROE has been only 30% of the increase or decrease in long-term Canada bond yields.

[64] 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.

At the 2010 forecast 30-year government bond yield of 4.25%, the indicated utility equity risk premium is approximately 5.4%. The indicated cost of equity would be 9.7%. However, this analysis does not incorporate other factors which impact on the cost of equity.

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.[65] To capture this factor, I tested the relationship among utility equity risk premiums[66] and the spreads between long-term utility[67] 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 second regression analysis over the same 1991-March 2009 period (Schedule 12, page 2). 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. Specifically, the analysis showed that the equity risk premium has increased or decreased by approximately 40 basis points when the government bond yield has decreased or increased by 100 basis points and has increased or decreased by 12 basis points for every 10 basis point increase or decrease in the utility/government bond yield spread. The inclusion of the spread as a second explanatory variable also supports the conclusion that the utility cost of equity changes by significantly less than 75% of the change in long-term government bond yields.[68]

As of the end of March 2009, the spread between the yields on a sample of long-term A rated Canadian utility bonds and 30-year Government of Canada bonds was approximately 345 basis points. Although the spreads had narrowed since their December peak of 390 basis points,[69] the spreads remain well in excess of their historic averages as well as in excess of their historic peaks. As spreads vary over the business/interest rate cycle, spreads

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[65] Or, alternatively, risk aversion i.e., willingness to take risks.
[66] Measured, as in the prior analysis, as the DCF cost of equity minus the long-term government bond yield.
[67] Based on Moody's long-term A-rated utility bond index.
[68] Similar regressions using allowed ROEs for U.S. utilities, long-term government bond yields and spreads, as discussed on page 9, also demonstrated that the ROE is less sensitive to the change in the government bond yield than implied by the current formula.
[69] In mid-February 2009, TGI raised 30-year debt at a spread of approximately 285 basis points.

should narrow further as the economy improves, as has been observed historically. However, three factors suggest that the spreads will remain above their historic levels.

First, historically, the existence of the FPR and the high demand in Canada for a relatively limited supply of high quality issues kept high grade Canadian bond spreads relatively low.[70] With the elimination of the FPR, spreads on domestic bond issues will tend to converge with those of global issuers of similar risk.[71] Second, while the consensus forecast anticipates that the economy will improve in 2010 compared to 2009, the first year of recovery is expected to be relatively weak, pointing to the persistence of higher than average spreads. Third, the financial crisis has led to a global repricing of risk across various types of securities, including A rated Canadian utility bonds.

As of the beginning of April 2009, the cost of a new 30-year debt issue for a Canadian A rated utility e.g., TGI, was approximately 6.5-6.75%. While the spread with long-term Canada bonds should decline as long-term Canada bond yields rise, there is no basis for concluding that the absolute cost of new A-rated long-term debt will retreat significantly from current levels.[72] At a 2010 forecast long Canada yield of 4.25% and assuming that the absolute cost of long-term debt for an A-rated utility remains in the range of 6.50% to 6.75%, the A rated utility bond/long-term Canada bond yield spread will be approximately 225-250 basis points. The indicated utility equity risk premium at a long-term Canada bond yield of 4.25% and a yield spread of 225-250 basis points is approximately 6.0%. The indicated utility cost of equity before any adjustment for financing flexibility is 10.25%.

The average cost of equity based on both the single and two variable DCF-based equity risk premium approaches is 10.0%.

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[70] Prior to the elimination of the FPR, the Canadian bond market was largely a domestic market. As long as there was a cap on foreign investment, pension funds limited their foreign investments primarily to equities, and allocated their bond investments to Canadian bonds, which constrained yield spreads.

[71] Utility bond yields in Canada and the U.S. have already exhibited convergence as discussed in footnote 20 above.

[72] Blue Chip *Financial Forecasts*, December 2008 anticipates that, although credit spreads with Treasury bonds will decline, the absolute yields on AAA rated U.S. corporate bonds will remain essentially flat between 2009 and 2010 and then gradually rise by approximately 50 basis points between 2010 and 2014.

B.5. 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 (1956-2008),[73] the average achieved utility equity risk premium was 4.1% for Canadian electric and gas utilities in relation to total bond returns and 4.2% in relation to bond income returns respectively.[74] For U.S. gas utilities, the corresponding average historic equity risk premiums over the entire post-World War II period (1947-2008) were 5.5% and 6.1% respectively. For U.S. electric utilities, the 1947-2008 average risk premiums were 4.2% and 4.8% (See Schedule 13).

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 the three utility indices in the table below.

Table 9

	Utility Equity Returns	Bond Total Returns	Bond Income Returns
Canadian Utilities	12.0%	7.9%	7.8%
U.S. Gas Utilities	12.1%	6.6%	6.0%
U.S. Electric Utilities	10.8%	6.6%	6.0%

Source: Schedule 13.

[73] The longest period for which Canadian utility data are available from the TSE.
[74] Based on the Gas/Electric Index of the TSE 300 (from 1956 to 1987) and on the S&P/TSX Utilities Index from 1988-2008.

An analysis of the underlying data indicates there has been no upward or downward trend in the utility equity returns (Schedule 14); the utility returns in both the U.S. and Canada have clustered in the range of 11.0-12.0%, with a mid-point of approximately 11.5%. However, as noted in Section B.3.b(6) above and in Appendix B, the achieved bond returns (both total and income returns), particularly in Canada, are well above the levels forecast over the longer-term. The forecast long-term Canada bond yield for the longer-term is approximately 5.25%. Compared to a utility return of approximately 11.5%, the indicated utility equity risk premium is approximately 6.25%. Using the forecast 2010 long-term Canada bond yield of 4.25% and a utility risk premium of 6.25%, the indicated utility cost of equity, before adjustment for financing flexibility, is 10.5%.

B.6. <u>Cost of Equity Based on Equity Risk Premium Tests</u>

The estimated utility costs of equity based on the three equity risk premium methodologies are as follows:

Table 10

Risk Premium Test	Cost of Equity
Risk-Adjusted Equity Market	8.75%
DCF-Based	10.0%
Historic Utility	10.5%

The three risk premium tests indicate a utility cost of equity of approximately 9.75% before any allowance for financing flexibility.

C. DISCOUNTED CASH FLOW TEST[75]

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,

[75] See Appendix D for a more detailed discussion.

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 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. In addition, the DCF model is a positive model; that is, it deals with "what is" as opposed to "what should be". 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. To estimate the DCF cost of equity, I utilized both a constant growth and a two-stage model.[76] 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 TGI.[77]

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

[76] The two-stage model is a form of multiple period model; please see Appendix D for discussion of the DCF models used; the criteria for the low risk U.S. utility sample selection are described in Appendix C.

[77] Reliance on U.S. utilities was explained in the discussion of the DCF-based equity risk premium test in Section VI.B.4.

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.)

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. In applying the constant growth model, I relied primarily on the consensus (mean) of analysts' earnings growth rate forecasts as the proxy for investors' long-term growth expectations.

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), the average expected long-term growth rate, as estimated using analysts' forecasts, for the entire 1991-March 2009 period of analysis was 5.0%. That growth rate is lower than the expected long-term nominal growth in the economy as a whole has been over the same period.[78] 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.

In addition, I incorporated *Value Line* forecasts of earnings growth in addition to the I/B/E/S consensus forecasts. As an independent research firm, *Value Line* has no incentive to "inflate" its estimates of earnings growth in an attempt to make stocks more attractive to

[78] The average expected long-term nominal rate of growth in the U.S. economy, based on consensus forecasts (Blue Chip *Economic Indicators*, March editions, 1991-2009), has been 5.4% over the same period covered by the DCF-based equity risk premium test.

investors. Incorporating *Value Line* estimates of earnings growth is a means of assessing the reasonableness of the results obtains through use of the I/B/E/S consensus estimates.[79]

The mean and median *Value Line* expected long-term earnings growth rate for the utility sample were both 6.0%; the corresponding I/B/E/S forecasts were 5.7% and 5.4%. This comparison suggests no upward bias in the I/B/E/S forecasts. The constant growth models indicate a cost of equity of approximately 11.0% (Schedules 16 and 17).

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 two-stage model indicates a cost of equity of approximately 10.4% (Schedule 18).

The two DCF models support a cost of equity, before adjustment for financing flexibility in the range of 10.5-11.0%.

It is important to recognize that the 10.5-11.0% DCF cost represents the return investors expect to earn on the current market value 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 2012-2014 will be approximately 11.6-12.3% (Schedule 15).

D. ALLOWANCE FOR FINANCING FLEXIBILITY[80]

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

[79] The BCUC found, in Order G-14-06, "The Commission Panel is more persuaded by Ms. McShane's evidence which compares *Value Line* and I/B/E/S forecasts and finds no upward bias in the latter."
[80] See Appendix E for a more complete discussion.

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.

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 2.0 times over the full business cycle (1991-2007); the corresponding average market/book ratio of the S&P 500 has been 3.1 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.[81] As this financing flexibility adjustment is minimal, it does not fully address the comparable returns standard.

The addition of an allowance for financing flexibility of 50 basis points to the “bare-bones” return on equity estimate of 9.75%-10.75% derived from both the DCF and equity risk premium tests, results in an estimate of the fair return on equity of 10.25%-11.25%.

E. 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

[81] Based on the DCF model; see Appendix E for calculation.

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 returns standard, as distinguished from the cost of attracting capital standard. The comparable earnings test recognizes that utility costs are measured in vintaged dollars and that rates are based on accounting costs, not economic costs. In contrast, the tests for estimating the cost of attracting capital rely 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 returns standard, as well as the principle of fairness, suggests that, if competitive 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 returns 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.[82] 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.

The principal issues in the application of the comparable earnings test are:[83]

- The selection of a sample of unregulated companies of reasonably comparable total risk to a 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 unregulated companies are not of precisely equivalent risk to a utility.
- The need for a downward adjustment for the unregulated companies' market/book ratios.

[82] As previously noted, the 50 basis point financing flexibility adjustment is only a minimal recognition of the discrepancy.
[83] Full discussion in Appendix F.

The application of the comparable earnings test first requires the selection of a sample of unregulated companies of reasonably comparable risk to a 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 a sample of unregulated 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 unregulated companies is sufficiently large to produce a representative sample of sufficient size, the focus of the comparable earnings analysis was on Canadian firms. The application of the selection criteria to the Canadian universe produced a sample of 27 companies.

Next, since unregulated companies' returns on equity tend to be cyclical, the selection of an appropriate period for measuring their 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 similar in terms of inflation and real economic growth. The full business cycle 1991-2007 provides an appropriate proxy for the next business cycle, as the average experienced rates of inflation and economic growth were reasonably similar to the rates projected by economists over the next business cycle. The experienced returns on equity of the sample of 27 Canadian low risk unregulated companies over this period were in the range of 12.5%-12.75% (see Appendix F and Schedule 20).

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 Canadian utility relative to the selected unregulated companies. The comparative risk data (including betas and stock and bond ratings) indicate, on balance, the unregulated Canadian companies are of modestly higher risk than the typical Canadian utility, e.g., TGI. To recognize the unregulated companies' somewhat higher risk, a downward adjustment of 75-100 basis points[84] to their returns on equity was made, resulting in a comparable earnings result in the range of 11.5%-11.75%.

While the focus of the comparable earnings analysis is on the Canadian sample, I also selected a sample of low risk unregulated U.S. companies to corroborate the reasonableness of the Canadian results. The selection criteria were similar to those used for the Canadian unregulated company sample. The greater breadth of the U.S. market allowed the selection of a sample of 81 companies in the same stable industries used to select the Canadian unregulated companies. The experienced returns of the U.S. unregulated companies were approximately 15.5%. (see Appendix F and Schedule 21). The comparative risk data indicate that the U.S. unregulated companies are of somewhat higher risk than the benchmark sample of U.S. utilities (see Appendix F and Schedules 19 and 21). The ROE adjusted for the U.S. unregulated companies' higher risk relative to utilities is approximately 14%. The returns of the significantly larger U.S. unregulated company sample underscore the reasonableness of the comparable earnings results for the sample of unregulated Canadian companies.

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 high market/book ratio (relative to that of the overall market) could suggest 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 unregulated companies over the 1991-2007 period was 2.1 times, virtually identical to the market/book ratio of the S&P/TSX composite over the same period and substantially lower than the 3.1 times recorded by the S&P 500 (see Appendix F). The similar to lower average market/book ratio of the Canadian proxy sample relative to both the Canadian and U.S. equity market composites indicates no evidence of market power. Thus there is no rationale for making an

[84] Based on the typical spread between Moody's BBB rated long-term industrial bond yields and long-term A-rated utility bond yields and the relative betas of the unregulated companies and the Canadian and U.S. utility samples.

additional downward adjustment to the unregulated Canadian companies' returns on equity due to their market/book ratios. As a result, a fair return on equity based on the comparable earnings test is approximately 11.5% to 11.75%.

F. FAIR RETURN ON EQUITY FOR TGI

The results of the three tests used to estimate a fair return on equity for TGI are summarized below:

Table 11

Test	**Cost of Equity**	**Fair Return on Equity**
Equity Risk Premium	9.75%	10.25%
Discounted Cash Flow	10.5-11.0%	11.0-11.5%
Comparable Earnings	N/A	11.5-11.75%

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 9.75-10.75%. Including the allowance for financing flexibility, the indicated return on equity is 10.25-11.25%. However, the results of the comparable earnings test are also entitled to significant weight when setting a fair return. A fair ROE for TGI, at its proposed common equity ratio of 40.0%, based on all three tests is approximately 11.0%.

G. THE FAIR RETURN FOR TGI WITHIN THE ATWACC FRAMEWORK

In its May 19, 2009 Reasons for Decision for TQM, the NEB adopted the after-tax weighted average cost of capital (ATWACC) methodology for setting the allowed return for TQM for 2007 and 2008. The following section is intended to translate my recommendations to an ATWACC framework.

ATWACC is equal to:

[(% Debt) x (Cost of Debt) x (1-tax rate)] + [(% Equity) x (Cost of Equity)]

Where,

(1) the cost of debt is the current cost of debt, and

(2) the debt and equity components are measured on a market value basis, rather than on a book value basis.

The rationale for using market value capital structures recognizes that estimates of the cost of capital reflects the market value of the firms' capital, both debt and equity. To provide for an income tax allowance, the ATWACC must be adjusted to a before tax value as follows:

ATWACC/ (1-corporate income tax rate)[85]

For example, in Brealey, Myers and Allen, Principles of Corporate Finance, Eighth Edition (McGraw-Hill/Irwin, 2006, p. 504), the authors state the following in reference to the calculation of the weighted average cost of capital:

> "Why did we show the book balance sheet? Only so you could draw a big X through it. Do so now.
>
> When estimating the weighted-average cost of capital, you are not interested in past investments but in current values and expectations for the future."

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

[85] For utilities which are regulated on a flow-through income tax methodology, the indicated income tax allowance must be adjusted for timing differences.

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. Schedules 24 and 25 provide the market and book value capital structures for both the Canadian utilities and the benchmark sample of U.S. gas and electric utilities used to develop the cost of equity for TGI.[86]

To put this concept in common sense terms, assume that I purchased my home 10 years ago for $100,000 and took out a mortgage for the full amount. My home is currently worth $250,000 and my mortgage is now $85,000. If I were applying for a loan, the bank would consider my net worth (equity) to be $165,000 (market value of $250,000 less the $85,000 unpaid mortgage), not the “book value” of the equity in my home of $15,000, which reflects the original purchase price less the unpaid 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 deviate from the book value common equity ratios, application of an unadjusted market-derived cost of equity to the book value capital structure fails to recognize the differences in financial risk between market value and book value capital structures and the corresponding difference in the cost of equity implied by the book value capital structures.

In opting for the ATWACC approach rather than the approach which it and other Canadian regulators have historically relied upon, the NEB concluded that it:

[86] For purposes of estimating the market value capital structures, the simplifying assumptions were made that (a) the market value of debt is equal to the book value and (b) the small average preferred share component of the samples’ capital structures was assigned to debt.

(1) "is more aligned with the way capital budgeting decision making takes place in the business world as compared to an approach by component that would include a stand-alone cost of equity estimate; "

(2) enables better comparisons of return on capital between companies that have similar risk, whereas the approach by component requires a determination of both ROE and capital structure, which are inextricably linked; and

(3) provides an ease of comparison which leads to fewer errors and enhanced clarity.

To apply the ATWACC methodology, only the market-based cost of equity tests would be considered. The comparable earnings test, which estimates returns related to book value, would not be considered in the ATWACC framework. In addition, since the market value capital structures for the proxy samples are in excess of book value, the financing flexibility adjustment is partly subsumed by reliance on market value capital structures.[87]

The table below summarizes the ATWACCs based on the CAPM using the market value capital structures of the Canadian utilities, and the DCF-based risk premium test and the DCF test using the market value capital structures of the U.S benchmark utility sample.[88] [89] The average ATWACC based on these three tests is approximately 7.4%.

[87] In principle, the component of financing flexibility which represents actual flotation costs, i.e., out of pocket expenses and the new issue pricing discount would be added to the cost of equity when estimating the ATWACC. For simplicity, I have estimated the ATWACC using the "bare-bones" costs of debt and equity.

[88] The ATWACC was not estimated using the historical utility equity risk premium test as the test was developed using aggregate data for the gas and electric utility industries in Canada and the U.S. over the long-term. The data necessary to develop the market value capital structure which prevailed over the entire historic period are not readily available.

[89] The corporate income tax used in all cases is the 2010 combined federal/BC rate of 28.5%.

Table 12

Test	Debt (%)	Cost of Debt	1-t	After-tax Cost of Debt	Equity (%)	Cost of Equity	ATWACC
CAPM	50.5%	6.625%	0.715	4.74%	49.5%	8.75%	6.7%
DCF-RP	45%	6.625%	0.715	4.74%	55%	10.0%	7.6%
DCF	45%	6.625%	0.715	4.74%	55%	10.5%	7.9%

Source: Schedules 24, page 1 of 3, Schedule 25, page 1 of 3 and Sections VI B.6 and VI.C. of testimony.

To translate these ATWACCs into an equivalent ROE and capital structure, two approaches, or theories of capital structure, can be used that quantify the impact of a change in financial risk on the cost of 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 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 and to present the equivalent ROEs at TGI’s proposed book value common equity ratio of 40.0%. Schedules 24 and 25 present the methodology and illustrative calculations.

Table 13

Test	ATWACC	Equivalent ROE at 40.0% Common Equity Ratio [1/]
CAPM	6.7%	9.5%
DCF-Based RP	7.6%	11.5%
DCF	7.9%	12.25%

[1/] Average of Theory 1 and Theory 2 Results

Based solely on these three tests, the equivalent ROE using the ATWACC approach would be approximately 11.1%, compared to the 11.0% recommended. [90]

[90] The average ATWACC equivalent ROEs and the ROE indicated using the traditional ROE/capital structure approach would have been virtually identical had the ROEs estimated using the DCF-based risk premium test and the DCF test been adjusted for the difference between TGI's proposed book value common equity ratio and the benchmark U.S. utility sample's average book value common equity ratio.

VII. AUTOMATIC ADJUSTMENT MECHANISM

TGI is proposing to fix the benchmark ROE for a period of time longer than one year, or until one or more parties conclude it is no longer meeting the Fair Return Standard and seeks to have the BCUC review the allowed ROE. In principle, the proposal to fix the benchmark ROE until such time as stakeholders consider that the ROE is no longer meeting the fair return standard is not unreasonable, as the fair return does not typically fluctuate widely from year to year.

The proposal to fix the ROE for a period of time under the current circumstances is reasonable for two other reasons. First, it is difficult at the present time, given the unusually volatile capital market conditions and the abnormally low levels of long-term Government of Canada bond yields, to specify a simple, objective and transparent formula that will, with some degree of certainty, be equally applicable when the capital markets return to more normal conditions.

Second, the empirical evidence shows that, with the benefit of hindsight, it is clear that the cost of equity has not tracked the downward trend in long-term Canada bond yields nearly to the extent implied by the existing automatic adjustment formula. A 50% elasticity factor would be more closely aligned with the correlation between the utility cost of equity and long-term government bond yields.

However, it is critical to recognize that the implementation of a 50% elasticity factor is only appropriate if the allowed ROE is set at a level that meets the fair return standard. The allowed ROEs for BC utilities, as well as for other Canadian utilities subject to a similar formula, have been persistently declining since the formulas' inception, by approximately 75% of the decline in long-term Canada bond yields. The implementation of a formula still tied to long-term Canada bond yields and a lower sliding scale factor would be unfair and unreasonable without an explicit recognition that the operation of the existing formulas has overstated the decline in the cost of equity. Consequently, it is reasonable for TGI not to propose an alternative automatic adjustment mechanism until such time as the level of the benchmark return has been determined by the Commission.

Appendices

Capital Structure and Fair Return on Equity

Prepared for

TERASEN GAS INC.

Prepared by

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FOSTER ASSOCIATES, INC.

May 2009

APPENDICES

A THE FAIR RETURN STANDARD

B. RISK-ADJUSTED EQUITY MARKET RISK PREMIUM TEST

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E. FINANCING FLEXIBILITY ADJUSTMENT

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APPENDIX A

THE FAIR RETURN STANDARD

Three standards for a fair return have arisen from the legal precedents for establishing a fair return, the capital attraction, financial integrity and comparable returns, or comparable investment, 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/financial integrity standards and the comparable returns 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 B

RISK-ADJUSTED EQUITY MARKET RISK PREMIUM TEST

1. 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:

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

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:

a. Perfect, or efficient, markets exist where,

(1) each investor assumes he has no effect on security prices;

(2) there are no taxes or transaction costs;

(3) all assets are publicly traded and perfectly divisible;

(4) there are no constraints on short-sales; and,

(5) the same risk-free rate applies to both borrowing and lending.

b. 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.

The CAPM is a normative model, that is, it estimates the equity return that an investor **should** require under the restrictive assumptions outlined above, based on the relative systematic risk of the stock.

2. RISK-FREE RATE

a. 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 frequently 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.

b. 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:

(1) 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 since 1997/1998 (eleven years), which has reduced its financing requirements.[1] 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, 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.

(2) 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

[1] The Federal government is anticipating budget deficits for fiscal years 2009/10 to 2012/13.

be captured in the typical application of the CAPM which focuses on a long-term average market risk premium. Particularly in periods of capital market upheaval, e.g., the "Asian contagion" in the fall of 1998, during the technology sector sell-off beginning in mid-2000, the post 9/11 period, and most recently, in the wake of the subprime mortgage crisis commencing in late 2007, investors have shifted to the safe haven of government securities, pushing down government bond yields and increasing the required equity risk premium. The typical application of the CAPM captures the lower government bond yields, but not the increase in the equity risk premium.

(3) 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, particularly as the changes impact the measurement of the equity market risk premium.

(4) The radical change in Canada's fiscal performance over the past decade has contributed to a steady decline in long-term government bond yields and a corresponding increase in total returns achieved by investors in long-term government securities. As a result, the achieved equity market risk premiums in Canada have been squeezed by the performance of the government bond market. The low prevailing and forecast long-term Government of Canada bond yields relative to both the historic yields and total returns on those securities indicate that the historic yields and returns on long-term Government of Canada bonds overstate the forward looking risk-free rate.

3. THE CANADIAN EQUITY MARKET

Several factors inherent in the Canadian equity market make historic Canadian equity risk returns problematic in estimating the forward-looking expected equity market return. First and foremost, the Canadian equity market has been, and continues to be dominated by a relatively small number of sectors; the returns do not reflect those of a fully diversified portfolio.

Historically, the Canadian equity market composite has been dominated by resource-based stocks. At the end of 1980, no less than 46% of the market value of the TSX Composite Index (previously the TSE 300), was resource-based stocks.[2] The next largest sector, financial services, at less than 15% of the total market value of the composite, was a distant second. With the rise of the technology-based sectors and the increasing market presence of financial services, at the end of 2000, resource-based stocks had dropped to less than 20% of the total market value of the TSX Composite Index. By comparison, as indicated in Table B-1 below, the technology-based and financial service sectors accounted for over half of the market value of the index.

Table B-1

	1980	**2000**
Information Technology	0.9%	24.1%
Telecommunication Services	4.8%	6.5%
Financial Services	13.5%	24.1%
Total	19.2%	54.7%

Source: *TSE Review*, December 1980 and December 2000.

With the technology sector bust in 2000-2001, and the run-up in commodity prices commencing in 2004, the resource-based sectors reclaimed dominance. At the end of 2007, the energy and materials (largely mining) sectors accounted for close to 45% of the total market value of the composite. Including the financial services sector, three sectors accounted for close to 75% of the total market value of the composite. Despite the sharp decline in commodity prices in 2008

[2] 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.

and the fall-out of the sub-prime mortgage crisis, at the end of 2008, the same three sectors continued to represent close to three-quarters of the value of the S&P/TSX Composite Index.

By comparison, the U.S. market has been significantly more diversified among industry sectors. A comparison of market weights in Canada and the U.S. of the major sectors at December 2008 demonstrates the difference.

Table B-2

Sector	S&P/TSX Canada	S&P 500 U.S.
Consumer Discretionary	4.7%	8.4%
Consumer Staples	3.4%	12.9%
Energy	27.4%	13.3%
Financials	29.2%	13.3%
Health Care	0.4%	14.8%
Industrials	6.1%	11.1%
Information Technology	3.3%	15.3%
Materials	17.6%	3.0%
Telecommunication Services	6.0%	3.8%
Utilities	1.9%	4.2%

Source: *TSX Review* December 2008 and Standardandpoors.com.

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, health care and retailing.

Further, the performance of the Canadian equity market as the "market portfolio" has been, at different periods of time, unduly influenced by a small number of companies. In mid-2000, before the debacle in Nortel Networks' stock value, Nortel shares alone accounted for almost 35% of the total market value of the TSX Composite Index as compared to the largest stock in the S&P 500 at that time (General Electric) which accounted for only 4% of total market value. In 2007, two stocks, Potash Corporation and Research in Motion, were responsible for approximately half of the gain in the S&P/TSX Composite Index. The undue influence of a small number of stocks requires caution in drawing conclusions from the history of the Composite regarding the forward-looking market risk premium.

Criticism of the former TSE 300 Index cited the lack of liquidity as well as questioned the quality and size of the stocks which comprised the index. 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.

Standard & Poor's and the TSX addressed some these concerns when it overhauled the TSE 300 in May 2002, creating the S&P/TSX Composite Index. The overhaul of the index, which included more stringent criteria for inclusion, did not require that a specific number of companies be included in the index. As a result, only 275 companies were initially included instead of the previous 300. At December 31, 2008 there were 220 companies in the S&P/TSX Composite Index, including 53 income trusts.

The addition of income trusts in 2005 represented a significant change in the make-up of the Composite Index. From the beginning of the decade to their peak in late 2006, the market value of income trusts grew rapidly, from a market capitalization of approximately $20 billion, to more than $200 billion. At the end of September 2006, prior to the announced change in tax treatment for income trusts, they accounted for over 11.5% of the total market value of the S&P/TSX Composite. At the end of 2008, income trusts continued to be a significant component of the S&P/TSX, accounting for approximately 25% of the issues and 7% of the value of the index.

Despite the change to the income tax treatment of income trusts announced in October 2006, income trusts significantly outperformed "conventional" equities 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 1998-2008 period averaged 10.8%, compared to 4.7% 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.

A further complication is created 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) for approximately five decades (1957-2005). The restrictions on the ability of Canadians to invest globally negatively impacted their achieved returns. 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 annual returns by 1% and that a 30% limit would increase returns a further 0.5%.[3] 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*,[4] which supported the removal of the cap.[5] The *Globe and Mail* reported that the

[3] Tom Hockin, President and CEO IFIC, *Paving the Way for Change to RRSP Foreign Content Rules*, January 31, 2000.
[4] David Burgess and Joel Fried, *The Foreign Property Rule: A Cost-Benefit Analysis*, The University of Western Ontario, November 2002.
[5] The IFIC's report *Year 2002 in Review* stated,

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."[6] The Foreign Property Rule was finally eliminated in 2005.

4. USE OF ARITHMETIC AVERAGES OF HISTORIC RETURNS TO ESTIMATE THE EXPECTED 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, Stewart C. Myers and Franklin Allen, *Principles of Corporate Finance*, Boston: Irwin/McGraw Hill, 2006 (p. 151), 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:

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.

[6] Rob Carrick, *Finance: Your Bottom Line*, Globeandmail.com, February 23, 2005.

> 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.[7]

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.

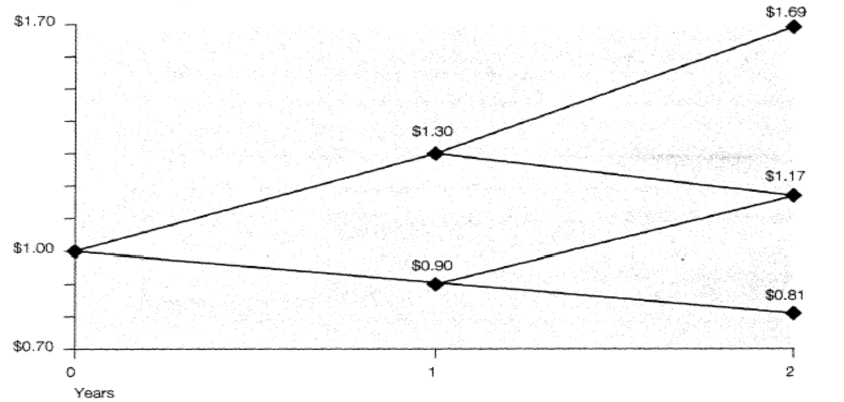
[7] An illustration from Ibbotson Associates demonstrating why the arithmetic average is more appropriate than the geometric average for estimating the expected risk premium is presented on pages B11 and B12.

b. Illustration of Why Arithmetic Average Should be Used

In Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: Valuation Edition, 2008,* 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.

Graph 5-4
Growth of Wealth Example



> 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)	=	<u>$0.2025</u>
	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:

$$\$1 \text{ x } (1{+}0.0.082)^2 = \$1.17$$

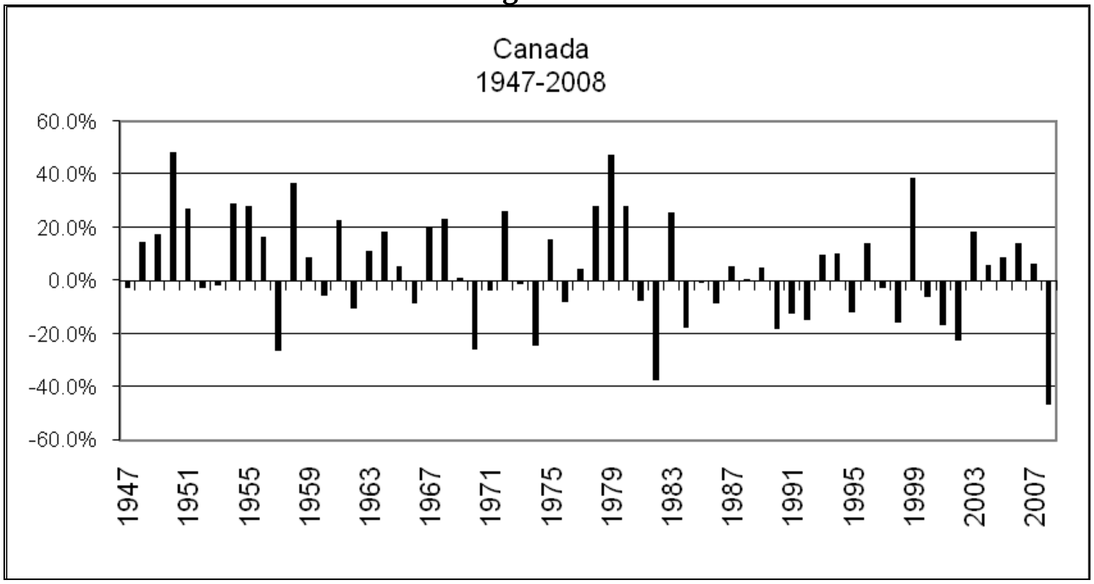
The arithmetic mean equates the expected future value with the present value; it is therefore the appropriate discount rate.

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.[8]

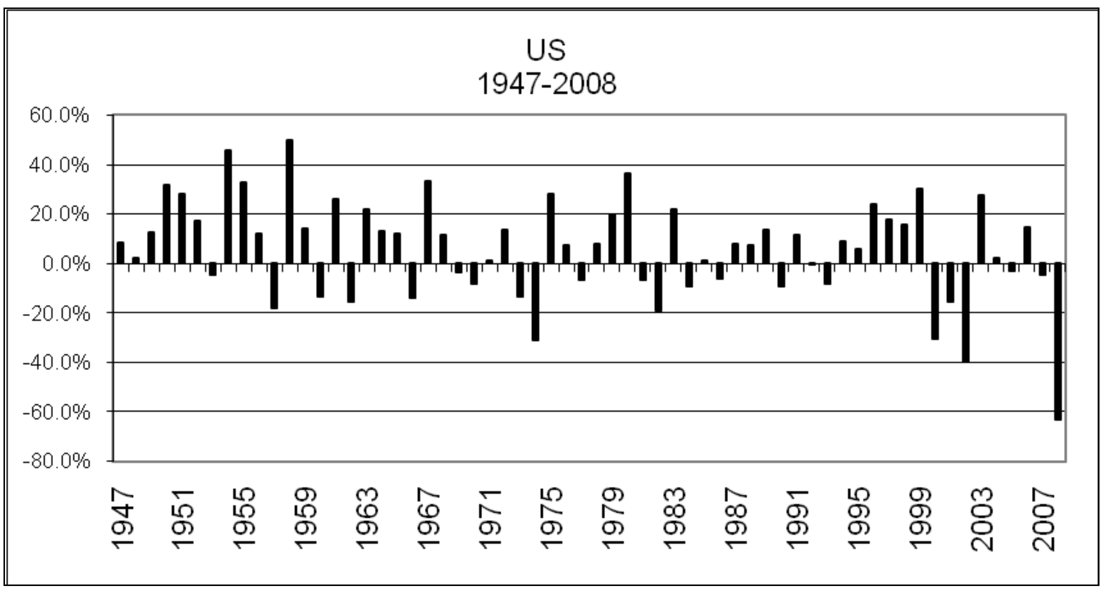
[8] A test for serial correlation between the year-to-year equity risk premiums shows that the serial correlation between the current year's risk premium and that of the prior year for the period 1947-2008 is 0.06 for Canada and -0.02 for the U.S. If the current year's risk premium were predictable based on the prior year's risk premium, the serial correlation would be close to positive or negative 1.0.

Figure B-1



Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics, 1924-2006*; Ibbotson *Canadian Risk Premia Over Time 2008*, *TSX Review* and Bank of Canada

Figure B-2



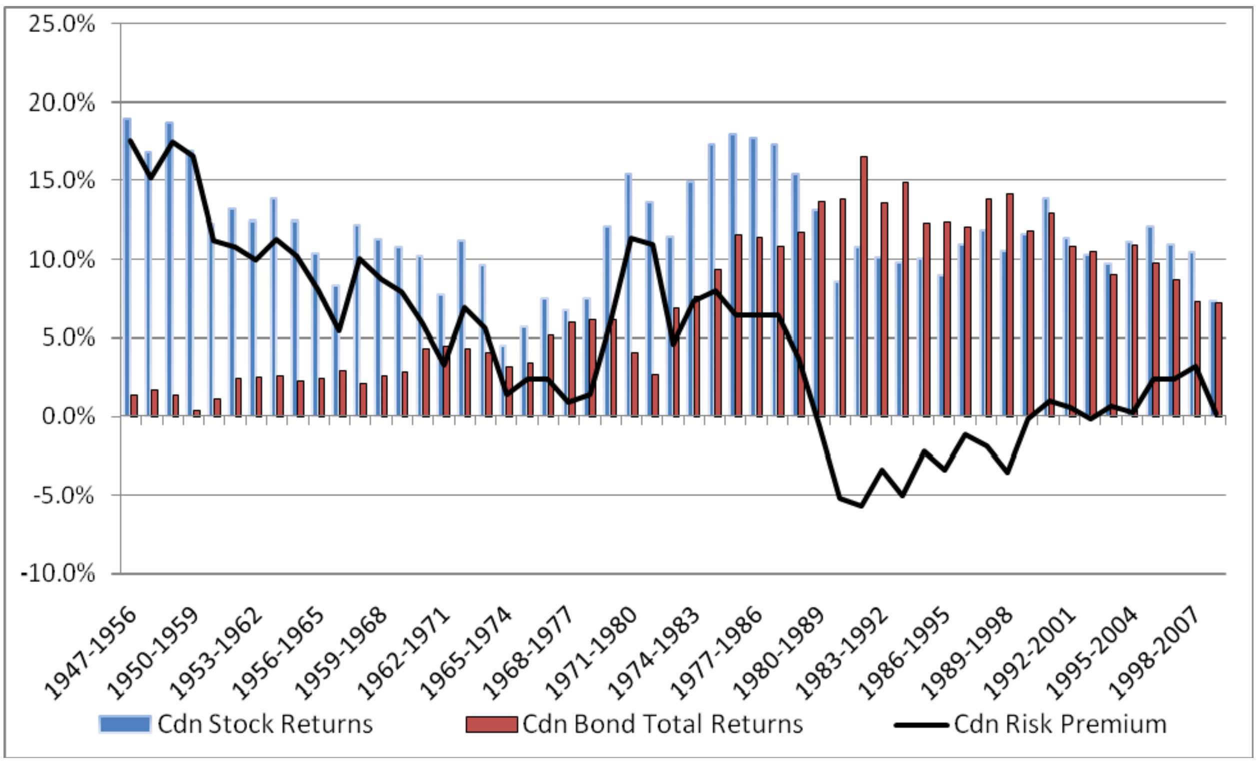
Source: Ibbotson Associates, *Stocks, Bonds, Bills & Inflation, 2009 Yearbook*, www.standardandpoors.com and the Federal Reserve

5. FUTURE vs. HISTORIC RISK PREMIUMS

a. Trends in Canadian Equity and Government Bond Returns

Figures B-3 and B-4 compare historic Canadian stock returns, long-term government bond total and income[9] returns and equity risk premiums, over rolling 10-year periods ending 1956-2008.

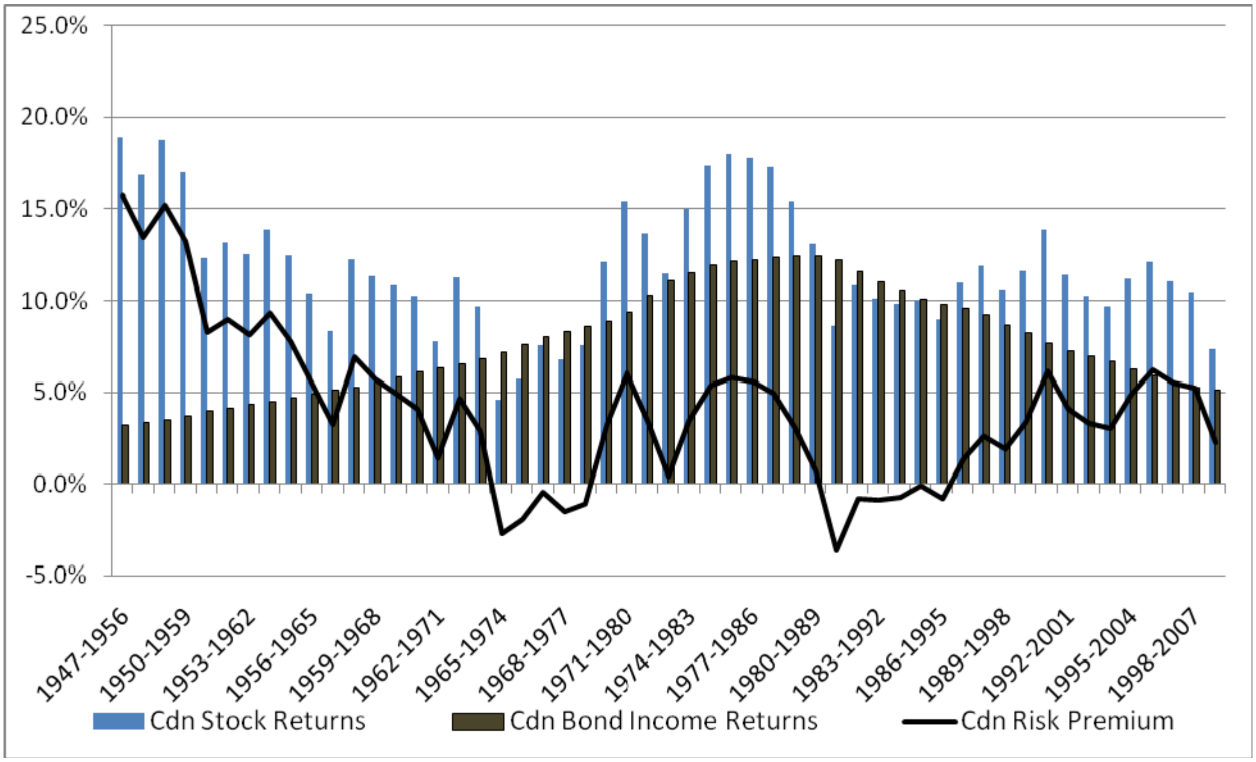
Figure B-3



Source: Schedule 9.

[9] The income return reflects only the bond coupon portion of the total bond return. The other components are the reinvestment return and the capital gain or loss. The bond coupon payment represents the riskless portion of the bond total return.

Figure B-4



Source: Schedule 9.

The rolling ten-year averages in both Figures B-3 and B-4 suggest that there has been no upward or downward trend over time in equity returns over time. On average, equity market returns in Canada have been approximately 11.5% from 1947-2008. By comparison, bond returns (both Total and Income returns) exhibited an increase throughout much of the period, before beginning to decline in the early to mid-1990s. The pattern in the bond returns results from:

- ♦ rising bond yields in the 1950s through the mid-1980s, which produced capital losses on bonds and low bond total return;

- ♦ high bond income and income returns in the 1980s, reflecting the high rates of inflation; and,

- high bond total returns in the 1990s and first half of the 2000s, reflecting the decline in long-term government bond yields, resulting in capital gains and total returns well in excess of the yields.[10]

The resulting average income and total return on long-term government bonds in Canada has been approximately 7.0% during the post-World War II period (1947-2008), well in excess of the long-term Canada bond yields which are forecast to prevail going forward.

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, based solely on the post-World War II Canadian equity market returns, is approximately 11.5%. Based on a 2010 forecast long-term Canada bond yields of 4.25%, and an expected equity market return over the long-term of 11.5%, the indicated equity market risk premium is approximately 7.25%. Based on the longer-term (2009-2019) forecast for long-term Canada bond yields of approximately 5.25%,[11] the indicated equity market risk premium is 6.25%.

b. Trends in Price/Earnings Ratios

Several studies of historic and equity risk premiums conclude that the equity returns generated historically 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[12] of the S&P 500 averaged 13.25 times from 1936-1988, with no discernible upward trend.[13] From 11.7 times in

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[10] The bond yield is, in fact, an estimate of the expected return.
[11] Consensus Economics, *Consensus Forecasts*, April 2009 anticipates the 10-year Canada bond yield to average approximately 5.0% from 2009 to 2019. The average spread between 10- and 30-year Canada bond yields has historically averaged approximately 0.30%.
[12] Price to trailing earnings.
[13] The average from 1947-1988 was 13 times.

1988, the P/E ratio gradually rose, peaking at over 46 times in late 2001. 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 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.[14] By mid-2006, the P/E ratio had fallen to 17 times; in mid-February 2009, with the sell-off in the market which commenced in mid-2007, it was 15 times (based on estimated 2008 operating earnings), compared to the long-term (1936-2008) average of approximately 16 times.

To assess the impact of rising P/E ratios on achieved returns, I analyzed the equity returns of the S&P 500 achieved between 1936 and 1988, that is, prior to the observed upward trend in P/E ratios. The analysis indicates that the achieved arithmetic average equity return for the S&P 500 was 12.3% from 1936-1988. The corresponding average return from 1936-2008 was 11.8%. Hence, despite the increase in P/E ratios experienced during the 1990s, the average equity market returns were actually lower over the entire 1936-2008 period than over the 1936-1988 period. The results are similar for the post-World War II period. The average returns from 1947-1988, at 13.1%, are higher than the average of 12.2% over the entire 1947-2008 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 level of approximately 12.0% is not unreasonable. Relative to the consensus forecast yield for 30-year Treasury bonds for 2010 of

[14] Weakness in the equity markets was partly responsible (along with low interest rates) for the burgeoning income trust market in Canada.

approximately 4.25% and for the longer term of approximately 5.4%,[15] the risk premium would be approximately 6.5-7.75%.

My review of equity returns in Canada indicates similar results. The 1936-1988 arithmetic average return for the Canadian equity market was 11.8%, identical to the average U.S. equity market return for the same period, and higher than the average 1936-2008 return of 11.0%. Similarly, the 1947-1988 return of 12.9% is higher than the 1947-2008 return of 11.6%. There is no indication that rising P/E ratios during the bull market of the 1990s have produced returns that are unsustainable going forward.

c. Equity Market Risk Premium

The analysis of stock and bond returns in Canada and the U.S. during the post World War II 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 (in relation to bond total returns) from 1947-1988 was 7.7%; in the U.S., it was 8.4%. By comparison, the corresponding 1947-2008 achieved risk premiums (in relation to the total returns on bonds) were 4.6% and 5.6% for Canada and the U.S. respectively. An analysis of the data shows that high bond returns have been the principal reason for the decline in experienced risk premiums, not a downward trend in equity returns. The average bond total return (income plus capital appreciation) in Canada from 1989-2008 was 10.7%.

Over the entire 1947-2008 period, the average income total return on long-term Canada bonds was approximately 7.0%. With interest rates currently at historically low levels (approximately 3.75% at mid-April 2009), and more likely to increase rather than decrease further, the 1947-2008 average bond returns of approximately 7.0% overstate the forward-looking expected bond return indicated by current and forecast 30-year Canada bond yields. A reasonable expected value of the long-term Canada bond return

[15] Blue Chip *Financial Forecasts*, December 1, 2008.

for the purpose of estimating the forward-looking equity market risk premium is the forecast long-term Canada bond yields, rather than the historic average bond returns.

Thus a reasonable estimate of the forward-looking equity market risk premium is approximately 6.75%, based on historic equity market returns in Canada and the U.S. in the range of 11.0% to 12.0%[16] and a risk-free rate of 4.25% (2010 forecast of 30-year Canada bond yield) to 5.25% (forecast of 30-year Canada bond yield over the longer term).

6. RELATIVE RISK ADJUSTMENT

a. Beta

Impediments to reliance on beta as the sole relative risk measure, as the CAPM indicates, include:

(1) The assumption that all risk for which investors require compensation can be captured and expressed in a single risk variable;

(2) The only risk for which investors expect compensation is non-diversifiable equity market risk; no other risk is considered (and priced) by investors; and,

(3) 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)[17] are a good measure of the relative return requirement.

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[16] Over the three-month period, January 2009-March 2009, the average dividend yield on the S&P/TSX was 2.6%. The expected long-term growth rate for the index based on available analysts' forecasts for the companies in the Composite, is 9.9%, indicating an expected return (based on a discounted cash flow approach) of approximately 12.8%.

[17] The beta is equal to:

$$\frac{\text{Covariance}\ (R_E, R_M)}{\text{Variance}\ (R_M)}$$

(4) 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 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.)

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.

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.[18]

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 very sensitive to the particular market proxy against which they are measured.

[18] The additional factors are size and book to market.

> 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.[19]

b. 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; (b) 1956-1997, which eliminates the major effects of the "technology bubble", and (c) all potential non-overlapping 10-year periods from 2003 backwards.

[19] Dr. Stephen A. Ross, "Is Beta Useful?" *The CAPM Controversy: Policy and Strategy Implications for Investment Management*, AIMR, 1993.

The analysis showed the following:

Table B-3

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 11, 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 B-3 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) 1988-2008, the longest period for which data for the new Composite and its sector components are available; (b) 1988-1997,[20] and (c) the most recent 10-year period ending 2008.

[20] 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.

That analysis showed the following:

Table B-4

Returns Measured Over:	**Coefficient on Beta**	**R^2**
1988-2008	-.047	26%
1988-1997	-.017	1%
1999-2008	-.084	32%

Source: Schedule 11, page 2 of 3.

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. The results strongly suggest that, at a minimum, adjusted betas, rather than "raw" betas, should be relied upon in the application of the CAPM. Adjusting betas toward the equity market mean beta of 1.0 takes account of the empirically observed tendency of stocks with "raw" betas below 1.0 to achieve returns higher than implied by the theoretical single variable CAPM and vice versa.

APPENDIX C

DCF-BASED RISK PREMIUM TEST

1. SELECTION OF LOW RISK BENCHMARK U.S. 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:

a. Classified by *Value Line* as a gas distributor or an electric utility;

b. *Value Line* Safety Rank of "2" or better;

c. Standard & Poor's business risk profile of "Excellent";

d. Standard & Poor's debt rating of A- or higher;

e. Not presently being acquired; and,

f. Consistent history of analysts' forecasts.

The 13 utilities that met these criteria are listed on Schedule 15.

2. 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 1991-2008. 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 mean 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 on Schedule 12, page 2 of 2.

APPENDIX D

DISCOUNTED CASH FLOW TEST

1. DCF MODELS

a. 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.

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[21]
$\mathbf{P_o}$ = current price
$\mathbf{g}$ = constant growth rate

[21] 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).

b. 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 for conventional corporations 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)

3. 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 C.

4. 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. In the second stage, the investor growth expectations are proxied by the expected nominal long-run rate of growth in the economy (GDP) based on the consensus of economists' long-term forecasts (published twice annually) found in *Blue Chip Financial Forecasts* (December 1, 2008). The consensus forecast rate of growth in the long-term (2010-2019) is 5.0%.

5. APPLICATION OF THE DCF MODELS

a. 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 March 31, 2009 as D_o; and,

(2) the average of the high and low monthly prices for the period January 1, 2009 to March 31, 2009 as P_o.

For the expected growth rates, the March 2009 I/B/E/S consensus (mean) earnings growth forecasts and the most recent *Value Line* forecasts of earnings growth[22] were used to estimate "g" in the growth component for each utility and to adjust the current dividend yield to the expected dividend yield.

Table D-1 below summarizes the results of the constant growth model.

Table D-1

Earnings Growth Forecast	DCF Cost of Equity	
	Mean	**Median**
I/B/E/S	11.0%	10.9%
Value Line	11.3%	11.0%

Source: Schedules 16 and 17.

[22] Estimates issued in November and December 2008.

b. 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 (2010-2019) expected nominal rate of growth in GDP, as noted above, is 5.0%.

The two-stage DCF model estimates of the cost of equity for the benchmark low risk U.S. utility sample (Schedule 18) are as follows:

Mean	10.3%
Median	10.5%

c. 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 10.4% (two-stage model) to 11.0% (constant growth model).

APPENDIX E

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 unregulated companies 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 unregulated companies 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 unregulated companies, 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 unregulated companies 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. The concept of a financing flexibility or flotation cost allowance has been accepted by most Canadian regulators.

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.[23]

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 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.

[23] *Independent Assessment Team Power Purchase Arrangement Report*, July 1999, page XLV, footnote 99.

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.[24]

Schedules 24 and 25 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 of approximately 100 basis 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

[24] 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.

integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 is approximately 50 basis points.[25]

The financing flexibility allowance should be, at a minimum, 50 basis points. As this financing flexibility adjustment is minimal, it does not fully address the comparable earnings standard.

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[25] 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 10.5%, the indicated ROE is:

$$\text{ROE} = \frac{1.075 \text{ x } 10.5\%}{1 + [.35\,(1.075 - 1.0)]}$$

$$\text{ROE} = 11.0\%$$

The difference of 50 basis points between the ROE and the "bare-bones" cost of equity is the financing flexibility allowance.

APPENDIX F

COMPARABLE EARNINGS TEST

1. SELECTION OF CANADIAN UNREGULATED COMPANIES

The selection process starts with the recognition that unregulated companies generally are exposed to higher business risk, but lower financial risk, than the typical utility. The selection of unregulated companies focuses on total investment risk, i.e., the combined business and financial risks. The unregulated companies' higher business risks are offset by a more conservative capital structure, i.e., higher equity ratios, thus permitting the selection of samples of reasonably comparable investment risk to utilities.

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.[26] The resulting universe contained 490 firms. Companies were removed which:

- Had 2007 equity less than $100 million,
- Had missing or negative common equity during 1991-2007,
- Were income trusts,
- Had less than five years of market data,
- Paid no dividends in any year 2004-2008,
- Traded fewer than 5% of their outstanding shares in 2007,

[26] 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.

- Had stock ranked “higher risk” or “speculative by the Canadian Business Service (CBS)
- Had debt 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,
- Had average five-year “raw” betas ending December 2007 and December 2008 in excess of 1.0.

The final sample of low risk Canadian unregulated companies is comprised of 27 companies (Schedule 19).

2. TIME PERIOD FOR MEASURING RETURNS

Since unregulated companies’ returns on equity tend to be cyclical, the appropriate period for measuring unregulated company 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 1991-2007 constitutes a full business cycle including the recession of 1991-1992. Over the period 1991-2007, the experienced returns on equity of the sample of 27 low risk unregulated Canadian companies were as follows.

Table F-1

ROEs for Low Risk Canadian Unregulated Companies (1991-2007)

Average	12.5%
Median	12.7%
Average of Annual Medians	12.8%

Source: Schedule 20.

Based on these data, the ROEs for the low risk Canadian unregulated companies are in the approximate range of 12.5-12.75%.

The average nominal economic growth for Canada during the 1991-2007 business cycle was 4.9%, compared to the consensus forecast for real growth of 2.7%, and for inflation (CPI) of approximately 2.1% for the period (2010-2019)[27], which suggests nominal long-term GDP growth of approximately 4.8%. Since nominal growth is expected to be virtually identical to the experienced rate during the past full business cycle, the experienced returns on book equity, absent extraordinary events, provide a reasonable proxy for the future.

3. RELATIVE RISK COMPARISON

With respect to the investment risk of the Canadian unregulated companies relative to Canadian utilities, comparisons of the various risk measures indicate that they are in a similar risk class. The median CBS stock rating for the unregulated companies is "Very Conservative", the same as that of the investor-owned Canadian utilities with publicly-traded stock. The median S&P and DBRS debt ratings for the unregulated companies are BBB and BBB/BBB(high) respectively, compared to Canadian utilities' median ratings of A- and A (See Schedules 3 and 19). The median adjusted beta for the unregulated companies averaged 0.71 for the two five-year periods ending December 2007 and 2008 (see Schedule 19), compared to the adjusted betas for Canadian utilities over the same time period of 0.59 (Schedule 11).

The estimate of a normal cycle average level of returns for low risk Canadian unregulated companies is in the approximate range of 12.5-12.75%. The comparative risk data indicate, on balance, the Canadian unregulated companies are somewhat riskier than utilities. The somewhat higher risk of the unregulated companies relative to the typical Canadian utility requires a

[27] Consensus Economics, *Consensus Forecasts*, April 2009.

modest downward adjustment. A downward adjustment of 75-100 basis points[28] reduces the ROE to a range of 11.5-11.75%.

4. U.S. UNREGULATED COMPANY SAMPLE

To ensure a sample of adequate size to provide reliable results, an additional sample of U.S. unregulated companies was selected to corroborate the reasonableness of the Canadian unregulated company results.

The U.S. unregulated sample was selected as follows: The initial universe consisted of all companies actively traded in the U.S. from S&P's Research Insight database in Global Industry Classification Standard (GICS) sectors 20-30. The resulting universe contained 2,585 companies. Companies were removed which:

- Are not incorporated in the U.S.
- Had 2007 equity less than $100 million.
- Had missing or negative common equity during 1991-2007.
- Had less than five years of market data.
- Paid no dividends in any year 2004-2008.
- Traded fewer than 5% of their outstanding shares in 2007.
- Had an S&P rating below BBB-.
- Had a *Value Line* Rank of "4" or "5".
- Had a *Value* Line beta of 1.0 or higher
- Had 1996-2007 returns outside one standard deviation of the sample average

The returns for the sample of 81 U.S. companies are summarized in Table F-2 below.

[28] Based on the typical spread between Moody's BBB rated long-term industrial bond yields and long-term A rated utility bond yields and the relative betas of the unregulated companies and the Canadian and U.S. utility samples.

Table F-2

ROEs for Low Risk U.S. Unregulated Companies (1991-2007)	
Average:	15.9%
Median	14.9%
Average of Annual Medians:	15.7%

Source: Schedule 21.

The sample of unregulated U.S. companies has the following risk measures, compared to the benchmark sample of U.S. utilities.

Table F-3

	Unregulated U.S, Companies		**Benchmark Sample of U.S. Utilities**	
	Median	Mean	Median	Mean
S&P Debt Ratings	A-	A-	A	A
Value Line Risk Measures:				
Safety	3	2	1	1
Beta	0.80	0.80	0.65	0.67

Source: Schedules 15and 21

The comparative risk data indicate that the U.S. unregulated companies are of somewhat lower risk than the benchmark sample of U.S. utilities. Using the relative betas of the unregulated U.S. companies and the utilities to adjust for the unregulated companies' higher risk, the indicated return on equity is approximately 14%. Used as a check on the returns on equity of the sample of unregulated Canadian firms, the ROEs of the significantly larger U.S. sample underscore the reasonableness of the comparable earnings results for the sample of Canadian unregulated companies.

5. MARKET/BOOK RATIOS

In arriving at its decision for TGI and TGVI in 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.

The argument that a downward adjustment to the comparable earnings test results for market/book ratios has been made on the following bases:

a. 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.

b. 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.

Both of these arguments are without merit. 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.[29] 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,[30] whose importance was underscored in a March 2002 *New York Times* article which stated, referring to Tobin's obituaries:

> 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.

[29] The general idea had been expressed decades earlier by the economist John Keynes.
[30] 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.

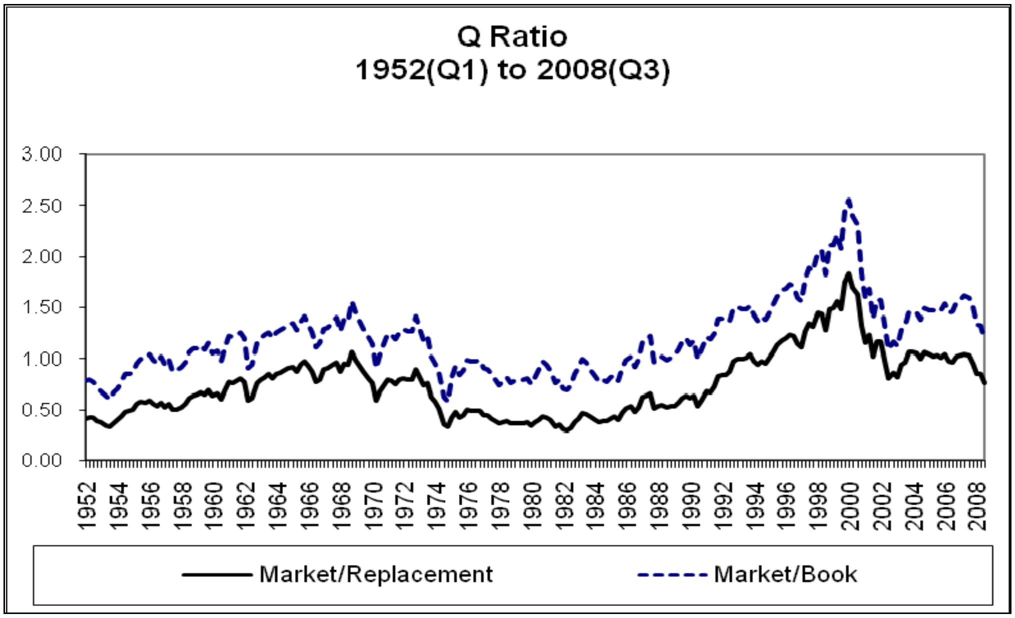
> Consider Tobin's Q, the ratio for which Dr. Tobin, at least at one time, was most famous among investors. This is the ratio of a company's total market capitalization to the replacement value of that company's total assets. <u>While the Q ratio – as Tobin's Q is often called – is conceptually similar 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[31] has averaged approximately 45% lower than the market/book ratio over the business cycle 1991-2007.

[31] Based on non-farm, non-financial corporate businesses.

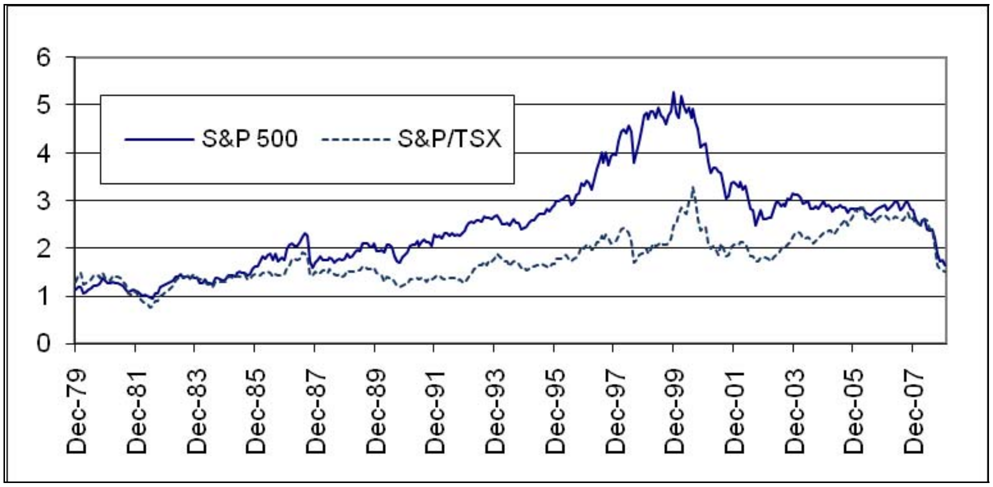
Figure F-1



Source: US Federal Reserve Flow of Funds (B102).

To test the potential for market power in the achieved returns of the sample of low risk unregulated Canadian firms used in the comparable earnings test, their market/book ratios were compared to those of Canadian and U.S. equity market composites. The figure below tracks the market/book values for the S&P/TSX Composite and the S&P 500 from 1980-2008.

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 1.8 times from 1980-2008, and approximately 2.0 times from 1991-2007, the period over which the comparable earnings test was conducted. Based on almost three decades of data, the market/book ratio for the Canadian equity market has varied around an average of close to 1.8 times, not 1.0 times. For the S&P 500, the market/book ratios were approximately 2.5 and 3.1 times, respectively, over the same two periods. Over the period 1991-2007 the market/book ratio for the sample of comparable Canadian unregulated companies averaged 2.1 times, approximately equal to the average for the S&P/TSX Composite and considerably lower than the market/book ratio of the S&P 500. The similar to lower average market/book ratio of the low risk unregulated Canadian companies relative to the Canadian and U.S. equity market composites permit the inference that the sample average returns are not characterized by market power. Thus, the comparable earnings results do not warrant an adjustment for market/book ratios.

APPENDIX G

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 190 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian gas distributors and pipelines, electric utilities and telephone companies. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, 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 AND CAPITAL STRUCTURE

Client	**Date**
Alberta Natural Gas	1994
AltaGas Utilities	2000
Ameren (Central Illinois Public Service)	2000, 2002, 2005, 2007 (2 cases)
Ameren (Central Illinois Light Company)	2005, 2007 (2 cases)
Ameren (Illinois Power)	2004, 2005, 2007 (2 cases)
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, 2007
ATCO Pipelines	2000, 2003, 2007
ATCO Utilities	2008
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, 2008
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, 2008
Gaz Metropolitain	1988
Gazifère	1993, 1994, 1995, 1996, 1997, 1998
Generic Cost of Capital, Alberta (ATCO and AltaGas Utilities)	2003
Heritage Gas	2004, 2008
Hydro One	1999, 2001, 2006 (2 cases)
Insurance Bureau of Canada (Newfoundland)	2004
Laclede Gas Company	1998, 1999, 2001, 2002, 2005
Laclede Pipeline	2006
Mackenzie Valley Pipeline	2005
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
Northland Utilities	2008 (2 cases)
Northwestel, Inc.	2000, 2006
Northwestern Utilities	1987, 1990
Northwest Territories Power Corp.	1990, 1992, 1993, 1995, 2001, 2006
Nova Scotia Power Inc.	2001, 2002, 2005, 2008
Ontario Power Generation	2007
Ozark Gas Transmission	2000
Pacific Northern Gas	1990, 1991, 1994, 1997, 1999, 2001, 2005
Plateau Pipe Line Ltd.	2007
Platte Pipeline Co.	2002
St. Lawrence Gas	1997, 2002
Southern Union Gas	1990, 1991, 1993
Stentor	1997

Tecumseh Gas Storage	1989, 1990
Telus Québec	2001
Terasen Gas	1992, 1994, 2005
Terasen Gas (Whistler)	2008
TransCanada PipeLines	1988, 1989, 1991 (2 cases), 1992, 1993
TransGas and SaskEnergy LDC	1995
Trans Québec & Maritimes Pipeline	1987
Union Gas	1988, 1989, 1990, 1992, 1994, 1996, 1998, 2001
Westcoast Energy	1989, 1990, 1992 (2 cases), 1993, 2005
Yukon Electrical Company	1991, 1993, 2008
Yukon Energy	1991, 1993

EXPERT TESTIMONY/OPINIONS
ON
OTHER ISSUES

Client	Issue	Date
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

COMPARISON BETWEEN ALLOWED EQUITY RISK PREMIUMS
FOR CANADIAN AND U.S. UTILITIES

	Canadian Utilities			U.S. Utilities			U.S. Gas Utilities		U.S. Electric Utilities	
Year	Allowed ROE [1/]	Average Long Canada Yield	Equity Risk Premium	Allowed ROE	Average Long Treasury Yield	Equity Risk Premium	Allowed ROE	Equity Risk Premium	Allowed ROE	Equity Risk Premium
1990	13.68	10.69	2.99	12.69	8.62	4.07	12.67	4.05	12.70	4.08
1991	13.56	9.72	3.85	12.51	8.09	4.43	12.46	4.38	12.55	4.47
1992	12.94	8.68	4.26	12.06	7.68	4.39	12.01	4.34	12.09	4.42
1993	12.16	7.86	4.30	11.37	6.58	4.79	11.35	4.77	11.41	4.83
1994	11.50	8.69	2.81	11.34	7.41	3.93	11.35	3.94	11.34	3.93
1995	12.13	8.41	3.72	11.51	6.81	4.70	11.43	4.62	11.55	4.74
1996	11.36	7.75	3.62	11.29	6.72	4.57	11.19	4.47	11.39	4.67
1997	10.84	6.66	4.18	11.34	6.57	4.77	11.29	4.72	11.40	4.83
1998	10.15	5.59	4.56	11.59	5.53	6.06	11.51	5.98	11.66	6.13
1999	9.50	5.72	3.78	10.74	5.91	4.83	10.66	4.75	10.77	4.86
2000	9.79	5.71	4.08	11.41	5.88	5.53	11.39	5.51	11.43	5.55
2001	9.68	5.77	3.92	11.05	5.47	5.58	10.95	5.48	11.09	5.62
2002	9.62	5.67	3.95	11.10	5.41	5.69	11.03	5.62	11.16	5.75
2003	9.73	5.31	4.42	10.98	5.03	5.95	10.99	5.96	10.97	5.94
2004	9.59	5.11	4.48	10.66	5.09	5.56	10.59	5.50	10.73	5.64
2005	9.51	4.38	5.13	10.50	4.52	5.98	10.46	5.94	10.54	6.02
2006	9.02	4.26	4.76	10.39	4.87	5.52	10.44	5.57	10.36	5.49
2007	8.66	4.30	4.37	10.30	4.80	5.51	10.24	5.44	10.36	5.56
2008	8.77	4.04	4.73	10.42	4.22	6.20	10.37	6.15	10.46	6.24

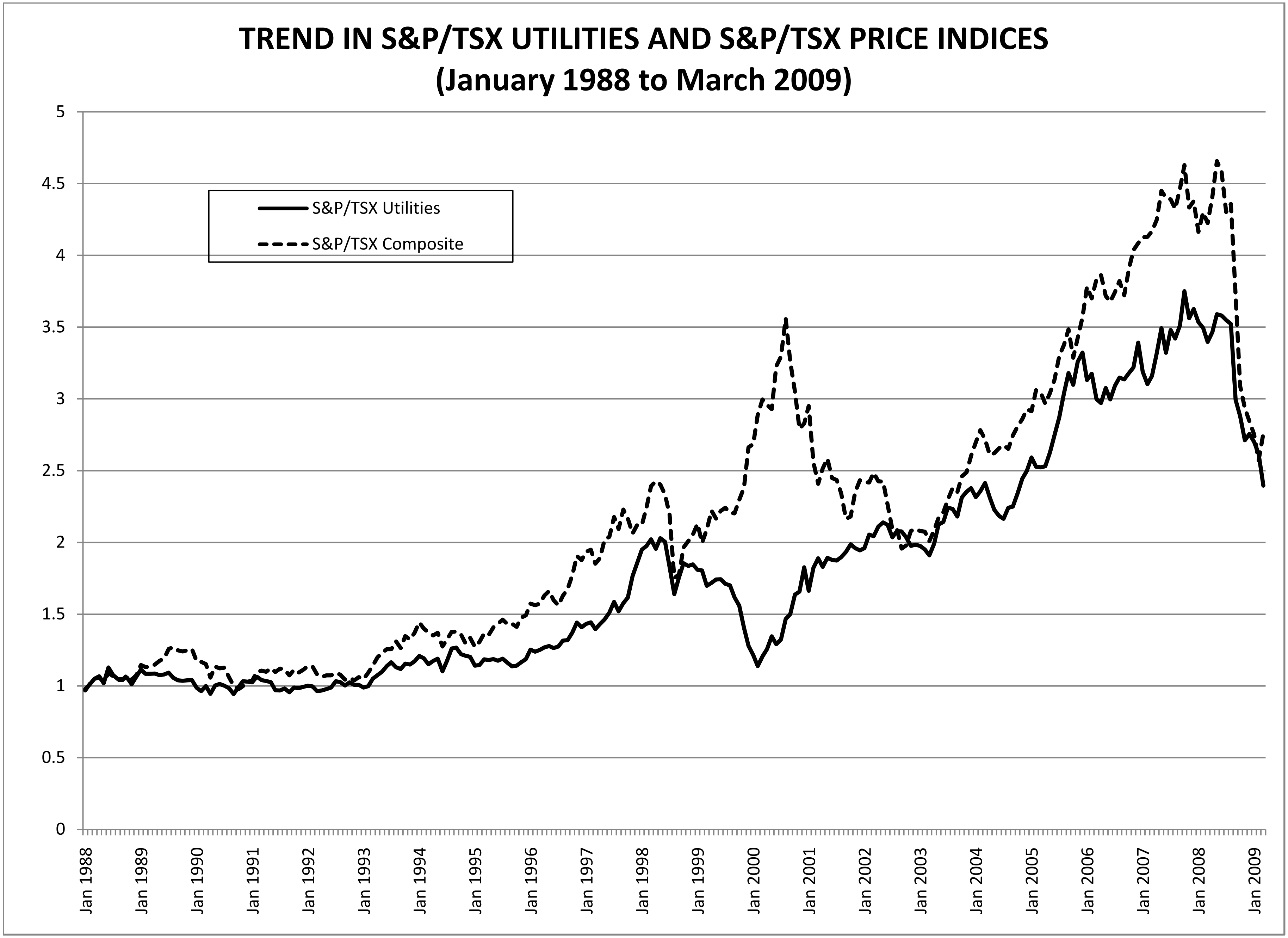
Means:

1990-1993	**13.08**	**9.24**	**3.85**	**12.16**	**7.74**	**4.42**	**12.12**	**4.38**	**12.19**	**4.45**
1994-1997	**11.46**	**7.88**	**3.58**	**11.37**	**6.88**	**4.49**	**11.32**	**4.44**	**11.42**	**4.54**
1998-2008	**9.46**	**5.08**	**4.38**	**10.83**	**5.16**	**5.67**	**10.78**	**5.63**	**10.87**	**5.71**

1/ 2008 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.


TREND IN S&P/TSX UTILITIES AND S&P/TSX PRICE INDICES
(January 1988 to March 2009)
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
S&P/TSX Utilities
S&P/TSX Composite
Jan 1988
Jan 1989
Jan 1990
Jan 1991
Jan 1992
Jan 1993
Jan 1994
Jan 1995
Jan 1996
Jan 1997
Jan 1998
Jan 1999
Jan 2000
Jan 2001
Jan 2002
Jan 2003
Jan 2004
Jan 2005
Jan 2006
Jan 2007
Jan 2008
Jan 2009

TREND IN INTEREST RATES AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

Year	Government Securities: T-Bills Canadian	T-Bills U.S. [1/]	10 Year Canadian	10 Year U.S.	Long-Term Canadian	Long-Term U.S. [2/]	Canada Bonds Over 10 Years [3/]	Canadian Inflation Indexed Bonds	Canadian A-Rated Utility Bonds [4/]	Canadian A-Rated Spread Over Long Canadas	Moody's U.S. Utility Long-Term A-Rated Bonds	Exchange Rates (Canadian dollars in U.S. funds)
Annual												
1990	12.81	7.49	10.76	8.55	10.69	8.61	10.85		12.13	1.44	9.86	0.86
1991	8.73	5.38	9.42	7.86	9.72	8.14	9.76		11.00	1.28	9.36	0.84
1992	6.59	3.43	8.05	7.01	8.68	7.67	8.77	4.62	10.01	1.33	8.64	0.82
1993	4.84	3.02	7.22	5.87	7.86	6.59	7.85	4.28	9.08	1.22	7.59	0.77
1994	5.54	4.34	8.43	7.08	8.69	7.39	8.63	4.41	9.81	1.12	8.30	0.73
1995	6.89	5.44	8.08	6.58	8.41	6.85	8.28	4.68	9.29	0.88	7.89	0.73
1996	4.21	5.04	7.20	6.44	7.75	6.73	7.50	4.61	8.38	0.63	7.75	0.73
1997	3.26	5.11	6.11	6.32	6.66	6.58	6.42	4.14	7.19	0.53	7.60	0.72
1998	4.73	4.79	5.30	5.26	5.59	5.54	5.47	4.02	6.38	0.79	7.04	0.68
1999	4.69	4.71	5.55	5.68	5.72	5.91	5.69	4.07	6.92	1.20	7.62	0.67
2000	5.45	5.85	5.89	5.98	5.71	5.88	5.89	3.69	7.02	1.31	8.24	0.67
2001	3.78	3.34	5.49	4.99	5.77	5.50	5.76	3.59	7.25	1.48	7.73	0.65
2002	2.55	1.63	5.27	4.56	5.67	5.41	5.65	3.49	7.22	1.55	7.35	0.64
2003	2.86	1.03	4.78	4.02	5.31	5.03	5.26	3.04	6.78	1.46	6.54	0.72
2004	2.21	1.44	4.55	4.27	5.11	5.08	5.05	2.34	6.28	1.17	6.14	0.77
2005	2.73	3.29	4.04	4.27	4.38	4.52	4.36	1.81	5.53	1.16	5.62	0.83
2006	4.05	4.86	4.21	4.79	4.26	4.87	4.28	1.67	5.47	1.21	6.06	0.89
2007	4.13	4.42	4.25	4.58	4.30	4.80	4.31	1.95	5.61	1.31	6.06	0.94
2008	2.26	1.28	3.56	3.61	4.04	4.22	4.03	1.90	6.41	2.37	6.54	0.94

[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	Canadian A-Rated Utility Bonds [5/]	Canadian A-Rated Spread Over Long Canadas	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	q1	2.12	0.94	4.41	4.00	5.09	4.96	4.99	2.50	6.17	1.08	6.06	0.76
	q2	1.98	1.13	4.74	4.60	5.29	5.35	5.22	2.38	6.48	1.19	6.45	0.74
	q3	2.23	1.58	4.66	4.26	5.14	5.08	5.13	2.29	6.37	1.23	6.11	0.77
	q4	2.53	2.11	4.40	4.22	4.92	4.93	4.87	2.18	6.09	1.17	5.95	0.83
2005	q1	2.47	2.67	4.27	4.33	4.72	4.70	4.69	2.05	5.86	1.13	5.72	0.82
	q2	2.46	3.01	3.93	4.05	4.39	4.36	4.35	1.86	5.59	1.21	5.43	0.81
	q3	2.73	3.50	3.88	4.21	4.20	4.39	4.19	1.75	5.32	1.12	5.49	0.84
	q4	3.25	4.00	4.07	4.49	4.19	4.63	4.21	1.59	5.36	1.17	5.82	0.85
2006	q1	3.70	4.57	4.18	4.65	4.23	4.70	4.25	1.53	5.43	1.20	5.92	0.87
	q2	4.17	4.84	4.51	5.11	4.54	5.19	4.57	1.81	5.75	1.21	6.41	0.90
	q3	4.14	5.00	4.14	4.79	4.21	4.91	4.23	1.67	5.45	1.23	6.09	0.89
	q4	4.16	5.04	4.00	4.59	4.07	4.70	4.08	1.68	5.27	1.20	5.82	0.87
2007	q1	4.17	5.11	4.10	4.68	4.17	4.82	4.18	1.77	5.36	1.19	5.92	0.86
	q2	4.29	4.82	4.39	4.85	4.35	4.98	4.38	1.94	5.61	1.25	6.08	0.92
	q3	4.17	4.26	4.43	4.64	4.45	4.86	4.46	2.09	5.79	1.34	6.19	0.97
	q4	3.90	3.48	4.09	4.16	4.21	4.53	4.21	2.01	5.68	1.47	6.05	1.02
2008	q1	2.76	1.73	3.65	3.55	4.07	4.35	4.03	1.80	5.75	1.68	6.16	0.99
	q2	2.60	1.74	3.68	3.94	4.10	4.58	4.07	1.60	5.99	1.89	6.30	0.99
	q3	2.23	1.44	3.66	3.89	4.11	4.44	4.13	1.78	6.33	2.21	6.58	0.95
	q4	1.45	0.19	3.26	3.06	3.88	3.50	3.91	2.42	7.56	3.69	7.13	0.82
2009	q1	0.61	0.24	2.99	2.87	3.68	3.62	3.65	2.13	7.28	3.60	6.44	0.80
2006	Jan	3.51	4.47	4.17	4.53	4.26	4.69	4.26	1.53	5.43	1.17	5.84	0.88
	Feb	3.74	4.62	4.12	4.55	4.17	4.51	4.17	1.47	5.37	1.20	5.77	0.88
	Mar	3.86	4.61	4.26	4.86	4.26	4.89	4.32	1.58	5.49	1.23	6.14	0.86
	Apr	4.04	4.65	4.51	5.07	4.52	5.17	4.57	1.72	5.70	1.18	6.37	0.89
	May	4.18	4.86	4.45	5.12	4.50	5.21	4.51	1.83	5.68	1.18	6.43	0.91
	Jun	4.30	5.01	4.58	5.15	4.61	5.19	4.63	1.88	5.86	1.25	6.43	0.90
	Jul	4.15	5.10	4.31	4.99	4.37	5.07	4.39	1.73	5.62	1.25	6.29	0.88
	Aug	4.12	5.02	4.11	4.74	4.19	4.88	4.20	1.62	5.42	1.23	6.07	0.90
	Sep	4.16	4.89	3.99	4.64	4.08	4.77	4.09	1.67	5.30	1.22	5.90	0.89
	Oct	4.17	5.08	4.02	4.61	4.08	4.72	4.10	1.69	5.28	1.20	5.84	0.89
	Nov	4.17	5.03	3.90	4.46	3.99	4.56	4.00	1.60	5.18	1.19	5.68	0.88
	Dec	4.15	5.02	4.08	4.71	4.14	4.81	4.15	1.75	5.34	1.20	5.95	0.86
2007	Jan	4.17	5.12	4.17	4.83	4.22	4.93	4.23	1.79	5.41	1.19	6.01	0.85
	Feb	4.19	5.16	4.03	4.56	4.09	4.68	4.10	1.75	5.28	1.19	5.78	0.85
	Mar	4.16	5.04	4.11	4.65	4.20	4.84	4.21	1.77	5.39	1.19	5.97	0.87
	Apr	4.16	4.91	4.14	4.63	4.19	4.81	4.20	1.76	5.45	1.26	5.90	0.90
	May	4.29	4.73	4.49	4.90	4.38	5.01	4.42	1.99	5.62	1.24	6.10	0.93
	Jun	4.43	4.82	4.55	5.03	4.49	5.12	4.51	2.08	5.75	1.26	6.24	0.94
	Jul	4.56	4.96	4.52	4.78	4.45	4.92	4.48	2.07	5.78	1.33	6.18	0.94
	Aug	3.99	4.01	4.42	4.54	4.46	4.83	4.47	2.14	5.76	1.30	6.17	0.95
	Sep	3.96	3.82	4.34	4.59	4.44	4.83	4.44	2.07	5.83	1.39	6.22	1.01
	Oct	3.96	3.94	4.31	4.48	4.38	4.74	4.39	2.05	5.73	1.35	6.07	1.06
	Nov	3.91	3.15	3.98	3.97	4.16	4.40	4.15	2.07	5.69	1.53	6.00	1.00
	Dec	3.82	3.36	3.99	4.04	4.10	4.45	4.10	1.91	5.62	1.52	6.07	1.01
2008	Jan	3.38	1.96	3.88	3.67	4.18	4.35	4.16	1.96	5.81	1.63	6.07	1.00
	Feb	3.04	1.85	3.64	3.53	4.09	4.41	4.04	1.85	5.73	1.64	6.22	1.02
	Mar	1.87	1.38	3.43	3.45	3.94	4.30	3.88	1.60	5.71	1.77	6.20	0.97
	Apr	2.68	1.43	3.58	3.77	4.08	4.49	4.02	1.72	5.97	1.89	6.22	0.99
	May	2.64	1.89	3.71	4.06	4.13	4.72	4.09	1.61	5.98	1.85	6.36	0.99
	Jun	2.48	1.90	3.74	3.99	4.08	4.53	4.10	1.47	6.02	1.94	6.32	0.98
	Jul	2.39	1.68	3.70	3.99	4.10	4.59	4.11	1.54	6.08	1.98	6.44	0.98
	Aug	2.40	1.72	3.53	3.83	4.01	4.43	4.02	1.57	6.25	2.24	6.32	0.94
	Sep	1.89	0.92	3.75	3.85	4.23	4.31	4.25	2.23	6.65	2.42	6.98	0.94
	Oct	1.85	0.46	3.76	4.01	4.28	4.35	4.33	2.51	7.86	3.58	8.01	0.82
	Nov	1.67	0.01	3.32	2.93	3.90	3.45	3.96	2.65	7.47	3.57	7.18	0.81
	Dec	0.83	0.11	2.69	2.25	3.45	2.69	3.45	2.10	7.36	3.91	6.20	0.82
2009	Jan	0.86	0.24	3.06	2.87	3.77	3.58	3.80	2.27	7.57	3.80	6.52	0.81
	Feb	0.59	0.26	3.12	3.02	3.70	3.71	3.70	2.32	7.26	3.56	6.38	0.79
	Mar	0.39	0.21	2.79	2.71	3.57	3.56	3.46	1.81	7.01	3.44	6.41	0.79

[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 l0 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

Schedule 2

SELECTED INDICATORS OF ECONOMIC ACTIVITY
(1989 = 100)

		Canada					United States				
		Gross Domestic Product			GDP	Consumer	Gross Domestic Product			Implicit	Consumer
		Constant	Current	Industrial	Deflator	Price	Constant	Current	Industrial	Price	Price
Year		Dollars	Dollars	Production	Index	Index	Dollars	Dollars	Production	Index	Index
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(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	144.8	132.6	145.1
2003		142.6	184.4	137.7	129.4	137.4	147.6	199.9	146.6	135.4	148.4
2004		147.0	196.3	139.8	133.5	139.9	152.9	213.1	150.2	139.3	152.3
2005		151.3	208.7	142.0	138.0	143.0	157.4	226.5	155.2	143.9	157.5
2006		156.0	220.5	142.3	141.4	145.9	161.8	240.3	158.6	148.5	162.6
2007		160.2	233.5	142.6	145.8	149.0	165.1	251.8	161.3	152.5	167.2
2008		160.9	243.6	136.7	151.4	152.6	167.2	260.4	158.5	155.8	173.6
2004	1Q	144.7	190.5	139.2	131.7	138.5	151.0	208.0	148.8	137.7	150.2
	2Q	146.4	195.4	139.7	133.5	140.0	152.3	211.7	149.5	139.0	152.4
	3Q	148.0	198.5	139.9	134.2	140.3	153.7	214.8	150.2	139.8	152.9
	4Q	149.0	200.6	140.5	134.7	140.9	154.6	217.9	152.4	140.9	153.8
2005	1Q	149.3	202.5	140.5	135.7	141.4	155.8	221.6	154.4	142.3	154.8
	2Q	150.4	205.5	141.3	136.7	142.7	156.8	224.2	155.1	143.0	156.9
	3Q	151.9	211.1	142.5	139.1	144.0	158.3	228.6	155.0	144.4	158.8
	4Q	153.5	215.6	143.7	140.6	144.1	158.8	231.5	156.4	145.8	159.6
2006	1Q	155.1	217.8	143.7	140.4	144.8	160.7	236.3	157.6	147.1	160.4
	2Q	155.7	219.7	142.2	141.2	146.4	161.7	239.5	158.6	148.1	163.1
	3Q	156.1	221.7	141.9	142.1	146.5	162.1	241.6	159.4	149.1	164.1
	4Q	157.0	223.0	141.2	142.1	146.0	162.7	243.8	159.0	149.9	162.7
2007	1Q	158.5	228.6	142.6	144.3	147.4	162.7	246.4	159.6	151.4	164.3
	2Q	160.0	233.6	143.6	146.1	149.6	164.6	250.5	160.8	152.2	167.5
	3Q	161.0	234.4	143.1	145.7	149.6	166.5	254.4	162.3	152.8	167.9
	4Q	161.3	237.2	140.9	147.1	149.5	166.5	255.8	162.4	153.7	169.1
2008	1Q	160.9	240.1	138.4	149.2	150.0	166.8	258.0	162.6	154.7	171.0
	2Q	161.2	246.3	137.3	152.8	153.1	168.0	260.6	161.2	155.2	174.8
	3Q	161.5	248.5	137.4	153.8	154.7	167.8	262.8	157.5	156.7	176.8
	4Q	160.1	239.7	133.5	149.7	152.4	166.1	260.1	152.7	156.6	171.8

Note: Data are based on Chain Weighted Indexes.

Source: www.cansim2.statcan.ca, www.bea.gov , www.federalreserve.gov

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
Gas Distributors					
Enbridge Gas Distribution	Senior Unsecured	A		A-	Very conservative
Gaz Metropolitain	Senior Secured	A		A	
Pacific Northern Gas	Senior Secured	BBB(low)		NR [2/]	Average
Terasen Gas	Senior Secured	A	A2	AA-	
	Senior Unsecured	A	A3	A	
Terasen Gas (Vancouver Is.)	Senior Unsecured		A3		
Union Gas Limited	Senior Unsecured	A		BBB+	
Electric Utilities					
AltaLink L.P.	Senior Secured	A		A-	
CU Inc.	Senior Unsecured	A(high)		A	Very conservative
Enersource	Issuer	A			
ENMAX	Unsecured Debentures	A(low)		BBB+	
EPCOR Utilities Inc	Senior Unsecured	A(low)		BBB+	
FortisAlberta Inc.	Senior Unsecured	A(low)	Baa1	A-	Very conservative
FortisBC Inc	Secured Debentures	BBB(high)	Baa2		Very conservative
Hamilton Utilities	Senior Unsecured			A+	
Hydro One	Senior Unsecured	A(high)	Aa3	A+	
Hydro Ottawa Holding Inc.	Senior Unsecured	A(low)		A	
London Hydro	Issuer			A	
Maritime Electric	Senior Secured			A	Very conservative
Newfoundland Power	Senior Secured	A	Baa1	NR [1/]	Very conservative
Nova Scotia Power	Senior Unsecured	A(low)	Baa1	BBB	Very conservative
Toronto Hydro	Senior Unsecured	A		A	
Veridian	Issuer	A			
Pipelines					
Enbridge Pipelines	Senior Unsecured	A(high)		A-	Very conservative
NOVA Gas Transmission	Senior Unsecured	A	A3	A-	Very conservative
Trans Quebec & Maritimes	Senior Unsecured	A(low)		BBB+	
TransCanada PipeLines	Senior Unsecured	A	A3	A-	Very conservative
Westcoast Energy	Senior Unsecured	A(low)		BBB+	
Medians					
Gas Distributors		**A**	**A3**	**A**	**Very conservative**
Electric T&D		**A**	**Baa1**	**A**	**Very conservative**
Electric Integrated		**A(low)**	**Baa2**	**A-**	**Very conservative**
All Electric		**A(low)**	**Baa1**	**A**	**Very conservative**
Pipelines		**A**	**A3**	**A-**	**Very conservative**
All Companies		**A**	**A3**	**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.

CAPITAL STRUCTURE RATIOS
OF CANADIAN UTILITIES WITH RATED DEBT
(2008)

	Long-Term Debt [1/]	Short-Term Debt	Preferred Stock [2/]	Common Stock Equity [3/]
Gas Distributors				
Enbridge Gas Distribution	44.2%	18.1%	1.9%	35.8%
Gaz Metro	64.0%	2.0%	0.0%	34.0%
Pacific Northern Gas	45.6%	1.8%	3.0%	49.6%
Terasen Gas	55.7%	9.5%	0.0%	34.8%
Terasen Gas (Vancouver Is.)	46.3%	18.2%	0.0%	35.5%
Union Gas	56.1%	8.1%	2.6%	33.2%
Electric Utilities				
Altalink LP	61.7%	0.0%	0.0%	38.3%
CU Inc	56.6%	0.0%	5.2%	38.3%
Enersource [4/]	57.5%	0.0%	0.0%	42.5%
ENMAX Corp.	37.3%	4.6%	0.0%	58.1%
EPCOR Utilities Inc.	50.3%	2.6%	2.3%	44.8%
FortisAlberta	60.0%	0.5%	0.0%	39.4%
FortisBC	59.1%	0.0%	0.0%	40.9%
Hamilton Utilities [4/]	35.4%	0.0%	0.0%	64.6%
Hydro One Inc.	54.5%	0.0%	2.9%	42.6%
Hydro Ottawa Holding Inc. [4/]	43.8%	4.3%	0.0%	51.9%
London Hydro [4/]	36.5%	0.0%	0.0%	63.5%
Maritime Electric	53.6%	6.2%	0.0%	40.2%
Newfoundland Power	53.4%	0.0%	1.1%	45.5%
Nova Scotia Power	54.3%	0.8%	4.7%	40.1%
Toronto Hydro	55.2%	0.0%	0.0%	44.8%
Veridian [4/]	40.4%	0.0%	0.0%	59.6%
Pipelines				
Enbridge Pipelines	52.7%	7.0%	0.0%	40.4%
Nova Gas Transmission Ltd.	61.4%	0.6%	0.0%	38.0%
Trans Quebec & Maritimes [4/]	69.8%	0.0%	0.0%	30.2%
TransCanada Pipelines	54.1%	5.0%	1.2%	39.7%
Westcoast Energy	52.6%	1.2%	4.9%	41.3%
Medians				
Gas Distributors	**51.0%**	**8.8%**	**1.0%**	**35.2%**
Electric T&D	**53.4%**	**0.0%**	**0.0%**	**45.5%**
Electric Integrated	**54.3%**	**0.8%**	**2.3%**	**40.2%**
All Electric	**54.0%**	**0.0%**	**0.0%**	**43.7%**
Pipelines	**54.1%**	**1.2%**	**0.0%**	**39.7%**
All Companies	**54.1%**	**0.8%**	**0.0%**	**40.4%**

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/ Capital structures for 2007.

Source: Annual Reports to Shareholders

FINANCIAL METRICS
FOR CANADIAN UTILITIES WITH RATED DEBT
2005-2007

Company	EBIT Coverage	FFO/ Total Debt	FFO Coverage [1/]
Gas Distributors			
Enbridge Gas Distribution	2.1	11.5	2.6
Gaz Metropolitain	2.5	20.9	5.0
Pacific Northern Gas	2.4	12.5	2.5
Terasen Gas	2.0	9.1	2.4
Terasen Gas (Vancouver Is.)	2.8	10.3	3.1
Union Gas	2.1	12.4	2.8
Electric Utilities			
AltaLink L.P.	1.9	12.6	3.1
CU Inc.	2.5	17.1	3.4
Enersource	2.2	14.9	3.2
ENMAX Corp.	8.2	18.0	3.9
EPCOR Utilities Inc.	2.8	20.3	3.6
FortisAlberta Inc.	2.2	14.3	4.2
FortisBC Inc.	2.1	10.4	2.7
Hamilton Utilities	3.2	32.2	4.9
Hydro One Inc.	2.8	14.5	3.4
Hydro Ottawa Holding Inc.	3.5	22.3	5.3
London Hydro	2.9	20.9	4.0
Maritime Electric	2.7	13.5	2.8
Newfoundland Power	2.3	14.1	2.7
Nova Scotia Power	2.5	13.8	3.4
Toronto Hydro	2.3	17.7	3.5
Veridian	3.4	29.5	4.2
Pipelines			
Enbridge Pipelines	3.3	16.9	3.5
Nova Gas Transmission Ltd.	2.4	19.0	3.2
Trans Quebec & Maritimes	2.4	10.4	2.7
TransCanada PipeLines Ltd.	2.5	14.3	2.8
Westcoast Energy Inc.	2.2	17.0	3.2
Medians			
Gas Distributors	**2.3**	**12.0**	**2.7**
Electric T&D	**2.8**	**17.7**	**3.9**
Electric Integrated	**2.5**	**13.8**	**3.4**
All Electric	**2.6**	**16.0**	**3.5**
Pipelines	**2.4**	**16.9**	**3.2**
All Companies	**2.5**	**14.5**	**3.2**

[1/] S&P defines Funds from Operations as follows:
FFO = (income from continuing operations + depreciation & amortization + deferred income taxes – AFUDC).

Source: Annual Reports to Shareholders and Standard and Poor's

DEBT RATINGS AND FINANCIAL METRICS FOR U.S. NATURAL GAS UTILITIES RATED A- OR HIGHER

Name	S&P							Moody's Debt Rating	Common Equity Ratio (2008) [2]	Average ROE 2006-2008
				Average 2005-2007 [1]						
	Debt Rating	Business Profile	Financial Profile	Debt Ratio	EBIT Coverage	FFO/Debt	FFO Coverage			
AGL Resources Inc.	A-	Excellent	Intermediate	58.2	3.7	19.6	4.4	A3	39.4	13.2
Indiana Gas Co. Inc.	A-	Excellent	Intermediate	48.0	2.8	16.4	3.6	Baa1	na	na
Laclede Gas Co.	A	Excellent	Intermediate	60.0	2.3	13.8	3.1	Baa1	34.0	9.7
Laclede Group	A	Excellent	Intermediate	57.9	3.0	17.7	3.6	na	44.5	13.9
New Jersey Natural Gas	A	Excellent	Intermediate	42.8	5.4	24.2	5.5	A1	51.2	13.9
Nicor Inc.	AA	Excellent	Intermediate	45.3	3.9	28.3	6.0	A3	44.0	14.2
Nicor Gas	AA	Excellent	Intermediate	47.1	2.7	19.7	4.7	na	na	na
North Shore Gas	A-	Excellent	Intermediate	45.6	4.5	20.6	4.9	A2	54.8	7.1
Northwest Natural Gas Co.	AA-	Excellent	Intermediate	53.4	3.6	21.2	4.4	A3	45.3	11.5
Piedmont Natural Gas Co. Inc.	A	Excellent	Intermediate	50.5	3.9	24.9	4.9	A3	41.9	11.8
Public Service (North Carolina) 4/	A-	Excellent	Aggressive	42.1	2.9	14.3	3.3	A3	58.3	5.3
Southern California Gas Co.	A	Excellent	Intermediate	56.2	4.6	30.6	6.4	A2	50.9	16.0
Vectren Corp.	A-	Excellent	Intermediate	58.4	2.8	17.1	4.0	na	42.2	10.4
Vectren Utility Holdings Inc.	A-	Excellent	Intermediate	53.7	2.9	19.0	4.1	Baa1	48.2	9.4
Washington Gas Light Co.	AA-	Excellent	Intermediate	50.8	4.6	24.1	5.5	A2	49.9	10.9
WGL Holdings Inc.	AA-	Excellent	Intermediate	52.8	4.6	22.2	5.3	na	51.7	10.8
Mean	**A**	**Excellent**	**Intermediate**	**51.4**	**3.6**	**20.9**	**4.6**	**A3**	**46.9**	**11.3**
Median	**A**	**Excellent**	**Intermediate**	**51.8**	**3.7**	**20.2**	**4.5**	**A3**	**46.7**	**11.2**

[1] S&P Credit Stats

[2] Equity ratio based on total capital.

[3] ROE and equity ratio for New Jersey Resources Corp.

[4] Common equity ratio is 2007, and average ROE is for 2005-2007.

Source: S&P: *Issuer Ranking: U.S. Natural Gas Distributors and Integrated Gas Companies, Strongest to Weakest, March 10, 2009* and S&P, Credit Stats, September 2008 and www.moodys.com

DEBT RATINGS AND FINANCIAL METRICS FOR U.S. ELECTRIC UTILITIES RATED A- or HIGHER

Name	S&P Debt Rating	S&P Business Profile	S&P Financial Profile	S&P Average 2005-2007 [1/] Debt Ratio	EBIT Coverage	FFO/Debt	FFO Coverage	Moody's Debt Rating	Common Equity Ratio (2008) [2/]	Average ROE 2006-2008
Alabama Power Co.	A	Excellent	Intermediate	52.7	4.2	21.8	5.3	A2	42.5	13.4
Central Hudson Gas & Electric Corp.	A	Excellent	Intermediate	61.4	4.5	16.1	4.5	A2	43.7	9.3
Florida Power & Light Co.	A	Excellent	Intermediate	43.3	5.0	30.3	6.3	A1	56.0	10.9
FPL Group Inc.	A	Excellent	Intermediate	51.4	2.9	25.8	5.3	A2	40.6	13.7
Georgia Power Co.	A	Excellent	Intermediate	49.7	4.8	23.3	5.5	A2	46.5	13.7
Gulf Power Co.	A	Excellent	Intermediate	53.2	3.8	20.1	4.6	A2	42.9	12.4
Mississippi Power Co.	A	Excellent	Intermediate	47.0	6.9	44.7	11.3	A1	57.5	14.0
San Diego Gas & Electric Co.	A	Excellent	Intermediate	51.5	3.4	30.5	4.6	A2	53.3	14.0
Southern Co.	A	Excellent	Intermediate	56.4	3.6	21.3	5.1	A3	40.5	14.1
Consolidated Edison Co. of New York Inc.	A-	Excellent	Intermediate	54.1	3.0	15.5	3.6	A1	48.8	10.1
Consolidated Edison Inc.	A-	Excellent	Intermediate	57.1	2.9	14.7	3.6	A2	48.5	11.1
Dominion Resources	A-	Excellent	Aggressive	60.3	2.5	13.0	3.1	Baa2	36.3	18.3
Duke Energy Carolinas LLC	A-	Excellent	Intermediate	47.9	4.1	31.3	9.9	A3	na	na
Duke Energy Corp.	A-	Excellent	Intermediate	44.3	3.6	22.4	4.5	Baa2	59.2	7.1
Duke Energy Indiana Inc. [3/]	A-	Excellent	Intermediate	55.0	3.1	17.4	4.4	Baa1	46.7	9.1
Duke Energy Kentucky	A-	Excellent	Intermediate	69.0	1.3	8.2	2.7	Baa1	na	na
Duke Energy Ohio Inc.	A-	Excellent	Intermediate	32.1	3.9	24.0	5.4	Baa1	na	na
MidAmerican Energy Co.	A-	Excellent	Aggressive	53.0	4.2	23.3	5.3	A2	43.4	14.6
Northern States Power (Wisconsin)	A-	Excellent	Intermediate	44.9	3.4	24.0	4.9	A3	51.3	9.3
PacifiCorp	A-	Excellent	Aggressive	55.6	2.8	16.8	3.8	Baa1	51.1	7.1
PPL Electric Utilities Corp.	A-	Excellent	Intermediate	52.3	3.4	20.4	4.1	Baa1	38.3	12.5
SCANA Corp.	A-	Excellent	Aggressive	57.5	2.4	19.6	4.3	Baa1	39.3	11.2
South Carolina Electric & Gas Co.	A-	Excellent	Aggressive	49.1	2.6	27.3	5.3	A3	44.9	9.5
Southern Indiana Gas & Electric	A-	Excellent	Intermediate	46.1	3.7	23.5	4.8	Baa1	na	na
Virginia Electric Power [3/]	A-	Excellent	Aggressive	52.5	3.2	20.0	4.4	Baa1	47.1	6.5
Wisconsin Electric Power Co.	A-	Excellent	Intermediate	46.4	3.7	28.3	5.3	A1	46.7	11.1
Wisconsin Power & Light Co.	A-	Excellent	Intermediate	50.8	3.8	20.2	4.8	A2	53.7	10.0
Wisconsin Public Service Corp.	A-	Excellent	Aggressive	55.5	3.1	18.7	4.1	A1	54.2	10.1
NSTAR	A+	Excellent	Intermediate	62.4	3.5	23.2	5.3	A2	36.8	13.5
Madison Gas & Electric Co.	AA-	Excellent	Intermediate	50.8	4.6	20.5	5.4	Aa3	53.6	11.1
Mean	**A-**	**Excellent**	**Intermediate**	**52.1**	**3.6**	**22.2**	**5.1**	**A3**	**47.1**	**11.4**
Median	**A-**	**Excellent**	**Intermediate**	**52.4**	**3.6**	**21.6**	**4.8**	**A2/A3**	**46.7**	**11.1**

[1/] S&P Credit Stats

[2/] Equity ratio based on total capital.

[3/] Common equity ratio is 2007, and average ROE is for 2005-2007.

Source: S&P: Research Insight; *Issuer Ranking: U.S. Regulated Electric Utilities, Strongest to Weakest,* March 31, 2009;
S&P, *Credit Stats,* September 2008 and www.moodys.com

HISTORIC EQUITY MARKET RISK PREMIUMS

(ARITHMETIC AVERAGES)

Canada (1947-2008)

Stock Return	Bond Total Return	Risk Premium
11.6	7.0	4.6

Stock Return	Bond Income Return	Risk Premium
11.6	7.2	4.4

United States (1947-2008)

Stock Return	Bond Total Return	Risk Premium
12.2	6.6	5.6

Stock Return	Bond Income Return	Risk Premium
12.2	6.0	6.2

Source: Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2009 Yearbook; Ibbotson Associates, Canadian Risk Premia Over Time Report 2008; Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006; www.standardandpoors.com, TSX Review www.federalreserve.gov

HISTORIC EQUITY MARKET RISK PREMIUMS

(Arithmetic Averages)

Canada
(1924-2008)

Stock Return	Bond Total Return	Risk Premium
11.3	6.6	4.7

Stock Return	Bond Income Return	Risk Premium
11.3	6.3	5.0

United States
(1926-2008)

Stock Return	Bond Total Return	Risk Premium
11.7	6.1	5.6

Stock Return	Bond Income Return	Risk Premium
11.7	5.2	6.5

Source: Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2009 Yearbook;
Ibbotson Associates, Canadian Risk Premia Over Time Report 2008; Canadian Institute of Actuaries,
Report on Canadian Economic Statistics 1924-2006; www.standardandpoors.com, TSX Review
www.federalreserve.gov

10-YEAR ROLLING AVERAGE CANADIAN MARKET RETURNS

	Canadian Stock Returns	Canadian Bond Total Returns	Canadian Risk Premium Bond Total Returns	Canadian Bond Income Returns	Canadian Risk Premium Bond Income Returns
1947-1956	18.94%	1.40%	17.53%	3.21%	15.72%
1948-1957	16.84%	1.68%	15.17%	3.37%	13.47%
1949-1958	18.76%	1.35%	17.41%	3.50%	15.26%
1950-1959	16.95%	0.42%	16.54%	3.72%	13.23%
1951-1960	12.29%	1.14%	11.15%	3.96%	8.32%
1952-1961	13.16%	2.43%	10.73%	4.15%	9.01%
1953-1962	12.49%	2.54%	9.96%	4.31%	8.18%
1954-1963	13.84%	2.60%	11.24%	4.46%	9.38%
1955-1964	12.48%	2.30%	10.18%	4.67%	7.81%
1956-1965	10.36%	2.43%	7.94%	4.88%	5.48%
1957-1966	8.33%	2.94%	5.39%	5.10%	3.24%
1958-1967	12.20%	2.14%	10.07%	5.29%	6.91%
1959-1968	11.32%	2.62%	8.70%	5.57%	5.76%
1960-1969	10.78%	2.87%	7.92%	5.83%	4.95%
1961-1970	10.25%	4.35%	5.89%	6.12%	4.13%
1962-1971	7.77%	4.53%	3.24%	6.32%	1.45%
1963-1972	11.22%	4.34%	6.88%	6.55%	4.67%
1964-1973	9.69%	4.08%	5.60%	6.81%	2.88%
1965-1974	4.55%	3.22%	1.33%	7.20%	-2.65%
1966-1975	5.73%	3.40%	2.33%	7.61%	-1.88%
1967-1976	7.54%	5.15%	2.39%	7.99%	-0.45%
1968-1977	6.80%	5.97%	0.84%	8.28%	-1.48%
1969-1978	7.53%	6.18%	1.35%	8.55%	-1.03%
1970-1979	12.09%	6.11%	5.97%	8.84%	3.25%
1971-1980	15.46%	4.12%	11.33%	9.34%	6.12%
1972-1981	13.63%	2.67%	10.97%	10.26%	3.37%
1973-1982	11.45%	6.85%	4.59%	11.03%	0.42%
1974-1983	14.97%	7.64%	7.33%	11.49%	3.48%
1975-1984	17.32%	9.32%	8.00%	11.92%	5.40%
1976-1985	17.98%	11.56%	6.42%	12.14%	5.84%
1977-1986	17.77%	11.42%	6.36%	12.18%	5.60%
1978-1987	17.29%	10.86%	6.43%	12.31%	4.98%
1979-1988	15.43%	11.78%	3.65%	12.41%	3.01%
1980-1989	13.09%	13.67%	-0.58%	12.38%	0.71%
1981-1990	8.59%	13.80%	-5.20%	12.20%	-3.61%
1982-1991	10.82%	16.54%	-5.72%	11.59%	-0.77%
1983-1992	10.12%	13.55%	-3.43%	10.98%	-0.85%
1984-1993	9.83%	14.88%	-5.05%	10.55%	-0.72%
1985-1994	10.05%	12.33%	-2.27%	10.09%	-0.04%
1986-1995	9.00%	12.43%	-3.43%	9.79%	-0.79%
1987-1996	10.94%	12.10%	-1.17%	9.57%	1.36%
1988-1997	11.85%	13.80%	-1.96%	9.19%	2.65%
1989-1998	10.58%	14.17%	-3.59%	8.68%	1.90%
1990-1999	11.61%	11.83%	-0.21%	8.23%	3.38%
1991-2000	13.83%	12.86%	0.98%	7.69%	6.14%
1992-2001	11.38%	10.81%	0.57%	7.27%	4.11%
1993-2002	10.28%	10.51%	-0.23%	6.93%	3.34%
1994-2003	9.69%	9.03%	0.67%	6.65%	3.04%
1995-2004	11.16%	10.92%	0.24%	6.26%	4.90%
1996-2005	12.12%	9.79%	2.32%	5.86%	6.25%
1997-2006	11.01%	8.69%	2.32%	5.50%	5.51%
1998-2007	10.47%	7.27%	3.20%	5.24%	5.23%
1999-2008	7.33%	7.22%	0.12%	5.09%	2.24%

Source: Ibbotson Associates, Canadian Risk Premia Over Time Report 2008;
Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006, TSX Review

10-YEAR ROLLING AVERAGE U.S. MARKET RETURNS

	US Stock Returns	US Bond Total Returns	US Risk Premium Bond Total Returns	US Bond Income Returns	US Risk Premium Bond Income Returns
1947-1956	19.38%	0.85%	18.54%	2.53%	16.85%
1948-1957	17.74%	1.86%	15.88%	2.66%	15.07%
1949-1958	21.52%	0.91%	20.62%	2.75%	18.77%
1950-1959	20.84%	0.04%	20.80%	2.93%	17.91%
1951-1960	17.71%	1.41%	16.31%	3.14%	14.58%
1952-1961	18.00%	1.90%	16.10%	3.28%	14.72%
1953-1962	15.29%	2.47%	12.82%	3.42%	11.87%
1954-1963	17.67%	2.23%	15.44%	3.52%	14.15%
1955-1964	14.06%	1.86%	12.20%	3.66%	10.40%
1956-1965	12.15%	2.06%	10.09%	3.80%	8.34%
1957-1966	10.48%	2.98%	7.50%	3.95%	6.53%
1958-1967	13.96%	1.32%	12.64%	4.07%	9.89%
1959-1968	10.73%	1.90%	8.83%	4.29%	6.44%
1960-1969	8.68%	1.62%	7.06%	4.49%	4.20%
1961-1970	9.04%	1.45%	7.58%	4.73%	4.30%
1962-1971	7.78%	2.68%	5.10%	4.98%	2.80%
1963-1972	10.55%	2.56%	7.99%	5.17%	5.38%
1964-1973	6.80%	2.33%	4.48%	5.43%	1.37%
1965-1974	2.51%	2.41%	0.10%	5.74%	-3.23%
1966-1975	4.98%	3.26%	1.72%	6.12%	-1.14%
1967-1976	8.37%	4.57%	3.80%	6.46%	1.91%
1968-1977	5.26%	5.42%	-0.16%	6.72%	-1.46%
1969-1978	4.81%	5.33%	-0.52%	6.96%	-2.15%
1970-1979	7.50%	5.71%	1.79%	7.25%	0.25%
1971-1980	10.34%	4.11%	6.24%	7.57%	2.77%
1972-1981	8.42%	2.97%	5.45%	8.10%	0.33%
1973-1982	8.67%	6.44%	2.23%	8.86%	-0.19%
1974-1983	12.38%	6.61%	5.77%	9.25%	3.14%
1975-1984	15.66%	7.73%	7.93%	9.69%	5.96%
1976-1985	15.15%	9.90%	5.25%	10.02%	5.13%
1977-1986	14.61%	10.68%	3.93%	10.13%	4.49%
1978-1987	15.86%	10.48%	5.38%	10.21%	5.65%
1979-1988	16.88%	11.56%	5.32%	10.31%	6.57%
1980-1989	18.19%	13.50%	4.69%	10.31%	7.88%
1981-1990	14.63%	14.51%	0.12%	10.13%	4.50%
1982-1991	18.17%	16.25%	1.92%	9.80%	8.38%
1983-1992	16.80%	13.02%	3.78%	9.17%	7.63%
1984-1993	15.55%	14.78%	0.76%	8.85%	6.70%
1985-1994	15.05%	12.46%	2.59%	8.34%	6.71%
1986-1995	15.58%	12.53%	3.05%	7.97%	7.61%
1987-1996	16.04%	9.98%	6.06%	7.69%	8.35%
1988-1997	18.85%	11.84%	7.01%	7.56%	11.29%
1989-1998	20.03%	12.18%	7.85%	7.25%	12.78%
1990-1999	18.98%	9.47%	9.51%	6.93%	12.06%
1991-2000	18.39%	11.00%	7.39%	6.76%	11.63%
1992-2001	14.15%	9.44%	4.71%	6.49%	7.66%
1993-2002	11.17%	10.42%	0.75%	6.32%	4.85%
1994-2003	13.04%	8.74%	4.30%	6.08%	6.96%
1995-2004	14.00%	10.37%	3.63%	5.93%	8.07%
1996-2005	10.74%	7.98%	2.76%	5.64%	5.11%
1997-2006	10.02%	8.19%	1.82%	5.49%	4.53%
1998-2007	7.23%	7.60%	-0.37%	5.31%	1.92%
1999-2008	0.67%	8.88%	-8.21%	5.17%	-4.50%

Source: Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2009 Yearbook,
www.federalreserve.gov, www.standardandpoors.com

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	2007	2008	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**	**2.86**	**4.35**	**4.52**
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	3.08	3.84	4.51
Consumer Staples	3.57	4.01	3.70	4.04	4.17	4.76	4.45	4.37	4.05	3.88	2.97	3.24	3.94
Energy	5.60	6.16	7.31	7.97	8.30	8.10	6.98	5.72	5.56	5.46	5.40	7.04	6.63
Financials	4.27	5.89	5.92	6.22	6.17	6.06	4.58	4.23	3.77	3.36	2.97	3.99	4.78
Health Care	6.62	7.73	8.19	9.38	9.00	9.39	8.93	8.68	6.98	6.57	5.45	4.92	7.65
Industrials	4.13	4.93	4.69	5.12	6.50	7.18	6.92	6.87	6.48	5.16	4.08	4.87	5.58
Information Technology	7.99	9.17	10.35	12.27	15.16	17.12	16.64	17.09	15.81	13.36	10.20	11.82	13.08
Materials	5.87	6.98	7.22	7.29	7.40	7.25	5.89	5.65	5.67	5.88	5.59	7.96	6.55
Telecommunication Services	3.66	5.82	7.37	7.87	8.46	8.71	7.54	5.74	4.97	4.64	4.18	5.08	6.17
Utilities	3.12	3.80	4.00	4.80	5.06	4.88	4.49	4.09	3.36	3.13	3.49	4.04	4.02
Mean	**4.85**	**5.89**	**6.34**	**7.00**	**7.56**	**7.92**	**7.18**	**6.75**	**6.10**	**5.51**	**4.74**	**5.68**	**6.29**
Median	**4.20**	**5.85**	**6.57**	**6.76**	**6.95**	**7.21**	**6.41**	**5.68**	**5.27**	**4.90**	**4.13**	**4.90**	**5.74**

Ratios of Standard Deviations

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**	**0.74**	**0.71**	**0.64**
10 Sector Indices (Median)	**0.74**	**0.65**	**0.61**	**0.71**	**0.73**	**0.68**	**0.70**	**0.72**	**0.64**	**0.64**	**0.85**	**0.82**	**0.71**

Source: TSX Review

5-YEAR PRICE BETAS FOR S&P/TSX SECTOR INDICES

	Consumer Discretionary	Consumer Staples	Energy	Financials	Health Care	Industrials	Information Technology	Materials	Telecommunication Services	Utilities
1997	0.82	0.62	0.97	0.94	0.60	0.97	1.57	1.32	0.64	0.53
1998	0.80	0.60	0.85	1.12	1.01	0.93	1.41	1.12	0.92	0.55
1999	0.73	0.44	0.90	1.00	1.00	0.78	1.55	1.04	1.11	0.30
2000	0.69	0.23	0.66	0.78	1.09	0.72	1.78	0.74	0.92	0.14
2001	0.68	0.10	0.49	0.66	0.98	0.82	2.13	0.60	0.94	-0.03
2002	0.73	0.08	0.43	0.66	0.99	0.86	2.28	0.57	0.93	-0.06
2003	0.74	-0.08	0.26	0.38	0.85	0.91	2.74	0.43	0.83	-0.25
2004	0.80	-0.07	0.17	0.39	0.82	1.05	2.87	0.41	0.58	-0.13
2005	0.83	0.07	0.48	0.56	0.72	1.13	2.68	0.77	0.74	0.00
2006	0.86	0.37	1.03	0.68	0.85	1.06	2.07	1.32	0.52	0.25
2007	0.73	0.54	1.44	0.51	0.54	0.96	1.12	1.45	0.62	0.46
2008	0.59	0.32	1.43	0.61	0.48	0.81	1.43	1.30	0.55	0.49

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		
	88-08	**88-97**	**99-08**	**88-08**	**88-97**	**99-08**
Consumer Discretionary	0.058	0.102	0.009	0.761	0.904	0.676
Consumer Staples	0.116	0.127	0.092	0.351	0.727	0.105
Energy	0.099	0.084	0.165	0.774	0.765	0.767
Financials	0.119	0.183	0.067	0.761	1.039	0.471
Health Care	0.016	0.155	-0.104	0.806	0.807	0.698
Industrials	0.050	0.083	0.033	0.947	1.131	0.863
Information Technology	0.050	0.218	-0.097	1.746	1.213	2.189
Materials	0.057	0.034	0.102	0.970	1.257	0.814
Telecommunication Services	0.124	0.154	0.084	0.720	0.578	0.698
Utilities	0.098	0.115	0.088	0.300	0.624	0.065
Intercept				**0.12**	**0.14**	**0.11**
Adjusted R Square				**26%**	**1%**	**32%**
Beta				**-0.047**	**-0.017**	**-0.084**

[1/] Data only available starting December 1987

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	2007	2008	2009 [3/]
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	0.58	0.19	0.41
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	0.24	0.17	0.38
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	0.54	0.30	0.56
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	0.65	0.21	0.49
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	0.35	0.26	0.21
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	na	na	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	0.52	0.38	0.47
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**	**0.48**	**0.25**	**0.42**
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**	**0.53**	**0.24**	**0.44**
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	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	0.46	0.49	0.56

Adjusted Betas [2/]
Five Year Period Ending:

COMPANY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009 [3/]
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	0.72	0.45	0.61
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	0.49	0.44	0.59
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	0.69	0.53	0.70
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	0.77	0.47	0.66
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	0.56	0.50	0.47
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	na	na	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	0.68	0.58	0.65
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**	**0.65**	**0.50**	**0.61**
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**	**0.68**	**0.49**	**0.63**
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	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	0.64	0.66	0.71

[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%.

[3/] Three-year beta based on weekly data calculated through March 2009.

Source: Standard and Poor's Research Insight and TSX Review.

DCF-BASED EQUITY RISK PREMIUM STUDY FOR BENCHMARK U.S. GAS AND ELECTRIC UTILITIES
(Annual Averages of Monthly Data)

	Expected Dividend Yield [1/]	I/B/E/S EPS Growth Forecast	DCF Cost	Long Treasury Yield	Risk Premium
1991	7.0	4.6	11.6	8.1	3.6
1992	6.4	4.4	10.8	7.7	3.1
1993	5.6	4.6	10.1	6.6	3.6
1994	6.3	4.1	10.4	7.4	3.0
1995	6.1	3.9	9.9	6.8	3.1
1996	5.7	4.0	9.7	6.7	3.0
1997	5.5	4.2	9.8	6.6	3.2
1998	4.7	4.6	9.4	5.5	3.8
1999	5.1	5.0	10.2	5.9	4.3
2000	5.2	5.7	11.0	5.9	5.1
2001	4.8	6.6	11.4	5.5	6.0
2002	4.8	6.4	11.2	5.4	5.8
2003	4.9	5.2	10.1	5.0	5.1
2004	4.5	4.6	9.1	5.1	4.0
2005	4.1	4.7	8.8	4.5	4.3
2006	4.2	5.3	9.6	4.9	4.7
2007	4.1	5.3	9.4	4.8	4.6
2008	4.5	5.7	10.2	4.2	6.0
2009 (Through March)	5.3	5.7	11.0	3.6	7.4
Means for Long Treasury Yields:					
Under 5.0	**4.4**	**5.3**	**9.7**	**4.6**	**5.1**
5.0-5.99	**4.8**	**5.5**	**10.3**	**5.5**	**4.8**
6.0-6.99	**5.6**	**4.4**	**10.0**	**6.5**	**3.5**
7.0 and above	**6.5**	**4.3**	**10.8**	**7.7**	**3.1**
Means:					
1991 - 2009Q1	**5.2**	**5.0**	**10.2**	**5.9**	**4.3**
1993 - 2009Q1	**5.0**	**5.0**	**10.0**	**5.6**	**4.4**
1998 - 2009Q1	**4.7**	**5.4**	**10.1**	**5.1**	**4.9**

[1/] Dividend Yield is adjusted for I/B/E/S/ growth
Source: Standard & Poor's Research Insight, I/B/E/S and www.federalreserve.gov

DCF-BASED EQUITY RISK PREMIUM STUDY FOR BENCHMARK U.S. GAS AND ELECTRIC UTILITIES
Regression Analysis Results

Equation 1:

Equity Risk Premium = 8.40 - 0.70 (30-Year Treasury Yield)

t-statistics:
Long-term Bond Yield = -15.81
R^2 = 53%

Equity Risk Premium at Long-Term Bond Yield of 4.25% = 5.42

Equation 2:

Equity Risk Premium = 4.97 - 0.42 (30-Year Treasury Yield) + 1.23 (Spread)

Where Spread = Spread between A-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:
Long-term Bond Yield = -13.55
Utility/government bond yield spread = 19.21

R^2 = 83%

Equity Risk Premium at Long-term Bond Yield of 4.25% and Spread of 2.25-2.50 = 6.1

HISTORIC UTILITY EQUITY RISK PREMIUMS

Canada
(1956-2008)

Utilities Index Return	Bond Total Return	Risk Premium
12.0	7.9	4.1

Utilities Index Return	Bond Income Return	Risk Premium
12.0	7.8	4.2

United States
(1947-2008)

S&P / Moody's Gas Distribution Index Return	Bond Total Return	Risk Premium
12.1	6.6	5.5

S&P / Moody's Gas Distribution Index Return	Bond Income Return	Risk Premium
12.1	6.0	6.1

S&P/Moody's Electric Index Return	Bond Total Return	Risk Premium
10.8	6.6	4.2

S&P/Moody's Electric Index Return	Bond Income Return	Risk Premium
10.8	6.0	4.8

Notes:
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

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 2002-2008 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.

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 2008 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.

Source: Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2009 Yearbook;
Ibbotson Associates, Canadian Risk Premia Over Time Report 2008; Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006; www.standardandpoors.com, TSX Review
Mergent Corporate News Reports, www.federal reserve.com

**10-YEAR ROLLING AVERAGE RETURNS FOR
CANADIAN UTILITIES AND GOVERNMENT BONDS**

	S&P/TSX Utilities Returns	Canadian Bond Total Returns	Canadian Risk Premium Bond Total Returns	Canadian Bond Income Returns	Canadian Risk Premium Bond Income Returns
1956-1965	14.3%	2.4%	11.9%	4.9%	9.4%
1957-1966	10.1%	2.9%	7.1%	5.1%	5.0%
1958-1967	11.3%	2.1%	9.2%	5.3%	6.0%
1959-1968	10.8%	2.6%	8.2%	5.6%	5.2%
1960-1969	7.9%	2.9%	5.0%	5.8%	2.1%
1961-1970	7.2%	4.4%	2.8%	6.1%	1.0%
1962-1971	6.9%	4.5%	2.4%	6.3%	0.6%
1963-1972	9.2%	4.3%	4.9%	6.5%	2.7%
1964-1973	6.9%	4.1%	2.8%	6.8%	0.1%
1965-1974	6.1%	3.2%	2.8%	7.2%	-1.1%
1966-1975	4.7%	3.4%	1.3%	7.6%	-2.9%
1967-1976	9.3%	5.1%	4.1%	8.0%	1.3%
1968-1977	9.6%	6.0%	3.6%	8.3%	1.3%
1969-1978	9.2%	6.2%	3.1%	8.6%	0.7%
1970-1979	13.6%	6.1%	7.5%	8.8%	4.8%
1971-1980	13.8%	4.1%	9.7%	9.3%	4.5%
1972-1981	12.2%	2.7%	9.5%	10.3%	1.9%
1973-1982	15.4%	6.9%	8.5%	11.0%	4.3%
1974-1983	17.2%	7.6%	9.6%	11.5%	5.7%
1975-1984	19.5%	9.3%	10.2%	11.9%	7.6%
1976-1985	19.7%	11.6%	8.1%	12.1%	7.5%
1977-1986	17.3%	11.4%	5.9%	12.2%	5.2%
1978-1987	15.9%	10.9%	5.1%	12.3%	3.6%
1979-1988	15.4%	11.8%	3.7%	12.4%	3.0%
1980-1989	12.8%	13.7%	-0.9%	12.4%	0.4%
1981-1990	11.1%	13.8%	-2.7%	12.2%	-1.1%
1982-1991	12.1%	16.5%	-4.5%	11.6%	0.5%
1983-1992	8.9%	13.6%	-4.7%	11.0%	-2.1%
1984-1993	10.4%	14.9%	-4.5%	10.5%	-0.1%
1985-1994	9.2%	12.3%	-3.1%	10.1%	-0.9%
1986-1995	7.2%	12.4%	-5.2%	9.8%	-2.6%
1987-1996	8.8%	12.1%	-3.3%	9.6%	-0.7%
1988-1997	12.0%	13.8%	-1.8%	9.2%	2.8%
1989-1998	11.2%	14.2%	-2.9%	8.7%	2.5%
1990-1999	8.2%	11.8%	-3.6%	8.2%	0.0%
1991-2000	12.8%	12.9%	-0.1%	7.7%	5.1%
1992-2001	13.7%	10.8%	2.9%	7.3%	6.4%
1993-2002	13.7%	10.5%	3.1%	6.9%	6.7%
1994-2003	14.0%	9.0%	5.0%	6.7%	7.3%
1995-2004	14.2%	10.9%	3.3%	6.3%	8.0%
1996-2005	17.7%	9.8%	7.9%	5.9%	11.9%
1997-2006	16.0%	8.7%	7.3%	5.5%	10.5%
1998-2007	13.5%	7.3%	6.2%	5.2%	8.3%
1999-2008	11.1%	7.2%	3.9%	5.1%	6.0%

Source:

Ibbotson Associates, Canadian Risk Premia Over Time Report 2008; Canadian Institute of Actuaries, Report on Canadian Economic Statistics 1924-2006' TSX Review

10-YEAR ROLLING AVERAGE RETURNS FOR

U.S. UTILITIES AND GOVERNMENT BONDS

	S&P/Moody's Gas Distributors Returns	S&P/Moody's Electric Returns	US Bond Total Returns	US Gas Risk Premium Bond Total Returns	US Electric Risk Premium Bond Total Returns	US Bond Income Returns	US Gas Risk Premium Bond Income Returns	US Electric Risk Premium Bond Income Returns
1947-1956	12.4%	10.4%	0.8%	11.5%	9.5%	2.5%	9.8%	7.8%
1948-1957	12.6%	12.6%	1.9%	10.8%	10.8%	2.7%	10.0%	10.0%
1949-1958	15.7%	16.3%	0.9%	14.8%	15.4%	2.7%	12.9%	13.6%
1950-1959	12.6%	14.3%	0.0%	12.6%	14.3%	2.9%	9.7%	11.4%
1951-1960	14.6%	16.0%	1.4%	13.2%	14.6%	3.1%	11.5%	12.9%
1952-1961	15.9%	17.2%	1.9%	14.0%	15.3%	3.3%	12.6%	13.9%
1953-1962	14.3%	15.4%	2.5%	11.9%	12.9%	3.4%	10.9%	11.9%
1954-1963	15.0%	15.5%	2.2%	12.8%	13.2%	3.5%	11.5%	12.0%
1955-1964	13.5%	14.7%	1.9%	11.6%	12.8%	3.7%	9.8%	11.0%
1956-1965	12.4%	13.7%	2.1%	10.4%	11.7%	3.8%	8.6%	9.9%
1957-1966	9.9%	13.0%	3.0%	6.9%	10.0%	4.0%	6.0%	9.1%
1958-1967	10.8%	11.7%	1.3%	9.5%	10.4%	4.1%	6.7%	7.6%
1959-1968	8.6%	8.7%	1.9%	6.7%	6.8%	4.3%	4.3%	4.5%
1960-1969	6.9%	6.9%	1.6%	5.2%	5.3%	4.5%	2.4%	2.4%
1961-1970	7.9%	6.0%	1.5%	6.4%	4.6%	4.7%	3.2%	1.3%
1962-1971	4.7%	3.3%	2.7%	2.1%	0.7%	5.0%	-0.3%	-1.6%
1963-1972	6.5%	3.6%	2.6%	4.0%	1.0%	5.2%	1.4%	-1.6%
1964-1973	3.8%	0.7%	2.3%	1.4%	-1.6%	5.4%	-1.7%	-4.7%
1965-1974	2.7%	-3.4%	2.4%	0.3%	-5.8%	5.7%	-3.0%	-9.1%
1966-1975	5.1%	1.4%	3.3%	1.9%	-1.9%	6.1%	-1.0%	-4.8%
1967-1976	11.4%	4.1%	4.6%	6.8%	-0.4%	6.5%	4.9%	-2.3%
1968-1977	11.4%	5.3%	5.4%	6.0%	-0.1%	6.7%	4.7%	-1.4%
1969-1978	9.4%	4.1%	5.3%	4.1%	-1.2%	7.0%	2.4%	-2.9%
1970-1979	14.6%	5.5%	5.7%	8.9%	-0.2%	7.2%	7.4%	-1.8%
1971-1980	14.7%	4.9%	4.1%	10.6%	0.8%	7.6%	7.1%	-2.7%
1972-1981	13.6%	6.7%	3.0%	10.6%	3.8%	8.1%	5.5%	-1.4%
1973-1982	12.0%	9.9%	6.4%	5.6%	3.4%	8.9%	3.2%	1.0%
1974-1983	17.1%	13.1%	6.6%	10.5%	6.5%	9.2%	7.9%	3.8%
1975-1984	18.7%	18.1%	7.7%	11.0%	10.4%	9.7%	9.0%	8.4%
1976-1985	18.2%	15.6%	9.9%	8.3%	5.7%	10.0%	8.2%	5.6%
1977-1986	15.9%	16.0%	10.7%	5.3%	5.4%	10.1%	5.8%	5.9%
1978-1987	14.0%	14.4%	10.5%	3.6%	3.9%	10.2%	3.8%	4.2%
1979-1988	16.4%	16.5%	11.6%	4.8%	4.9%	10.3%	6.1%	6.2%
1980-1989	17.1%	19.8%	13.5%	3.6%	6.3%	10.3%	6.8%	9.4%
1981-1990	13.9%	19.3%	14.5%	-0.6%	4.8%	10.1%	3.8%	9.2%
1982-1991	17.0%	20.3%	16.3%	0.7%	4.0%	9.8%	7.2%	10.5%
1983-1992	19.0%	17.3%	13.0%	5.9%	4.3%	9.2%	9.8%	8.2%
1984-1993	17.2%	17.3%	14.8%	2.5%	2.5%	8.9%	8.4%	8.4%
1985-1994	14.2%	13.5%	12.5%	1.8%	1.0%	8.3%	5.9%	5.1%
1986-1995	15.3%	14.0%	12.5%	2.8%	1.5%	8.0%	7.3%	6.1%
1987-1996	13.9%	11.2%	10.0%	3.9%	1.2%	7.7%	6.2%	3.5%
1988-1997	16.8%	14.6%	11.8%	5.0%	2.8%	7.6%	9.3%	7.0%
1989-1998	14.5%	15.2%	12.2%	2.3%	3.0%	7.2%	7.2%	8.0%
1990-1999	10.0%	10.2%	9.5%	0.5%	0.7%	6.9%	3.1%	3.2%
1991-2000	12.7%	15.8%	11.0%	1.7%	4.8%	6.8%	5.9%	9.1%
1992-2001	11.0%	12.3%	9.4%	1.6%	2.9%	6.5%	4.6%	5.8%
1993-2002	9.8%	10.6%	10.4%	-0.6%	0.2%	6.3%	3.5%	4.3%
1994-2003	10.1%	11.2%	8.7%	1.3%	2.5%	6.1%	4.0%	5.1%
1995-2004	12.8%	14.1%	10.4%	2.4%	3.7%	5.9%	6.8%	8.2%
1996-2005	9.6%	11.9%	8.0%	1.6%	3.9%	5.6%	3.9%	6.2%
1997-2006	10.7%	13.7%	8.2%	2.5%	5.5%	5.5%	5.2%	8.2%
1998-2007	8.8%	12.4%	7.6%	1.2%	4.8%	5.3%	3.5%	7.1%
1999-2008	9.6%	7.4%	8.9%	0.8%	-1.4%	5.2%	4.5%	2.3%

Source: Ibbotson Associates, Stocks, Bonds, Bills and Inflation: 2009 Yearbook;
www.standardandpoors.com, Mergent Corporate News Reports,
www.federal reserve.com

INDIVIDUAL COMPANY RISK DATA FOR BENCHMARK SAMPLE OF U.S. GAS AND ELECTRIC UTILITIES

	Value Line							S & P		Moody's	
	Safety	Forecast Common Equity Ratio 2012-2014	Forecast Return On Average Common Equity 2012-2014	Dividend Payout Forecast 2012-2014	Beta	Research Insight Beta [1/]	Common Equity Ratio 2008	Business Risk Profile	Debt Rating	Debt Rating [2/]	Average Market/ Book Ratio 2008
AGL Resources	2	55.0%	15.2%	58.8%	0.75	0.312	39.4%	Excellent	A-	Baa1	1.36
Consolidated Edison	1	53.5%	9.0%	64.2%	0.65	0.339	48.5%	Excellent	A-	A2	1.08
Dominion Resources	2	47.5%	15.0%	55.0%	0.65	0.565	36.3%	Excellent	A-	Baa2	1.89
Duke Energy	2	53.5%	8.4%	73.3%	NMF	0.395	59.2%	Excellent	A-	Baa2	0.87
FPL	1	45.0%	14.6%	38.3%	0.75	0.683	40.6%	Excellent	A	A2	1.70
New Jersey Resources	1	67.0%	11.4%	49.1%	0.65	0.200	51.2%	Excellent	A	A1	2.12
Northwest Nat. Gas	1	53.0%	11.6%	58.0%	0.60	0.395	45.3%	Excellent	AA-	A3	1.79
NSTAR	1	51.5%	15.0%	60.0%	0.65	0.351	36.8%	Excellent	A+	A2	1.95
Piedmont Natural Gas	2	53.0%	14.0%	58.1%	0.65	0.328	41.9%	Excellent	A	A3	2.14
Scana	2	42.0%	10.9%	60.0%	0.65	0.630	39.3%	Excellent	A-	Baa1	1.24
Southern Co.	1	44.0%	13.8%	66.7%	0.55	0.465	40.5%	Excellent	A	A3	1.88
Vectren	2	52.0%	10.5%	64.3%	0.75	0.358	42.2%	Excellent	A-	Baa1	1.37
WGL Holdings Inc.	1	64.5%	10.6%	58.2%	0.65	0.323	51.7%	Excellent	AA-	A2	1.53
Mean	**1**	**52.4%**	**12.3%**	**58.8%**	**0.66**	**0.41**	**44.1%**	**Excellent**	**A**	**A3**	**1.61**
Median	**1**	**53.0%**	**11.6%**	**58.8%**	**0.65**	**0.36**	**41.9%**	**Excellent**	**A**	**A3**	**1.70**

1/ Calculated using monthly data against the S&P 500 (60 months ending March 2009).

2/ Rating for WGL Holdings is Washington Gas Light.

Source: Standard and Poor's Research Insight, Value Line (February and March 2009), www.Moodys.com,
Standard and Poor's, *Issuer Ranking: U.S. Regulated Electric Utilities, Strongest To Weakest* (March 31, 2009) and
Standard and Poor's, *Issuer Ranking: U.S. Natural Gas Distributors And Integrated Gas Companies, Strongest To Weakest* (March 10, 2009).

DCF COST OF EQUITY FOR BENCHMARK SAMPLE OF U.S. GAS AND ELECTRIC UTILITIES (BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)

Company	Annualized Last Paid Dividend	Average Monthly High/Low Prices Jan 2009-Mar 2009	Expected Dividend Yield [1/]	Average I/B/E/S Long-Term EPS Forecasts	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)	(5)
AGL Resources	1.72	29.30	6.1	4.3	10.4
Consolidated Edison	2.36	38.41	6.3	2.5	8.8
Dominion Resources	1.75	32.69	5.8	7.8	13.5
Duke Energy	0.92	14.35	6.7	4.5	11.1
FPL	1.89	48.70	4.3	9.6	13.9
New Jersey Resources	1.24	36.57	3.6	7.0	10.6
Northwest Nat. Gas	1.58	42.36	3.9	4.8	8.7
NSTAR	1.50	32.61	4.9	6.0	10.9
Piedmont Natural Gas	1.08	25.89	4.5	7.1	11.6
Scana	1.88	32.05	6.1	4.6	10.7
Southern Co.	1.68	32.11	5.5	5.4	10.9
Vectren	1.34	22.87	6.3	7.2	13.5
WGL Holdings Inc.	1.42	32.05	4.6	4.0	8.6
Mean	**1.57**	**32.30**	**5.3**	**5.7**	**11.0**
Median	**1.58**	**32.11**	**5.5**	**5.4**	**10.9**

[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 (March 2009)

DCF COST OF EQUITY FOR BENCHMARK SAMPLE OF
U.S. GAS AND ELECTRIC UTILITIES
(BASED ON VALUE LINE LONG TERM EPS GROWTH RATES)

Company	Annualized Last Paid Dividend	Average Monthly High/Low Prices Jan 2009-Mar 2009	Expected Dividend Yield [1/]	Value Line EPS Growth	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)	(5)
AGL Resources	1.72	29.30	6.0	3.0	9.0
Consolidated Edison	2.36	38.41	6.2	1.0	7.2
Dominion Resources	1.75	32.69	5.9	10.5	16.4
Duke Energy	0.92	14.35	6.9	7.0	13.9
FPL	1.89	48.70	4.3	10.5	14.8
New Jersey Resources	1.24	36.57	3.6	5.5	9.1
Northwest Nat. Gas	1.58	42.36	4.0	7.0	11.0
NSTAR	1.50	32.61	4.9	7.5	12.4
Piedmont Natural Gas	1.08	25.89	4.5	7.5	12.0
Scana	1.88	32.05	6.1	4.0	10.1
Southern Co.	1.68	32.11	5.5	4.5	10.0
Vectren	1.34	22.87	6.2	6.0	12.2
WGL Holdings Inc.	1.42	32.05	4.6	4.0	8.6
Mean	**1.57**	**32.30**	**5.3**	**6.0**	**11.3**
Median	**1.58**	**32.11**	**5.5**	**6.0**	**11.0**

[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 and *Value Line* (Issue 1, February 27, 2009; Issue 3, March 13, 2009; Issue 5, March 27, 2009)

DCF COSTS OF EQUITY FOR BENCHMARK SAMPLE OF
U.S. GAS AND ELECTRIC UTILITIES
(TWO-STAGE MODEL)

Company	Annualized Last Paid Dividend	Average Monthly High/Low Prices Jan 2009-Mar 2009	Stage 1 I/B/E/S EPS Forecasts	Stage 2 GDP Growth 1/	DCF Cost of Equity 2/
	(1)	(2)	(3)	(4)	(5)
AGL Resources	1.72	29.30	4.3	5.0	10.9
Consolidated Edison	2.36	38.41	2.5	5.0	10.8
Dominion Resources	1.75	32.69	7.8	5.0	11.3
Duke Energy	0.92	14.35	4.5	5.0	11.6
FPL	1.89	48.70	9.6	5.0	9.9
New Jersey Resources	1.24	36.57	7.0	5.0	8.8
Northwest Nat. Gas	1.58	42.36	4.8	5.0	8.8
NSTAR	1.50	32.61	6.0	5.0	10.0
Piedmont Natural Gas	1.08	25.89	7.1	5.0	9.7
Scana	1.88	32.05	4.6	5.0	11.0
Southern Co.	1.68	32.11	5.4	5.0	10.5
Vectren	1.34	22.87	7.2	5.0	11.7
WGL Holdings Inc.	1.42	32.05	4.0	5.0	9.4
Mean	**1.57**	**32.30**	**5.7**	**5.0**	**10.3**
Median	**1.58**	**32.11**	**5.4**	**5.0**	**10.5**

1/ Forecast nominal rate of GDP growth, 2010-19
2/ Internal Rate of Return: average I/B/E/S EPS forecast growth rate applies for first 5 years; GDP growth thereafter.

Source: Standard & Poor's Research Insight; www.yahoo.com; Blue Chip Economic Indicators (March 2009); I/B/E/S (March 2009)

RISK MEASURES FOR 27 LOW RISK UNREGULATED CANADIAN COMPANIES

Company Name	Debt Ratings S&P	Debt Ratings DBRS	CBS Stock Rating	Beta 2003-2007 Raw	Beta 2003-2007 Adjusted	Beta 2004-2008 Raw	Beta 2004-2008 Adjusted	2007 Equity Ratio Based On Total Capital	1991-2007 Average Market To Book Ratio
ANDREW PELLER LTD			Average	0.55	0.70	0.56	0.70	47.9%	1.33
ASTRAL MEDIA INC -CL A			Very Conservative	0.60	0.73	0.56	0.70	100.0%	1.65
CANADIAN NATIONAL RAILWAY CO	A-	A (low)	Very Conservative	0.97	0.98	0.46	0.64	64.4%	2.02
CANADIAN PACIFIC RAILWAY LTD	BBB	BBB	Very Conservative	0.70	0.80	0.69	0.79	55.3%	1.46
CANADIAN TIRE CORP -CL A	BBB+	A (low)	Very Conservative	0.84	0.89	0.53	0.68	65.9%	1.64
COGECO INC -SUB VTG			Very Conservative	0.60	0.73	1.01	1.01	27.0%	1.13
FINNING INTERNATIONAL INC	BBB+	A (low)	Conservative	0.83	0.88	1.03	1.02	57.6%	1.95
JEAN COUTU GROUP			Very Conservative	0.59	0.73	0.33	0.55	89.6%	2.72
LEON'S FURNITURE LTD			Average	0.59	0.72	0.71	0.80	99.9%	2.41
LINAMAR CORP			Conservative	0.69	0.79	1.22	1.15	65.3%	2.35
LOBLAW COMPANIES LTD	BBB	BBB	Very Conservative	0.73	0.82	0.22	0.48	54.1%	2.96
MAGNA INTERNATIONAL -CL A	BBB	A	Conservative	0.99	0.99	0.80	0.87	91.5%	1.62
MAPLE LEAF FOODS INC			Very Conservative	0.30	0.53	0.09	0.39	56.8%	2.02
METRO INC -CL A	BBB	BBB	Very Conservative	0.80	0.86	0.29	0.52	64.9%	2.15
NEWFOUNDLAND CAP CORP -CL A			Average	0.03	0.35	0.04	0.36	62.8%	1.41
REITMANS (CANADA) -CL A			Average	1.12	1.08	0.85	0.90	97.0%	1.61
RICHELIEU HARDWARE LTD			Average	0.41	0.60	0.39	0.59	96.8%	2.47
SAPUTO INC			Very Conservative	0.37	0.58	0.31	0.54	78.3%	3.14
SHAW COMMUNICATIONS INC-CL B	BBB-	BBB (low)	Very Conservative	0.40	0.59	0.41	0.60	39.4%	2.61
SNC-LAVALIN GROUP INC	BBB+	BBB (high)	Very Conservative	0.55	0.70	0.97	0.98	30.6%	2.85
THOMSON-REUTERS CORP (CDN)	A-	A (low)	Very Conservative	0.46	0.64	0.34	0.56	73.0%	2.53
TOROMONT INDUSTRIES LTD		BBB	Average	0.79	0.86	0.74	0.83	74.0%	2.62
TORSTAR CORP -CL B		BBB	Conservative	0.28	0.52	0.50	0.66	58.4%	2.10
TRANSCONTINENTAL INC -CL A	BBB	BBB (high)	Very Conservative	0.88	0.92	0.76	0.84	68.7%	1.51
TVA GROUP INC -CL B			Average	0.55	0.70	0.95	0.97	78.5%	2.06
UNI-SELECT INC			Average	0.42	0.61	0.43	0.62	70.4%	2.14
WESTON (GEORGE) LTD	BBB	BBB	Very Conservative	0.59	0.73	-0.22	0.18	32.7%	2.52
Mean	**BBB**	**BBB(high)**	**Conservative**	**0.61**	**0.74**	**0.55**	**0.70**	**66.7%**	**2.11**
Median	**BBB**	**BBB/BBB(high)**	**Very Conservative**	**0.59**	**0.73**	**0.53**	**0.68**	**65.3%**	**2.10**

Source: Standard and Poor's Research Insight, DBRS and The Blue Book of CBS Stock Reports.

RETURNS ON AVERAGE COMMON STOCK EQUITY FOR
27 LOW RISK UNREGULATED CANADIAN COMPANIES

Company Name	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	Average 1991-2007
ANDREW PELLER LTD	10.1	9.3	9.0	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	11.5	10.7
ASTRAL MEDIA INC -CL A	6.3	4.8	5.8	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	13.0	7.0
CANADIAN NATIONAL RAILWAY CO	-0.4	-33.4	-3.2	9.7	-43.7	6.1	13.9	2.8	12.6	14.4	12.5	8.9	11.2	18.8	18.8	21.9	21.6	5.4
CANADIAN PACIFIC RAILWAY LTD	-12.6	-7.4	-3.1	6.1	-13.0	13.5	18.0	10.3	7.3	20.2	6.6	15.2	11.3	10.8	13.0	17.2	18.3	7.7
CANADIAN TIRE CORP -CL A	11.9	6.4	6.9	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	14.2	10.8
COGECO INC -SUB VTG	-2.4	0.7	21.9	6.8	3.0	0.0	10.8	11.3	25.1	3.5	25.3	12.5	2.9	-3.1	-6.3	7.4	21.0	8.3
FINNING INTERNATIONAL INC	1.1	0.7	6.5	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	17.2	11.0
JEAN COUTU GROUP	20.3	18.5	10.1	17.0	15.2	16.2	15.3	15.5	15.7	14.9	15.7	16.6	16.2	8.9	6.6	8.0	-14.3	12.7
LEON'S FURNITURE LTD	14.6	11.4	16.4	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	19.2	16.8
LINAMAR CORP	14.1	18.1	20.5	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	12.6	17.5
LOBLAW COMPANIES LTD	13.2	8.7	9.6	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	6.0	12.8
MAGNA INTERNATIONAL -CL A	6.6	22.8	19.6	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	7.8	14.4
MAPLE LEAF FOODS INC	8.8	7.9	7.3	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	19.2	8.5
METRO INC -CL A	6.1	7.3	13.0	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	15.1	18.6
NEWFOUNDLAND CAP CORP -CL A	-21.0	-39.8	17.7	19.4	8.6	9.0	62.1	45.1	4.7	3.3	-5.6	12.7	7.9	12.2	7.1	13.8	20.7	10.5
REITMANS (CANADA) -CL A	9.4	15.4	11.1	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	24.7	14.1
RICHELIEU HARDWARE LTD	NA	NA	NA	17.4	10.9	11.6	15.5	16.5	17.4	19.8	19.9	21.8	21.2	20.5	18.4	18.3	17.2	17.6
SAPUTO INC	NA	NA	NA	NA	NA	37.3	18.9	19.3	18.6	16.0	19.4	18.1	19.5	18.8	14.1	16.2	18.3	19.5
SHAW COMMUNICATIONS INC-CL B	12.9	11.5	11.5	10.2	6.2	11.8	2.9	-0.1	1.9	5.5	-8.4	-14.1	-4.5	2.8	7.7	27.2	20.4	6.2
SNC-LAVALIN GROUP INC	3.2	5.6	8.9	13.1	13.8	15.8	14.5	14.3	10.7	6.7	6.6	38.9	13.8	15.1	17.2	18.7	16.7	13.7
THOMSON-REUTERS CORP (CDN)	9.9	6.0	10.0	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	31.1	14.0
TOROMONT INDUSTRIES LTD	14.0	13.6	20.7	30.6	27.1	24.3	47.5	22.5	16.6	15.4	16.4	12.7	16.9	17.8	17.6	19.0	20.0	20.8
TORSTAR CORP -CL B	-0.6	8.4	-1.7	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	9.5
TRANSCONTINENTAL INC -CL A	0.3	8.1	9.3	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	10.3	10.2
TVA GROUP INC -CL B	-17.9	2.1	9.4	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	19.4	8.1
UNI-SELECT INC	NA	NA	NA	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	13.7	18.2
WESTON (GEORGE) LTD	7.0	3.2	4.5	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	12.7	13.6
Mean	**4.8**	**4.6**	**10.1**	**12.9**	**9.4**	**13.3**	**19.1**	**14.8**	**14.5**	**12.8**	**8.8**	**15.0**	**13.6**	**13.9**	**12.9**	**12.5**	**15.5**	**12.5**
Median	**6.8**	**7.6**	**9.5**	**11.3**	**11.6**	**13.8**	**15.1**	**13.0**	**14.0**	**14.9**	**12.5**	**15.2**	**14.0**	**13.9**	**13.3**	**13.4**	**17.2**	**12.7**
Average of Annual Medians																		**12.8**

Source: Standard and Poor's Research Insight.

RISK MEASURES AND RETURNS ON EQUITY FOR 81 LOW RISK UNREGULATED U.S. COMPANIES

Company Name	S&P Debt Rating	Value Line Safety	Value Line Earnings Predictability	Value Line Financial Strength	Value Line Beta	Equity Ratio (Total Capital) 2006	Equity Ratio (Total Capital) 2007	Return on Average Common Equity 1991-2007	*Value Line* Forecast Return on Average Common Equity 2011-2013	1991-2007 Average Market To Book Ratio
3M CO	AA	1	80	A++	0.75	73%	70%	26.9	31.5	5.5
AARON RENTS INC		3	65	B++	0.80	82%	78%	13.1		2.0
ABM INDUSTRIES INC		3	90	B++	0.95	100%	100%	13.4	11.9	1.9
ACETO CORP		3	60	B++	0.85	100%	100%	10.1		1.4
ARDEN GROUP INC -CL A		3	65	B++	0.55	98%	99%	15.7		2.3
BOB EVANS FARMS		3	55	B++	0.90	77%	67%	11.4	12.2	1.8
BROWN-FORMAN -CL B	A	1	100	A+	0.70	57%	63%	24.0	20.1	4.5
CASEYS GENERAL STORES INC		3	70	B	0.75	70%	75%	11.9	12.9	2.1
CATO CORP -CL A		3	65	B++	0.95	100%	100%	18.1	18.8	2.6
CLARCOR INC		3	100	B++	0.95	97%	97%	17.2	13.7	2.7
COCA-COLA ENTERPRISES INC	A	3	5	B	0.90	31%	38%	4.9	12.8	2.8
CONAGRA FOODS INC	BBB+	2	75	A	0.65	57%	57%	17.1	16.4	3.4
COURIER CORP		3	65	B+	0.95	91%	92%	11.9		1.5
CSS INDUSTRIES INC		3	75	B+	0.95	90%	93%	13.2		1.4
CVS CAREMARK CORP	BBB+	2	95	A	0.80	65%	75%	10.4	11.7	3.2
ENNIS INC		3	95	B++	0.95	78%	79%	19.8		2.5
FAMILY DOLLAR STORES		3	90	A	0.60	83%	82%	19.0	15.9	3.5
FARMER BROS CO		3	10	B++	0.95	100%	100%	8.2		1.4
FEDEX CORP	BBB+	2	80	B++	0.85	83%	88%	11.7	14.5	2.3
FLEXSTEEL INDUSTRIES INC		3	45	B+	0.40	77%	80%	7.8		1.1
FLOWERS FOODS INC	BBB-	3	60	B	0.70	87%	96%	9.4	16.6	2.7
FORTUNE BRANDS INC	BBB+	2	85	B++	0.95	45%	56%	13.1	10.3	2.3
FRISCH'S RESTAURANTS INC		3	70	B++	0.65	73%	77%	9.5		1.4
G&K SERVICES INC -CL A		3	90	B+	0.85	72%	73%	12.8	7.2	2.7
GENERAL DYNAMICS CORP	A	1	100	A++	0.90	78%	81%	24.6	18.0	2.8
GENUINE PARTS CO		1	100	A++	0.80	84%	84%	17.9	21.2	2.9
HASBRO INC	BBB+	3	40	B++	0.80	75%	62%	10.9	21.0	2.2
HAVERTY FURNITURE		3	40	B	0.75	85%	91%	8.9		1.2
HEALTHCARE SERVICES GROUP		3	90	B++	0.75	100%	100%	9.4		2.0
HEARTLAND EXPRESS INC		3	75	B++	0.85	100%	100%	19.8	16.9	4.1
HOME DEPOT INC	BBB+	1	75	A++	0.95	68%	57%	19.7	15.1	5.8
HORMEL FOODS CORP	A	1	100	A	0.70	84%	82%	16.8	13.5	2.8
ILLINOIS TOOL WORKS	AA-	1	100	A++	0.95	86%	80%	18.6	22.2	3.5
INTL SPEEDWAY CORP -CL A	BBB+	3	85	B+	0.90	76%	75%	17.1	10.6	3.4
KIMBERLY-CLARK CORP	A	1	100	A++	0.55	63%	49%	25.2	35.9	5.2
LANCASTER COLONY CORP		1	90	A+	0.75	98%	90%	21.1	19.8	3.1
LANCE INC		3	55	B+	0.75	82%	83%	11.6	14.2	2.7
LOCKHEED MARTIN CORP	A-	1	90	A++	0.80	61%	69%	14.4	32.6	2.9
MATTEL INC	BBB-	3	80	B++	0.85	78%	71%	19.7	29.7	4.2
MATTHEWS INTL CORP -CL A		3	100	B+	0.90	73%	72%	19.3	17.3	3.3
MCCORMICK & COMPANY INC	A-	2	100	A	0.60	59%	60%	24.8	23.4	5.1

RISK MEASURES AND RETURNS ON EQUITY FOR 81 LOW RISK UNREGULATED U.S. COMPANIES

Company Name	S&P Debt Rating	Value Line Safety	Value Line Earnings Predictability	Value Line Financial Strength	Value Line Beta	Equity Ratio (Total Capital) 2006	Equity Ratio (Total Capital) 2007	Return on Average Common Equity 1991-2007	*Value Line* Forecast Return on Average Common Equity 2011-2013	1991-2007 Average Market To Book Ratio
MCDONALD'S CORP	A	1	90	A++	0.75	65%	62%	17.9	30.2	3.6
MEREDITH CORP		2	80	B++	0.90	55%	64%	18.7	12.9	3.7
MOLSON COORS BREWING CO	BBB+	3	NMF	B+	0.55	73%	76%	8.2	9.6	1.6
MULTI-COLOR CORP		3	75	B+	0.95	93%	48%	8.1		3.0
NIKE INC -CL B	A+	1	95	A+	0.90	93%	93%	21.2	23.4	3.9
NORTHROP GRUMMAN CORP	BBB+	1	85	A+	0.75	79%	80%	10.9	12.4	1.5
OMNICOM GROUP	A-	2	100	B++	0.95	56%	57%	24.3	28.3	5.6
OTTER TAIL CORP	BBB-	2	75	A	0.90	61%	53%	14.1	9.6	2.1
PEPSIAMERICAS INC	A	3	85	B	0.85	49%	46%	11.8	13.5	2.9
PEPSICO INC	A+	1	100	A++	0.60	85%	79%	29.4	31.1	7.0
PROCTER & GAMBLE CO	AA-	1	100	A++	0.55	62%	65%	26.7	17.9	6.2
RAYTHEON CO	A-	1	65	A+	0.70	74%	85%	9.8	14.6	1.7
ROLLINS INC		3	90	B++	0.80	100%	99%	23.1	28.0	6.4
ROSS STORES INC	BBB+	3	85	A	0.90	86%	87%	25.9	29.2	3.7
RUDDICK CORP		3	95	B+	0.60	73%	73%	11.3	11.8	1.7
SEABOARD CORP		3	5	B++	0.90	82%	86%	11.8		1.1
SHERWIN-WILLIAMS CO	A-	2	95	A	0.75	69%	65%	19.7	23.9	3.2
SMITH (A O) CORP		3	60	B+	0.90	61%	66%	12.2	10.5	1.5
SMUCKER (JM) CO		2	90	A	0.65	81%	70%	11.7	11.1	2.2
SOUTHWEST AIRLINES	BBB+	3	55	B+	0.90	79%	77%	12.4	9.7	2.7
STANDEX INTERNATIONAL CORP		3	70	B+	0.95	63%	55%	16.1	13.9	2.2
SYSCO CORP	AA-	1	95	A++	0.65	63%	65%	26.1	37.5	6.2
TANDY BRANDS ACCESSORIES INC		3	10	B+	0.65	88%	95%	9.3		1.3
TOOTSIE ROLL INDUSTRIES INC		1	90	A+	0.70	99%	99%	15.1	7.3	3.5
UNIFIRST CORP		3	90	B+	0.80	68%	71%	11.3	10.2	1.7
UNITED PARCEL SERVICE INC	AA-	1	95	A	0.75	79%	53%	20.5	37.2	5.9
UNITED TECHNOLOGIES CORP	A	1	100	A++	0.95	69%	70%	18.1	17.1	3.4
UNIVERSAL CORP/VA	BBB-	3	50	B++	0.75	47%	55%	15.5	11.2	1.9
VF CORP	A-	2	100	A	0.95	80%	74%	17.0	16.9	2.3
VILLAGE SUPER MARKET -CL A		3	90	B++	0.75	82%	86%	7.3		0.7
WALGREEN CO	A+	1	100	A+	0.75	94%	90%	19.0	15.1	5.7
WAL-MART STORES INC	AA	1	100	A++	0.60	61%	59%	21.9	18.9	5.0
WASHINGTON POST -CL B	A+	1	55	A+	0.85	88%	87%	14.9	7.1	3.1
WASTE MANAGEMENT INC	BBB+	2	100	A	0.85	43%	41%	10.8	21.1	3.4
WD-40 CO		3	85	B++	0.80	71%	76%	34.8	19.8	5.9
WEIS MARKETS INC		1	80	A	0.65	100%	100%	9.7	9.1	1.7
WERNER ENTERPRISES INC		3	80	B++	0.90	90%	100%	12.1	12.8	2.0
WEYCO GROUP INC		3	80	B++	0.90	93%	100%	14.0		1.5
WILEY (JOHN) & SONS -CL A		3	95	B+	0.90	35%	45%	21.8	19.5	4.7
WOLVERINE WORLD WIDE		3	100	A	0.80	96%	98%	11.5	16.8	2.2
Mean	**A-**	**2**	**79**	**A**	**0.80**	**77%**	**76%**	**15.9**	**17.8**	**3.0**
Median	**A-**	**3**	**85**	**B++**	**0.80**	**78%**	**77%**	**14.9**	**16.4**	**2.7**
Average of Annual Medians								**15.7**		

Source: Standard and Poor's Research Insight, *Value Line* (www.valueline.com, February 27, 2009 and various issues)

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)
Gas Distributors								
ATCO Gas	7/04; 11/07	EUB	2004-052; U2007-347	55.10	6.90	38.00	8.75	4.55
Enbridge Gas Distribution Inc	1/04; 7/07; 2/08	OEB	RP-2002-0158; EB-2006-0034; EB-2007-0615	61.33	2.67	36.00	8.39	4.23
Gazifere	2/01; 12/08	Régie	D-2008-153; D-2001-55	60.00	0.00	40.00	8.82	4.13
Gaz Metropolitain	11/08	Régie	D-2008-140	54.00	7.50	38.50	8.76	4.56
Pacific Northern Gas	5/07; 11/08	BCUC	G-55-07; L-55-08	56.20	3.80	40.00	9.12	4.35
Terasen Gas [1/]	3/06; 11/08	BCUC	G-14-06; L-55-08	64.99	0.00	35.01	8.47	4.35
Terasen Gas (Vancouver Island)	3/06; 11/08	BCUC	G-14-06; L-55-08	65.00	0.00	40.00	9.17	4.35
Union Gas	1/04; 6/06; 1/08	OEB	RP-2002-0158; EB-2005-0520; EB-2007-0606	60.60	3.40	36.00	8.54	4.23
Electric Utilities								
AltaLink	7/04; 11/07	EUB	2004-052; U2007-347	67.00	0.00	33.00	8.75	4.55
ATCO Electric		EUB						
Transmission	7/04; 11/07		2004-052; U2007-347	61.00	6.00	33.00	8.75	4.55
Distribution	7/04; 11/07		2004-052; U2007-347	56.10	6.90	37.00	8.75	4.55
EPCOR		EUB						
Transmission	7/04; 11/07		2004-052; U2007-347	65.00	0.00	35.00	8.75	4.55
Distribution	7/04; 11/07		2004-052; U2007-347	61.00	0.00	39.00	8.75	4.55
FortisAlberta Inc.	7/04; 11/07	EUB	2004-052; U2007-347	63.00	0.00	37.00	8.75	4.55
FortisBC Inc.	3/06; 11/08	BCUC	G-14-06; L-55-08	60.00	0.00	40.00	8.87	4.35
Hydro One Transmission	8/07	OEB	EB-2006-0501	60.00	0.00	40.00	8.35	4.16
Maritime Electric	2/09	IRAC	UE-09-02	59.50	0.00	40.50	9.75	na
Newfoundland Power	12/07	NLPub	P.U.32 (2007)	54.01	1.15	44.84	8.95	4.60
Nova Scotia Power	1/05;11/08	NSUARB	2005 NSUARB 27; 2008 NSUARB 140	53.30	9.20	37.50	9.35	na
Ontario Electricity Distributors	12/06;2/09	OEB	Report of the Board	60.00	0.00	40.00	8.01 [2/]	3.71
Ontario Power Generation	11/08	OEB	EB-2007-0905	53.00	0.00	47.00	8.65	4.75
Gas Pipelines								
Foothills Pipe Lines (Yukon) Ltd.	12/05; 11/08	NEB	RH-2-94;TG-08-2005	64.00	0.00	36.00	8.57	4.35
TCPL-BC System	2/06; 11/08	NEB	RH-2-94;TG-02-2006	64.00	0.00	36.00	8.57	4.35
TransCanada PipeLines	11/08; 5/07	NEB	RH-2-94/RH-2-2004/TG-06-2007	60.00	0.00	40.00	8.57	4.35
Trans Quebec & Maritimes Pipeline [3/]	3/09	NEB	RH-1-2008	60.00	0.00	40.00	9.70	4.35
Westcoast Energy	12/06; 11/08	NEB	RH-2-94;TG-05-2006	64.00	0.00	36.00	8.57	4.35

1/ The equity ratio reflect the impact of the amalgamation of TGI and Squamish Gas.
2/ The OEB has initiated a process to review the reasonableness of the 2009 cost of capital values.
3/ The NEB approved an after-tax weighted average cost of capital of 6.4%. The ROE of 9.7% and 40% equity ratio represent equivalent values cited by the NEB to facilitate comparisons.

Source: Board Decisions.

RATES OF RETURN ON COMMON EQUITY ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
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	8.75	na
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	8.39	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	9.05	8.76
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	9.27	9.12
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	8.62	8.47
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	8.89	8.54	8.54	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**	**8.96**	**8.59**	**8.77**	**8.66**
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	8.75	na
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	8.75	na
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	8.75	na
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	9.02	8.87
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	8.95	8.95
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	na	9.35
Ontario Electricity Distributors	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.35	9.88	9.88	9.88	9.88	9.88	9.88	9.00	9.00	8.57	8.01
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	na	na
Mean of Electric Utilities	**13.61**	**13.42**	**12.75**	**11.75**	**11.00**	**12.25**	**11.10**	**10.50**	**9.75**	**9.34**	**9.68**	**9.74**	**9.59**	**9.63**	**9.66**	**9.51**	**9.11**	**8.78**	**8.80**	**8.80**
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	8.71	8.57
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	8.71	8.57
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**	**8.71**	**8.57**
Mean of All Companies	**13.68**	**13.56**	**12.94**	**12.16**	**11.50**	**12.13**	**11.36**	**10.84**	**10.15**	**9.50**	**9.79**	**9.68**	**9.62**	**9.71**	**9.59**	**9.51**	**9.02**	**8.66**	**8.77**	**8.69**

[1/] Negotiated settlement, details not available.

[2/] Negotiated settlement, implicit ROE made public is 10.5%.

Source: Regulatory Decisions

ESTIMATE OF MARKET VALUE CAPITAL STRUCTURES FOR CANADIAN UTILITIES

Company	Stock Price (Average Monthly High/Low Jan 2009-Mar 2009) (1)	Book Value Per Share Year End 2008 (2)	Market/Book Ratio (3) = (1)/(2)	Book Value Total Capital Common Equity Ratio Year End 2008 (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	39.39	21.92	1.80	41.2%	55.8%	44.2%
EMERA INC	20.79	13.78	1.51	40.7%	50.9%	49.1%
ENBRIDGE INC	39.28	17.41	2.26	34.4%	54.1%	45.9%
FORTIS INC	23.44	18.00	1.30	31.6%	37.6%	62.4%
TRANSCANADA CORP	32.01	20.92	1.53	39.1%	49.5%	50.5%
Mean				**37.4%**	**49.6%**	**50.4%**

Sources: 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)

APPROACH 1:

The after-tax weighted average cost of capital ($WACC_{AT}$) is invariant to changes in the capital structure. The cost of equity increases as leverage (debt ratio) increases, 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)

ASSUMPTIONS:

Debt Cost	=	Current Cost of Long Term Debt for A rated utility
	=	6.625%
Equity Cost	=	CAPM Cost of Equity
	=	8.75%
Tax Rate	=	28.5%
CEQ Ratio	(1)	49.6%
Debt Ratio	(1)	50.4%
CEQ Ratio	(2)	37.4%
Debt Ratio	(2)	62.6%

STEPS:

1. Estimate $WACC_{AT}$ for the less levered sample (common equity ratio of 49.6%)

   $WACC_{AT}$ = (6.625%)(1-.285)(50.4%) + (8.75%)(49.6%)
   = 6.73%

2. Estimate Cost of Equity for sample at 37.4% common equity ratio with $WACC_{AT}$ unchanged at 6.73%

   $WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)
   6.73% = (6.6%)(1-.285)(62.6%) + (X)(37.4%)
   Cost of Equity at 37.4% Equity Ratio = 10.06%

3. Difference between Equity Return at 49.6% and 37.4% common equity ratios:

   10.06% - 8.75% = 1.31% (131 basis points)

APPROACH 2:

After-Tax Cost of Capital Falls as Debt Ratio Increases; Cost of Equity Increases

$$WACC_{AT(LL)} = WACC_{AT(ML)} \times \frac{(1-tD_{LL})}{(1-tD_{ML})}$$

Where LL,ML as before
t = tax rate
D = debt ratio

ASSUMPTIONS:

Debt Cost	=	Current Cost of Long Term Debt for A rated utility
	=	6.625%
Equity Cost	=	Cost of Equity
	=	8.75%
Tax Rate	=	28.5%
CEQ Ratio	(1)	49.6%
Debt Ratio	(1)	50.4%
CEQ Ratio	(2)	37.4%
Debt Ratio	(2)	62.6%

STEPS:

1. Estimate $WACC_{AT}$ for less levered sample (common equity ratio of 49.6%)

$WACC_{AT}$ = (6.625%)(1-.285)(50.4%) + (8.75%)(49.6%)
= 6.73%

2. Estimate $WACC_{AT}$ for more levered firm (common equity ratio of 37.4%)

$WACC_{AT(ML)} = WACC_{AT(LL)}$ x (1-t x Debt $Ratio_{ML}$)/(1-t x Debt $Ratio_{LL}$)

$$WACC_{AT(ML)} = 6.73\% \times \frac{(1-.285 \times 62.6\%)}{(1-.285 \times 50.4\%)}$$

$WACC_{AT(ML)}$ = 6.45%

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 $Ratio_{ML}$)
6.45% = (6.625%)(1-.285)(62.6%) + (X)(37.4%)
Cost of Equity at 37.4% Equity Ratio = 9.33%

4. Difference between Equity Return at 49.6% and 37.40% common equity ratios:

9.33% - 8.75% = 0.58% (58 basis points)

ESTIMATE OF IMPACT OF CHANGE IN CAPITAL STRUCTURE ON COST OF EQUITY
60-130 Basis Points (Midpoint of 100)

ESTIMATE OF MARKET VALUE CAPITAL STRUCTURES FOR BENCHMARK SAMPLE OF U.S. GAS AND ELECTRIC UTILITIES

Company	Average Monthly High/Low Prices Jan 2009-Mar 2009 (2)	Book Value Per Share Year End 2008 (2)	Market/Book Ratio (3) = (1)/(2)	Book Value Total Capital Common Equity Ratio 2008 (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 INC	29.30	21.48	1.36	39.4%	47.0%	53.0%
CONSOLIDATED EDISON INC	38.41	35.43	1.08	48.5%	50.5%	49.5%
DOMINION RESOURCES INC	32.69	17.28	1.89	36.3%	51.9%	48.1%
DUKE ENERGY CORP	14.35	16.50	0.87	59.2%	55.8%	44.2%
FPL GROUP INC	48.70	28.57	1.70	40.6%	53.8%	46.2%
NEW JERSEY RESOURCES CORP	36.57	17.29	2.12	51.2%	68.9%	31.1%
NORTHWEST NATURAL GAS CO	42.36	23.71	1.79	45.3%	59.6%	40.4%
NSTAR	32.61	16.74	1.95	36.8%	53.2%	46.8%
PIEDMONT NATURAL GAS CO	25.89	12.11	2.14	41.9%	60.6%	39.4%
SCANA CORP	32.05	25.81	1.24	39.3%	44.6%	55.4%
SOUTHERN CO	32.11	17.07	1.88	40.5%	56.2%	43.8%
VECTREN CORP	22.87	16.69	1.37	42.2%	50.1%	49.9%
WGL HOLDINGS INC	32.05	20.99	1.53	51.7%	62.0%	38.0%
Mean				**44.1%**	**54.9%**	**45.1%**

Sources: Schedule 16 for stock prices, Standard & Poor's Research Insight

QUANTIFICATION OF IMPACT ON EQUITY RETURN REQUIREMENT FOR DIFFERENCE BETWEEN MARKET VALUE AND BOOK VALUE CAPITAL STRUCTURES: U.S. UTILITIES

Formula for After-Tax Weighted Average Cost of Capital:

$WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

APPROACH 1:

The after-tax weighted average cost of capital ($WACC_{AT}$) is invariant to changes in the capital structure. The cost of equity increases as leverage (debt ratio) increases, 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)

ASSUMPTIONS:

Debt Cost	=	Current Cost of Long Term Debt for A rated utility
	=	6.625%
Equity Cost	=	Midpoint of DCF-Based Risk Premium and DCF Cost of Equity Test Results
	=	10.25%
Tax Rate	=	28.5%
CEQ Ratio	(1)	54.9%
Debt Ratio	(1)	45.1%
CEQ Ratio	(2)	44.1%
Debt Ratio	(2)	55.9%

STEPS:

1. Estimate $WACC_{AT}$ for the less levered sample (common equity ratio of 54.9%)

   $WACC_{AT}$ = (6.625%)(1-.285)(45.1%) + (10.25%)(54.9%)

   = 7.76%

2. Estimate Cost of Equity for sample at 44.1% common equity ratio with $WACC_{AT}$ unchanged at 7.76%

   Tax Rate Declines to Canadian Level

   $WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

   7.76% = (6.625%)(1-.285)(55.9%) + (X)(44.1%)

   Cost of Equity at 44.1% Equity Ratio = 11.60%

3. Difference between Equity Return at 54.9% and 44.1% common equity ratios:

   11.60% - 10.25% = 1.35% (135 basis points)

APPROACH 2:

After-Tax Cost of Capital Falls as Debt Ratio Increases; Cost of Equity Increases

$$WACC_{AT(LL)} = WACC_{AT(ML)} \times \frac{(1-tD_{LL})}{(1-tD_{ML})}$$

Where LL,ML as before
t = tax rate
D = debt ratio

ASSUMPTIONS:

Debt Cost	=	Current Cost of Long Term Debt for A rated utility
	=	6.625%
Equity Cost	=	Cost of Equity
	=	10.25%
Tax Rate	=	28.5%
CEQ Ratio	(1)	54.9%
Debt Ratio	(1)	45.1%
CEQ Ratio	(2)	44.10%
Debt Ratio	(2)	55.90%

STEPS:

1. Estimate $WACC_{AT}$ for less levered sample (common equity ratio of 54.9%)

$WACC_{AT}$ = (6.625%)(1-.285)(45.1%) + (10.25%)(54.9%)
= 7.76%

2. Estimate $WACC_{AT}$ for more levered firm (common equity ratio of 44.1%)
Tax Rate Declines to Canadian Level

$WACC_{AT(ML)} = WACC_{AT(LL)}$ x (1-t x Debt $Ratio_{ML}$)/(1-t x Debt $Ratio_{LL}$)

$$WACC_{AT(ML)} = 7.76\% \times \frac{(1-.285 \times 55.9\%)}{(1-.285 \times 45.1\%)}$$

$WACC_{AT(ML)}$ = 7.49%

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 $RatioM_{LL}$)
7.49% = (6.625%)(1-.29)(55.9%) + (X)(44.1%)
Cost of Equity at 44.10% Equity Ratio = 10.98%

4. Difference between Equity Return at 54.9% and 44.1% common equity ratios:
10.98% - 10.25% = 0.73% (73 basis points)

ESTIMATE OF IMPACT OF CHANGE IN CAPITAL STRUCTURE AND TAX RATE ON COST OF EQUITY
Approximately 75 to 135 basis points (Midpoint of 105)

BRITISH COLUMBIA UTILITIES COMMISSION

WRITTEN EVIDENCE

OF

JAMES H. VANDER WEIDE, PH.D.

FOR

TERASEN GAS INC.

MAY 2009

WRITTEN EVIDENCE OF
JAMES H. VANDER WEIDE

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WRITTEN EVIDENCE OF

JAMES H. VANDER WEIDE

I. Introduction

Q 1 What is your name, occupation, and business address?

A 1 My name is James H. Vander Weide. I am Research Professor of Finance and Economics at Duke University, Fuqua School of Business. I am also President of Financial Strategy Associates, a firm that provides strategic and financial consulting services to corporate clients. My business address is 3606 Stoneybrook Drive, Durham, North Carolina 27705.

Q 2 Please summarize your qualifications.

A 2 I received a Bachelor's Degree in Economics from Cornell University and a Ph.D. in Finance from Northwestern University. After joining the faculty of the School of Business at Duke University, I was named Assistant Professor, Associate Professor, and then Professor. I have published research in the areas of finance and economics and taught courses in these fields at Duke for more than 35 years.

Q 3 Have you previously testified on financial and economic issues?

A 3 Yes. As an expert on financial and economic theory and practice, I have participated in more than 400 regulatory and legal proceedings before the U.S. Congress, the Canadian Radio-Television and Telecommunications Commission, the National Energy Board, the Alberta Utilities Commission, the Federal Communications Commission, the National Telecommunications and Information Administration, the Federal Energy Regulatory Commission, the public service commissions of 42 states, the insurance commissions of five states, the Iowa State Board of Tax Review, the National Association of Securities Dealers, and the North Carolina Property Tax Commission. In addition, I have provided expert testimony in proceedings before the U.S. District Court for the District of Nebraska; the U.S. District Court for the District of New Hampshire; the U.S. District Court for the Eastern District of North Carolina; the

U.S. District Court for the Northern District of California; Montana Second Judicial District Court, Silver Bow County; the Superior Court, North Carolina; the U.S. Bankruptcy Court for the Southern District of West Virginia; and the U. S. District Court for the Eastern District of Michigan. My resume is shown in Appendix 1.

Q 4 What is the purpose of your testimony?

A 4 I have been asked by Terasen Gas Inc. ("TGI") to: (1) assess the validity of the Automatic Adjustment Mechanism ("AAM") adopted by the British Columbia Utilities Commission ("BC Utilities Commission") in Order G-14-06 dated March 2, 2006; (2) conduct an analysis of the cost of equity for TGI; and (3) recommend an appropriate fair ROE and deemed equity ratio for TGI.

II. The Fair Return Standard

Q 5 What is a fair return?

A 5 A fair return is a return that is: (i) equal to the returns investors expect to earn on other investments of comparable risk; (ii) sufficient to allow the regulated firm to attract capital on reasonable terms; and (iii) sufficient to allow the regulated firm to maintain its financial integrity.

Q 6 What is the economic definition of the required rate of return, or cost of capital, associated with particular investment decisions, such as the decision to invest in natural gas distribution facilities?

A 6 The economic definition of the cost of capital is identical to the definition of the fair return, namely, the cost of capital is the return investors expect to receive on alternative investments of comparable risk.

Q 7 How does the cost of capital affect a firm's investment decisions?

A 7 A central goal of a firm is to maximize the value of the firm. This goal can be accomplished by accepting all investments in plant and equipment with an expected rate of return greater than the cost of capital. Thus, from an economic perspective, a firm should continue to invest in plant and equipment only so long as the return on its investment is greater than or equal to its cost of capital.

Q 8 How does the cost of capital affect investors' willingness to invest in a company?

A 8 The cost of capital measures the return investors can expect on investments of comparable risk. The cost of capital also measures the investor's required rate of return on investment because rational investors will not invest in a particular investment opportunity if the expected return on that opportunity is less than the cost of capital. Thus, the cost of capital is a hurdle rate for both investors and the firm.

Q 9 Do all investors have the same position in the firm?

A 9 No. Bond investors have a fixed claim on a firm's assets and income that must be paid prior to any payment to the firm's equity investors. Since the firm's equity investors have a residual claim on the firm's assets and income, equity investments are riskier than bond investments. Thus, the cost of equity exceeds the cost of debt.

Q 10 What is the overall or average cost of capital?

A 10 The overall or average cost of capital is a weighted average of the cost of debt and cost of equity, where the weights are the percentages of debt and equity in a firm's capital structure.

Q 11 Can you illustrate the calculation of the overall or weighted average cost of capital?

A 11 Yes. Assume that the cost of debt is 6 percent, the cost of equity is 11 percent, and the percentages of debt and equity in the firm's capital structure are 50 percent and 50 percent, respectively. Then the weighted average cost of capital is expressed by .50 times 6 percent plus .50 times 11 percent, or 8.5 percent.[1]

[1] The weighted average cost of capital may be calculated on either an after-tax or a before-tax basis. The difference between these calculations is that the after-tax cost of debt is used to calculate the weighted average cost of capital in an after-tax calculation. For simplicity, I present a before-tax calculation of the weighted average cost of capital in this example.

Q 12 What is the economic definition of the cost of equity?

A 12 The cost of equity is the return investors expect to receive on alternative equity investments of comparable risk. Since the return on an equity investment of comparable risk is not a contractual return, the cost of equity is more difficult to measure than the cost of debt. However, as I have already noted, the cost of equity is greater than the cost of debt. The cost of equity, like the cost of debt, is both forward looking and market based.

Q 13 How do economists measure the percentages of debt and equity in a firm's capital structure?

A 13 Economists measure the percentages of debt and equity in a firm's capital structure by first calculating the market value of the firm's debt and the market value of its equity. The percentage of debt is then calculated by the ratio of the market value of debt to the combined market value of debt and equity, and the percentage of equity by the ratio of the market value of equity to the combined market values of debt and equity. For example, if a firm's debt has a market value of $25 million and its equity has a market value of $75 million, then its total market capitalization is $100 million, and its capital structure contains 25 percent debt and 75 percent equity.

Q 14 Why do economists measure a firm's capital structure in terms of the market values of its debt and equity?

A 14 Economists measure a firm's capital structure in terms of the market values of its debt and equity because: (1) the weighted average cost of capital is defined as the return investors expect to earn on a portfolio of the company's debt and equity securities; (2) investors measure the expected return and risk on their portfolios using market value weights, not book value weights; and (3) market values are the best measures of the amounts of debt and equity investors have invested in the company on a going forward basis.

Q 15 Why do investors measure the return on their investment portfolios using market value weights rather than book value weights?

A 15 Investors measure the return on their investment portfolios using market value weights because market value weights are the best measure of the amounts the investors currently have invested in each security in the portfolio. From the point of view of investors, the historical cost or book value of their investment is entirely irrelevant to the current risk and return on their portfolios because if they were to sell their investments, they would receive market value, not historical cost. Thus, the return can only be measured in terms of market values.

Q 16 Does the required rate of return on an investment vary with the risk of that investment?

A 16 Yes. Since investors are averse to risk, they require a higher rate of return on investments with greater risk.

Q 17 Do investors consider future industry changes when they estimate the risk of a particular investment?

A 17 Yes. Investors consider all the risks that a firm might incur over the future life of the company.

Q 18 Are these economic principles regarding the fair return for capital recognized in any Supreme Court cases?

A 18 Yes. These economic principles, relating to the supply of and demand for capital, are recognized in at least one Canadian and two United States Supreme Court cases: (1) *Northwestern Utilities Ltd. v. Edmonton*, [1929]; (2) *Bluefield Water Works and Improvement Co. v. Public Service Commission*; and (3) *Federal Power Commission v. Hope Natural Gas Co*. In *Northwestern Utilities Ltd. v. Edmonton*, Mr. Justice Lamont states:

> 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. [*Northwestern Utilities Ltd. v. Edmonton*, [1929] S.C.R. 186.]

The Court clearly recognizes here that a regulated utility must be allowed to earn a return on the value of its property that is at least equal to its cost of capital.

III. The AAM ROE Formula Is Not Valid.

A. The AAM ROE Formula

Q 19 Are you familiar with the BC Utilities Commission's automatic adjustment mechanism (AAM) ROE formula for the regulated electric and natural gas companies under its jurisdiction?

A 19 Yes. The AAM ROE Formula is given by the equation:

$$ROE_t = 9.145\% - [0.75 \times (5.25\% - YLD_t)]$$

where:

YLD_t = the forecast long-term Canada bond yield for year *t*.

Q 20 What is the current forecast yield on long-term Canada bonds?

A 20 As of April 2009, the Consensus Economics forecast yield on long-term Canada bonds is equal to 3.69 percent.

Q 21 Using a 3.69 percent forecast yield on long-term Canada bonds, what ROE is obtained using the AAM ROE Formula?

A 21 The AAM ROE Formula produces an ROE equal to 7.98 percent. This result is calculated as follows: 7.98 = 9.145 + [0.75 x (5.25 – 3.69)].

Q 22 What equity risk premium is implied by the AAM ROE Formula?

A 22 The AAM ROE Formula implies an equity risk premium equal to 4.29 percent (7.98 – 3.69 = 4.29).

B. Six Tests of the Validity of the AAM ROE Formula

Q 23 Have you performed any tests of the validity of the AAM ROE Formula?

A 23 Yes. I have performed six tests of the validity of the AAM ROE Formula. First, I have examined evidence on the experienced returns achieved by equity investors in two groups of Canadian utilities compared to interest rates on long-term Canada bonds. My studies indicate that the average experienced equity risk premium on an investment in Canadian utility stocks is approximately 5.5 percent.

Second, I have examined evidence on the allowed rates of return on equity and allowed common equity ratios for U.S. electric and natural gas utilities. My studies indicate that allowed rates of return on equity and allowed equity ratios for U.S. utilities average approximately 10.4 percent and 49 percent, respectively. Since the AAM ROE Formula currently produces a 7.98 percent ROE on an allowed equity ratio of 35 percent, this evidence supports the conclusion that the AAM ROE Formula fails to provide returns that are commensurate with returns on other investments of comparable risk.

Third, I have examined evidence on the sensitivity of the forward-looking, or ex ante, required equity risk premium on utility stocks to changes in interest rates. Specifically, while the ROE adjustment formula implies that the cost of equity for TGI declines by 75 basis points for every 100-basis-point decline in the yield to maturity on long Canada bonds, my evidence supports the conclusion that the cost of equity declines by less than 50 basis points for every 100-basis-point decline in the yield to maturity on long Canada bonds. From my ex ante risk premium studies, I find that the forward-looking required equity risk premium on utility stocks is in the range 7.5 percent to 8.0 percent. Since the risk premium implied by the AAM ROE Formula is currently 4.29 percent, this evidence supports the conclusion that the AAM ROE Formula is not working.

Fourth, I have examined evidence on the sensitivity of the equity risk premium implied by U.S. utility allowed rates of return on equity to changes in the interest rate on long-term government bonds. My studies indicate that U.S. utility allowed equity risk premiums are significantly less sensitive to changes in interest rates on long-term government bonds than the allowed equity risk premium implied by the AAM ROE Formula. Specifically, while the ROE adjustment formula reduces the allowed ROE by 75 basis points when the yield to maturity on long-term government bonds declines by 100 basis points, U.S. regulators typically reduce the allowed ROE by less than 50 basis points when the yield to maturity on long-term government bonds declines by 100 basis points. This evidence also supports the conclusion that the AAM ROE Formula is not working.

Fifth, I have examined evidence on the volatility of returns on Canadian utility stocks compared to the volatility of returns on the Canadian market index. My studies indicate that the volatility of returns on Canadian utility stocks exceeds or approximates the volatility of returns on the Canadian market index. Because investors demand a higher return for bearing more risk, this evidence also supports the conclusion that the equity risk premium on Canadian utility stocks is higher than the equity risk premium implied by the AAM ROE Formula.

Sixth, I have examined whether the AAM ROE Formula produces an ROE result that is consistent with the increased risk associated with today's highly uncertain economic and capital market conditions. I conclude that, contrary to a reasonable expectation, the AAM ROE Formula produces a lower ROE estimate at a time when the increased risks of highly uncertain economic and capital market conditions are causing capital costs to increase dramatically.

1. Evidence on Experienced Equity Risk Premiums on Investments in Canadian Utility Stocks

Q 24 How do you measure the experienced equity risk premium on an investment in Canadian utility stocks?

A 24 I measure the experienced equity risk premium on an investment in Canadian utility stocks from data on returns earned by investors in

Canadian utility stocks compared to interest rates on long-term Canada bonds.

Q 25 How do you measure the return experienced by investors in Canadian utility stocks?

A 25 I measure the return experienced by investors in Canadian utility stocks from historical data on returns earned by investors in: (1) the S&P/TSX utilities stock index[2]; and (2) a basket of Canadian utility stocks created by BMO Capital Markets ("BMO CM").

Q 26 What companies are currently included in these indices of Canadian utility stock performance?

A 26 The companies included in the S&P/TSX utilities stock index are Algonquin Power Income Fund, ATCO Ltd., Canadian Utilities Ltd., Emera Inc., Energy Savings Income Fund, EPCOR Power L.P., Fortis Inc., Northland Power Income Fund, and TransAlta Corporation. The index also included Calpine Power Units until February 2007 and TransAlta Power, L.P., until December 2007. In addition, Canadian Hydro Developers, Inc. was added to the index in March 2008.

The BMO CM basket of utility and pipeline companies includes Canadian Utilities Ltd., Emera Inc., Enbridge Inc., Fortis Inc., Pacific Northern Gas, and TransCanada Corporation. The BMO CM basket also includes return data for Westcoast Energy Inc. until December 2001 and Terasen Inc. through July 2005.

Q 27 What time periods do your experienced Canadian utility stock return data cover?

[2] The legacy S&P/TSX utilities index was discontinued by Standard & Poor's in Spring 2002 when Standard & Poor's introduced a new S&P/TSX Composite utilities index that included the GICs 5500 utilities. Standard & Poor's provided total return index value data going back to 1999. The historical data on returns earned by investors in the S&P/TSX utilities index therefore includes total returns on the S&P/TSX legacy utilities index through 1998 and total returns on the new S&P/TSX composite utilities index from 1999 through 2008.

A 27 The S&P/TSX utilities stock return data covers the period 1956 through 2008, and the BMO CM stock return data covers the period 1983 through 2008.

Q 28 Why do you analyze investors' experienced returns over such long time periods?

A 28 I analyze investors' experienced returns over long time periods because experienced returns over short periods can deviate significantly from expectations. However, I also recognize that experienced returns over long periods may also deviate from expected returns if the data in some portion of the long time period are unreliable.

Q 29 Would your study provide different risk premium results if you had included different time periods?

A 29 Yes. The risk premium results do vary somewhat depending on the historical time period chosen. My policy was to go back as far in history as I could get reliable data. With regard to the S&P/TSX utilities index, the data began in 1956, and for the BMO CM utility stock basket, the data began in 1983.

Q 30 Why do you choose two sets of Canadian utilities stock return performance data rather than simply relying on the S&P/TSX utilities stock index data?

A 30 I choose two sets of Canadian utility stock return performance data because each data set provides different information on Canadian utility stock returns. The S&P/TSX utilities index is valuable because it provides information on the returns experienced by investors in a portfolio of Canadian utility stocks over a relatively long period of time. However, six of the nine companies included in the S&P/TSX utility index operate mainly in non-traditional utility markets. The BMO CM utility stock return database is valuable because it provides information on the experienced returns for a sample of Canadian companies that receive a significantly higher percentage of revenues from traditional utility operations than the companies in the S&P/TSX

index. However, the time period covered is not as long as the period covered by the S&P/TSX utility index.

Q 31 How are the experienced returns on an investment in each utility data set calculated?

A 31 The experienced returns on an investment in each utility data set are calculated from the historical record of stock prices and dividends for the companies in the data set. From the historical record of stock prices and dividends, the index sponsors construct an index of investors' wealth at the end of each period, assuming a $100 investment in the index at the time the index was constructed. An annual rate of return is calculated from the wealth index by dividing the wealth index at the end of each period by the wealth index at the beginning of the period and subtracting one [$r_t = (W_t \div W_{t-1}) - 1$].

Q 32 How do you measure the interest rate earned on long-term Canada bonds in your experienced, or ex post, risk premium studies?

A 32 I use the interest rate data on long-term Canada bonds reported by the Canadian Institute of Actuaries.

Q 33 What average risk premium results do you obtain from your analysis of returns experienced by investors in Canadian utility stocks?

A 33 As shown in Table 1 below, I obtain an average experienced risk premium equal to 5.5 percent (the annual data that produce these results are shown in Exhibit 1 and Exhibit 2).

TABLE 1
EX POST RISK PREMIUM RESULTS

COMPARABLE GROUP	PERIOD OF STUDY	AVERAGE STOCK RETURN	AVERAGE BOND YIELD	RISK PREMIUM
S&P/TSX Utilities	1956 – 2008	11.84	7.54	4.3
BMO CM Utilities Stock Data Set	1983 – 2008	14.31	7.66	6.6
Average				**5.5**

Q 34 What conclusions do you draw from your experienced, or ex post, risk premium studies about the required risk premium on an investment in Canadian utility stocks?

A 34 My ex post risk premium studies provide evidence that investors require an equity return that is at least 5.5 percentage points above the interest rate on long-term Canada bonds.

Q 35 Do you have any evidence that the required equity risk premium may actually be greater than 5.5 percentage points?

A 35 Yes. I provide evidence below that the required equity risk premium increases when interest rates decline and decreases when interest rates rise. Since the expected 3.69 percent yield on long Canada bonds is significantly less than the 7.6 percent average yield on long Canada bonds over the period of my ex post risk premium studies, the current required equity risk premium should be significantly higher than the average 5.5 percent equity risk premium I obtain from my ex post risk premium studies.

Q 36 What equity risk premium is implied by the AAM ROE Formula?

A 36 The AAM ROE Formula produces an ROE equal to 7.98 percent based on a 3.69 percent forecast yield to maturity on long Canada bonds. Thus, the AAM ROE Formula implies an equity risk premium of 429 basis points.

Q 37 How does your evidence on the experienced equity risk premium support your conclusion that the AAM ROE Formula is not working?

A 37 My analysis supports the conclusion that investors require an equity risk premium on Canadian utility stocks equal to at least 5.5 percent. Thus, my evidence supports the conclusion that the AAM ROE Formula understates the required equity risk premium on Canadian utility stocks.

2. Evidence on Recent Allowed Rates of Return on Equity for U.S. Utilities

Q 38 Do you have evidence on recent allowed rates of return on equity for U.S. Utilities?

A 38 Yes. I have evidence on recent allowed rates of return on equity for U.S. electric and natural gas utilities from January 2006 through December 2008. Since January 2006, the average allowed ROE for electric utilities is 10.4 percent, and for natural gas utilities, 10.3 percent. In 2008, the average allowed ROE for electric utilities is 10.5 percent, and for natural gas utilities, 10.4 percent (see Exhibit 3).

Q 39 Why do you examine data on allowed rates of return on equity for U.S. utilities rather than Canadian utilities?

A 39 I examine data on allowed rates of return on equity for U.S. utilities rather than Canadian utilities because allowed rates of return on equity for U.S. utilities are based on cost of equity studies for utilities at the time of each case rather than on an ROE formula such as the AAM ROE Formula. Thus, recent allowed rates of return on equity for U.S. utilities are an independent test of whether the AAM ROE Formula is valid.

Q 40 Are allowed rates of return on equity the best measure of the cost of equity at each point in time?

A 40 No. Since the cost of equity is determined by investors in the marketplace, not by regulators, the cost of equity is best measured using market models such as the equity risk premium and the discounted cash flow model. However, as noted above, because allowed rates of return in non-formula jurisdictions are based on regulators' judgments regarding the cost of equity and fair rate of return, they provide additional information on the validity of the AAM ROE Formula.

Q 41 How do the average allowed ROEs for U.S. electric and natural gas utilities compare to the ROE implied by the AAM ROE Formula?

A 41 The average allowed rates of return on equity for U.S. utilities are approximately 10.4 percent. As noted above, the AAM ROE Formula currently implies an ROE equal to 7.98 percent. Thus, the average allowed returns for the U.S. utilities exceed the generic ROE by approximately 250 basis points [10.4 – 7.9 = 250].

Q 42 Can the difference between allowed ROEs for U.S. utilities and the ROE implied by the AAM ROE Formula be explained by differences in business risk?

A 42 No. The business risk of electric and natural gas utilities is approximately the same in the U.S. as it is in Canada.

Q 43 Why is the business risk of electric and natural gas utilities approximately the same in the U.S. as it is in Canada?

A 43 The business risk of electric and natural gas utilities is similar in the U.S. and Canada because: (1) U.S. electric and natural gas utilities rely on essentially the same electric and natural gas technologies to deliver their services to the public as electric and gas utilities in Canada; (2) the economics of electric and natural gas transmission and distribution is similar in the U.S. and Canada; and (3) U.S. electric and gas utilities are regulated under similar cost-based regulatory structures and fair rate of return principles as Canadian utilities.

Q 44 Some observers have argued that Canadian utilities have lower regulatory risk than U.S. utilities because Canadian regulators generally make greater use of deferral accounts than U.S. regulators. Do you agree with this argument?

A 44 No. Regulatory risk is associated with the possibility that a utility will be unable to earn its required rate of return as a result of regulation. Although deferral accounts generally reduce the gap between a utility's actual and allowed returns, they do not necessarily reduce the gap between a utility's actual and required returns. Canadian utilities face greater regulatory risk than U.S. utilities because Canadian utilities are generally regulated through formula ROEs such as the

AAM ROE Formula, and formula ROEs are more likely to differ from the market cost of equity than ROEs based on market evidence in each rate proceeding.

Q 45 How does the financial risk of Canadian utilities compare to the financial risk of U.S. utilities?

A 45 Canadian utilities have greater financial risk than U.S. utilities because U.S. utilities generally have allowed equity ratios in the range 45 percent to 50 percent (see Exhibit 4), whereas Canadian utilities generally have allowed equity ratios in the range 30 percent to 40 percent.

Q 46 What conclusions do you draw from your evidence that allowed ROEs for comparable U.S. utilities are significantly higher than the ROE implied by the AAM ROE Formula?

A 46 My evidence on allowed ROEs for U.S. utilities provides further support for the conclusion that the AAM ROE Formula is not working.

3. Evidence on the Sensitivity of the Forward-looking Required Equity Risk Premium on Utility Stocks to Changes in Interest Rates

Q 47 How do you study the sensitivity of the forward-looking required equity risk premium on utility stocks to changes in interest rates?

A 47 I study the sensitivity of the forward-looking required equity risk premium on utility stocks to changes in interest rates in two steps. First, I estimate the forward-looking required equity risk premium on utility stocks in each month of my study period. Second, I perform a statistical regression analysis of the relationship between changes in the required equity risk premium and changes in interest rates.

Q 48 Please describe how you measure the forward-looking required equity risk premium on an equity investment in utility stocks in each month of your study period.

A 48 My estimate of the required equity risk premium is based on studies of the discounted cash flow ("DCF") expected return on comparable groups of utilities in each month of my study period compared to the interest rate on long-term government bonds. Specifically, for each month in my study period, I calculate the risk premium using the equation,

$$RP_{COMP} = DCF_{COMP} – I_B$$

where:

RP_{COMP}	=	the required risk premium on an equity investment in the comparable companies,
DCF_{COMP}	=	average DCF expected rate of return on a portfolio of comparable companies; and
I_B	=	the yield to maturity on an investment in long-term U.S. Treasury bonds.

Q 49 Please describe the DCF model you used to estimate the forward-looking, or ex ante, required risk premium on an equity investment in utility stocks.

A 49 The DCF model is based on the assumption that investors value an asset on the basis of the future cash flows they expect to receive from owning the asset. Under the assumption that future cash flows grow at a constant rate, *g*, the resulting cost of equity equation is $k = D_1/P_s + g$, where k is the cost of equity, D_1 is the equivalent future value of the next four quarterly dividends at the end of the year, P_s is the current price of the stock, and g is the constant annual growth rate in earnings, dividends, and book value per share. A complete description of my approach to calculating the DCF-estimated cost of equity for my comparable group of utilities is contained in Appendix 2.

Q 50 What comparable companies do you use in your forward-looking equity risk premium studies?

A 50 I use two sets of comparable U.S. utilities, an electric utilities company group and a natural gas utilities company group. For my electric group, I use the Moody's group of 24 electric companies because they are a widely-followed group of utilities, and the use of this constant group greatly simplified the data collection task required to estimate the ex ante risk premium over the months of my study.

Simplifying the data collection task is desirable because my forward-looking equity risk premium studies require that the DCF model be estimated for every company in every month of the study period. For my natural gas company group, I select all the utilities in Value Line's natural gas company groups that: (1) paid dividends during every quarter and did not decrease dividends during any quarter of the past two years; (2) have at least three analysts included in the I/B/E/S mean growth forecast; (3) are not in the process of being acquired; (4) have a Value Line Safety Rank of 1, 2, or 3; and (5) have investment grade S&P bond ratings.

Q 51 Why do you use U.S. utilities rather than Canadian utilities in your forward-looking, or ex ante, risk premium studies?

A 51 My ex ante risk premium studies rely on the DCF model to determine the expected risk premium on utility stocks. As noted above, the DCF model requires estimates of investors' growth expectations, which are best measured from the average of analysts' growth forecasts for each company. The difficulty with using Canadian utilities is that there are very few, if any, analysts' growth forecasts available for each Canadian utility over the 10-year time period of my study.

Q 52 How do you test whether your forward-looking required equity risk premium estimates are sensitive to changes in interest rates?

A 52 To test whether my estimated monthly equity risk premiums are sensitive to changes in interest rates, I perform a regression analysis of the relationship between the forward-looking equity risk premium and the yield to maturity on 20-year U.S. Treasury bonds using the equation:

$$RP_{COMP} = a + (b \times I_B) + e$$

where:

RP_{COMP} = risk premium on comparable company group;

I_B = yield to maturity on long-term U.S. Treasury bonds;

e = a random residual; and

a, b = coefficients estimated by the regression procedure.

Q 53 What does your regression analysis reveal regarding the sensitivity of the forward-looking required equity risk premium to changes in interest rates?

A 53 My regression analysis reveals that the forward-looking required equity risk premium increases by more than 50 basis points when the yield to maturity on long-term government bonds declines by 100 basis points. These results suggest that, contrary to the AAM ROE Formula, the cost of equity for utilities declines by less than 50 basis points when the yield on long-term government bonds declines by 100 basis points, rather than the 75-basis point decline in the cost of equity that is implied by the AAM ROE Formula. A more detailed description of my regression analysis is contained in Appendix 3. The risk premium data used in the regression analysis is shown in Exhibit 5 and Exhibit 6.

Q 54 What risk premium estimates do you obtain from your forward-looking risk premium studies?

A 54 For my electric utility comparable group, I obtain a forward-looking risk premium equal to approximately 8.0 percent; and for my natural gas comparable group, I obtain a forward-looking risk premium equal to 7.5 percent.

Q 55 What do your forward-looking equity risk premium studies imply about the validity of the AAM ROE Formula?

A 55 Like my studies of experienced risk premiums on Canadian utility stocks, my forward-looking equity risk premium studies imply that the AAM ROE Formula is not valid.

4. Evidence on the Sensitivity of the Allowed Equity Risk Premium for U.S. Utilities to Changes in Interest Rates

Q 56 How do you define the allowed equity risk premium for U.S. utilities?

A 56 I define the allowed equity risk premium as the difference between the average allowed return on equity for U.S. utilities and the yield to maturity on long-term U.S. Treasury bonds.

Q 57 How do you test whether the allowed equity risk premium is sensitive to changes in interest rates?

A 57 I test whether the allowed equity risk premium is sensitive to changes in interest rates by performing a regression analysis of the relationship between the allowed equity risk premium and the yield to maturity on 20-year U.S. Treasury bonds over the period 1988 through 2008.

Q 58 What are the results of your regression analysis?

A 58 My allowed equity risk premium analysis confirms the results of my ex ante risk premium analysis; namely, my results confirm that there is an inverse relationship between equity risk premiums and the yield to maturity on long-term government bonds. Specifically, I find that when the yield to maturity on long-term government bonds increases by 100 basis points, the allowed equity risk premium tends to decrease by approximately 55 basis points; and when the yield to maturity on long-term government bonds decreases by 100 basis points, the allowed equity risk premium tends to increase by approximately 55 basis points. These results imply that the allowed return on equity for U.S. utilities declines by less than 50 basis points when the yield to maturity on long-term government bonds declines by 100 basis points. The allowed equity risk premium data in my study and my regression results are shown in Exhibit 7.

Q 59 What forecast allowed equity risk premium results do you obtain from your allowed equity risk premium studies?

A 59 I obtain a forecast allowed equity risk premium equal to 5.6 percent. This forecast allowed equity risk premium for U.S. utilities is 129 basis points higher than the 4.29 percent basis point equity risk premium implied by the AAM ROE Formula at April 2009..

Q 60 What conclusions do you reach from your analysis of the sensitivity of allowed U.S. equity risk premiums to changes in interest rates?

A 60 I conclude that the AAM ROE Formula is not working.

5. Evidence on the Relative Risk of Returns on Canadian Utility Stocks Compared to the Canadian Market Index

Q 61 What data do you examine on the relative risk of Canadian utility stocks compared to the risk of the Canadian stock market as a whole?

A 61 I examine the standard deviation, or volatility, of utility stock returns compared to the standard deviation, or volatility, of the returns on the TSX market index. In addition, I examine the realized returns on Canadian utility stocks compared to the realized returns on the Canadian stock market index.

Q 62 What has been the standard deviation, or volatility, of returns on Canadian utility stocks compared to the standard deviation of returns on the Canadian market index?

A 62 As shown below, over comparable annual time periods, the standard deviation of returns for Canadian utility stocks has exceeded or approximated the standard deviation of returns for the Canadian market index.

TABLE 2
STANDARD DEVIATION OF ANNUAL RETURNS
BMO CM UTILITIES STOCK DATA SET,
S&P/TSX UTILITIES, AND TSX MARKET INDEX

PERIOD	BMO CM UTILITIES STOCK DATA SET	S&P/TSX UTILITIES INDEX	TSX CANADIAN MARKET
1983 – 2008	17.29	18.64	16.67
1956 – 2008		15.76	16.72

Q 63 What have been the realized returns on Canadian utility stocks compared to realized returns on the Canadian market index?

A 63 As shown below, the realized returns on Canadian utility stocks have exceeded realized returns on the Canadian market index over the periods 1956–2008 and 1983–2008.

TABLE 3
AVERAGE ANNUAL RETURNS
BMO CM UTILITIES STOCK DATA SET,
S&P/TSX UTILITIES, AND TSX MARKET INDEX

PERIOD	BMO CM UTILITIES STOCK DATA SET	S&P/TSX UTILITIES INDEX	TSX CANADIAN MARKET
1983 – 2008	14.31	15.18	10.13
1956 – 2008		11.84	10.30

Q 64 What conclusions do you draw from your evidence that the standard deviation of annual returns on Canadian utility stocks has exceeded or approximated the standard deviation of returns on the Canadian market as a whole?

A 64 I conclude that the risk of Canadian utility stocks compared to the risk of the Canadian stock market as a whole is greater than is implied by the AAM ROE Formula. Specifically, while the AAM ROE Formula implies that Canadian utility stocks are only half as risky as the Canadian stock market as a whole (the Formula assumes a beta equal to 0.50 for Canadian utility stocks),[3] my evidence indicates

[3] See Commission Order No. G-14-06, March 2, 2006, at 53.

that Canadian utility stocks have approximately the same risk as the Canadian stock market as a whole.

Q 65 What conclusions do you draw from your evidence that the realized returns on Canadian utility stocks have exceeded realized returns on the Canadian stock market index over the periods 1956 – 2008 and 1983 – 2008?

A 65 This evidence corroborates my conclusion that Canadian utility stocks are more risky relative to the Canadian stock market as a whole than is implied by the AAM ROE Formula.

6. Evidence that the AAM ROE Formula Produces Lower Results in a Period of Increased Risk and Uncertainty in the Economic and Capital Markets

Q 66 Does an investor's required rate of return on investment depend on investment risk?

A 66 Yes. Since investors are risk averse, their required rate of return on an investment increases with the risk of the investment. That is, the greater the risk, the higher the required rate of return.

Q 67 Does greater uncertainty in economic and capital market conditions produce greater risk for investors?

A 67 Yes. It is widely recognized that investment risk is related to uncertainty, with higher uncertainty indicating higher investment risk.

Q 68 Do you have any evidence that investors' required rates of return on utility stock investments have increased in response to the greater uncertainty in current economic and capital market conditions?

A 68 Yes. During periods of greater uncertainty in economic and capital market conditions, the required rate of return on utility stock investments generally moves in the same direction as the required rate of return on utility bond investments. The required rate of return on utility bond investments is measured by the yield on utility bonds. Since the yield on utility bonds has increased in response to greater uncertainty in economic and capital market conditions, it is highly likely that the required rate of return on utility stock investments has increased as well. (I provide a direct estimate of the required return on utility stock investments in Section IV.)

Q 69 What evidence do you have that interest rates on utility bond investments have increased in response to greater uncertainty in economic and capital market conditions?

A 69 In the United States, for example, interest rates on A-rated utility bonds have increased from 6.0 percent in January 2008 to 6.4 percent in March 2009. The increase in interest rates on Baa-rated utility bonds has been even greater, increasing from 6.4 percent in January 2008, to 7.9 percent in March 2009. In Canada, the indicated yield on Terasen's 30-year bonds has increased from approximately 5.7 percent at year end 2007 to approximately 6.7 percent in February 2009.[4] As further evidence that the yield on Canadian utility bonds has increased, I note that TransCanada has recently issued long-term debt securities with a nominal yield to maturity equal to 7.625 percent.

Q 70 Have interest rates on long-term government bonds increased in line with interest rates on long-term utility bonds?

A 70 No. Interest rates on medium-term and long-term government bonds have declined. In the United States, for example, the interest rate on 10-year U.S. Treasury bonds declined from 4.5 percent in October 2007 to 2.8 percent in March 2009; and interest rates on 30-year U.S. Treasury bonds declined from 4.8 percent in October 2007 to 3.6 percent in March 2009. Similarly, the yield on 10-year Canada bonds declined from 4.4 percent in October 2007 to 3.0 percent in March 2009, and the yield on long Canada bonds declined from 4.4 percent to 3.7 percent.

Q 71 Has the AAM ROE Formula estimated ROE increased in line with greater uncertainty in economic and capital market conditions?

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[4] Data provided by Terasen.

A 71 No. Because the AAM ROE Formula estimated ROE depends on the yield on long Canada bonds rather than the yield on corporate bonds, and the yield on long Canada bonds has declined, the formula-estimated ROE has declined at the same time that there is greater uncertainty in economic and capital market conditions.

Q 72 What conclusions do you draw from the evidence that the AAM ROE Formula estimated ROE has declined during this period of greater uncertainty and risk in economic and capital markets?

A 72 I conclude that a AAM ROE Formula based on government bonds produces unreasonable results. While the costs of utility capital have increased in line with increased risk and uncertainty in economic and capital markets, the AAM ROE Formula based on long Canada bonds indicates that the required return on an equity investment in Canadian utilities has declined.

IV. The Cost of Equity for Companies whose Risk is Similar to TGI Is Significantly Higher than the Cost of Equity Implied by the AAM ROE Formula.

A. Comparable Companies

Q 73 What methods did you use to estimate the cost of equity for your comparable companies?

A 73 I estimated the cost of equity for these companies by first identifying companies of similar risk to TGI and then applying several standard cost of equity methodologies to data for these companies.

Q 74 What criteria did you use to select companies whose risk is similar to that of TGI?

A 74 I used the following criteria to select groups of similar risk companies: (1) must have stock that is publicly traded; (2) must have sufficient available data to reasonably apply standard cost of equity estimation techniques; (3) must be comparable in risk; and (4) taken together, must constitute a relatively large sample of companies.

Q 75 Why must comparable companies be publicly traded?

A 75 Comparable companies must be publicly traded because information on a company’s stock price is a key input in standard cost of equity estimation methods. If the company is not publicly traded, the information required to estimate the cost of equity will not be available.

Q 76 Why is data availability a concern in estimating the cost of equity for TGI?

A 76 Data availability is a concern because standard cost of equity estimation methods like the equity risk premium and the DCF require estimates of inputs, such as the required risk premium and the expected growth rate, that are inherently uncertain. If there is insufficient data available to estimate these inputs, there is little basis for arriving at a reasonable estimate of the cost of equity for the comparable risk companies.

Q 77 Is there any way to assure that the companies used to estimate the cost of equity have exactly the same risk as TGI?

A 77 No. First, TGI is a regulated natural gas distribution utility, and there are few regulated natural gas distribution utilities that have publicly-traded stock. Second, it is not possible to measure the risk of TGI precisely because most generally accepted risk measures require that a company have publicly-traded stock. Third, there is no single generally agreed upon measure of risk.

Q 78 Recognizing the difficulty in identifying companies with exactly the same risk as TGI, what companies did you consider as potential comparables for the purpose of estimating the cost of equity for TGI?

A 78 I considered two groups of Canadian utilities and two groups of US utilities.

Q 79 What two groups of Canadian utilities did you consider?

A 79 I considered the small group of Canadian utilities included in the BMO CM’s basket of utility and pipeline companies and a larger group consisting of the companies in the S&P/TSX utilities index.

Q 80 What are the advantages of using the BMO CM basket of Canadian utilities as comparables for the purpose of estimating the cost of equity for TGI?

A 80 The primary advantage of the BMO CM basket of Canadian utilities is that it only includes companies that receive a significant portion of their revenues from traditional utility operations.

Q 81 What are the advantages of using the S&P/TSX utilities index as comparables in this proceeding?

A 81 The primary advantage of using the S&P/TSX utilities index is that there are more companies in the index and return data for this index is available for a longer period of time than for the BMO CM basket of utility stocks.

Q 82 What are the advantages of using your two U.S. utilities groups as comparables for the purpose of estimating the cost of equity for TGI?

A 82 The primary advantages of my U.S. utilities groups are that: (1) they include a significantly larger sample of companies with traditional utility operations than my Canadian groups; (2) reasonable estimates of expected growth rates are available for these companies, whereas the same data are not available for the Canadian utilities; and (3) historical data for the U.S. utilities are available for a much greater length of time than for the Canadian utilities.

Q 83 What conclusions do you draw from your investigation of alternative groups of comparable companies?

A 83 I conclude that the BC Utilities Commission should give significantly greater weight to the cost of equity results for the U.S. utilities groups than it has previously. The U.S. utilities are more involved in traditional utility operations than the companies included in the Canadian utilities indices. In addition, the sample of U.S. regulated utilities is significantly larger than the sample of Canadian regulated utilities, and the data required to estimate the cost of equity is more readily available for the U.S. utilities than for the Canadian utilities. Furthermore, Canadian investors have greater access to international stock market investments, including investments in the U.S., than they did prior to the elimination of the foreign property rule in 2005. For these reasons, the U.S. data provide important information on the cost of equity for TGI.

Q 84 Did the National Energy Board ("NEB") recently determine that cost of equity evidence for U.S. utilities is useful in determining the cost of equity for Trans Québec & Maritimes Pipeline Inc. ("TQM")?

A 84 Yes. In Decision RH-1-2008 the Board finds:

> In light of the Board's views expressed above on the integration of U.S. and Canadian financial markets, the problems with comparisons to either Canadian negotiated or litigated returns, and the Board's view that risk differences between Canada and the U.S. can be understood and accounted for, the Board is of the view that U.S. comparisons are very informative for determining a fair return for TQM for 2007 and 2008. [RH-1-2008 at 71.]

B. Estimating the Cost of Equity

Q 85 What methods did you use to estimate the cost of equity for TGI?

A 85 I used two generally accepted methods: the equity risk premium and the discounted cash flow ("DCF"). The equity risk premium method assumes that the investor's required rate of return on an equity investment is equal to the interest rate on a long-term bond plus an additional equity risk premium to compensate the investor for the risks of investing in equities compared to bonds. The DCF method assumes that the current market price of a firm's stock is equal to the discounted value of all expected future cash flows.

1. Equity Risk Premium Method

Q 86 Please describe the equity risk premium method.

A 86 The equity risk premium method is based on the principle that investors expect to earn a return on an equity investment that reflects a "premium" over and above the return they expect to earn on an investment in a portfolio of bonds. This equity risk premium compensates equity investors for the additional risk they bear in making equity investments versus bond investments.

Q 87 How did you measure the required risk premium on an equity investment in your comparable risk companies?

A 87 I used two methods to estimate the required risk premium on an equity investment in my comparable risk companies. The first is called the ex post risk premium method and the second is called the ex ante risk premium method.

a) Ex Post Risk Premium

Q 88 Please describe your ex post risk premium method for measuring the required risk premium on an equity investment.

A 88 My ex post risk premium method measures the required risk premium on an equity investment in TGI from historical data on the returns experienced by investors in Canadian utility stocks compared to investors in long-term Canada bonds.

Q 89 How do you measure the return experienced by investors in Canadian utility stocks?

A 89 I measure the return experienced by investors in Canadian utility stocks from historical data on returns earned by investors in: (1) the S&P/TSX utilities stock index; and (2) a basket of Canadian utility stocks created by the BMO CM.

Q 90 Does your ex post risk premium cost of equity study use the same investor experienced return data that you discussed above when you described your tests of the validity of the AAM ROE Formula?

A 90 Yes, it does.

Q 91 How do you measure the forecast bond yield for your ex post risk premium studies?

A 91 I measure the forecast bond yield from information on the forecast yield on long-term Canada bonds as reported by Consensus Economics.

Q 92 What risk premium results do you obtain from your ex post risk premium method?

A 92 As shown below, for the S&P/TSX utilities index, I obtain an experienced risk premium of 4.3 percent; and for the BMO CM utility stock data set, an experienced risk premium of 6.6 percent, with an average experienced risk premium of 5.5 percent (as noted above, the annual data that produce these results are shown in Exhibit 1 and Exhibit 2).

TABLE 4
EX POST RISK PREMIUM RESULTS

COMPARABLE GROUP	PERIOD OF STUDY	AVERAGE STOCK RETURN	AVERAGE BOND YIELD	RISK PREMIUM
S&P/TSX Utilities	1956 – 2008	11.84	7.54	4.3
BMO CM Utilities Stock Data Set	1983 – 2008	14.31	7.66	6.6
Average				5.5

Q 93 What conclusions do you draw from your ex post risk premium analyses about your comparable companies' cost of equity?

A 93 My studies provide evidence that investors in these companies require an equity return equal to at least 5.5 percentage points above the interest rate on long-term Canada bonds. The Consensus Economics forecast interest rate on long-term Canada bonds for 2010 as of April 2009 is 3.69 percent. Adding a 5.5 percentage point risk premium to an expected yield of 3.69 percent on long-term Canada bonds and including a 50-basis allowance for flotation costs and financial flexibility produces an expected return on equity equal to 9.7 percent from my ex post risk premium studies.

Q 94 Do you have any evidence that 9.7 percent is a conservative estimate of the required return on utility stocks based on experienced risk premiums?

A 94 Yes. During periods of greater uncertainty in economic and capital market conditions such as we have experienced in recent months, the return on utility stocks moves more in line with utility bond yields than with government bond yields. My studies indicate that the required risk premium on utility stocks compared to utility bonds based on experienced risk premium studies is in the range 4.2 percent to 4.5 percent. Adding a 4.2 percent to 4.5 percent risk premium to an approximate yield of 6.0 percent on Canadian utility bonds, and including 50 basis point allowance for flotation costs and financial flexibility produces a required return on equity in the range 10.7 percent to 11.0 percent.

In addition, my ex ante risk premium studies indicate that the required equity risk premium increases when interest rates on long-term government bonds decline. Since the interest rate on long Canada bonds is significantly below the average interest rate on long Canada bonds over my ex post risk premium study period, the required equity risk premium can reasonably be expected to be greater than the 5.5 percent equity risk premium I obtain from my ex post risk premium studies.

b) Ex Ante Risk Premium Method

Q 95 Please describe your ex ante risk premium approach for measuring the required risk premium on an equity investment in TGI.

A 95 My ex ante risk premium method is based on studies of the expected return on comparable groups of utilities in each month of my study period compared to the interest rate on long-term government bonds.

Q 96 Does your ex ante risk premium cost of equity study use the same forward looking, or ex ante, risk premium data that you discussed above when you described your analysis of the sensitivity of the forward looking required equity risk premium on utility stocks to changes in interest rates?

A 96 Yes, it does.

Q 97 What risk premium estimates do you obtain from your ex ante risk premium studies?

A 97 For my electric utility comparable group, I obtain an ex ante risk premium equal to 8.0 percent, and for my natural gas comparable group, I obtain an ex ante risk premium equal to 7.5 percent.

Q 98 What cost of equity results do you obtain from your ex ante risk premium studies?

A 98 As described above, in the ex ante risk premium approach, one must add the expected interest rate on long-term government bonds to the estimated risk premium to calculate the cost of equity. Since TGI is a Canadian utility, I estimated the expected yield on long-term government bonds using the forecast interest rate on long-term Canada bonds, 3.69 percent. Adding this 3.69 percent interest rate to my 8.0 percent and 7.5 percent ex ante risk premium estimates, I obtain cost of equity estimates of 11.7 percent and 11.2 percent (3.7 + 8.0 = 11.7 and 3.7 + 7.5 = 11.2), with an average estimate of 11.4 percent. A more detailed description of my ex ante risk premium approach and results is described in Exhibit 5, Exhibit 6, and Exhibit 14, Appendix 3.

2. Discounted Cash Flow Model

Q 99 How do you use the DCF model to estimate the cost of equity on an investment in your comparable risk companies?

A 99 I apply the DCF model to the Value Line electric and natural gas utilities shown in Exhibit 8 and Exhibit 9.

Q 100 How do you select your comparable groups of Value Line utilities?

A 100 I select all the utilities in Value Line's electric and natural gas industry groups that: (1) paid dividends during every quarter and did not decrease dividends during any quarter of the past two years; (2) have at least three analysts included in the I/B/E/S mean growth forecast; (3) are not in the process of being acquired; (4) have a Value Line Safety Rank of 1, 2, or 3; and (5) have investment grade S&P bond ratings.

Q 101 Why do you eliminate companies that have either decreased or eliminated their dividend during the past two years?

A 101 The DCF model requires the assumption that dividends will grow at a constant positive rate into the indefinite future. If a company has decreased its dividend in recent years, an assumption that the company's dividend will grow at the same positive rate into the indefinite future is questionable.

Q 102 Why do you eliminate companies that have fewer than three analysts' estimates included in the I/B/E/S mean forecast?

A 102 The DCF model also requires a reliable estimate of a company's expected future growth. For most companies, the I/B/E/S mean growth forecast is the best available estimate of the growth term in the DCF Model. However, the I/B/E/S estimate may be less reliable if the mean estimate is based on the inputs of very few analysts. On the basis of my professional judgment, I believe that at least three analysts' estimates are a reasonable minimum number.

Q 103 Why do you eliminate companies that are in the process of being acquired?

A 103 I eliminate companies that are in the process of being acquired because announcement of an acquisition frequently has a significant impact on a company's stock price as a result of anticipated merger-related cost savings and new market opportunities. Analysts' growth forecasts, on the other hand, are necessarily related to companies as they currently exist, and do not reflect investors' views of the potential cost savings and new market opportunities associated with mergers. The use of a stock price that includes the value of potential mergers in conjunction with growth forecasts that do not include the growth enhancing prospects of potential mergers produces DCF results that tend to distort a company's cost of equity.

Q 104 Please summarize the results of your application of the DCF model to your comparable groups of companies.

A 104 My application of the DCF model to my comparable group of natural gas companies produces a result of 11.5 percent, and to my comparable group of electric companies, 12.4 percent (see Exhibit 8 and Exhibit 9). The average DCF result for my two comparable groups is 11.9 percent.

Q 105 Based on your application of the equity risk premium and DCF methods to your comparable risk companies, what is your conclusion regarding your comparable risk companies' cost of equity?

A 105 I conservatively conclude that my comparable companies' cost of equity is 11.0 percent. As shown below, 11.0 percent is the simple average of the cost of equity results I obtain from my cost of equity models. However, my comparable companies' cost of equity is likely to be above 11.0 percent because, as noted above, the results of my ex post risk premium method very likely understate the cost of equity for my comparable companies.

TABLE 5
SUMMARY OF COST OF EQUITY RESULTS

METHOD	COST OF EQUITY
Ex Post Risk Premium	9.7
Ex Ante Risk Premium	11.4
Discounted Cash Flow	11.9
Average	11.0

V. Comparable Risk Utilities Have Significantly Higher Allowed Equity Ratios than TGI.

Q 106 What common equity ratio did the BC Utilities Commission approve for TGI in its 2006 cost of capital order?

A 106 The BC Utilities Commission approved a 35 percent equity ratio for TGI.

Q 107 How does the approved equity ratio for TGI compare to approved equity ratios for U.S. utilities?

A 107 As noted above and as shown in Exhibit 4, the average approved equity ratio for U.S. electric utilities during the period 2006 through 2008 is 48 percent and for U.S. natural gas utilities, 49 percent. Thus, the average approved equity ratio for U.S. utilities is significantly higher than the approved equity ratio for TGI.

Q 108 How does the approved equity ratio for TGI compare to market value equity ratios for U.S. utilities at March 2009?

A 108 The average market value equity ratio for U.S. electric utilities at March 2009 is 55 percent, and 63 percent for natural gas utilities (See Exhibit 10).

Q 109 Why do you present evidence on market value equity ratios for U.S. utilities as well as book value equity ratios?

A 109 I present evidence on market value equity ratios as well as book value equity ratios because financial risk depends on the market value percentages of debt and equity in a company's capital structure rather than on the book value percentages of debt and equity in the company's capital structure.

Q 110 How does the business risk of TGI compare to the average business risk of U.S. electric and natural gas utilities?

A 110 As discussed above, the business risk of TGI is approximately equal to the average business risk of U.S. electric and natural gas utilities.

Q 111 How does the financial risk of TGI compare to the average financial risk of U.S. electric and natural gas utilities?

A 111 Since TGI has an allowed equity ratio of 35 percent, and the U.S. electric and natural gas utilities have average allowed equity ratios of 48 percent and 49 percent, the financial risk of U.S. electric and natural gas utilities is significantly less than the financial risk of TGI. This conclusion is further supported by the observation that the average market value equity ratio for U.S. electric utilities is 55 percent, and for natural gas utilities, 63 percent. This observation is important because financial risk is best measured using market value equity ratios rather than book value equity ratios.

VI. Summary and Recommendations

Q 112 Please summarize your written evidence in this proceeding.

A 112 My written evidence may be summarized as follows:

1. Experienced equity risk premiums on investments in Canadian utility stocks average 5.5 percent, whereas the AAM ROE Formula implies an equity risk premium of only 4.29 percent.

2. Recent average allowed returns for U.S. utilities are in the range 10.3 percent to 10.4 percent, whereas the AAM ROE Formula implies an ROE equal to 7.9 percent (based on capital market data at March 2009).
3. The forward-looking required equity risk premium on utility stocks is less sensitive to changes in government bond yields than is implied by the AAM ROE Formula.
4. The allowed equity risk premium for U.S. utilities is less sensitive to changes in government bond yields than is implied by the AAM ROE Formula.
5. The risk of investing in Canadian utility stocks is higher relative to the Canadian stock market as a whole than is implied by the AAM ROE Formula.
6. The cost of equity for investments in comparable risk utilities is 11.0 percent based on ex post risk premium, ex ante risk premium, and discounted cash flow studies.
7. Allowed equity ratios for U.S. utilities are in the range 48 percent to 49 percent, whereas the allowed equity ratio for TGI is 35 percent.
8. The business risk of TGI is approximately equal to the average business risk of U.S. utilities, whereas the average financial risk of TGI is significantly greater than the average financial risk of U.S. utilities.

Q 113 What conclusion do you reach from this evidence?

A 113 I conclude that the allowed rate of return on rate base, or overall rate of return, obtained by applying the AAM ROE Formula to TGI's deemed equity ratio is significantly less than the overall return that investors could earn on other investments of similar risk.

Q 114 Based on your evidence regarding average allowed ROEs and equity ratios for U.S. utilities, what is your estimate of the average allowed rate of return on rate base for comparable risk U.S. utilities?

A 114 I estimate that the average allowed rate of return on rate base for U.S. utilities is approximately 8 percent (see Table 6).

TABLE 6
ESTIMATE OF AVERAGE ALLOWED RETURN ON RATE BASE
FOR U.S. UTILITIES

CAPITAL COMPONENT	% TOTAL	COST RATE	WEIGHTED COST
Debt	52.00%	6.00%	3.12%
Equity	48.00%	10.30%	4.94%
Total	100.00%		8.06%

Q 115 Does TGI need to be allowed an ROE of 10.30 percent on an equity base of 48.0 percent in order to have the same allowed rate of return on rate base as comparable risk U.S. utilities?

A 115 No. TGI could be allowed any combination of ROE and deemed equity ratio that produces an overall rate of return of at least 8 percent. As noted above, one such combination is an ROE of 10.3 percent and a deemed equity ratio of 48 percent. An allowed ROE of 11 percent and a deemed equity ratio of 40 percent also produces an overall return of 8 percent (see Table 7).

TABLE 7
ALTERNATIVE COST OF EQUITY AND EQUITY RATIO
THAT PRODUCES AN 8.0 PERCENT
ALLOWED RETURN ON RATE BASE

CAPITAL COMPONENT	% TOTAL	COST RATE	WEIGHTED COST
Debt	60.00%	6.00%	3.60%
Equity	40.00%	11.00%	4.40%
Total	100.00%		8.00%

Q 116 What is your specific recommendation regarding the rate of return on equity and equity percentage for TGI?

A 116 I conservatively recommend that TGI be awarded an allowed ROE of 11.0 percent on an equity base of 40 percent, that is five percent above its last allowed deemed equity ratio.

Q 117 Does this conclude your written evidence?

A 117 Yes, it does.

EXHIBIT 1
EXPERIENCED RISK PREMIUMS ON
S&P/TSX CANADIAN UTILITIES STOCK INDEX
1956—2008

LINE NO.	YEAR	S&P/TSX CANADIAN UTILITIES STOCK INDEX TOTAL RETURN	YIELD LONG-TERM CANADA BOND	RISK PREMIUM
1	1956	0.17	3.63	-3.45
2	1957	-3.43	4.11	-7.54
3	1958	9.81	4.15	5.66
4	1959	0.21	5.08	-4.86
5	1960	26.81	5.19	21.62
6	1961	19.17	5.05	14.12
7	1962	-0.72	5.11	-5.83
8	1963	6.19	5.09	1.10
9	1964	21.59	5.18	16.41
10	1965	4.23	5.21	-0.98
11	1966	-13.17	5.69	-18.86
12	1967	5.07	5.94	-0.87
13	1968	7.41	6.75	0.66
14	1969	-8.62	7.58	-16.20
15	1970	23.34	7.91	15.43
16	1971	4.29	6.95	-2.66
17	1972	-0.44	7.23	-7.68
18	1973	-4.14	7.56	-11.70
19	1974	14.38	8.90	5.48
20	1975	5.75	9.04	-3.28
21	1976	15.02	9.18	5.84
22	1977	19.00	8.70	10.30
23	1978	27.28	9.27	18.01
24	1979	12.61	10.21	2.40
25	1980	5.74	12.48	-6.74
26	1981	-0.55	15.22	-15.77
27	1982	35.90	14.26	21.65
28	1983	40.97	11.79	29.17
29	1984	24.31	12.75	11.56
30	1985	10.04	11.04	-1.00
31	1986	11.48	9.52	1.96
32	1987	1.07	9.95	-8.88
33	1988	5.63	10.22	-4.59
34	1989	22.07	9.92	12.15
35	1990	0.58	10.85	-10.28

LINE NO.	YEAR	S&P/TSX CANADIAN UTILITIES STOCK INDEX TOTAL RETURN	YIELD LONG-TERM CANADA BOND	RISK PREMIUM
36	1991	27.02	9.76	17.25
37	1992	-2.24	8.77	-11.00
38	1993	23.52	7.85	15.67
39	1994	-6.04	8.63	-14.68
40	1995	18.44	8.28	10.16
41	1996	32.68	7.50	25.18
42	1997	37.33	6.42	30.91
43	1998	36.55	5.47	31.09
44	1999	-27.14	5.69	-32.83
45	2000	50.06	5.89	44.17
46	2001	10.83	5.78	5.05
47	2002	6.33	5.66	0.67
48	2003	24.94	5.28	19.66
49	2004	9.42	5.08	4.34
50	2005	38.29	4.39	33.90
51	2006	7.01	4.30	2.71
52	2007	11.89	4.34	7.55
53	2008	-20.46	4.05	-24.50
54	Average	11.84	7.54	4.29

EXHIBIT 2
EXPERIENCED RISK PREMIUMS ON BMO CAPITAL MARKETS UTILITIES STOCK DATA SET
1983—2008

LINE NO.	YEAR	BMO CAPITAL MARKETS UTILITIES TOTAL RETURN	YIELD LONG-TERM CANADA BOND	RISK PREMIUM
1	1983	25.63	11.79	13.84
2	1984	5.46	12.75	-7.29
3	1985	18.95	11.04	7.90
4	1986	-3.48	9.52	-13.00
5	1987	9.97	9.95	0.02
6	1988	7.84	10.22	-2.38
7	1989	18.36	9.92	8.44
8	1990	6.31	10.85	-4.54
9	1991	4.01	9.76	-5.75
10	1992	-0.36	8.77	-9.12
11	1993	31.52	7.85	23.68
12	1994	-2.64	8.63	-11.27
13	1995	14.73	8.28	6.45
14	1996	30.56	7.50	23.05
15	1997	48.52	6.42	42.10
16	1998	4.06	5.47	-1.40
17	1999	-24.03	5.69	-29.72
18	2000	57.77	5.89	51.89
19	2001	14.72	5.78	8.93
20	2002	13.93	5.66	8.27
21	2003	27.75	5.28	22.47
22	2004	15.00	5.08	9.92
23	2005	32.02	4.39	27.64
24	2006	16.61	4.30	12.31
25	2007	3.88	4.34	-0.45
26	2008	-5.17	4.05	-9.22
27	Average	14.31	7.66	6.64

EXHIBIT 3
ALLOWED RETURNS ON EQUITY FOR
U.S. ELECTRIC AND NATURAL GAS UTILITIES
2006 – 2008[5]

ELECTRIC UTILITIES

LINE NO.	DATE	COMPANY	STATE	ROE
1	5-Jan-06	Northern States Power (WI)	WI	11.00
2	27-Jan-06	United Illuminating (CT)	CT	9.75
3	3-Mar-06	Interstate Power & Light (MN)	MN	10.39
4	17-Apr-06	PacifiCorp (WA)	WA	10.20
5	18-Apr-06	MidAmerican Energy	IA	11.90
6	26-Apr-06	Sierra Pacific Power	NV	10.60
7	12-May-06	Idaho Power	ID	10.60
8	6-Jun-06	Delmarva Power & Light	DE	10.00
9	27-Jun-06	Upper Penninsula Power	MI	10.75
10	6-Jul-06	Maine Public Service	ME	10.20
11	24-Jul-06	Central Hudson Gas & Electric	NY	9.60
12	26-Jul-06	Appalachian Power	WV	10.50
13	28-Jul-06	Commonwealth Edison	IL	10.05
14	23-Aug-06	NY State Electric & Gas	NY	9.55
15	1-Sep-06	Northern States Power	MN	10.54
16	14-Sep-06	PacifiCorp	OR	10.00
17	6-Oct-06	Unitil Energy Systems	NH	9.67
18	21-Nov-06	Central Illinois Public Service	IL	10.08
19	21-Nov-06	Central Illinois Light	IL	10.08
20	21-Nov-06	Illinois Power	IL	10.12
21	1-Dec-06	PacifiCorp	UT	10.25
22	1-Dec-06	Public Service Colorado	CO	10.50
23	7-Dec-06	Central Vermont Public Service	VT	10.75
24	21-Dec-06	Empire District Electric Co.	MO	10.90
25	21-Dec-06	Kansas City Power & Light	MO	11.25
26	22-Dec-06	Green Mountain Power	VT	10.25
27	5-Jan-07	Oklahoma G & E	AR	10.00
28	5-Jan-07	Puget Sound Energy	WA	10.40
29	11-Jan-07	Metropolitan Edison	PA	10.10
30	11-Jan-07	Pennsylvania Electric	PA	10.10
31	11-Jan-07	Wisconsin Public Service	WI	10.90
32	12-Jan-07	Portland General Electric	OR	10.10
33	19-Jan-07	Wisconsin Power & Light	WI	10.80
34	22-Mar-07	Rockland Electric	NJ	9.75
35	15-May-07	Appalachian Power	VA	10.00
36	17-May-07	Aquila MPS	MO	10.25
37	17-May-07	Aquila LP	MO	10.25

[5] Regulatory Research Associates, Inc., "Major Rate Case Decisions–January 2006–December 2007," January 8, 2008; "Major Rate Case Decisions–January 2007-December 2008," January 12, 2009.

LINE NO.	DATE	COMPANY	STATE	ROE
38	22-May-07	Union Electric	MO	10.20
39	22-May-07	Monongahela	WV	10.50
40	23-May-07	Nevada Power	NV	10.70
41	25-May-07	Public Service NH	NH	9.67
42	15-Jun-07	Entergy AR	AR	9.90
43	21-Jun-07	PacifiCorp	WA	10.20
44	22-Jun-07	Appalachian Power	WV	10.50
45	28-Jun-07	AZ Public Service	AZ	10.75
46	12-Jul-07	Granite State Electric	NH	9.67
47	19-Jul-07	DelMarva P & L	MD	10.00
48	19-Jul-07	Potomac Electric Power	MD	10.00
49	15-Aug-07	Southern Indiana G & E	IN	10.40
50	9-Oct-07	Public Service Oklahoma	OK	10.00
51	18-Oct-07	Orange and Rockland	NY	9.10
52	31-Oct-07	Electric Transmission Texas	TX	9.96
53	29-Nov-07	Cheyenne Light	WY	10.90
54	6-Dec-07	Kansas City Power & Light	MO	10.75
55	13-Dec-07	AEP Texas	TX	9.96
56	14-Dec-07	South Carolina Electric & Gas	SC	10.70
57	14-Dec-07	Madison Gas and Electric	WI	10.80
58	19-Dec-07	Avista Corporation	WA	10.20
59	20-Dec-07	Bangor Hydro-Electric	ME	10.20
60	20-Dec-07	Duke Energy Carolinas	NC	11.00
61	21-Dec-07	San Diego Gas & Electric	CA	11.10
62	21-Dec-07	Pacific Gas and Electric	CA	11.35
63	21-Dec-07	Southern California Edison	CA	11.50
64	28-Dec-07	PacifiCorp	ID	10.25
65	31-Dec-07	Georgia Power	GA	11.25
66	8-Jan-08	Northern States Power	WI	10.75
67	17-Jan-08	Wisconsin Electric Power	WI	10.75
68	28-Jan-08	Connecticut Light & Power	CT	9.40
69	30-Jan-08	Potomac Electric Power	DC	10.00
70	31-Jan-08	Central Vermont	VT	10.71
71	6-Feb-08	Interstate Power & Light	IA	11.70
72	29-Feb-08	Fitchburg Gas & Electric	MA	10.25
73	12-Mar-08	PacifiCorp	WY	10.25
74	25-Mar-08	Consolidated Edison	NY	9.10
75	31-Mar-08	Virginia Electric Power	VA	12.12
76	22-Apr-08	MDU Resources	MT	10.25
77	24-Apr-08	Public Service Co. New Mexico	NM	10.10
78	1-May-08	Hawaiian Electric Company	HI	10.70
79	27-May-08	UNS Electric	AZ	10.00
80	10-Jun-08	Consumers Energy	MI	10.70
81	16-Jun-08	MidAmerican Energy	IA	11.70
82	27-Jun-08	Appalachian Power	WV	10.50
83	10-Jul-08	Otter Tail Corporation	MN	10.43
84	16-Jul-08	Orange and Rockland Utilities	NY	9.40

LINE NO.	DATE	COMPANY	STATE	ROE
85	30-Jul-08	Empire District Electric Co.	MO	10.80
86	11-Aug-08	PacifiCorp	UT	10.25
87	26-Aug-08	Southwestern Public Service	NM	10.18
88	27-Aug-08	MidAmerican Energy	IA	11.70
89	10-Sep-08	Commonwealth Edison	IL	10.30
90	24-Sep-08	Central Illinois Light	IL	10.65
91	24-Sep-08	Central Illinois Public Service	IL	10.65
92	24-Sep-08	Illinois Power	IL	10.65
93	30-Sep-08	Avista Corp.	ID	10.20
94	8-Oct-08	Puget Sound Energy	WA	10.15
95	13-Nov-08	NorthWestern Corporation	MT	10.00
96	17-Nov-08	Appalachian Power	VA	10.20
97	1-Dec-08	Tucson Electric Power	AZ	10.25
98	23-Dec-08	Detroit Edison	MI	11.00
99	29-Dec-08	Portland General Electric	OR	10.10
100	29-Dec-08	Avista Corp.	WA	10.20
101	31-Dec-08	Northern States Power	ND	10.75
102		Average 2006 - 2008		10.40
103		Average 2008		10.47

EXHIBIT 3 (CONTINUED)
ALLOWED RETURNS ON EQUITY
FOR U.S. ELECTRIC AND NATURAL GAS UTILITIES
2006 – 2008

NATURAL GAS UTILITIES

LINE NO.	DATE	COMPANY	STATE	ROE
1	5-Jan-06	Northern States Power	WI	11.00
2	25-Jan-06	Wisconsin Electric Power	WI	11.20
3	25-Jan-06	Wisconsin Gas	WI	11.20
4	3-Feb-06	Public Service Colorado	CO	10.50
5	23-Feb-06	Southwest Gas	AZ	9.50
6	1-Mar-06	Aquila	IA	10.40
7	26-Apr-06	Sierra Pacific Power	NV	10.60
8	25-May-06	Atmos Energy	LA	10.40
9	24-Jul-06	Central Hudson Gas & Electric	NY	9.60
10	20-Sep-06	Knight Inc.	WY	11.00
11	26-Sep-06	Chesapeake Utilities	MD	10.75
12	20-Oct-06	Orange & Rockland Utilities	NY	9.80
13	2-Nov-06	Centerpoint Energy MN Gas	MN	9.71
14	9-Nov-06	Public Service E & G	NJ	10.00
15	21-Nov-06	Consumers Energy	MI	11.00
16	5-Dec-06	Chatanooga Gas	TN	10.20
17	5-Jan-07	Puget Sound Energy	WA	10.40
18	9-Jan-07	Semco Energy Gas	MI	11.00
19	11-Jan-07	Wisconsin Public Service	WI	10.90
20	19-Jan-07	Wisconsin Power & light	WI	10.80
21	26-Jan-07	Fitchburg Gas & Electric	MA	10.00
22	8-Feb-07	PPL Gas Utilities	PA	10.40
23	14-Mar-07	Connecticut Natural Gas	CT	10.10
24	20-Mar-07	Delmarva Power & Light	DE	10.25
25	22-Mar-07	Southern Union	MO	10.50
26	29-Mar-07	Atmos Energy	TX	10.00
27	5-Jun-07	Cascade Natural Gas	OR	10.10
28	13-Jun-07	Northern States Power	ND	10.75
29	29-Jun-07	Public Service New Mexico	NM	9.53
30	29-Jun-07	Yankee Gas Services	CT	10.10
31	3-Jul-07	Public Serivce Colorado	CO	10.25
32	13-Jul-07	Arkansas Western Gas	AR	9.50
33	24-Jul-07	Aquila	NE	10.40
34	1-Aug-07	Southern Indian Gas & Electric	IN	10.15
35	29-Aug-07	Columbia Gas of Kentucky	KY	10.50
36	10-Sep-07	Northern States Power	MN	9.71
37	19-Sep-07	Washington Gas Light	VA	10.00
38	8-Oct-07	Atmos Energy	TN	10.48
39	19-Oct-07	Delta Natural Gas	KY	10.50
40	25-Oct-07	Centerpoint Energy Resources	AR	9.65
41	15-Nov-07	Washington Gas Light	MD	10.00
42	20-Nov-07	Arkansas Oklahoma Gas	AR	9.90

LINE NO.	DATE	COMPANY	STATE	ROE
43	27-Nov-07	UNS Gas	AZ	10.00
44	29-Nov-07	Cheyenne Light Fuel & Power	WY	10.90
45	14-Dec-07	Madison Gas & Electric	WI	10.80
46	18-Dec-07	Northwestern Energy Div.	NE	10.40
47	19-Dec-07	Avista Corp.	WA	10.20
48	21-Dec-07	Brooklyn Union Gas	NY	9.80
49	21-Dec-07	Keyspan Gas East	NY	9.80
50	21-Dec-07	National Fuel Gas Distribution	NY	9.10
51	21-Dec-07	Pacific Gas & Electric	CA	11.35
52	21-Dec-07	San Diego Gas & Electric	CA	11.10
53	8-Jan-08	Northern States Power	WI	10.75
54	17-Jan-08	Wisconsin Electric Power	WI	10.75
55	17-Jan-08	Wisconsin Gas	WI	10.75
56	5-Feb-08	North Shore Gas	IL	9.99
57	5-Feb-08	Peoples Gas Light & Coke	IL	10.19
58	13-Feb-08	Indiana Gas	IN	10.20
59	31-Mar-08	Avista Corp.	OR	10.00
60	28-May-08	Duke Energy	OH	10.50
61	24-Jun-08	Atmos Energy	TX	10.00
62	27-Jun-08	Questar Gas	UT	10.00
63	27-Aug-08	SourceGas Distribution	CO	10.25
64	2-Sep-08	Chesapeake Utilities	DE	10.25
65	17-Sep-08	Atmos Energy	GA	10.70
66	24-Sep-08	Central Illinois Light	IL	10.68
67	24-Sep-08	Central Illinois Public Service	IL	10.68
68	24-Sep-08	Illinois Power	IL	10.68
69	30-Sep-08	Avista Corp.	ID	10.20
70	3-Oct-08	New Jersey Natural Gas	NJ	10.30
71	8-Oct-08	Puget Sound Energy	WA	10.15
72	20-Oct-08	CenterPoint Energy Resources	TX	10.06
73	24-Oct-08	Piedmont Natural Gas	NC	10.60
74	24-Oct-08	Public Service of North Carolina	NC	10.60
75	24-Nov-08	Southwest Gas-So. California Div.	CA	10.50
76	24-Nov-08	Southwest Gas-No. California Div.	CA	10.50
77	24-Nov-08	Southwest Gas-So. Lk. Tahoe Dist.	CA	10.50
78	24-Nov-08	Narragansett Electric	RI	10.50
79	3-Dec-08	Columbia Gas of Ohio	OH	10.39
80	24-Dec-08	Southwest Gas	AZ	10.00
81	26-Dec-08	Northwest Natural Gas	WA	10.10
82	29-Dec-08	Avista Corporation	WA	10.20
83		Average 2006 - 2008		10.33
84		Average 2008		10.37

EXHIBIT 4
ALLOWED EQUITY RATIOS FOR
U.S. ELECTRIC AND NATURAL GAS UTILITIES
2006 – 2008[6]

ELECTRIC UTILITIES

DATE	COMPANY	STATE	COMMON EQUITY /TOTAL CAP (%)
1/5/2006	Northern States Power Co-WI	Wisconsin	53.66
1/27/2006	United Illuminating Co.	Connecticut	48.00
3/3/2006	Interstate Power & Light Co.	Minnesota	49.10
4/17/2006	PacifiCorp	Washington	46.00
4/26/2006	Sierra Pacific Power Co.	Nevada	40.76
5/17/2006	Southern California Edison Co.	California	48.00
6/6/2006	Delmarva Power & Light Co.	Delaware	47.72
6/27/2006	Upper Peninsula Power Co.	Michigan	47.12
7/6/2006	Maine Public Service Co.	Maine	50.00
7/24/2006	Central Hudson Gas & Electric	New York	45.00
7/28/2006	Commonwealth Edison Co.	Illinois	42.86
8/23/2006	NY State Electric & Gas Corp.	New York	41.60
9/1/2006	Northern States Power Co. - MN	Minnesota	51.67
9/14/2006	PacifiCorp	Oregon	50.00
9/22/2006	Consolidated Edison Co. of NY	New York	48.00
10/6/2006	Unitil Energy Systems Inc.	New Hampshire	43.10
11/21/2006	Central Illinois Light Co.	Illinois	45.57
11/21/2006	Central Illinois Public	Illinois	48.92
11/21/2006	Illinois Power Co.	Illinois	51.56
11/30/2006	Duquesne Light Co.	Pennsylvania	45.00
12/1/2006	Public Service Co. of CO	Colorado	60.00
12/7/2006	Central Vermont Public Service	Vermont	55.57
12/21/2006	Empire District Electric Co.	Missouri	50.80
12/21/2006	Kansas City Power & Light	Missouri	53.69
12/22/2006	Green Mountain Power Corp.	Vermont	52.76
12/22/2006	Green Mountain Power Corp.	Vermont	52.76
1/5/2007	Oklahoma Gas and Electric Co.	Arkansas	32.33
1/11/2007	Metropolitan Edison Co.	Pennsylvania	49.00
1/11/2007	Pennsylvania Electric Co.	Pennsylvania	49.00
1/11/2007	Wisconsin Public Service Corp	Wisconsin	57.46
1/12/2007	Portland General Electric Co.	Oregon	50.00
1/13/2007	Puget Sound Energy Inc.	Washington	44.00
1/19/2007	Wisconsin Power and Light Co	Wisconsin	54.13
3/21/2007	Pacific Gas and Electric Co.	California	52.00

[6] Regulatory Research Associates, Inc., “Major Rate Case Decisions–January 2006–December 2007,” January 8, 2008; “Major Rate Case Decisions–January 2007-December 2008,” January 12, 2009.

DATE	COMPANY	STATE	COMMON EQUITY /TOTAL CAP (%)
3/22/2007	Rockland Electric Company	New Jersey	46.51
5/15/2007	Appalachian Power Co.	Virginia	41.11
5/17/2007	KCP&L Greater Missouri Op Co	Missouri	48.17
5/17/2007	KCP&L Greater Missouri Op Co	Missouri	48.17
5/22/2007	Monongahela Power Co.	West Virginia	46.07
5/22/2007	Union Electric Co.	Missouri	52.22
5/23/2007	Nevada Power Co.	Nevada	47.29
5/25/2007	Public Service Co. of NH	New Hampshire	47.66
6/15/2007	Entergy Arkansas Inc.	Arkansas	32.19
6/21/2007	PacifiCorp	Washington	46.00
6/22/2007	Appalachian Power Co.	West Virginia	42.88
6/28/2007	Arizona Public Service Co.	Arizona	54.50
7/12/2007	Granite State Electric Company	New Hampshire	50.00
7/19/2007	Potomac Electric Power Co.	Maryland	47.69
7/19/2007	Delmarva Power & Light Co.	Maryland	48.63
8/15/2007	Southern Indiana Gas & Elec Co	Indiana	47.05
10/9/2007	Public Service Co. of OK	Oklahoma	46.02
10/17/2007	Orange & Rockland Utlts Inc.	New York	47.54
10/31/2007	Electric Transmission Texas	Texas	40.00
11/29/2007	Cheyenne Light Fuel Power Co.	Wyoming	54.00
12/6/2007	Kansas City Power & Light	Missouri	57.62
12/13/2007	AEP Texas Central Co.	Texas	40.00
12/14/2007	South Carolina Electric & Gas	South Carolina	53.32
12/14/2007	Madison Gas and Electric Co.	Wisconsin	57.36
12/19/2007	Avista Corp.	Washington	46.00
12/20/2007	Duke Energy Carolinas LLC	North Carolina	53.00
12/28/2007	PacifiCorp	Idaho	50.40
1/8/2008	Northern States Power Co-WI	Wisconsin	52.51
1/17/2008	Wisconsin Electric Power Co.	Wisconsin	54.36
1/28/2008	Connecticut Light & Power Co.	Connecticut	48.99
1/30/2008	Potomac Electric Power Co.	District of Columbia	46.55
1/31/2008	Central Vermont Public Service	Vermont	50.02
2/29/2008	Fitchburg Gas & Electric Light	Massachusetts	42.80
3/12/2008	PacifiCorp	Wyoming	50.80
3/25/2008	Consolidated Edison Co. of NY	New York	47.98
4/22/2008	MDU Resources Group Inc.	Montana	50.67
4/24/2008	Public Service Co. of NM	New Mexico	51.37
5/1/2008	Hawaiian Electric Co.	Hawaii	55.79
5/27/2008	UNS Electric Inc.	Arizona	48.85
6/10/2008	Consumers Energy Co.	Michigan	41.75
6/27/2008	Appalachian Power Co.	West Virginia	41.54
6/27/2008	Sierra Pacific Power Co.	Nevada	43.49
7/10/2008	Otter Tail Corp.	Minnesota	50.00
7/16/2008	Orange & Rockland Utlts Inc.	New York	48.00

DATE	COMPANY	STATE	COMMON EQUITY /TOTAL CAP (%)
7/30/2008	Empire District Electric Co.	Missouri	50.78
7/31/2008	San Diego Gas & Electric Co.	California	49.00
8/11/2008	PacifiCorp	Utah	50.40
8/26/2008	Southwestern Public Service Co	New Mexico	51.23
9/10/2008	Commonwealth Edison Co.	Illinois	45.04
9/17/2008	Consolidated Edison Co. of NY	New York	48.00
9/24/2008	Central Illinois Light Co.	Illinois	46.50
9/24/2008	Central Illinois Public	Illinois	47.91
9/24/2008	Illinois Power Co.	Illinois	51.76
9/30/2008	Avista Corp.	Idaho	47.94
10/8/2008	Puget Sound Energy Inc.	Washington	46.00
12/1/2008	Tucson Electric Power Co.	Arizona	42.50
12/23/2008	Detroit Edison Co.	Michigan	40.68
12/29/2008	Avista Corp.	Washington	46.30
12/29/2008	Portland General Electric Co.	Oregon	50.00
12/30/2008	Wisconsin Public Service Corp	Wisconsin	53.41
12/31/2008	Northern States Power Co. - MN	North Dakota	51.77
	Average		48.35
	Average 2008		48.43

EXHIBIT 4 (CONTINUED)
ALLOWED EQUITY RATIOS FOR
U.S. ELECTRIC AND NATURAL GAS UTILITIES
2006 – 2008[7]

NATURAL GAS UTILITIES

DATE	COMPANY	STATE	COMMON EQUITY /TOTAL CAP (%)
1/5/2006	Northern States Power Co-WI	Wisconsin	53.66
1/25/2006	Wisconsin Gas LLC	Wisconsin	50.20
1/25/2006	Wisconsin Electric Power Co.	Wisconsin	56.34
2/3/2006	Public Service Co. of CO	Colorado	55.49
2/23/2006	Southwest Gas Corp.	Arizona	40.00
3/1/2006	KCP&L Greater Missouri Op Co	Iowa	51.39
4/26/2006	Sierra Pacific Power Co.	Nevada	40.76
7/24/2006	Central Hudson Gas & Electric	New York	45.00
9/20/2006	SourceGas Distribution LLC	Wyoming	43.56
9/26/2006	Chesapeake Utilities Corp.	Maryland	53.00
10/20/2006	Orange & Rockland Utlts Inc.	New York	48.00
11/2/2006	CenterPoint Energy Resources	Minnesota	46.14
11/9/2006	Public Service Electric Gas	New Jersey	47.40
11/21/2006	Consumers Energy Co.	Michigan	35.06
12/5/2006	Chattanooga Gas Company	Tennessee	44.80
1/5/2007	Puget Sound Energy Inc.	Washington	44.00
1/9/2007	SEMCO Energy Inc.	Michigan	42.94
1/11/2007	Wisconsin Public Service Corp	Wisconsin	57.46
1/19/2007	Wisconsin Power and Light Co	Wisconsin	54.13
2/8/2007	UGI Central Penn Gas	Pennsylvania	51.79
3/14/2007	CT Natural Gas Corp.	Connecticut	53.60
3/20/2007	Delmarva Power & Light Co.	Delaware	46.90
3/21/2007	Pacific Gas and Electric Co.	California	52.00
3/22/2007	Southern Union Co.	Missouri	36.06
3/29/2007	Atmos Energy Corp.	Texas	48.10
6/13/2007	Northern States Power Co. - MN	North Dakota	51.59
6/29/2007	Yankee Gas Services Co.	Connecticut	50.30
6/29/2007	Public Service Co. of NM	New Mexico	51.80
7/3/2007	Public Service Co. of CO	Colorado	60.17
7/13/2007	Arkansas Western Gas Co.	Arkansas	34.29
7/24/2007	Black Hills/Nebraska Gas	Nebraska	50.73
8/1/2007	Southern Indiana Gas & Elec Co	Indiana	47.05

[7] Regulatory Research Associates, Inc., “Major Rate Case Decisions–January 2006–December 2007,” January 8, 2008; “Major Rate Case Decisions–January–March 2008,” April 2, 2008. Data not included for companies whose ratios are identified as including "cost-free items or tax credit balances at the overall rate of return." This does not substantially affect the average result.

DATE	COMPANY	STATE	COMMON EQUITY /TOTAL CAP (%)
9/10/2007	Northern States Power Co. - MN	Minnesota	51.98
9/25/2007	Consolidated Edison Co. of NY	New York	48.00
10/8/2007	Atmos Energy Corp.	Tennessee	44.20
10/25/2007	CenterPoint Energy Resources	Arkansas	33.73
11/15/2007	Washington Gas Light Co.	Maryland	53.02
11/20/2007	Arkansas Oklahoma Gas Corp.	Arkansas	41.46
11/27/2007	UNS Gas Inc.	Arizona	50.00
11/29/2007	Cheyenne Light Fuel Power Co.	Wyoming	54.00
12/14/2007	Madison Gas and Electric Co.	Wisconsin	57.36
12/19/2007	Avista Corp.	Washington	46.00
12/21/2007	National Fuel Gas Dist Corp.	New York	44.35
1/8/2008	Northern States Power Co-WI	Wisconsin	52.51
1/17/2008	Wisconsin Gas LLC	Wisconsin	46.64
1/17/2008	Wisconsin Electric Power Co.	Wisconsin	54.36
2/5/2008	North Shore Gas Co.	Illinois	56.00
2/5/2008	Peoples Gas Light & Coke Co.	Illinois	56.00
2/13/2008	Indiana Gas Co.	Indiana	48.99
3/31/2008	Avista Corp.	Oregon	50.00
5/28/2008	Duke Energy Ohio Inc.	Ohio	55.76
6/24/2008	Atmos Energy Corp.	Texas	48.27
6/27/2008	Questar Gas Co.	Utah	51.38
7/31/2008	Southern California Gas Co.	California	48.00
7/31/2008	San Diego Gas & Electric Co.	California	49.00
8/27/2008	SourceGas Distribution LLC	Colorado	53.13
9/2/2008	Chesapeake Utilities Corp.	Delaware	61.81
9/17/2008	Atmos Energy Corp.	Georgia	45.00
9/24/2008	Central Illinois Light Co.	Illinois	46.50
9/24/2008	Central Illinois Public	Illinois	47.91
9/24/2008	Illinois Power Co.	Illinois	51.76
9/30/2008	Avista Corp.	Idaho	47.94
10/3/2008	New Jersey Natural Gas Co.	New Jersey	51.20
10/8/2008	Puget Sound Energy Inc.	Washington	46.00
10/20/2008	CenterPoint Energy Resources	Texas	55.40
10/24/2008	Piedmont Natural Gas Co.	North Carolina	51.00
10/24/2008	Public Service Co. of NC	North Carolina	54.00
11/21/2008	Southwest Gas Corp.	California	47.00
11/21/2008	Southwest Gas Corp.	California	47.00
11/21/2008	Southwest Gas Corp.	California	47.00
12/24/2008	Southwest Gas Corp.	Arizona	43.44
12/26/2008	Northwest Natural Gas Co.	Washington	50.74
12/29/2008	Avista Corp.	Washington	46.30
12/30/2008	Wisconsin Public Service Corp	Wisconsin	53.41
	Average 2006 – 2008		49.07
	Average 2008		50.43

EXHIBIT 5
COMPARISON OF DCF EXPECTED RETURN ON AN INVESTMENT IN ELECTRIC UTILITIES TO THE INTEREST RATE ON LONG-TERM GOVERNMENT BONDS

LINE NO.	DATE	DCF	BOND YIELD	RISK PREMIUM
1	Sep-99	11.69%	6.50%	5.19%
2	Oct-99	11.77%	6.66%	5.11%
3	Nov-99	12.08%	6.48%	5.60%
4	Dec-99	12.58%	6.69%	5.89%
5	Jan-00	12.50%	6.86%	5.64%
6	Feb-00	12.95%	6.54%	6.41%
7	Mar-00	13.36%	6.38%	6.98%
8	Apr-00	12.57%	6.18%	6.39%
9	May-00	12.42%	6.55%	5.87%
10	Jun-00	12.66%	6.28%	6.38%
11	Jul-00	12.76%	6.20%	6.56%
12	Aug-00	12.47%	6.02%	6.45%
13	Sep-00	11.80%	6.09%	5.71%
14	Oct-00	11.82%	6.04%	5.78%
15	Nov-00	11.87%	5.98%	5.89%
16	Dec-00	11.69%	5.64%	6.05%
17	Jan-01	12.05%	5.65%	6.40%
18	Feb-01	12.10%	5.62%	6.48%
19	Mar-01	12.15%	5.49%	6.66%
20	Apr-01	12.77%	5.78%	6.99%
21	May-01	13.04%	5.92%	7.12%
22	Jun-01	13.09%	5.82%	7.27%
23	Jul-01	13.24%	5.75%	7.49%
24	Aug-01	13.30%	5.58%	7.72%
25	Sep-01	13.56%	5.53%	8.03%
26	Oct-01	13.34%	5.34%	8.00%
27	Nov-01	13.38%	5.33%	8.05%
28	Dec-01	13.35%	5.76%	7.59%
29	Jan-02	13.14%	5.69%	7.45%
30	Feb-02	13.27%	5.61%	7.66%
31	Mar-02	12.86%	5.93%	6.93%
32	Apr-02	12.50%	5.85%	6.65%
33	May-02	12.58%	5.81%	6.77%
34	Jun-02	12.57%	5.65%	6.92%
35	Jul-02	13.22%	5.51%	7.71%
36	Aug-02	12.69%	5.19%	7.50%
37	Sep-02	12.88%	4.87%	8.01%
38	Oct-02	12.92%	5.00%	7.92%
39	Nov-02	12.38%	5.04%	7.34%
40	Dec-02	12.08%	5.01%	7.07%
41	Jan-03	11.72%	5.02%	6.70%
42	Feb-03	12.10%	4.87%	7.23%
43	Mar-03	11.71%	4.82%	6.89%
44	Apr-03	11.31%	4.91%	6.40%

LINE NO.	DATE	DCF	BOND YIELD	RISK PREMIUM
45	May-03	10.72%	4.52%	6.20%
46	Jun-03	10.27%	4.34%	5.93%
47	Jul-03	10.34%	4.92%	5.42%
48	Aug-03	10.35%	5.39%	4.96%
49	Sep-03	10.06%	5.21%	4.85%
50	Oct-03	9.89%	5.21%	4.68%
51	Nov-03	9.78%	5.17%	4.61%
52	Dec-03	9.49%	5.11%	4.38%
53	Jan-04	9.23%	5.01%	4.22%
54	Feb-04	9.19%	4.94%	4.25%
55	Mar-04	9.16%	4.72%	4.44%
56	Apr-04	9.27%	5.16%	4.11%
57	May-04	9.66%	5.46%	4.20%
58	Jun-04	9.67%	5.45%	4.22%
59	Jul-04	9.59%	5.24%	4.35%
60	Aug-04	9.64%	5.07%	4.57%
61	Sep-04	9.56%	4.89%	4.67%
62	Oct-04	9.53%	4.85%	4.68%
63	Nov-04	9.11%	4.89%	4.22%
64	Dec-04	9.31%	4.88%	4.43%
65	Jan-05	9.33%	4.77%	4.56%
66	Feb-05	9.30%	4.61%	4.69%
67	Mar-05	9.25%	4.89%	4.36%
68	Apr-05	9.27%	4.75%	4.52%
69	May-05	9.22%	4.56%	4.66%
70	Jun-05	9.27%	4.35%	4.92%
71	Jul-05	9.13%	4.48%	4.65%
72	Aug-05	9.23%	4.53%	4.70%
73	Sep-05	9.50%	4.51%	4.99%
74	Oct-05	9.62%	4.74%	4.88%
75	Nov-05	10.05%	4.83%	5.22%
76	Dec-05	10.12%	4.73%	5.39%
77	Jan-06	10.15%	4.65%	5.50%
78	Feb-06	11.26%	4.73%	6.53%
79	Mar-06	11.11%	4.91%	6.20%
80	Apr-06	11.22%	5.22%	6.00%
81	May-06	11.18%	5.35%	5.83%
82	Jun-06	11.57%	5.29%	6.28%
83	Jul-06	11.51%	5.25%	6.26%
84	Aug-06	11.38%	5.08%	6.30%
85	Sep-06	11.64%	4.93%	6.71%
86	Oct-06	11.54%	4.94%	6.60%
87	Nov-06	11.58%	4.78%	6.80%
88	Dec-06	11.45%	4.78%	6.67%
89	Jan-07	11.36%	4.95%	6.41%
90	Feb-07	11.10%	4.93%	6.17%
91	Mar-07	11.20%	4.81%	6.39%
92	Apr-07	10.74%	4.95%	5.79%
93	May-07	11.08%	4.98%	6.10%
94	Jun-07	11.69%	5.29%	6.40%
95	Jul-07	11.79%	5.19%	6.60%
96	Aug-07	11.69%	5.00%	6.69%

LINE NO.	DATE	DCF	BOND YIELD	RISK PREMIUM
97	Sep-07	11.35%	4.84%	6.51%
98	Oct-07	11.29%	4.83%	6.46%
99	Nov-07	11.08%	4.56%	6.52%
100	Dec-07	11.29%	4.57%	6.72%
101	Jan-08	12.29%	4.35%	7.94%
102	Feb-08	11.43%	4.49%	6.94%
103	Mar-08	11.78%	4.36%	7.42%
104	Apr-08	11.37%	4.44%	6.93%
105	May-08	11.42%	4.60%	6.82%
106	Jun-08	11.23%	4.74%	6.49%
107	Jul-08	11.72%	4.62%	7.10%
108	Aug-08	11.84%	4.53%	7.31%
109	Sep-08	11.28%	5.32%	5.96%
110	Oct-08	12.19%	4.45%	7.74%
111	Nov-08	12.47%	4.27%	8.20%
112	Dec-08	12.46%	3.18%	9.28%
113	Jan-09	12.25%	3.46%	8.79%
114	Feb-09	12.54%	3.83%	8.71%
115	Average	11.38%	5.17%	6.21%

Notes: See written evidence above and Appendix 3 for a description of the ex ante methodology and data employed. Government bond yield information from the Federal Reserve. DCF results are calculated using a quarterly DCF model as follows:

d_0	=	Latest quarterly dividend per Value Line
P_0	=	Average of the monthly high and low stock prices for each month per Thomson Reuters.
FC	=	Flotation costs expressed as a percent of gross proceeds.
g	=	I/B/E/S forecast of future earnings growth for each month.
k	=	Cost of equity using the quarterly version of the DCF model.

$$k = \left[\frac{d_0 (1+g)^{\frac{1}{4}}}{P_0 (1-FC)} \right]^4 - 1$$

EXHIBIT 6
COMPARISON OF DCF EXPECTED RETURN ON AN INVESTMENT IN NATURAL GAS UTILITIES TO THE INTEREST RATE ON LONG-TERM GOVERNMENT BONDS

LINE NO.	DATE	DCF	BOND YIELD	RISK PREMIUM
1	Jun-98	11.54%	5.80%	5.74%
2	Jul-98	11.86%	5.78%	6.08%
3	Aug-98	12.34%	5.66%	6.68%
4	Sep-98	12.73%	5.38%	7.35%
5	Oct-98	12.60%	5.30%	7.30%
6	Nov-98	12.11%	5.48%	6.63%
7	Dec-98	11.85%	5.36%	6.49%
8	Jan-99	11.95%	5.45%	6.50%
9	Feb-99	12.43%	5.66%	6.77%
10	Mar-99	12.57%	5.87%	6.70%
11	Apr-99	12.60%	5.82%	6.78%
12	May-99	12.21%	6.08%	6.13%
13	Jun-99	12.08%	6.36%	5.72%
14	Jul-99	12.22%	6.28%	5.94%
15	Aug-99	12.20%	6.43%	5.77%
16	Sep-99	12.26%	6.50%	5.76%
17	Oct-99	12.33%	6.66%	5.67%
18	Nov-99	12.40%	6.48%	5.92%
19	Dec-99	12.80%	6.69%	6.11%
20	Jan-00	13.01%	6.86%	6.15%
21	Feb-00	13.44%	6.54%	6.90%
22	Mar-00	13.44%	6.38%	7.06%
23	Apr-00	13.16%	6.18%	6.98%
24	May-00	12.92%	6.55%	6.37%
25	Jun-00	12.95%	6.28%	6.67%
26	Jul-00	13.17%	6.20%	6.97%
27	Aug-00	12.90%	6.02%	6.88%
28	Sep-00	12.57%	6.09%	6.48%
29	Oct-00	12.60%	6.04%	6.56%
30	Nov-00	12.51%	5.98%	6.53%
31	Dec-00	12.39%	5.64%	6.75%
32	Jan-01	12.61%	5.65%	6.96%
33	Feb-01	12.61%	5.62%	6.99%
34	Mar-01	12.75%	5.49%	7.26%
35	Apr-01	12.27%	5.78%	6.49%
36	May-01	13.02%	5.92%	7.10%
37	Jun-01	13.04%	5.82%	7.22%
38	Jul-01	13.38%	5.75%	7.63%
39	Aug-01	13.27%	5.58%	7.69%
40	Sep-01	12.68%	5.53%	7.15%

LINE NO.	DATE	DCF	BOND YIELD	RISK PREMIUM
41	Oct-01	12.68%	5.34%	7.34%
42	Nov-01	12.68%	5.33%	7.35%
43	Dec-01	12.54%	5.76%	6.78%
44	Jan-02	12.36%	5.69%	6.67%
45	Feb-02	12.41%	5.61%	6.80%
46	Mar-02	11.89%	5.93%	5.96%
47	Apr-02	11.59%	5.85%	5.74%
48	May-02	11.62%	5.81%	5.81%
49	Jun-02	11.70%	5.65%	6.05%
50	Jul-02	12.42%	5.51%	6.91%
51	Aug-02	12.34%	5.19%	7.15%
52	Sep-02	12.60%	4.87%	7.73%
53	Oct-02	12.50%	5.00%	7.50%
54	Nov-02	12.21%	5.04%	7.17%
55	Dec-02	12.16%	5.01%	7.15%
56	Jan-03	12.19%	5.02%	7.17%
57	Feb-03	12.32%	4.87%	7.45%
58	Mar-03	11.95%	4.82%	7.13%
59	Apr-03	11.62%	4.91%	6.71%
60	May-03	11.26%	4.52%	6.74%
61	Jun-03	11.14%	4.34%	6.80%
62	Jul-03	11.27%	4.92%	6.35%
63	Aug-03	11.39%	5.39%	6.00%
64	Sep-03	11.27%	5.21%	6.06%
65	Oct-03	11.23%	5.21%	6.02%
66	Nov-03	10.89%	5.17%	5.72%
67	Dec-03	10.71%	5.11%	5.60%
68	Jan-04	10.59%	5.01%	5.58%
69	Feb-04	10.39%	4.94%	5.45%
70	Mar-04	10.37%	4.72%	5.65%
71	Apr-04	10.41%	5.16%	5.25%
72	May-04	10.45%	5.46%	4.99%
73	Jun-04	10.36%	5.45%	4.91%
74	Jul-04	10.11%	5.24%	4.87%
75	Aug-04	10.08%	5.07%	5.01%
76	Sep-04	9.76%	4.89%	4.87%
77	Oct-04	9.74%	4.85%	4.89%
78	Nov-04	9.62%	4.89%	4.73%
79	Dec-04	9.70%	4.88%	4.82%
80	Jan-05	9.90%	4.77%	5.13%
81	Feb-05	9.79%	4.61%	5.18%
82	Mar-05	9.79%	4.89%	4.90%
83	Apr-05	9.88%	4.75%	5.13%
84	May-05	9.81%	4.56%	5.25%
85	Jun-05	9.76%	4.35%	5.41%
86	Jul-05	9.66%	4.48%	5.18%
87	Aug-05	9.69%	4.53%	5.16%

LINE NO.	DATE	DCF	BOND YIELD	RISK PREMIUM
88	Sep-05	9.80%	4.51%	5.29%
89	Oct-05	9.90%	4.74%	5.16%
90	Nov-05	10.49%	4.83%	5.66%
91	Dec-05	10.45%	4.73%	5.72%
92	Jan-06	9.82%	4.65%	5.17%
93	Feb-06	11.24%	4.73%	6.51%
94	Mar-06	11.27%	4.91%	6.36%
95	Apr-06	11.00%	5.22%	5.78%
96	May-06	10.56%	5.35%	5.21%
97	Jun-06	10.49%	5.29%	5.20%
98	Jul-06	10.87%	5.25%	5.62%
99	Aug-06	10.41%	5.08%	5.33%
100	Sep-06	10.53%	4.93%	5.60%
101	Oct-06	10.30%	4.94%	5.36%
102	Nov-06	10.33%	4.78%	5.55%
103	Dec-06	10.35%	4.78%	5.57%
104	Jan-07	10.13%	4.95%	5.18%
105	Feb-07	10.18%	4.93%	5.25%
106	Mar-07	10.18%	4.81%	5.37%
107	Apr-07	10.07%	4.95%	5.12%
108	May-07	9.67%	4.98%	4.69%
109	Jun-07	9.70%	5.29%	4.41%
110	Jul-07	10.06%	5.19%	4.87%
111	Aug-07	10.21%	5.00%	5.21%
112	Sep-07	10.14%	4.84%	5.30%
113	Oct-07	10.80%	4.83%	5.97%
114	Nov-07	10.83%	4.56%	6.27%
115	Dec-07	10.84%	4.57%	6.27%
116	Jan-08	11.13%	4.35%	6.78%
117	Feb-08	11.39%	4.49%	6.90%
118	Mar-08	11.47%	4.36%	7.11%
119	Apr-08	11.67%	4.44%	7.23%
120	May-08	10.69%	4.60%	6.09%
121	Jun-08	10.62%	4.74%	5.88%
122	Jul-08	10.86%	4.62%	6.24%
123	Aug-08	11.23%	4.53%	6.70%
124	Sep-08	11.30%	5.32%	5.98%
125	Oct-08	12.13%	4.45%	7.68%
126	Nov-08	12.21%	4.27%	7.94%
127	Dec-08	11.62%	3.18%	8.44%
128	Jan-09	11.31%	3.46%	7.85%
129	Feb-09	11.55%	3.83%	7.72%
130	Average	11.43%	5.24%	6.19%

Notes: Government bond yield information from the Federal Reserve. DCF results are calculated using a quarterly DCF model as follows:

d_0	=	Latest quarterly dividend per Value Line
P_0	=	Average of the monthly high and low stock prices for each month per Thomson Reuters.
FC	=	Flotation costs expressed as a percent of gross proceeds.
g	=	I/B/E/S forecast of future earnings growth for each month
k	=	Cost of equity using the quarterly version of the DCF model.

$$k = \left[\frac{d_0 (1+g)^{\frac{1}{4}}}{P_0 (1-FC)} \right]^4 - 1$$

EXHIBIT 7
IMPLIED ALLOWED EQUITY RISK PREMIUM[8]

YEAR	AVERAGE ALLOWED RETURN	20-YEAR U.S. TREASURY BOND	RISK PREMIUM
1988	0.1282	0.0859	0.0423
1989	0.1293	0.0896	0.0397
1990	0.1269	0.0845	0.0424
1991	0.1251	0.0861	0.0390
1992	0.1206	0.0814	0.0392
1993	0.1137	0.0767	0.0370
1994	0.1134	0.0629	0.0505
1995	0.1151	0.0749	0.0402
1996	0.1129	0.0695	0.0434
1997	0.1134	0.0683	0.0451
1998	0.1159	0.0669	0.0490
1999	0.1074	0.0572	0.0502
2000	0.1141	0.0620	0.0521
2001	0.1105	0.0623	0.0482
2002	0.1110	0.0563	0.0547
2003	0.1098	0.0543	0.0555
2004	0.1067	0.0496	0.0571
2005	0.1050	0.0504	0.0546
2006	0.1039	0.0464	0.0575
2007	0.1030	0.0500	0.0530
2008	0.1042	0.0491	0.0551

IMPLIED ALLOWED EQUITY RISK PREMIUM
REGRESSION RESULTS

INTERCEPT COEFFICIENT	0.0776
Slope Coefficient	(0.4509)
Treasury Bond Yield	0.0480
Slope x Bond Yield	(0.0216)
Forecast Risk Premium	0.0560

Treasury bond yield is 2010 forecast at March 2009 from Global Insight.

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[8] Regulatory Research Associates, Inc., “Major Rate Case Decisions–January 2006–December 2007,” January 8, 2008; “Major Rate Case Decisions–January 2007–December 2008,” January 12, 2009. Treasury bond yield is 2010 forecast at March 2009 from Global Insight.

EXHIBIT 8
SUMMARY OF DISCOUNTED CASH FLOW ANALYSIS
FOR VALUE LINE ELECTRIC COMPANIES

LINE NO.	COMPANY	D_0	P_0	GROWTH	COST OF EQUITY
1	Amer. Elec. Power	0.410	31.363	4.16%	10.1%
2	Avista Corp.	0.180	17.990	4.67%	9.1%
3	Dominion Resources	0.438	34.423	8.16%	13.8%
4	DPL Inc.	0.275	21.508	10.33%	16.6%
5	Duke Energy	0.230	14.863	4.46%	11.5%
6	Consol. Edison	0.585	39.205	2.61%	9.3%
7	Entergy Corp.	0.750	77.203	9.42%	14.1%
8	Exelon Corp.	0.525	53.210	8.47%	13.1%
9	FirstEnergy Corp.	0.550	49.527	9.00%	14.4%
10	FPL Group	0.473	48.890	9.62%	14.1%
11	NSTAR	0.375	34.283	6.00%	10.8%
12	Northeast Utilities	0.238	23.365	8.15%	12.5%
13	PG&E Corp.	0.390	37.313	6.84%	11.7%
14	Progress Energy	0.620	38.453	5.56%	13.0%
15	Pinnacle West Capital	0.525	31.242	4.33%	12.0%
16	Pepco Holdings	0.270	17.060	4.67%	12.0%
17	Portland General	0.245	18.268	5.44%	11.6%
18	SCANA Corp.	0.460	34.060	4.52%	10.7%
19	Southern Co.	0.420	34.428	5.36%	11.0%
20	Sempra Energy	0.350	42.948	7.20%	10.9%
21	Vectren Corp.	0.335	24.848	7.20%	13.4%
22	Wisconsin Energy	0.338	42.678	9.13%	12.3%
23	Westar Energy	0.290	19.268	3.84%	10.7%
24	Xcel Energy Inc.	0.238	18.153	6.72%	12.8%
25	Market-Weighted Average				12.4%

Notes:

d_0	=	Most recent quarterly dividend.
d_1,d_2,d_3,d_4	=	Next four quarterly dividends, calculated by multiplying the last four quarterly dividends per *Value Line* by the factor (1 + g).
P_0	=	Average of the monthly high and low stock prices during the three months ending February 2009 per Thomson Reuters.
FC	=	Flotation costs expressed as a percent of gross proceeds.
g	=	I/B/E/S forecast of future earnings growth February 2009.
k	=	Cost of equity using the quarterly version of the DCF model.

$$k = \frac{d_1(1+k)^{.75} + d_2(1+k)^{.50} + d_3(1+k)^{.25} + d_4}{P_0(1-FC)} + g$$

EXHIBIT 9
SUMMARY OF DISCOUNTED CASH FLOW ANALYSIS
FOR VALUE LINE NATURAL GAS COMPANIES

LINE NO.	COMPANY	D_0	P_0	GROWTH	COST OF EQUITY
1	AGL Resources	0.430	30.354	4.25%	10.6%
2	Atmos Energy	0.330	23.847	5.00%	11.3%
3	Equitable Resources	0.220	32.892	11.67%	15.0%
4	Nicor Inc.	0.465	34.098	2.85%	9.0%
5	NiSource Inc.	0.230	10.462	1.60%	11.4%
6	Northwest Nat. Gas	0.395	43.777	4.75%	8.8%
7	Piedmont Natural Gas	0.260	28.345	7.13%	11.4%
8	South Jersey Inds.	0.284	37.268	7.50%	11.0%
9	Questar Corp.	0.125	31.988	9.00%	10.8%
10	Southwest Gas	0.238	24.100	6.00%	10.3%
11	Market-Weighted Average				11.5%

Notes:

d_0	=	Most recent quarterly dividend.
d_1, d_2, d_3, d_4	=	Next four quarterly dividends, calculated by multiplying the last four quarterly dividends per *Value Line* by the factor (1 + g).
P_0	=	Average of the monthly high and low stock prices during the three months ending February 2009 per Thomson Reuters.
FC	=	Flotation costs expressed as a percent of gross proceeds.
g	=	I/B/E/S forecast of future earnings growth February 2009.[9]
k	=	Cost of equity using the quarterly version of the DCF model.

$$k = \frac{d_1(1+k)^{.75} + d_2(1+k)^{.50} + d_3(1+k)^{.25} + d_4}{P_0(1-FC)} + g$$

[9] Although I normally specify that the I/B/E/S long-term earnings growth forecast must include the forecasts of at least three analysts, in March 2009 there are only four companies with growth forecasts from at least three analysts. In this study, therefore, I also include results for companies that had growth forecasts based on two analysts' growth forecasts.

EXHIBIT 10
MARKET VALUE EQUITY RATIOS FOR U.S. ELECTRIC AND NATURAL GAS COMPANIES AT MARCH 2009

LINE NO.	COMPANY	LONG-TERM DEBT	PREFERRED EQUITY	MARKET CAP $ (MIL)	% MARKET EQUITY
1	Amer. Elec. Power	14,202	61	11,320	44%
2	Avista Corp.	635	0	779	55%
3	Dominion Resources	13,235	257	17,610	57%
4	DPL Inc.	1,542	23	2,331	60%
5	Duke Energy	9,498	0	17,043	64%
6	Consol. Edison	7,611	213	9,908	56%
7	Entergy Corp.	9,728	311	12,759	56%
8	Exelon Corp.	11,965	87	31,082	72%
9	FirstEnergy Corp.	8,869	0	12,974	59%
10	FPL Group	11,280	0	18,528	62%
11	NSTAR	2,501	43	3,436	57%
12	Northeast Utilities	4,401	116	3,411	43%
13	PG&E Corp.	9,753	252	13,979	58%
14	Progress Energy	8,737	93	9,280	51%
15	Pinnacle West Capital	3,127	0	2,652	46%
16	Pepco Holdings	4,735	0	3,033	39%
17	Portland General	1,313	0	1,027	44%
18	SCANA Corp.	2,879	113	3,541	54%
19	Southern Co.	14,143	1,080	23,478	61%
20	Sempra Energy	4,553	193	10,119	68%
21	Vectren Corp.	1,245	0	1,690	58%
22	Wisconsin Energy	3,173	30	4,656	59%
23	Westar Energy	1,890	21	1,830	49%
24	Xcel Energy Inc.	6,342	105	7,966	55%
25	Market-Weighted Average	157,357	2,999	224,432	58%
26	Average				55%

Data are from The Value Line Investment Analyzer, March 2009.

EXHIBIT 10 (CONTINUED)
MARKET VALUE EQUITY RATIOS FOR U.S. ELECTRIC AND NATURAL GAS COMPANIES AT MARCH 2009

LINE NO.	COMPANY	LONG-TERM DEBT	PREFERRED EQUITY	MARKET CAP $ (MIL)	% MARKET EQUITY
1	AGL Resources	1,674	0	2,133	56%
2	Atmos Energy	2,126	0	2,000	48%
3	Equitable Resources	754	0	4,024	84%
4	Nicor Inc.	423	1	1,418	77%
5	NiSource Inc.	5,594	0	2,400	30%
6	Northwest Nat. Gas	512	0	1,084	68%
7	Piedmont Natural Gas	794	0	1,769	69%
8	South Jersey Inds.	358	0	1,072	75%
9	Questar Corp.	1,021	0	5,000	83%
10	Southwest Gas	1,366	0	856	39%
11	Market-Weighted Average	14,623	1	21,756	60%
12	Average				63%

EXHIBIT 11
APPENDIX 1
QUALIFICATIONS OF JAMES H. VANDER WEIDE, PH.D.

James H. Vander Weide is Research Professor of Finance and Economics at Duke University, the Fuqua School of Business. Dr. Vander Weide is also founder and President of Financial Strategy Associates, a consulting firm that provides strategic, financial, and economic consulting services to corporate clients, including cost of capital and valuation studies.

Educational Background and Prior Academic Experience

Dr. Vander Weide holds a Ph.D. in Finance from Northwestern University and a Bachelor of Arts from Cornell University. He joined the faculty at Duke University and was named Assistant Professor, Associate Professor, Professor, and then Research Professor of Finance and Economics.

Since joining the faculty at Duke, Dr. Vander Weide has taught courses in corporate finance, investment management, and management of financial institutions. He has also taught courses in statistics, economics, and operations research, and a Ph.D. seminar on the theory of public utility pricing. In addition, Dr. Vander Weide has been active in executive education at Duke and Duke Corporate Education, leading executive development seminars on topics including financial analysis, cost of capital, creating shareholder value, mergers and acquisitions, real options, capital budgeting, cash management, measuring corporate performance, valuation, short-run financial planning, depreciation policies, financial strategy, and competitive strategy. Dr. Vander Weide has designed and served as Program Director for several executive education programs, including the Advanced Management Program, Competitive Strategies in Telecommunications, and the Duke Program for Manager Development for managers from the former Soviet Union.

Publications

Dr. Vander Weide has written a book entitled *Managing Corporate Liquidity: An Introduction to Working Capital Management* published by John Wiley and Sons, Inc. He has also written a chapter titled, "Financial Management in the Short Run" for *The Handbook of Modern Finance*, and written research papers on such topics as portfolio management, capital budgeting, investments, the effect of regulation on the performance of public utilities, and cash management. His articles have been published in *American Economic Review, Financial Management, International Journal of Industrial Organization, Journal of Finance, Journal of Financial and Quantitative Analysis, Journal of Bank*

Research, Journal of Portfolio Management, Journal of Accounting Research, Journal of Cash Management, Management Science, Atlantic Economic Journal, Journal of Economics and Business, and *Computers and Operations Research*.

Professional Consulting Experience

Dr. Vander Weide has provided financial and economic consulting services to firms in the electric, gas, insurance, telecommunications, and water industries for more than 25 years. He has testified on the cost of capital, competition, risk, incentive regulation, forward-looking economic cost, economic pricing guidelines, depreciation, accounting, valuation, and other financial and economic issues in more than 400 cases before the United States Congress, the Canadian Radio-Television and Telecommunications Commission, the Federal Communications Commission, the National Telecommunications and Information Administration, the Federal Energy Regulatory Commission, the public service commissions of 42 states and the District of Columbia, the insurance commissions of five states, the Iowa State Board of Tax Review, the National Association of Securities Dealers, and the North Carolina Property Tax Commission. In addition, he has testified as an expert witness in proceedings before the United States District Court for the District of New Hampshire; United States District Court for the Northern District of California; United States District Court for the District of Nebraska; United States District Court for the Eastern District of North Carolina; Superior Court of North Carolina, the United States Bankruptcy Court for the Southern District of West Virginia; and United States District Court for the Eastern District of Michigan. With respect to implementation of the Telecommunications Act of 1996, Dr. Vander Weide has testified in 30 states on issues relating to the pricing of unbundled network elements and universal service cost studies and has consulted with Bell Canada, Deutsche Telekom, and Telefónica on similar issues. He has also provided expert testimony on issues related to electric and natural gas restructuring. He has worked for Bell Canada/Nortel on a special task force to study the effects of vertical integration in the Canadian telephone industry and has worked for Bell Canada as an expert witness on the cost of capital. Dr. Vander Weide has provided consulting and expert witness testimony to the following companies:

Telecommunications Companies

ALLTEL and its subsidiaries	Ameritech (now AT&T new)
AT&T (old)	Verizon (Bell Atlantic) and subsidiaries
Bell Canada/Nortel	BellSouth and its subsidiaries
Centel and its subsidiaries	Cincinnati Bell (Broadwing)
Cisco Systems	Citizens Telephone Company
Concord Telephone Company	Contel and its subsidiaries
Deutsche Telekom	GTE and subsidiaries (now Verizon)
Heins Telephone Company	Lucent Technologies

Minnesota Independent Equal Access Corp.
Pacific Telesis and its subsidiaries
Pine Drive Cooperative Telephone Co.
Siemens
Sherburne Telephone Company
The Stentor Companies
Telefónica
Woodbury Telephone Company
U S West (Qwest)
NYNEX and its subsidiaries (Verizon)
Phillips County Cooperative Tel. Co.
Roseville Telephone Company (SureWest)
SBC Communications (now AT&T new)
Southern New England Telephone
Sprint/United and its subsidiaries
Union Telephone Company
United States Telephone Association
Valor Telecommunications (Windstream)

Electric, Gas, and Water Companies
Alcoa Power Generating, Inc.
Alliant Energy
Ameren
American Water Works
Atmos Energy
Central Illinois Public Service
Citizens Utilities
Consolidated Natural Gas and its subsidiaries
Dominion Resources
Duke Energy
Empire District Electric Company
Interstate Power Company
Iowa-American Water Company
Iowa-Illinois Gas and Electric
Iowa Southern
Kentucky-American Water Company
Kentucky Power Company
MidAmerican Energy and its subsidiaries
Nevada Power Company
NICOR
North Carolina Natural Gas
Northern Natural Gas Company
NOVA Gas Transmission Ltd.
North Shore Gas
PacifiCorp
PG&E
Peoples Energy and its subsidiaries
The Peoples Gas, Light and Coke Co.
Progress Energy
Public Service Company of North Carolina
PSE&G
Sempra Energy
South Carolina Electric and Gas
Southern Company and subsidiaries
Tennessee-American Water Company
Trans Québec & Maritimes Pipeline Inc.
United Cities Gas Company

Insurance Companies
Allstate
North Carolina Rate Bureau
United Services Automobile Association (USAA)
The Travelers Indemnity Company
Gulf Insurance Company

Other Professional Experience

Dr. Vander Weide conducts in-house seminars and training sessions on topics such as creating shareholder value, financial analysis, competitive strategy, cost of capital, real options, financial strategy, managing growth, mergers and acquisitions, valuation, measuring corporate performance, capital budgeting, cash management, and financial planning. Among the firms for whom he has designed and taught tailored programs and training sessions are ABB Asea Brown Boveri, Accenture, Allstate, Ameritech, AT&T, Bell

Atlantic/Verizon, BellSouth, Progress Energy/Carolina Power & Light, Contel, Fisons, GlaxoSmithKline, GTE, Lafarge, MidAmerican Energy, New Century Energies, Norfolk Southern, Pacific Bell Telephone, The Rank Group, Siemens, Southern New England Telephone, TRW, and Wolseley Plc. Dr. Vander Weide has also hosted a nationally prominent conference/workshop on estimating the cost of capital. In 1989, at the request of Mr. Fuqua, Dr. Vander Weide designed the Duke Program for Manager Development for managers from the former Soviet Union, the first in the United States designed exclusively for managers from Russia and the former Soviet republics.

In the 1970's, Dr. Vander Weide helped found University Analytics, Inc., which at that time was one of the fastest growing small firms in the country. As an officer at University Analytics, he designed cash management models, databases, and software packages that are still used by most major U.S. banks in consulting with their corporate clients. Having sold his interest in University Analytics, Dr. Vander Weide now concentrates on strategic and financial consulting, academic research, and executive education.

PUBLICATIONS
JAMES H. VANDER WEIDE

The Lock-Box Location Problem: a Practical Reformulation, *Journal of Bank Research*, Summer, 1974, pp. 92-96 (with S. Maier). Reprinted in *Management Science in Banking*, edited by K. J. Cohen and S. E. Gibson, Warren, Gorham and Lamont, 1978.

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A Note on the Optimal Investment Policy of the Regulated Firm, *Atlantic Economic Journal*, Fall, 1976 (with D. Peterson).

A Unified Location Model for Cash Disbursements and Lock-Box Collections, *Journal of Bank Research*, Summer, 1976 (with S. Maier). Reprinted in *Management Science in Banking*, edited by K. J. Cohen and S. E. Gibson, Warren Gorham and Lamont, 1978. Also reprinted in *Readings on the Management of Working Capital*, edited by K. V. Smith, West Publishing Company, 1979.

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A Strategy which Maximizes the Geometric Mean Return on Portfolio Investments, *Management Science*, June, 1977, Vol. 23, No. 10, pp. 1117-1123 (with S. Maier and D. Peterson).

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General Telephone's Experience with a Short-run Financial Planning Model, *Cash Management Forum*, June 1980, Vol. 6, No. 1 (with J. Austin and S. Maier).

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Recent Developments in Management Science in Banking, *Management Science*, October 1981 (with K. Cohen and S. Maier).

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A Decision-Support System for Managing a Short-term Financial Instrument Portfolio, *Journal of Cash Management*, March 1982 (with S. Maier).

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The Bond Scheduling Problem of the Multi-subsidiary Holding Company, *Management Science*, July 1982 (with K. Baker).

Deregulation and Locational Rents in Banking: a Comment, *Journal of Bank Research*, Summer 1983.

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Measuring Investors' Growth Expectations: Analysts vs. History, *The Journal of Portfolio Management*, Spring 1988 (with W. Carleton).

Entry Auctions and Strategic Behavior under Cross-Market Price Constraints, *International Journal of Industrial Organization*, 20 (2002) 611-629 (with J. Anton and N. Vettas).

Principles for Lifetime Portfolio Selection: Lessons from Portfolio Theory, *Handbook of Portfolio Construction: Contemporary Applications of Markowitz Techniques*, John B. Guerard, (Ed.), Springer, forthcoming 2009.

Managing Corporate Liquidity: an Introduction to Working Capital Management, John Wiley and Sons, 1984 (with S. Maier).

SUMMARY EXPERT TESTIMONY
JAMES H. VANDER WEIDE

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Progress Energy	Florida	Mar-09	090079-EI
EPCOR, FortisAlberta, AltaLink	Alberta Utilities Commission	Nov-08	1578571, ID-85
NOVA Gas Transmission Ltd.	Alberta Utilities Commission	Nov-08	1578571, ID-85
Kentucky-American Water Company	Kentucky	Oct-08	2008-00427
Atmos Energy	Tennessee	Oct-08	0800197
Dorsey & Whitney LLP-Williams v. Gannon	Montana 2nd Judicial Dist. Ct. Silver Bow County	Apr-08	DV-02-201
Atmos Energy	Georgia	Mar-08	27163-U
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jan-08	
Trans Québec & Maritimes Pipeline Inc.	National Energy Board (Canada)	Dec-07	
Xcel Energy	North Dakota	Dec-07	PU-07-776
Verizon Southwest	Texas	Nov-07	34723
Empire District Electric Company	Missouri	Oct-07	ER-2008-0093
North Carolina Rate Bureau (workers compensation)	North Carolina Dept. of Insurance	Sep-07	
Verizon North Inc. Contel of the South Inc.	Michigan	Aug-07	Case No. U-15210
Georgia Power Company	Georgia	Jun-07	25060-U
Duke Energy Carolinas	North Carolina	May-07	E-7 Sub 828 et al
MidAmerican Energy Company	Iowa	May-07	SPU-06-5 et al
Morrison & Foerster LLP-JDS Uniphase Securities Litigation	U.S. District Court Northern District California	Feb-07	C-02-1486-CW
TransCanada Pipelines Ltd.	National Energy Board (Canada)	Feb-07	
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Dec-06	
San Diego Gas & Electric	FERC	Nov-06	ER07-284-000
North Carolina Rate Bureau (workers compensation)	North Carolina Dept. of Insurance	Aug-06	
Union Electric Company d/b/a AmerenUE	Missouri	Jun-06	ER-2007-0002
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	May-06	
North Carolina Rate Bureau (dwelling fire)	North Carolina Dept. of Insurance	Mar-06	
Empire District Electric Company	Missouri	Feb-06	ER-2006-0315
PacifiCorp Power & Light Company	Washington	Jan-06	UE-050684
Verizon Maine	Maine	Dec-05	2005-155
Winston & Strawn LLP-Cisco Systems Securities Litigation	U.S. District Court Northern District California	Nov-05	C-01-20418-JW
Dominion Virginia Power	Virginia	Nov-05	PUE-2004-00048
Bryan Cave LLP--Omniplex Comms. v. Lucent Technologies	U.S. District Court Eastern District Missouri	Sep-05	04CV00477 ERW
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-05	
Empire District Electric Company	Kansas	Sep-05	05-EPDE-980-RTS
Verizon Southwest	Texas	Jul-05	29315
PG&E Company	FERC	Jul-05	ER-05-1284
Dominion Hope	West Virginia	Jun-05	05-034-G42T
Empire District Electric Company	Missouri	Jun-05	EO-2005-0263
Verizon New England	U.S. District Court New Hampshire	May-05	04-CV-65-PB
San Diego Gas & Electric	California	May-05	05-05-012
Progress Energy	Florida	May-05	50078
Verizon Vermont	Vermont	Feb-05	6959
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Feb-05	
Verizon Florida	Florida	Jan-05	050059-TL
Verizon Illinois	Illinois	Jan-05	00-0812
Dominion Resources	North Carolina	Sep-04	E-22 Sub 412
Tennessee-American Water Company	Tennessee	Aug-04	04-00288
Valor Telecommunications of Texas, LP.	New Mexico	Jul-04	3495 Phase C
Alcoa Power Generating Inc.	North Carolina Property Tax	Jul-04	02 PTC 162 and 02 PTC 709

SPONSOR	JURISDICTION	DATE	DOCKET NO.
	Commission		
PG&E Company	California	May-04	04-05-21
Verizon Northwest	Washington	Apr-04	UT-040788
Verizon Northwest	Washington	Apr-04	UT-040788
Kentucky-American Water Company	Kentucky	Apr-04	2004-00103
MidAmerican Energy	South Dakota	Apr-04	NG4-001
Empire District Electric Company	Missouri	Apr-04	ER-2004-0570
Interstate Power and Light Company	Iowa	Mar-04	RPU-04-01
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Feb-04	
Northern Natural Gas Company	FERC	Feb-04	RP04-155-000
Verizon New Jersey	New Jersey	Jan-04	TO00060356
Verizon	FCC	Jan-04	03-173, FCC 03-224
Verizon	FCC	Dec-03	03-173, FCC 03-224
Verizon California Inc.	California	Nov-03	R93-04-003,I93-04-002
Phillips County Telephone Company	Colorado	Nov-03	03S-315T
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Oct-03	
PG&E Company	FERC	Oct-03	ER04-109-000
Allstate Insurance Company	Texas Department of Insurance	Sep-03	2568
Verizon Northwest Inc.	Washington	Jul-03	UT-023003
Empire District Electric Company	Oklahoma	Jul-03	Case No. PUD 200300121
Verizon Virginia Inc.	FCC	Apr-03	CC-00218,00249,00251
North Carolina Rate Bureau (dwelling fire)	North Carolina Dept. of Insurance	Apr-03	
Northern Natural Gas Company	FERC	Apr-03	RP03-398-000
MidAmerican Energy	Iowa	Apr-03	RPU-03-1, WRU-03-25-156
PG&E Company	FERC	Mar-03	ER03666000
Verizon Florida Inc.	Florida	Feb-03	981834-TP/990321-TP
Verizon North	Indiana	Feb-03	42259
San Diego Gas & Electric	FERC	Feb-03	ER03-601000
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jan-03	
Gulf Insurance Company	Superior Court, North Carolina	Jan-03	2000-CVS-3558
PG&E Company	FERC	Jan-03	ER03409000
Verizon New England Inc. New Hampshire	New Hampshire	Dec-02	DT 02-110
Verizon Northwest	Washington	Dec-02	UT 020406
PG&E Company	California	Dec-02	
MidAmerican Energy	Iowa	Nov-02	RPU-02-3, 02-8
MidAmerican Energy	Iowa	Nov-02	RPU-02-10
Verizon Michigan	US District Court Eastern District of Michigan	Sep-02	Civil Action No. 00-73208
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-02	
Verizon New England Inc. New Hampshire	New Hampshire	Aug-02	DT 02-110
Interstate Power Company	Iowa Board of Tax Review	Jul-02	832
PG&E Company	California	May-02	A 02-05-022 et al
Verizon New England Inc. Massachusetts	FCC	May-02	EB 02 MD 006
Verizon New England Inc. Rhode Island	Rhode Island	May-02	Docket No. 2681
Neumedia, Inc.	US Bankruptcy Court Southern District W. Virginia	Apr-02	Case No. 01-20873
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Mar-02	
MidAmerican Energy Company	Iowa	Mar-02	RPU 02 2
North Carolina Natural Gas Company	North Carolina	Feb-02	G21 Sub 424
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jan-02	
Verizon Pennsylvania	Pennsylvania	Dec-01	R-00016683
Verizon Florida	Florida	Nov-01	99064B-TP
PG&E Company	FERC	Nov-01	ER0166000
Verizon Delaware	Delaware	Oct-01	96-324 Phase II
Florida Power Corporation	Florida	Sep-01	000824-EL
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-01	
Verizon Washington DC	District of Columbia	Jul-01	962

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Verizon Virginia	FCC	Jul-01	CC-00218,00249,00251
Sherburne County Rural Telephone Company	Minnesota	Jul-01	P427/CI-00-712
Verizon New Jersey	New Jersey	Jun-01	TO01020095
Verizon Maryland	Maryland	May-01	8879
Verizon Massachusetts	Massachusetts	May-01	DTE 01-20
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Apr-01	
PG&E Company	FERC	Mar-01	ER011639000
Maupin Taylor & Ellis P.A.	National Association of Securities Dealers	Jan-01	99-05099
USTA	FCC	Oct-00	RM 10011
Verizon New York	New York	Oct-00	98-C-1357
Verizon New Jersey	New Jersey	Oct-00	TO00060356
PG&E Company	FERC	Oct-00	ER0166000
Verizon New Jersey	New Jersey	Sep-00	TO99120934
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-00	
PG&E Company	California	Aug-00	00-05-018
Verizon New York	New York	Jul-00	98-C-1357
PG&E Company	California	May-00	00-05-013
PG&E Company	FERC	Mar-00	ER00-66-000
PG&E Company	FERC	Mar-00	ER99-4323-000
Bell Atlantic	New York	Feb-00	98-C-1357
USTA	FCC	Jan-00	94-1, 96-262
MidAmerican Energy	Iowa	Nov-99	SPU-99-32
PG&E Company	California	Nov-99	99-11-003
PG&E Company	FERC	Nov-99	ER973255,981261,981685
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-99	
MidAmerican Energy	Illinois	Sep-99	99-0534
PG&E Company	FERC	Sep-99	ER99-4323-000
MidAmerican Energy	FERC	Jul-99	ER99-3887
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Jun-99	
Bell Atlantic	Vermont	May-99	6167
Nevada Power Company	FERC	May-99	
Bell Atlantic, GTE, US West	FCC	Apr-99	CC98-166
Nevada Power Company	Nevada	Apr-99	
Bell Atlantic, GTE, US West	FCC	Mar-99	CC98-166
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Mar-99	
PG&E Company	FERC	Mar-99	ER99-2326-000
MidAmerican Energy	Illinois	Mar-99	099-0310
PG&E Company	FERC	Feb-99	ER99-2358,2087,2351
MidAmerican Energy	US District Court, District of Nebraska	Feb-99	8:97 CV 346
Bell Atlantic, GTE, US West	FCC	Jan-99	CC98-166
The Southern Company	FERC	Jan-99	ER98-1096
Deutsche Telekom	Germany	Nov-98	
Telefonica	Spain	Nov-98	
Cincinnati Bell Telephone Company	Ohio	Oct-98	96899TPALT
MidAmerican Energy	Iowa	Sep-98	RPU 98-5
MidAmerican Energy	South Dakota	Sep-98	NG98-011
MidAmerican Energy	Iowa	Sep-98	SPU 98-8
GTE Florida Incorporated	Florida	Aug-98	980696-TP
GTE North and South	Illinois	Jun-98	960503
GTE Midwest Incorporated	Missouri	Jun-98	TO98329
GTE North and South	Illinois	May-98	960503
MidAmerican Energy	Iowa Board of Tax Review	May-98	835
San Diego Gas & Electric	California	May-98	98-05-024
GTE Midwest Incorporated	Nebraska	Apr-98	C1416
Carolina Telephone	North Carolina	Mar-98	P100Sub133d

SPONSOR	JURISDICTION	DATE	DOCKET NO.
GTE Southwest	Texas	Feb-98	18515
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Feb-98	P100sub133d
Public Service Electric & Gas	New Jersey	Feb-98	PUC734897N,-734797N,BPUEO97070461,-07070462
GTE North	Minnesota	Dec-97	P999/M97909
GTE Northwest	Oregon	Dec-97	UM874
The Southern Company	FERC	Dec-97	ER981096000
GTE North	Pennsylvania	Nov-97	A310125F0002
Bell Atlantic	Rhode Island	Nov-97	2681
GTE North	Indiana	Oct-97	40618
GTE North	Minnesota	Oct-97	P442,407/5321/CI961541
GTE Southwest	New Mexico	Oct-97	96310TC,96344TC
GTE Midwest Incorporated	Iowa	Sep-97	RPU-96-7
North Carolina Rate Bureau (workers)	North Carolina Dept. of Insurance	Sep-97	
GTE Hawaiian Telephone	Hawaii	Aug-97	7702
The Stentor Companies	Canadian Radio-television and Telecommunications Commission	Jul-97	CRTC97-11
New England Telephone	Vermont	Jul-97	5713
Bell-Atlantic-New Jersey	New Jersey	Jun-97	TX95120631
Nevada Bell	Nevada	May-97	96-9035
New England Telephone	Maine	Apr-97	96-781
GTE North, Inc.	Michigan	Apr-97	U11281
Bell Atlantic-Virginia	Virginia	Apr-97	970005
Cincinnati Bell Telephone	Ohio	Feb-97	96899TPALT
Bell Atlantic - Pennsylvania	Pennsylvania	Feb-97	A310203,213,236,258F002
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Feb-97	
Bell Atlantic-Washington, D.C.	District of Columbia	Jan-97	962
Pacific Bell, Sprint, US West	FCC	Jan-97	CC 96-45
United States Telephone Association	FCC	Jan-97	CC 96-262
Bell Atlantic-Maryland	Maryland	Jan-97	8731
Bell Atlantic-West Virginia	West Virginia	Jan-97	961516, 1561, 1009TPC,961533TT
Poe, Hoof, & Reinhardt	Durham Cnty Superior Court Kountis vs. Circle K	Jan-97	95CVS04754
Bell Atlantic-Delaware	Delaware	Dec-96	96324
Bell Atlantic-New Jersey	New Jersey	Nov-96	TX95120631
Carolina Power & Light Company	FERC	Nov-96	OA96-198-000
New England Telephone	Massachusetts	Oct-96	DPU 96-73/74,-75, -80/81, -83, -94
New England Telephone	New Hampshire	Oct-96	96-252
Bell Atlantic-Virginia	Virginia	Oct-96	960044
Citizens Utilities	Illinois	Sep-96	96-0200, 96-0240
Union Telephone Company	New Hampshire	Sep-96	95-311
Bell Atlantic-New Jersey	New Jersey	Sep-96	TO-96070519
New York Telephone	New York	Sep-96	95-C-0657, 94-C-0095,91-C-1174
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-96	
MidAmerican Energy Company	Illinois	Sep-96	96-0274
MidAmerican Energy Company	Iowa	Sep-96	RPU96-8
United States Telephone Association	FCC	Mar-96	AAD-96.28
United States Telephone Association	FCC	Mar-96	CC 94-1 PhaseIV
Bell Atlantic - Maryland	Maryland	Mar-96	8715
Nevada Bell	Nevada	Mar-96	96-3002
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Mar-96	
Carolina Tel. and Telegraph Co, Central Tel Co	North Carolina	Feb-96	P7 sub 825, P10 sub 479
Oklahoma Rural Telephone Coalition	Oklahoma	Oct-95	PUD950000119
BellSouth	Tennessee	Oct-95	95-02614
Wake County, North Carolina	US District Court, Eastern Dist. NC	Oct-95	594CV643H2
Bell Atlantic - District of Columbia	District of Columbia	Sep-95	814 Phase IV
South Central Bell Telephone Company	Tennessee	Aug-95	95-02614

SPONSOR	JURISDICTION	DATE	DOCKET NO.
GTE South	Virginia	Jun-95	95-0019
Roseville Telephone Company	California	May-95	A.95-05-030
Bell Atlantic - New Jersey	New Jersey	May-95	TX94090388
Cincinnati Bell Telephone Company	Ohio	May-95	941695TPACE
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	May-95	727
Northern Illinois Gas	Illinois	May-95	95-0219
South Central Bell Telephone Company	Kentucky	Apr-95	94-121
Midwest Gas	South Dakota	Mar-95	
Virginia Natural Gas, Inc.	Virginia	Mar-95	PUE940054
Hope Gas, Inc.	West Virginia	Mar-95	95-0003G42T
The Peoples Natural Gas Company	Pennsylvania	Feb-95	R-943252
and Coke Co., North Shore Gas, Iowa-Illinois Gas	Illinois	Jan-95	94-0403
and Electric, Central Illinois Public Service,	Illinois	Jan-95	94-0403
Northern Illinois Gas, The Peoples Gas, Light	Illinois	Jan-95	94-0403
United Cities Gas, and Interstate Power	Illinois	Jan-95	94-0403
Cincinnati Bell Telephone Company	Kentucky	Oct-94	94-355
Midwest Gas	Nebraska	Oct-94	
Midwest Power	Iowa	Sep-94	RPU-94-4
Bell Atlantic	FCC	Aug-94	CS 94-28, MM 93-215
Midwest Gas	Iowa	Jul-94	RPU-94-3
Bell Atlantic	FCC	Jun-94	CC 94-1
Nevada Power Company	Nevada	Jun-94	93-11045
Cincinnati Bell Telephone Company	Ohio	Mar-94	93-551-TP-CSS
Cincinnati Bell Telephone Company	Ohio	Mar-94	93-432-TP-ALT
GTE South/Contel	Virginia	Feb-94	PUC9300036
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Feb-94	689
Bell of Pennsylvania	Pennsylvania	Jan-94	P930715
GTE South	South Carolina	Jan-94	93-504-C
United Telephone-Southeast	Tennessee	Jan-94	93-04818
C&P of VA, GTE South, Contel, United Tel. SE	Virginia	Sep-93	PUC920029
Bell Atlantic, NYNEX, Pacific Companies	FCC	Aug-93	MM 93-215
C&P, Centel, Contel, GTE, & United	Virginia	Aug-93	PUC920029
Chesapeake & Potomac Tel Virginia	Virginia	Aug-93	93-00-
GTE North	Illinois	Jul-93	93-0301
Midwest Power	Iowa	Jul-93	INU-93-1
Midwest Power	South Dakota	Jul-93	EL93-016
Chesapeake & Potomac Tel. Co. DC	District of Columbia	Jun-93	926
Cincinnati Bell	Ohio	Jun-93	93432TPALT
North Carolina Rate Bureau (dwelling fire)	North Carolina Dept. of Insurance	Jun-93	671
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Jun-93	670
Pacific Bell Telephone Company	California	Mar-93	92-05-004
Minnesota Independent Equal Access Corp.	Minnesota	Mar-93	P3007/GR931
South Central Bell Telephone Company	Tennessee	Feb-93	92-13527
South Central Bell Telephone Company	Kentucky	Dec-92	92-523
Southern New England Telephone Company	Connecticut	Nov-92	92-09-19
Chesapeake & Potomac Tel. Co.CDC	District of Columbia	Nov-92	814
Diamond State Telephone Company	Delaware	Sep-92	PSC 92-47
New Jersey Bell Telephone Company	New Jersey	Sep-92	TO-92030958
Allstate Insurance Company	New Jersey Dept. of Insurance	Sep-92	INS 06174-92
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Aug-92	650
North Carolina Rate Bureau (workers' comp)	North Carolina Dept. of Insurance	Aug-92	647
Midwest Gas Company	Minnesota	Aug-92	G010/GR92710
Pennsylvania-American Water Company	Pennsylvania	Jul-92	R-922428
Central Telephone Co. of Florida	Florida	Jun-92	920310-TL
C&P of VA, GTE South, Contel, United Tel. SE	Virginia	Jun-92	PUC920029
Chesapeake & Potomac Tel. Co. Maryland	Maryland	May-92	8462

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Pacific Bell Telephone Company	California	Apr-92	92-05-004
Iowa Power Inc.	Iowa	Mar-92	RPU-92-2
Contel of Texas	Texas	Feb-92	10646
Southern Bell Telephone Company	Florida	Jan-92	880069-TL
Nevada Power Company	Nevada	Jan-92	92-1067
GTE South	Georgia	Dec-91	4003-U
GTE South	Georgia	Dec-91	4110-U
Allstate Insurance Company (property)	Texas Dept. of Insurance	Dec-91	1846
IPS Electric	Iowa	Oct-91	RPU-91-6
GTE South	Tennessee	Aug-91	91-05738
North Carolina Rate Bureau (workers' comp)	North Carolina Dept. of Insurance	Aug-91	609
Midwest Gas Company	Iowa	Jul-91	RPU-91-5
Pennsylvania-American Water Company	Pennsylvania	Jun-91	R-911909
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jun-91	606
Allstate Insurance Company	California Dept. of Insurance	May-91	RCD-2
Nevada Power Company	Nevada	May-91	91-5055
Kentucky Power Company	Kentucky	Apr-91	91-066
Chesapeake & Potomac Tel. Co.CD.C.	District of Columbia	Feb-91	850
Allstate Insurance Company	New Jersey Dept. of Insurance	Jan-91	INS-9536-90
GTE South	South Carolina	Nov-90	90-698-C
Southern Bell Telephone Company	Florida	Oct-90	880069-TL
GTE South	West Virginia	Aug-90	90-522-T-42T
North Carolina Rate Bureau (workers' comp)	North Carolina Dept. of Insurance	Aug-90	R90-08-
The Travelers Indemnity Company	Pennsylvania Dept. of Insurance	Aug-90	R-90-06-23
Chesapeake & Potomac Tel. Co.-Maryland	Maryland	Jul-90	8274
Allstate Insurance Company	Pennsylvania Dept. of Insurance	Jul-90	R90-07-01
Central Tel. Co. of Florida	Florida	Jun-90	89-1246-TL
Citizens Telephone Company	North Carolina	Jun-90	P-12, SUB 89
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jun-90	568
Iowa Resources, Inc. and Midwest Energy	Iowa	Jun-90	SPU-90-5
Contel of Illinois	Illinois	May-90	90-0128
Southern New England Tel. Co.	Connecticut	Apr-90	89-12-05
Bell Atlantic	FCC	Apr-90	89-624 II
Pennsylvania-American Water Company	Pennsylvania	Mar-90	R-901652
Bell Atlantic	FCC	Feb-90	89-624
GTE South	Tennessee	Jan-90	
Allstate Insurance Company	California Dept. of Insurance	Jan-90	REB-1002
Bell Atlantic	FCC	Nov-89	87-463 II
Allstate Insurance Company	California Dept. of Insurance	Sep-89	REB-1006
Pacific Bell	California	Mar-89	87-11-0033
Iowa Power & Light	Iowa	Dec-88	RPU-88-10
Pacific Bell	California	Oct-88	88-05-009
Southern Bell	Florida	Apr-88	880069TL
Carolina Independent Telcos.	North Carolina	Apr-88	P-100, Sub 81
United States Telephone Association	U. S. Congress	Apr-88	
Carolina Power & Light	South Carolina	Mar-88	88-11-E
New Jersey Bell Telephone Co.	New Jersey	Feb-88	87050398
Carolina Power & Light	FERC	Jan-88	ER-88-224-000
Carolina Power & Light	North Carolina	Dec-87	E-2, Sub 537
Bell Atlantic	FCC	Nov-87	87-463
Diamond State Telephone Co.	Delaware	Jul-87	86-20
Central Telephone Co. of Nevada	Nevada	Jun-87	87-1249
ALLTEL	Florida	Apr-87	870076-PU
Southern Bell	Florida	Apr-87	870076-PU
Carolina Power & Light	North Carolina	Apr-87	E-2, Sub 526
So. New England Telephone Co.	Connecticut	Mar-87	87-01-02

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Northern Illinois Gas Co.	Illinois	Mar-87	87-0032
Bell of Pennsylvania	Pennsylvania	Feb-87	860923
Carolina Power & Light	FERC	Jan-87	ER-87-240-000
Bell South	NTIA	Dec-86	61091-619
Heins Telephone Company	North Carolina	Oct-86	P-26, Sub 93
Public Service Co. of NC	North Carolina	Jul-86	G-5, Sub 207
Bell Atlantic	FCC	Feb-86	84-800 III
BellSouth	FCC	Feb-86	84-800 III
ALLTEL Carolina, Inc	North Carolina	Feb-86	P-118, Sub 39
ALLTEL Georgia, Inc.	Georgia	Jan-86	3567-U
ALLTEL Ohio	Ohio	Jan-86	86-60-TP-AIR
Western Reserve Telephone Co.	Ohio	Jan-86	85-1973-TP-AIR
New England Telephone & Telegraph	Maine	Dec-85	
ALLTEL-Florida	Florida	Oct-85	850064-TL
Iowa Southern Utilities	Iowa	Oct-85	RPU-85-11
Bell Atlantic	FCC	Sep-85	84-800 II
Pacific Telesis	FCC	Sep-85	84-800 II
Pacific Bell	California	Apr-85	85-01-034
United Telephone Co. of Missouri	Missouri	Apr-85	TR-85-179
South Carolina Generating Co.	FERC	Apr-85	85-204
South Central Bell	Kentucky	Mar-85	9160
New England Telephone & Telegraph	Vermont	Mar-85	5001
Chesapeake & Potomac Telephone Co.	West Virginia	Mar-85	84-747
Chesapeake & Potomac Telephone Co.	Maryland	Jan-85	7851
Central Telephone Co. of Ohio	Ohio	Dec-84	84-1431-TP-AIR
Ohio Bell	Ohio	Dec-84	84-1435-TP-AIR
Carolina Power & Light Co.	FERC	Dec-84	ER85-184000
BellSouth	FCC	Nov-84	84-800 I
Pacific Telesis	FCC	Nov-84	84-800 I
New Jersey Bell	New Jersey	Aug-84	848-856
Southern Bell	South Carolina	Aug-84	84-308-C
Pacific Power & Light Co.	Montana	Jul-84	84.73.8
Carolina Power & Light Co.	South Carolina	Jun-84	84-122-E
Southern Bell	Georgia	Mar-84	3465-U
Carolina Power & Light Co.	North Carolina	Feb-84	E-2, Sub 481
Southern Bell	North Carolina	Jan-84	P-55, Sub 834
South Carolina Electric & Gas	South Carolina	Nov-83	83-307-E
Empire Telephone Co.	Georgia	Oct-83	3343-U
Southern Bell	Georgia	Aug-83	3393-U
Carolina Power & Light Co.	FERC	Aug-83	ER83-765-000
General Telephone Co. of the SW	Arkansas	Jul-83	83-147-U
Heins Telephone Co.	North Carolina	Jul-83	No.26 Sub 88
General Telephone Co. of the NW	Washington	Jul-83	U-82-45
Leeds Telephone Co.	Alabama	Apr-83	18578
General Telephone Co. of California	California	Apr-83	83-07-02
North Carolina Natural Gas	North Carolina	Apr-83	G21 Sub 235
Carolina Power & Light	South Carolina	Apr-83	82-328-E
Eastern Illinois Telephone Co.	Illinois	Feb-83	83-0072
Carolina Power & Light	North Carolina	Feb-83	E-2 Sub 461
New Jersey Bell	New Jersey	Dec-82	8211-1030
Southern Bell	Florida	Nov-82	820294-TP
United Telephone of Missouri	Missouri	Nov-82	TR-83-135
Central Telephone Co. of NC	North Carolina	Nov-82	P-10 Sub 415
Concord Telephone Company	North Carolina	Nov-82	P-16 Sub 146
Carolina Telephone & Telegraph	North Carolina	Aug-82	P-7, Sub 670
Central Telephone Co. of Ohio	Ohio	Jul-82	82-636-TP-AIR

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Southern Bell	South Carolina	Jul-82	82-294-C
General Telephone Co. of the SW	Arkansas	Jun-82	82-232-U
General Telephone Co. of Illinois	Illinois	Jun-82	82-0458
General Telephone Co. of the SW	Oklahoma	Jun-82	27482
Empire Telephone Co.	Georgia	May-82	3355-U
Mid-Georgia Telephone Co.	Georgia	May-82	3354-U
General Telephone Co. of the SW	Texas	Apr-82	4300
General Telephone Co. of the SE	Alabama	Jan-82	18199
Carolina Power & Light Co.	South Carolina	Jan-82	81-163-E
Elmore-Coosa Telephone Co.	Alabama	Nov-81	18215
General Telephone Co. of the SE	North Carolina	Sep-81	P-19, Sub 182
United Telephone Co. of Ohio	Ohio	Sep-81	81-627-TP-AIR
General Telephone Co. of the SE	South Carolina	Sep-81	81-121-C
Carolina Telephone & Telegraph	North Carolina	Aug-81	P-7, Sub 652
Southern Bell	North Carolina	Aug-81	P-55, Sub 794
Woodbury Telephone Co.	Connecticut	Jul-81	810504
Central Telephone Co. of Virginia	Virginia	Jun-81	810030
United Telephone Co. of Missouri	Missouri	May-81	TR-81-302
General Telephone Co. of the SE	Virginia	Apr-81	810003
New England Telephone	Vermont	Mar-81	4546
Carolina Telephone & Telegraph	North Carolina	Aug-80	P-7, Sub 652
Southern Bell	North Carolina	Aug-80	P-55, Sub 784
General Telephone Co. of the SW	Arkansas	Jun-80	U-3138
General Telephone Co. of the SE	Alabama	May-80	17850
Southern Bell	North Carolina	Oct-79	P-55, Sub 777
Southern Bell	Georgia	Mar-79	3144-U
General Telephone Co. of the SE	Virginia	Mar-76	810038
General Telephone Co. of the SW	Arkansas	Feb-76	U-2693, U-2724
General Telephone Co. of the SE	Alabama	Sep-75	17058
General Telephone Co. of the SE	South Carolina	Jun-75	D-18269

EXHIBIT 12
APPENDIX 2
ESTIMATING THE EXPECTED RISK PREMIUM ON UTILITY STOCKS USING THE DCF MODEL

The DCF model is based on the assumption that investors value an asset on the basis of the future cash flows they expect to receive from owning the asset. Thus, investors value an investment in a bond because they expect to receive a sequence of semi-annual coupon payments over the life of the bond and a terminal payment equal to the bond's face value at the time the bond matures. Likewise, investors value an investment in a firm's stock because they expect to receive a sequence of dividend payments and, perhaps, expect to sell the stock at a higher price sometime in the future.

A second fundamental principle of the DCF method is that investors value a dollar received in the future less than a dollar received today. A future dollar is valued less than a current dollar because investors could invest a current dollar in an interest earning account and increase their wealth. This principle is called the time value of money.

Applying the two fundamental DCF principles noted above to an investment in a bond leads to the conclusion that investors value their investment in the bond on the basis of the present value of the bond's future cash flows. Thus, the price of the bond should be equal to:

EQUATION 1

$$P_B = \frac{C}{(1+i)} + \frac{C}{(1+i)^2} + \ldots + \frac{C+F}{(1+i)^n}$$

where:

P_B	=	Bond price;
C	=	Cash value of the coupon payment (assumed for notational convenience to occur annually rather than semi-annually);
F	=	Face value of the bond;

i	=	The rate of interest the investor could earn by investing his money in an alternative bond of equal risk; and
n	=	The number of periods before the bond matures.

Applying these same principles to an investment in a firm's stock suggests that the price of the stock should be equal to:

EQUATION 2

$$P_s = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_n + P_n}{(1+k)^n}$$

where:

P_S	=	Current price of the firm's stock;
$D_1, D_2 ... D_n$	=	Expected annual dividend per share on the firm's stock;
P_n	=	Price per share of stock at the time the investor expects to sell the stock; and
k	=	Return the investor expects to earn on alternative investments of the same risk, i.e., the investor's required rate of return.

Equation (2) is frequently called the annual discounted cash flow model of stock valuation. Assuming that dividends grow at a constant annual rate, *g*, this equation can be solved for *k*, the cost of equity. The resulting cost of equity equation is $k = D_1/P_s + g$, where *k* is the cost of equity, D_1 is the expected next period annual dividend, P_s is the current price of the stock, and *g* is the constant annual growth rate in earnings, dividends, and book value per share. The term D_1/P_s is called the dividend yield component of the annual DCF model, and the term *g* is called the growth component of the annual DCF model.

The annual DCF model is only a correct expression for the present value of future dividends if dividends are paid annually at the end of each year. Since most industrial and utility firms pay dividends quarterly, the annual DCF model produces downwardly biased estimates of the cost of equity. Investors can expect to earn a higher annual effective return on an investment in a firm that pays quarterly dividends than in one which pays the same amount of dollar dividends once at the end of each year.

The Dividend Component

The quarterly DCF model requires an estimate of the expected dividends for the next four quarters. I estimated the expected dividends for the next four quarters by multiplying the actual dividends for the last four quarters by the factor, (1 + the growth rate, g).

The Growth Component

To estimate the growth component of the DCF model, I used the analysts' estimates of future earnings per share (EPS) growth reported by I/B/E/S Thomson Financial. As part of their research, financial analysts working at Wall Street firms periodically estimate EPS growth for each firm they follow. The EPS forecasts for each firm are then published. Investors who are contemplating purchasing or selling shares in individual companies review the forecasts. These estimates represent five-year forecasts of EPS growth. I/B/E/S is a firm that reports analysts' EPS growth forecasts for a broad group of companies. The forecasts are expressed in terms of a mean forecast and a standard deviation of forecast for each firm. Investors use the mean forecast as a consensus estimate of future firm performance. The I/B/E/S growth rates: (1) are widely circulated in the financial community, (2) include the projections of reputable financial analysts who develop estimates of future EPS growth, (3) are reported on a timely basis to investors, and (4) are widely used by institutional and other investors.

I relied on analysts' projections of future EPS growth because there is considerable empirical evidence that investors use analysts' forecasts to estimate future earnings growth. To test whether investors use analysts' growth forecasts to estimate future dividend and earnings growth, I prepared a study in conjunction with Willard T. Carleton, Karl Eller Professor of Finance at the University of Arizona, on why analysts' forecasts are the best estimate of investors' expectation of future long-term growth. This study is described in a paper entitled "Investor Growth Expectations and Stock Prices: the Analysts versus Historical Growth Extrapolation," published in the Spring 1988 edition of *The Journal of Portfolio Management*.

In our paper, we describe how we first performed a correlation analysis to identify the historically-oriented growth rates which best described a firm's stock price. Then we did a regression study comparing the historical growth rates with the consensus analysts' forecasts. In every case, the regression equations containing the average of analysts' forecasts statistically outperformed the regression equations containing the historical growth estimates. These results are consistent with those found by Cragg and Malkiel, the early major research in this area (John G. Cragg and Burton G. Malkiel, *Expectations and the Structure of Share Prices*, University of Chicago Press, 1982). These results are also consistent with the hypothesis that investors use analysts' forecasts, rather than historically-oriented growth calculations, in making stock buy and sell decisions. They provide overwhelming evidence that the analysts' forecasts of future growth are superior to historically-oriented growth measures in predicting a firm's stock price.

My study has been updated to include more recent data. Researchers at State Street Financial Advisors updated my study using data through year-end 2003. Their results continue to confirm that analysts' growth forecasts are superior to historically-oriented growth measures in predicting a firm's stock price.

The Price Component

To measure the price component of the DCF model, I used a simple average of the monthly high and low stock prices for each firm over a three-month period. These high and low stock prices were obtained from Thomson Financial. I used the three-month average stock price in applying the DCF method because stock prices fluctuate daily, while financial analysts' forecasts for a given company are generally changed less frequently, often on a quarterly basis. Thus, to match the stock price with an earnings forecast, it is appropriate to average stock prices over a three-month period.

EXHIBIT 13
APPENDIX 3
THE SENSITIVITY OF THE FORWARD-LOOKING
REQUIRED EQUITY RISK PREMIUM ON UTILITY STOCKS
TO CHANGES IN INTEREST RATES

My estimate of the required equity risk premium on utility stocks is based on studies of the discounted cash flow (“DCF”) expected return on comparable groups of utilities in each month of my study period compared to the interest rate on long-term government bonds. Specifically, for each month in my study period, I calculate the risk premium using the equation

$$RP_{COMP} = DCF_{COMP} - I_B$$

where:

RP_{COMP} = the required risk premium on an equity investment in the comparable companies,

DCF_{COMP} = average DCF expected rate of return on a portfolio of comparable companies; and

I_B = the yield to maturity on an investment in long-term U.S. Treasury bonds.

<u>Electric Company Ex Ante Risk Premium Analysis</u>. For my electric company ex ante risk premium analysis, I began with the Moody’s group of 24 electric companies shown in Table 1. I used the Moody’s group of electric companies because they are a widely followed group of electric utilities, and use of this constant group greatly simplified the data collection task required to estimate the ex ante risk premium over the months of my study. Simplifying the data collection task was desirable because the ex ante risk premium approach requires that the DCF model be estimated for every company in every month of the study period. Exhibit 5 displays the average DCF expected return on an investment in the portfolio of electric companies and the yield to maturity on long-term Treasury bonds in each month of the study.

Previous studies have shown that the ex ante risk premium tends to vary inversely with the level of interest rates, that is, the risk premium tends to increase when interest rates decline, and decrease when interest rates go up. To test whether my studies also indicate that the ex ante risk premium varies inversely with the level of interest rates, I performed a regression analysis of the relationship between the ex ante risk premium and the yield to maturity on long-term Treasury bonds, using the equation,

$$RP_{COMP} = a + (b \times I_B) + e$$

where:

RP_{COMP} = risk premium on comparable company group;

I_B = yield to maturity on long-term U.S. Treasury bonds;

e = a random residual; and

a, b = coefficients estimated by the regression procedure.

Regression analysis assumes that the statistical residuals from the regression equation are random. My examination of the residuals revealed that there is a significant probability that the residuals are serially correlated (non-zero serial correlation indicates that the residual in one time period tends to be correlated with the residual in the previous time period). Therefore, I made adjustments to my data to correct for the possibility of serial correlation in the residuals.

The common procedure for dealing with serial correlation in the residuals is to estimate the regression coefficients in two steps. First, a multiple regression analysis is used to estimate the serial correlation coefficient, *r*. Second, the estimated serial correlation coefficient is used to transform the original variables into new variables whose serial correlation is approximately zero. The regression coefficients are then re-estimated using the transformed variables as inputs in the regression equation. Based on my regression analysis of the statistical relationship between the yield to maturity on long-term Treasury bonds and the required risk premium, my estimate of the ex ante risk premium on an investment in my proxy electric company group as compared to an investment in long-term Treasury bonds is given by the equation:

$$RP_{COMP} = \underset{(10.49)}{10.67} - \underset{(-4.98)}{0.867} \times I_B.$$

(10.49) (-4.98)[10] R^2 = 18.48 percent

This equation suggests that the ex ante risk premium on electric utility stocks increases by more than 80 basis points when the interest rate on long-term Treasury bonds declines by 100 basis points. Equivalently, this regression equation suggests that the cost of equity for electric utilities declines by less than 20 basis points when the interest rate on long-term Treasury bonds declines by 100 basis points. These data demonstrate that the AAM ROE

[10] The t-statistics are shown in parentheses.

Formula, which assumes that the cost of equity declines by 75 basis points when the yield to maturity on long Canada bonds declines by 100 basis points, is no longer appropriate for estimating the cost of equity.

Using the 2009 forecast 4.30 percent yield to maturity on long-term Canada bonds obtained from Consensus Economics as of July 2008, the regression equation produces an ex ante risk premium equal to 6.94 percent (10.67 – 0.867 x 4.30 = 6.94).

Natural Gas Company Ex Ante Risk Premium Analysis. I also conducted an ex ante risk premium study applied to a natural gas proxy group and followed the procedures described above. To select my ex ante risk premium natural gas proxy group of companies, I used the same criteria that I use when estimating the DCF cost of equity, namely, I selected all the companies in Value Line's groups of natural gas companies that: (1) paid dividends during every quarter of the last two years; (2) did not decrease dividends during any quarter of the past two years; (3) had at least three analysts included in the I/B/E/S mean growth forecast; (4) have an investment grade bond rating and a Value Line Safety Rank of 1, 2, or 3; and (5) have not announced a merger. Exhibit 6 displays the results of my ex ante risk premium study, showing the average DCF expected return on an investment in the portfolio of natural gas companies and the yield to maturity on long-term Treasury bonds in each month.[11]

Based on my knowledge of the statistical relationship between the yield to maturity on long-term Treasury bonds and the required risk premium, my estimate of the ex ante risk premium on an investment in my proxy natural gas companies as compared to an investment in long-term Treasury bonds is given by the equation:

$$RP_{COMP} = 0.1117 - 0.9636 \times I_B.$$

$$(13.22) \qquad (-6.374)^{[12]} \qquad R^2 = 25.45 \text{ percent}$$

This equation suggests that the ex ante risk premium on natural gas utility stocks increases by more than 90 basis points when the interest rate on long-term Treasury bonds declines by 100 basis points. Equivalently, this regression equation suggests that the cost of equity for natural gas utilities declines by less than 10 basis points when the interest rate on long-term Treasury bonds declines by 100 basis points. These data demonstrate that the AAM

[11] My two ex ante risk premium studies cover slightly different time periods, with the natural gas company risk premium study extending over a longer period of time, because I began doing an ex ante study using natural gas companies before I began performing a similar study for the electric companies.

[12] The t-statistics are shown in parentheses.

ROE Formula, which assumes that the cost of equity declines by 75 basis points when the yield to maturity on long Canada bonds declines by 100 basis points, is no longer appropriate for estimating the cost of equity.

Using the 4.30 percent forecast yield to maturity on long-term Canada bonds for 2009, the regression equation produces an ex ante risk premium equal to 7.03 percent (0.1117 – .9636 x 4.30 = 7.03).

As described above, my ex ante risk premium regression analysis indicates that the cost of equity for utilities is significantly less sensitive to interest rate changes than the AAM ROE Formula implies. Rather than declining by 75 basis points when the yield to maturity on long-term government bonds declines by 100 basis points, my analysis indicates that the cost of equity declines by less than 50 basis points when interest rates decline by 100 basis points. To test whether my conclusion is robust to changes in the cost of equity measurement period, I re-estimated my regression equations using quarterly cost of equity and interest data rather than monthly data. My regression analysis using quarterly data strongly supports my conclusion that the cost of equity for utilities is significantly less sensitive to interest rate changes than the AAM ROE Formula suggests. For example, my regression analysis for electric and natural gas utilities using data for one month of each quarter, indicates that the cost of equity declines by less than 50 basis points when interest rates decline by 100 basis points.

TABLE 1
MOODY'S ELECTRIC COMPANIES

American Electric Power
Constellation Energy
Progress Energy
CH Energy Group
Cinergy Corp.
Consolidated Edison Inc.
DPL Inc.
DTE Energy Co.
Dominion Resources Inc.
Duke Energy Corp.
Energy East Corp.
FirstEnergy Corp.
Reliant Energy Inc.
IDACORP. Inc.
IPALCO Enterprises Inc.
NiSource Inc.
OGE Energy Corp.
Exelon Corp.
PPL Corp.
Potomac Electric Power Co.
Public Service Enterprise Group
Southern Company
Teco Energy Inc.
Xcel Energy Inc.

Source of data: *Mergent Public Utility Manual*, August 2002. Of these 24 companies, I did not include three companies in my ex ante risk premium DCF analysis because there was insufficient data to perform a DCF analysis for most of my study period. Specifically, IPALCO merged with a company that is not in the electric utility industry; Reliant divested its electric utility operations; and CH Energy does not have any I/B/E/S analysts' estimates of long-term growth. In addition, Cinergy completed its merger with Duke Energy in 2006.

Appendices

The Fair Return Standard for Return on Investment by Canadian Gas Utilities:

Meaning, Application, Results, Implications

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Former Justice, Supreme Court of Canada

Roland Priddle
President, Roland Priddle Energy Consulting Inc.
Former Chair of the National Energy Board

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Acronyms and Abbreviations

AAM	Automatic adjustment mechanism
Alberta Board	Alberta Energy and Utilities Board
ATWACC	After-tax weighted average cost of capital
AUC	Alberta Utilities Commission
BC Commission	British Columbia Public Utilities Commission
BCUC	British Columbia Utilities Commission
California Commission	California Public Utilities Commission
CAPM	Capital asset pricing model
CE	Comparable earnings
CPUC	California Public Utilities Commission
DCF	Discounted cash flow
ERP	Equity risk premium
EUB	(Alberta) Energy and Utilities Board
FCA	Federal Court of Appeal
FRS	Fair return standard
LDC	Local distribution companies
Manitoba Commission	Manitoba Public Utilities Commission
MPUB	Manitoba Public Utilities Commission
MRP	Market risk premium
NGTL	NOVA Gas Transmission Ltd.
NEB	National Energy Board
NERA	National Economic Research Associates
Northwestern	*Northwestern Utilities Ltd v. Edmonton* [1929] S.C.R. 186
OEB, Ontario Board	Ontario Energy Board
Régie	Régie de l’énergie (du Québec)
RfD	Reasons for Decision
ROE	Rate of return on equity
SCC	Supreme Court of Canada
TCPL, TransCanada	TransCanada PipeLines Ltd
TQM	Gazoduc TransQuébec & Maritimes

Executive Summary

The meaning of the Fair Return Standard (FRS) Canadian governments responded to the growth of the gas business and the potential for abuse of dominant position in it by placing utilities under the jurisdiction of administrative tribunals. In theory, the extent of this regulation is unlimited. In practice it is constrained by the Constitution Act and by Common Law.

The Supreme Court in *Northwestern Utilities Ltd v. Edmonton* [1929] S.C.R. 186 (Northwestern) defined the scope of the utilities' right to price their product and their right as a result to a fair return. The Court stated "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". This definition remains in full legal effect today.

A fair rate of return to the corporation is paramount and is all that can be considered in arriving at a fair rate. In the unrealistic situation that a fair return worked a hardship on the consumer, the choices before government to provide relief are unlimited but they should not lower the fair rate of return. Indeed the Federal Court of Appeal (FCA) in *TransCanada PipeLines v. Canada National Energy Board* 2004 F.C.A. 149 confirmed that a fair return need not be modified out of deference to its impact upon customers.

As the operations of regulated utilities have become larger and more complicated, the courts have developed the view that a selected board of experts could deal more effectively with the rules of rate making than could the courts on appeal. Therefore, as long as the board in question acted within their jurisdiction, a successful appeal was unlikely. Notwithstanding the breadth of discretion afforded a regulator in establishing just and reasonable rates, the mutuality of interest between utilities and their customers nevertheless requires that a fair return be provided for the services rendered. The legal framework governing the determination of that fair return is the "Comparable Return Standard". It does not mandate any particular approach to that fair return.

The application of the FRS The current generic approach by Canadian regulators to gas utility rates of return on equity (ROE) awards pursuant to the FRS evolved after a long period in which regulators applied informed judgment to extensive evidence about a variety of tests. During that period, differing weights were given to the results but, with the exception of one jurisdiction and one test[1], none was ever permanently discarded. Over the years however, greatest reliance came to be placed on the equity risk premium (ERP) model.

With the passage of time, the phenomenon of successive protracted proceedings, eliciting similar evidence, stimulated the search for a generic approach. From the mid-1990's Canadian regulators accreted around the concept of an ROE for a benchmark utility based on an ERP over a risk-free rate, the resulting base-year award then being adjusted annually by a predetermined automatic mechanism. This is the essence of the generic ROE, now adopted for the regulation of that component of all major gas pipeline and distribution utilities' revenue requirements.

The results of regulators' current application of the FRS The number and duration of rate proceedings has been significantly reduced and in certain jurisdictions the way has been paved for long-term settlements, some of which have made provision for sharing of efficiency gains between customers and owners.

The Canadian approach to return matters stands in strong contrast to that in the USA, with which Canada shares the long tradition of cost of service utility regulation. There, in accordance with essentially similar jurisprudence, the fairness of return on investment is evaluated against the opportunity cost of capital.

While settlements are also common in the USA, American regulators have not pursued the generic ROE approach but instead maintain case by case reviews, emphasize the important role of informed judgment, entertain a variety of evidence, but tend to the discounted cash flow method (DCF) as the default mechanism for their fair return findings.

In the NEB generic ROE era, no new pipelines have applied for tolls based on that determination of ROE. Instead, new projects such as Alliance, Emera Brunswick, Maritimes and Northeast, and Mackenzie Valley have all come before the Board with negotiated tolls based on significantly higher ROEs. This suggests that the NEB's generic ROE is insufficient to attract capital to greenfield gas pipeline projects.

The implications of this application of the FRS The now-universal generic ROE approach by Canadian regulators of major gas utilities has created some regulatory economies. But unfortunately its mechanistic character suspends for lengthy periods the previously-valued application of informed judgment to the results of alternative methods of achieving the FRS required by Canadian jurisprudence in ROE awards.

A wide and unprecedented gap has developed between Canadian gas utility ROEs and those of USA utilities and of North American low risk industrials. This is factual ground for concluding that the FRS, essentially the opportunity cost of capital needed to ensure financial integrity and capital attraction, is no longer being achieved by the generic ROE approach.

Canadian regulatory convergence on the generic ROE may however inhibit its necessary reappraisal because particular regulators may be reluctant to break ranks with the group and because the consensus around an approved generic ROE is widely supported by stakeholders[2], for reasons of regulatory efficiency and short term economic self-interest.

It would be helpful if, at the same time as specific cases occasionally come before individual regulators[3], some further studies of general relevance were to be carried out. For example, examination is recommended of the results, *ex post*, of the generic approach in terms of the comparability of the resulting returns with non-utility and utility comparators and of the fundamentals of the present design including the choice of the risk-free rate; the appropriate measurement of the risk-premium; the adjustment mechanism; and the place of the DCF model which is accepted by the great majority of North American regulators.

Introduction

The Canadian Gas Association (CGA) Discussion Paper "Return on Equity: Allowed Returns for Canadian Gas Utilities"[4], highlighted the importance of a "fair return" in supporting investments for the long term strength of the nation's natural gas grid. The paper went on to summarize the origins and evolution of Canada's "fair return standard". The paper noted that Canadian gas utilities are not now receiving allowed returns comparable with those of U.S. gas utilities or low-risk unregulated companies. As a result, Canadian utilities, it stated, are treated unfairly and may be inhibited from offering a robust optimal system that would provide the highest quality of service today and would be properly oriented towards a sustainable energy future.

Against that background, the Association asked the present authors, who had provided advice in the drafting of the Discussion Paper, to expand on some of the issues raised in it, particularly the identified need for the policy community and regulators to ensure that allowed returns remain fair and appropriately reflect the significant changes in their foundational elements such as comparable earnings.

In response, the authors provide here an examination of the meaning of the FRS in jurisprudential terms, discuss its application by Canadian regulators over the decades, review the results of the convergence since the mid-1990s on a generic approach to returns on equity and consider the implications of that approach for the future health of Canada's gas utility businesses. As to the application of the FRS, regulators have received thousands of pages of evidence and written hundreds summarizing it, providing their views and setting out their reasons for decision. Our discussion is necessarily a selective and summary one. However, we hope not to have omitted any point of fundamental significance.

1. The Jurisprudential Meaning of the Fair Return Standard

The inception of utility regulation in Canada The introduction of utility regulation by governments was grounded in the view that the activity had evolved into a number of sufficiently large corporations operating in a business characterized by natural monopoly and therefore capable of exerting market power to the detriment of consumers.

History demonstrated a number of methods of control available to the authorities. In response to concerns about the monopoly power wielded by Standard Oil, the United States introduced anti-trust legislation which led to its massive restructuring into a number of smaller corporations, forcing increased competition. The result was re-organization of their position from virtual dominance of the sector to competition among the newly formed corporations. Similar experience occurred in diminishing the dominant areas in steel and railroads.

Canada, because of its size in terms of population and domestic product, chose to remove the actual or feared problem of monopolies in the utility field either by use of legislative regulation or by Crown ownership.

In the context of regulation, some economists express the view that a regulator serves as a surrogate for competition in terms of the regulated company's potential dominance of a particular activity. While this may not be a complete explanation of the public purpose, it is a useful analogy. The pertinent and difficult question is what should these regulated companies be entitled to charge their retail, commercial and industrial customers so as to ensure safe and modern service in exchange for a fair return on shareholders' capital?

Regulatory responsibility conferred on administrative tribunals The history of the natural gas industry is a relatively short one: it is only in the early part of the 20th century that independent commercial use started to visibly develop.

As privately-owned utilities started to evolve into fewer but larger companies capable of exerting market power, the response of Canadian governments was utility regulation under which administrative tribunals were given the jurisdiction to regulate private utility companies falling under their mandate. By and large, however, Crown-owned utilities were not regulated in the conventional way since their corporate governance was taken to be enlightened by the government's perception of the pubic interest of the day.

The recognition of the value of natural gas as a legitimate alternative to electricity and fuel oils as an energy source, and the need for such control, raised a number of regulatory and constitutional issues.

As a preliminary point, it is obvious that the constitutional division of powers dictated by sections 91 and 92 of the *British North America Act* divided the regulatory responsibility between the Federal and Provincial governments. This is a separate subject, capable of extensive comment, but it is sufficient for this paper to say intra-provincial activity fell to the Provincial Legislatures and extra-provincial activity to the Federal Parliament.

Constraints on the extent of regulation In Canada, the extent to which governments choose to regulate is theoretically unlimited. The absence of property rights for corporations makes them vulnerable to draconian legislation, if our governments so choose. However, the courts have recognized Common Law rights that co-exist with the Canadian Charter of Rights and Freedoms. Expropriation without compensation offends the Common Law rights of persons and corporations and is unknown to have occurred in Canada except for some unusual circumstances during war time.

The full reach and restraint by the Constitution Act or Common Law as they affect persons and corporations is beyond the narrower scope of this paper. It is sufficient to state that the rights are real, recognizable and enforceable.

Jurisprudence concerning utility rates—the fair return standard The important test of the prices or rates to be paid by consumers of natural gas supplied by a public utility has been established by our highest court, the Supreme Court of Canada (SCC). The Court confirmed the right of the companies to price the product within the confines of a fair rate of return on investments for the shareholder.

The SCC defined the scope of that right in 1929 and it remains in full legal effect today. It is consistently referred to and followed. The right to a fair return, and what it is, was defined by the SCC in *Northwestern Utilities Ltd. V. Edmonton,* [1929] S.C.R. 186 where 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”.

The importance of maintaining safe and reliable service requires a fair return as defined by Mr. Justice Lamont. The consumer has grown accustomed to a high standard in the delivery of gas services. Humanly, they are used to both the high quality of product and service. Equally human, they balk at rate increases while knowing that to avoid deterioration in service, timely increases are necessary.

“Fair return” vs. fairness to the consumer While it has not yet happened, if providing a fair return to utilities as defined by the courts results in hardship for the consumer, how should it be resolved? The greater good is served by the application of Mr. Justice Lamont’s definition. The language found in most legislation refers to words such as rate fair to the corporation and consumer. Fairness to the consumer in that sense is redundant. A fair rate of return to the corporation is paramount and is all that can be considered in arriving at a fair rate. The fair rate by logic alone should be deemed of necessity fair to the consumer.

That a fair rate of return would be a hardship on the consumer is practically unrealistic. It is academic and an unlikely result. An increase in rates is always unwelcome. If the rate rose to a hardship, some government intervention should be expected or the regulator may adjust the rate design while still ensuring the provision of a "fair return" to the utility. The point is that there are choices for relief, such as subsidies or a rate design short of lowering the fair rate of return. If hardship is the consequence of a fair return, nonetheless, the fair return must be set. Failure to do so over time will, as we have collectively seen, lead inevitably to the deterioration of, and in the extreme case, the failure of service and supply.

The Federal Court of Appeal (FCA) recently restated the principles of a fair return in *TransCanada PipeLines v. Canada National Energy Board* 2004 F.C.A. 149, where it confirmed the logic of Mr. Justice Lamont's definition by confirming that the fair return need not be modified out of deference to its impact upon customers. A fair return assures the opportunity to earn a level of profit equal to a comparable return from business of similar risk, although flexibility by which the ultimate tolls are designed may mitigate clear hardship or unfairness to consumers. However, by definition, a fair return should not result in these consequences.

Consumers and those outside the industry frequently forget or never considered that while utilities are by law always entitled to a fair return, it is a limited blessing in that higher earnings in buoyant times are not available to the utilities. There are no windfall profits such as may arise in other parts of the energy sector. It is only logical that the other side of that equation applies and a fair rate of return must also be allowed in less prosperous economic times.

Judicial review of regulatory awards The right to a fair return is one foundation of utility jurisprudence. Of concern is the growing development of the law that demonstrates a reluctance of the courts to review regulatory awards.

Until the 1930s, judicial review was more common as the courts viewed it their role to protect the public's interest. However, as Canada's industrial base grew and the operation of regulated utilities became both larger and more complicated, the view developed that a selected board of experts could deal more effectively with the rules of rate-making than the courts so long as the board in question acted within their jurisdiction, a successful appeal was unlikely.

The concept of judicial review was more elaborately defined by the SCC in *Pushpanathan v. Canada (Minister of Citizenship and Immigration),* [1998] 1 S.C.R. 982, where in summary it held that judicial review was identified by three tests. First, was the decision reasonable, second was the decision patently unreasonable and finally was the decision correct in law. It was only the latter, correct in law test, which receives a judicial welcome. It is the present law that a decision by the board must, if a question of law be correct any other finding or decision of the board must be patently unreasonable before judicial review is available.

The human concern by applicants of regulatory boards is the question of bias and fairness. A board that is neither can mouth the established fair return definition but not accept the applicant's facts. It is obvious that a fair return is dependant on the facts accepted by the Board and, except in extreme circumstances, the courts will not interfere. For fairness to occur dictates good faith by all participants.

Notwithstanding the breadth of the discretion afforded a regulator in establishing just and reasonable rates, the mutuality of interest between utilities and their customers nevertheless requires that a fair return be provided for the services rendered. The term just and reasonable does not displace the common law standard, rather it supports it (NWL 1929; TCPL 2004; see also *Ottawa Electric Railway Co. v. Nepean Township* (1920), 605 S.C.R. 216 at QL5, 11-12; *Chastain v. British Columbia Hydro and Power Authority* (1972), 32 D.L.R. (3d) 443 (C.C.S.C.) McIntyre J. at p. 454-456; *Re City of Dartmouth* [1976], N.S.J. No.457, 17 N.S.R. (2d) 425, MacKegan C.J. at QL para 11). As the Federal Court of Appeal most recently expressed it, failure to observe the fair return standard would result in tolls that are not just and reasonable. In some cases, the courts confirmed that the fair return need not be modified out of deference to its impact upon customers.

Conclusion Accordingly, it can be seen that the legal framework governing the determination of a fair return is the "Comparable Return Standard". It does not mandate any particular approach to the determination of a fair return. The courts have recognized the regulators' expertise in this area as superior to their own. What pervades the courts' approach to the determination of a fair return, however, is the mutuality of interest as amongst utilities and their customers in tying the availability of a fair return to the long term viability of the utility in providing the essential monopoly services our society requires.

The latitude given boards to set rates includes the ability to rely on a formula. It is unlikely that any one formula can fit all rates. A decision by a board that distorts fair return by the application of a formula that achieves that result poses the obvious risk of being incorrect at law and subject to judicial revision on that ground, a result any board would seek to avoid.

2. Application

The place given to the Lamont decision In their decisions on ROE[5], Canadian gas utility regulators[6] have seldom made explicit reference to the Lamont decision (Lamont). There have been important exceptions. Thus, in its seminal first decision on TransCanada's rates, the National Energy Board (NEB) in 1971 stated that it had been guided by relevant jurisprudence, as well as by its understanding of the [NEB] Act and then cited the "fair return" portion of the Lamont decision[7], followed by other now familiar cases, Canadian and American. Then, some 30 years later, in dealing with an application for review and variance of its 1995 decision on Cost of Capital[8], the Board noted that the applicant had cited Lamont and it went on to summarize the key elements of that decision, stating that in considering the legal framework associated with the determination of a fair return, the Board had looked at both prior judicial and Board consideration of the issue[9]. That 2002 decision was the subject of an application for review and variance and, in addressing the fair return standard, the Board in 2003 examined its legal obligations and again cited Lamont along with other Canadian and American jurisprudence[10]. Finally, in dealing in 2005 with an application for new tolls, the Board summarized the evidence and provided its views on the legal framework for determining a fair return, giving attention to Lamont and other cases[11]. The Alberta Energy and Utilities Board[12] (EUB, Alberta Board) in its landmark July 2004 decision on the Generic Cost of Capital, as part of its consideration of the legislative and judicial framework, examined relevant decisions, Canadian and American, starting with Lamont[13].

Lamont is present, whether explicitly so or not Despite the scarcity of specific references, it is nevertheless reasonable to assume that, while acting in accordance with their respective legislative mandates, all Canadian regulators in making ROE awards to gas utilities have recognized the jurisprudence relating to fair return, and specifically the Lamont decision, whether they have said so or not. In addition to the Lamont test of "comparable investment" or opportunity cost of capital, drawing on American jurisprudence[14], regulators have concluded that, in order for a return to be fair, it must also meet the tests of "capital attraction" and "financial integrity"[15]. In this connection, the Régie de l'Énergie du Québec (Régie) has in several decisions accepted the view that the cost of capital must be evaluated on the basis of the fundamental principle of the market opportunity cost of capital and that the rate of return must allow the regulated entity to assure and maintain its capacity to attract funds under reasonable conditions[16]. In other cases, intervenors have drawn regulators' attention to the Lamont text[17]. In still others, the regulator has referred obliquely to the objectives of fairness and capital attraction[18].

The traditional approach to ROE determinations Prior to the mid-1990's, the practice of Canadian gas utilities was to make rate applications, often every one or two years[19], generally requiring re-determination of their ROEs as one component of the total revenue requirement that could be recovered in rates. In these proceedings, as the Ontario Energy Board (OEB) has noted, four main approaches were traditionally used by experts to establish a fair ROE. The Comparable Earnings Test (CE), Discounted Cash Flow (DCF) test, Capital Asset Pricing Model (CAPM) and Equity Risk Premium (ERP) test [20], are all used in varying degrees to formulate an opinion regarding a fair return to investors for the test year. Parties, the OEB observed, have generally relied on a combination of these models to establish a utility's ROE. In a combined approach, the OEB and experts before it have assigned different weights to the results of the various tests in order to give more significance to those models which they consider to be the most relevant[21].

Within the compass of what must be a relatively short paper, it is impossible to trace the outworking of this approach by each of the Canadian gas utility regulators. However, successive NEB Reasons for Decision respecting TransCanada PipeLines' rates illustrate how this approach was followed by one regulator over the quarter century to 1994.

That Board, like others, was careful from the start to point out that "The final conclusion as to what is enough but not too much in the way of return is not precisely supportable on a mathematical basis."[22] "Many tests and techniques for assisting the process of reaching a just decision have been used" the Board said "but no single test is conclusive, nor is any group of them definitive: whatever tests may be used, in the last analysis the adjudicating body can not escape the responsibility of exercising judgment as to what, in a stated set of circumstances, is a just and reasonable return or rate of return, or what is a range of justness and reasonableness of return or rate of return."[23] Such reference to the necessity of the exercise of judgment in making return awards is a recurring theme in Canadian regulatory decisions over the years.[24]

Diversity of tests applied in the traditional approach Reverting to the NEB's practice, in the early years of the Board's "active" regulation of TransCanada's tolls, comparable earnings appear to have been at the centre of its attention. Thus: "The Board concludes, based primarily on the comparable earnings analysis of Canadian industrials which are reasonable alternative investment opportunities for the applicant's shareholders, that a return of…is appropriate for the test year…"[25] In an oil pipeline rate case about this time, there was applicant evidence "…that statistics relating to US utilities and industrials deserve perhaps a greater weight in the assessment of the current cost of equity capital than similar Canadian statistics." The Board however disagreed and expressed the belief that "…far greater weight should have been given to Canadian data…Accordingly the Board was particularly interested in the statistics presented relating to Canadian industrials…"[26] and concluded "…that the cost of equity should be equal to or slightly less than the opportunity cost of investment in such companies."[27]

By 1978, the evidence put before the Board included CE and DCF tests, the latter to measure "capital attraction", but additionally the beginnings of the ERP approach appeared. The applicant, TransCanada, was cited to the effect that "…a reasonable ROE could also be inferred from an examination of the yield differentials maintained in the past between long term bonds and those of an equity nature in the regulated industry".[28]

However, in that particular case, the Board again stated that it paid particular consideration to "…the CE of Canadian industrials which it believes to be representative of reasonable alternative investment opportunities for the applicant's shareholders."[29]

Over time, the ERP becomes the focus By 1981, intervenor evidence was being filed before the NEB and it related to the DCF method while the applicant relied primarily on the CE test[30]. However, within a couple of years something of a pattern had been established that was to last until the mid-1990s with the applicant and one intervenor filing CE, DCF and ERP evidence while gas-producer intervenors were focussing their efforts on the DCF approach.[31] In assessing this spectrum of evidence, the NEB tended over time to place at first "slightly more" reliance on ERP, to find inherent distortions in the CE data that it received and to be concerned about the results of the DCF test. By the time of the last rate hearing prior to the generic cost of capital proceeding, the Board found that "…in the light of recent and prevailing financial market conditions, neither the DCF test nor the CE test currently yield reliable results…" Accordingly these tests were given little or no weight in the Board's decision" and instead the Board was of the view that "…the ERP was the primary measure of investors' required returns in the circumstances of this case." However, the Board was careful to state its view that these tests (CE, DCF) may prove useful under different economic conditions.[32]

This era during which Canadian regulators determined ROE awards by reviewing evidence from multiple tests and applying their own judgment was summarized for the British Columbia Utilities Commission (BCUC, the BC Commission) in evidence and referred to by the Commission in a 2006 decision[33] as follows:

> "The evidence is that up to the 1960s the principal methodology to determine fair rates of return was CE, as, according to Dr. Booth, the DCF method and the ERP method which was derived from the CAPM, were developed in the 1960s. By the 1980s all three methodologies were in use in Canada. In the early 1990s capital markets in Canada fell into considerable turmoil, causing DCF and CE to give unreliable results, which resulted
> in the ERP becoming the main, if not the sole, methodology used by regulatory bodies in Canada to establish fair rates of return…The DCF and CE methods have never managed to restore themselves to favour in regulatory bodies' eyes...In the United States the DCF and CAPM methods got their start in the 1970s and have survived nearly unchanged as the primary rate of return methods, with the DCF the virtual default method in practically all U.S. regulatory jurisdictions."[34]

Search for a generic approach to ROE The context for the search by Canadian regulators for a generic approach to ROE was characterized by: frequent rate applications; repetitive evidence, often provided by the same expert witnesses, on the three principal tests; growing disenchantment with the CE and DCF tests; and increasing reliance on the ERP approach. That search was led by the BC Commission which "…was the first regulatory agency in Canada to examine the applicability of a generic, formula-based approach to setting a natural gas or electric utility ROE as a means of improving the efficiency and effectiveness of the regulatory process."[35]

British Columbia In its June 1994 decision resulting from that search,[36] the BC Commission expressed the view that the DCF test was of little use in the present economic climate, that CE raised a circularity problem when it was based on utilities data and that primary reliance should be placed on risk premium tests, with CE and DCF as checks. The Commission's view was that generic hearings produce cost savings and better quality of evidence because a variety of experts are gathered at a single point in time. This view has been borne out by the subsequent experiences of, for example, the Alberta Board and the NEB.

National Energy Board When the NEB reported its generic return decision nine months later in March 1995, it found that CE was only useful as a check, that there were practical limitations on the DCF method and that most experts gave primary weight to the ERP, which the Board also did. Annual adjustments in the resulting ROE were to be in a ratio of 0.75 of the forecasted change in the yields of Government of Canada long-term bonds (long Canadas).[37] The NEB later referred to this as "the RH-2-94 formula".

Manitoba Two months after that, the Manitoba Board Public Utilities Board (Manitoba Board, MPUB) decided a gas distributor rate case, prior to which the applicant had proposed a mechanical formula to adjust the Board's then-currently allowed ROE. The Board approved a spread, effectively an ERP, between long Canadas and the ROE for the distributor and an adjustment factor of 0.80 of the change in the underlying long Canada bond yields.[38]

Ontario The OEB has since 1997 followed its own guidelines on a formula-based return on common equity for utilities under its regulation.[39] The initial setup involved establishing a just and reasonable return applicable to each of the Ontario local distribution companies. This base comprised a forecasted yield on long Canadas for the test year to which was added an appropriate premium. The primary methodological approach to be used in evaluating the appropriate risk premium was the ERP. The annual adjustment factor proposed was 0.75 of the difference between the forecasted long Canadas yield and the corresponding forecasted yield for the immediately preceding year. The OEB gave three reasons for adopting the formula approach to ROE. The first was regulatory efficiency, already mentioned. The second was the weight of experience of other Canadian jurisdictions which had reviewed the issue and adopted a formula-based ERP. The third was that it may provide a first step towards formulaic rate making such as incentive rates.[40]

Alberta Alberta was the fifth jurisdiction to adopt a generic approach, which was done by a decision of July 2, 2004. The award for 2004 was based on the CAPM estimate, which the Alberta Energy and Utilities Board (Alberta Board, EUB) found was supported by no less than seven other methods examined in evidence while the Board did not put any weight on four other methods, including DCF and CE.[41] In this connection it is worth noting that the Board took the position that the CE test is not equivalent to the (Lamont) comparable investment test. The Board observed that the CE test measures actual earnings on actual book value of comparable companies, however it does not measure the return "…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."[42] This conceptual concern was one of the reasons the Board gave to place no weight on the CE test. Nevertheless, the Board did consider that there may be other measures of comparable investments that should be considered in establishing an appropriate ROE. It went on to examine eight possible ones.[43] [44] As to the adjustment mechanism, the Alberta Board concluded that an adjustment to the generic ROE based on 0.75 of the change in forecasted long-Canada bond yield would be appropriate, beginning in 2005.[45]

Québec The Régie has since its decision D-99-11 of 10 February 1999 respecting a rates application by Gas Métropolitain, applied a *de facto* generic ROE based on the CAPM model with an annual adjustment equal to 0.75 of the forecasted change in the risk-free return.[46] This approach was reconsidered in 2007: the ERP was adjusted marginally upwards on the assessment that Gaz Métropolitan's risk had increased compared to that of the benchmark distribution utility. The adjustment mechanism was to be left unchanged through 2009. In the 2007 proceeding, the applicant introduced as an alternative to CAPM, for the first time in Canada, the Fama-French model, which is used in the financial industry, but so far used only once in the United States in the regulatory context and never before in Canada.[47] Even though the two models differ, the objective of both is to estimate the return an investor expects to earn on an investment in securities having a certain risk. The main difference between the two approaches is in the method used to express that risk which, the applicant contended, Fama-French does better than CAPM for utility-type businesses. The Régie however did not retain the Fama-French model for establishing the rate of return in this decision: the Régie considered that the application of that model to regulated enterprises has not been sufficiently examined to date to be used as a basis for fixing the rate of return of a distributor.[48]

The generic approach reviewed and reconfirmed Two of the regulators who pioneered the generic ROE with automatic adjustment mechanism (AAM)—the BC Commission[49] and the NEB[50]—subsequently reviewed their decisions of the mid-1990s. After again receiving and reviewing much expert testimony, in the NEB case on two separate occasions (2002, 2005), the established methodology was reconfirmed by both. Indeed, one considered that "It is clear the ERP methodology is the "gold standard" for Canadian regulators..." and stated that "…the Commission Panel will give primary weight to its application and results…"[51]

A new test rejected TransCanada recommended in the RH-4-2001 NEB proceeding that the Board adopt an After Tax Weighted Average Cost of Capital (ATWACC) methodology to establish a fair return for its mainline. This was a new methodology as far as the NEB was concerned and it rejected it, just as the Régie was in 2007 to reject the Fama-French test, and it reaffirmed the ERP.[52] [53]

Legal obligation to apply the FRS? In its consideration of the application for review of its 2002 decision (RH-R-1-2002), the NEB refuted the assertion of TransCanada that the Board "is required by law to apply the comparable investment, financial integrity and capital attraction standards to determine a fair return for the Mainline" as an overstatement of the law on this issue. The Board went on to note that in its decision which was under review (RH-1-2002), it had agreed that the three components of the FRS, along with the balancing of customer and investor interests should be attributes of a fair return. The Board further noted the statement it had made in RH-1-2002 that these principles are reflected in the various accepted methodologies to establish cost of equity capital, such as the ERP approach, which is the basis of the RH-2-94 Formula and that no one took issue with this statement. In the Board's view, it was implicit that the application of a test that reflects these standards would result in a return that meets these standards. Therefore, the Board did not have to state explicitly that the resulting return would meet the comparable investment, financial integrity and capital attraction standards. The Board stated that an express finding, such as was sought by TransCanada, which discharges the fundamental legal obligation of the regulator is not necessary when the standards that must be met are imbedded in the methodology used to determine the return. The Board also considered that there is no legal obligation to use an FRS, comprised of the comparable investment, financial integrity and capital attraction standards to determine tolls. Rather, in normal circumstances, a fair return established by the Board should meet those three elements. This, the Board stated, was accomplished through the methodology that was used to determine the return.[54] This issue was revisited in depth by the NEB in RH-2-2004, Phase II, which followed the decision of the FCA in TCPL v. NEB. The Board stated that it "…also agrees with TransCanada that the case law establishes that it is the overall return on capital to the company which ought to meet the comparable investment, financial integrity and capital attraction requirements of the fair return standard."[55] The Board went on to say that it is not required to meet the FRS by subscribing to any particular methodology or solely by examining evidence on overall return (TCPL had suggested neither). It concluded that it would ensure that each element going into the traditional methodology is "reasonable", then "…uses its judgment to ensure that the resulting return is a fair return in accordance with the legal requirements."[56] In summary, the NEB in RH-2-2004 Phase II accepted that the law requires application of the FRS, including the comparable investment, capital attraction and financial integrity standards, in determining the overall return, but does not stipulate any particular methodology for doing so.

Risk-free rate critiqued The applicant before the BC Commission in 2006 stated, in the words of the Decision, that "the theoretical CAPM assumes that the risk-free rate is uncorrelated with the return on the market. 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. Similarly, an ROE formula that is predicated on a close tracking between the allowed return and the risk-free rate assumes the risk-free rate and the return on the market are highly correlated. 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:

- the yield on long-term government bonds reflects the impact of monetary and fiscal policy;
- yields on long-term government bonds may reflect shifting degrees of investors' risk aversion; and
- long-term government bond yields are not risk-free; they are subject to interest rate risk."[57]

This critique of the risk-free rate and the relationship of market returns to that rate, although recorded by the Commission, was not responded to in the Commission's decision.

Convergence among Canadian gas utility regulators Recent years have seen a rapid and complete convergence among the five Canadian utility regulators who have major gas distribution and transmission entities under their jurisdictions. All now base their ROE awards essentially on judgments as to an appropriate base year ROE for a benchmark utility. In every case, this base year award uses a risk free rate plus an ERP with, in some cases, an allowance for flotation costs. Subsequent annual adjustments are made mechanically on the basis of 0.75 of the changes in the forecasted long Canadas yields.[58]

Insofar as incumbent utilities are affected, the generic ROE plus AAM is entrenched in Canadian regulatory practice—Canadian regulators have in the last dozen years affirmed and reaffirmed the generic ROE based essentially on the ERP methodology as the sole method of awarding and, through the associated AAM, varying the returns on equity for gas utility investors. This position has withstood several review applications and one appeal to the courts. In one important case, as a result of a negotiated settlement, it cannot be reopened before 2012.[59]

Contrast with American practice This Canadian situation stands in sharp contrast with that in the USA with which Canada shares the tradition of cost of service utility regulation where the fairness of return on investment is evaluated against the opportunity cost of capital.[60] There, only two commissions undertook what turned out to be lengthy, expensive and ultimately unsuccessful searches for a generic solution. There is a longstanding seeming disinterest on the part of the American regulatory community in pursuing this search. Instead, where rate cases are not settled, U.S. regulators continue to rely on the application of judgment to multiple test results[61] with DCF as the default mechanism[62].

3. Results from the mid-1990s

The number and duration of rate proceedings involving ROE evidence significantly reduced In the period 1971-1994 inclusive, the NEB in respect of only one company, TransCanada, averaged one rate proceeding every 18 months. It is likely that, with TransCanada having now settled its tolls for the period 1 January 2007 through 31 December 2011, the similar hearings in the period 1995-2011 will turn out to have averaged one per eight years. Similar regulatory efficiencies affecting a large number of utilities, electric as well as gas, are being found by the principal provincial jurisdictions.

In some jurisdictions, the way paved for long-term settlements of rate matters The NEB's experience again furnishes an example. The Board's decision on a generic rate of return <u>may</u> have been a factor enabling TransCanada[63] and Westcoast Energy[64] to achieve their first multi-year negotiated settlements of remaining toll and tariff matters. Note that one of the objectives of both settlements was "to maintain ("or improve", in the case of TransCanada) the financial integrity…" of the pipeline company.[65] [66]

Regarding the Alberta Board, on the one hand a month after bringing down its Generic Cost of Capital decision in July 2004 approved NOVA Gas Transmission Ltd's (NGTL) application to commence negotiated settlement discussions. These eventuated in a settlement of all revenue requirement issues, return on equity being treated as a flow-through item, for the three-year maximum period allowed by the Board, commencing 1 January 2005.[67] On the other hand, prior to the implementation of the ROE formula, Northwestern Utilities and ATCO Electric both negotiated settlements. Since the introduction of the formula there have been no long term settlements other than NGTL.

The BC Commission has approved a Settlement Agreement for Terasen Gas for 2004-2007, incorporating a Performance-Based Rate Plan,[68] and subsequently approved its extension for 2008-2009.[69]

As to pipelines under the NEB's jurisdiction, two points are notable. First, settlements of toll issues have been the norm for oil pipelines since the mid-1990's. Second, all new oil and gas pipelines have applied for tolls, based on settlements, where the ROE exceeds that generated by the Board's generic formula, often by a generous amount.

Transmission utilities' incentive agreements have provided for efficiency gains and sharing of those gains between customers and utility owners Annual or biennial adversarial proceedings relating to ROE are for transmission businesses now a thing of the past. This <u>may</u> have encouraged and enabled parties to settlement negotiations to build-in to the resulting agreements features that encourage these pipelines to search for efficiencies with the prospect of retaining for the investor a share of those efficiencies. All of the negotiated settlements mentioned in the previous paragraph incorporate such features in one form or another. In a degree, these shared savings mechanisms have cushioned the impact of declining ROEs resulting from the application of the generic ROE decisions in an environment of declining bond yields. For example, in the letter to shareholders accompanying TransCanada's 1996 Annual Report, the management commented that there had been a one per cent decline in the rate of return on common equity allowed by the NEB in 1996. The letter went on to say "That one per cent represented a reduction in 1995 earnings of about $21 million that had to be made up. A substantial part of it came from discretionary revenue earned under an incentive agreement reached late in 1995 between TransCanada and its customers. Incentive regulation allows TransCanada to share in discretionary revenues and cost savings."[70] This cushioning effect may be available to some pipelines on a continuing basis, but in a regulatory context its results must not be seen as an element of a fair return. Fair return relates to the opportunity cost of capital. Earnings from incentive agreements are rewards for extraordinary cost-savings and for entrepreneurship in devising service offerings that create value for which shippers are willing to pay. As the Federal Court of Appeal reminded in the 2004 TransCanada decision,[71] the fair return must be determined independently of its impact upon resulting customer rates.

But Canadian and U.S. regulators' ROE practices are now widely divergent after decades of essentially parallel approaches Canadians have converged on the generic approach using essentially anticipated risk-free rates plus ERP and adjusting by a ratio to anticipated changes in risk-free rates. In the U.S., the federal and one state commission attempted to regularize the ROE component of rate cases, but failed to do so. One commentator has stated that "Efforts to make the process objective and mechanical are futile as an administrative and practical matter."[72] Instead, where cases are litigated, commissions continue to refer to the legal standards set by the landmark U.S. Supreme Court decisions in Bluefield and Hope. The regulators receive and access data from quantitative financial models and apply informed judgment in order, as the California Pubic Utilities Commission (CPUC, California Commission) has put it, to arrive at "An ROE set at a level commensurate with market returns on investments having comparable risks, and adequate to enable a utility to attract investors to finance the replacement and expansion of a utility's facilities to fulfill its public utility obligations."[73] Moreover, U.S. regulators: have continued to accept evidence that depends in large part on data about other U.S. gas and electric companies' returns; have had at least some regard to short term bond rates; and in some cases have stated a consistent practice to moderate changes in the ROE relative to changes in interest rates in order to increase the stability of ROE over time.[74]

And Canadian gas utility ROEs have fallen significantly below those of American ones and below those of low risk North American industrials Historically, the ROEs of Canadian gas local distribution companies (LDCs) have approximately matched those in the U.S. industry. Since the inception of the generic ROE approach by Canadian regulators, the returns enjoyed by Canadians have fallen increasingly and significantly (up to 150 bp) below those of these comparables. This result arises despite the fact that independent analysis shows that business risks faced by LDCs in Canada do not significantly differ from those in the U.S.; that the greatest risk-determinant for utilities, regulatory risk, is comparable in Canada and the U.S.; and that tax differences do not matter to the comparison of Canadian and U.S.[75] [76]

ROEs for greenfield interprovincial and international pipelines In the "generic ROE era" it has become the practice for new pipelines subject to NEB jurisdiction to apply for tolls that have been the subject of prior negotiation with shippers. Typically, these tolls reflect ROEs about 300 or more basis points higher than incumbent pipelines, such as Foothills, TCPL, TQM and Westcoast, receive under the generic ROE.[77] Two points arise. First, this practice suggests that the NEB's generic ROE is insufficient to attract capital needed for greenfield projects. Second, one wonders whether this *de facto* vintaging of ROEs in the Canadian interprovincial and international pipeline sector breaches a fundamental principle of fairness.

4. Implications

On the one hand, the generic ROE has created regulatory economies and encouraged the search for other efficiencies in the sector The frequency of adversarial proceedings leading to ROE awards has been greatly reduced with consequent public and private savings. The generic ROE may have encouraged negotiated settlements of remaining rate issues, which typically incorporate elements of incentive rate-making encouraging efficiencies in investment and operations. Some utilities may have been able in this way to partially compensate for the low ROEs resulting from the application of the generic formula. However where that may have happened, it has been at the expense of greater risks by the utilities. Even with the presence of incentive features, there is no assurance that settlements will result in a “fair return” being earned each year of the settlement and over its lifetime, which could be as much as five years. The scope to achieve efficiencies while ensuring high quality of service may be exhausted and the overall return may fail to meet the fairness standard.

On the other hand, the generic ROE approach is mechanistic and necessarily suspends the further application of regulatory judgment for extended periods, marking a sharp break with past practice

- It was not uncommon in the past for regulators to expressly reject mechanistic approaches to ROE awards and stress the importance of judgment.[78] The initial generic decisions and any subsequent reviews, like the annual or biennial rate cases that preceded them, were based on careful assessment of much evidence and the application of informed regulatory judgments.

- However, once decisions are taken on a generic process, including the now universal AAM, the further application of judgment as to whether the FRS is being attained is suspended.[79] In principle, as the Alberta Board has observed, parties are free at any time to petition the regulator to consider a review of the adjustment formula in which, in Alberta, the petitioning party would bear the onus of demonstrating a material change in facts or circumstances from the evidence filed in its generic proceeding to merit a review of the formula.[80] In practice, the party’s freedom to petition can be circumscribed for periods as long as five years as a result, for example, of a settlement agreement, a term which can therefore cover one or more economic cycles.

It would appear from work done prior to [81] and parallel with [82] this review that the FRS may not have been achieved on an ex-post basis This important conclusion is suggested by the comparison of Canadian gas LDCs’ ROEs and the ROEs of U.S. gas utilities and North American low risk industrials, already referred to. It seems reasonable as an aspect of the industry oversight expected of regulators that, especially after a change as fundamental as the generic ROE, they would assess that change in terms of whether the results required *ex ante* by the FRS have in fact been achieved *ex post*, with particular regard to the opportunity cost of capital. Such an examination by regulators is particularly warranted because the generic ROE plus AAM effectively prevents regulated entities from routinely presenting evidence and argument as to whether *ex post* the resulting ROEs have indeed reflected opportunity pricing of the cost of capital and achieved other objectives of the FRS which the generic regime is intended prospectively to do.[83]

Two fundamental features driving ROE changes and arguably driving the "wedge" between Canadian LDC returns and others, namely the risk free rate and the AAM ratio appear to deserve critical examination

- On the first point, as noted in Section 2 above, while one applicant has critiqued the risk-free rate, the regulator involved (the BC Commission), although summarizing the applicant's concerns, did not respond to them. It is not difficult, for instance by reading the Bank of Canada's periodic comments on factors influencing rates to find reasons to question why LDC ROE's should be directly linked to bond rates.[84]

- On the second point, the AAM ratio of 0.75 (and the 0.80 chosen initially by one regulator) had some empirical support in the proceedings leading to the respective initial generic decisions. Also it received principled support by the applicants in a number of proceedings. However it appears not subsequently to have been critically evaluated in terms of the behaviours of equity returns of comparable unregulated sectors in relation to changing bond yields in the dozen years since the earliest Canadian generic ROE decisions.

- Regarding U.S. LDC returns, the work of Concentric Energy Advisers for the OEB has shown a much lower coefficient of regression (0.46) between U.S. ROEs and long bonds compared to Ontario ROEs (0.86): in other words, that is for every one percentage point change in interest rates, the Ontario ROEs change by 86 basis points while U.S. ROEs change by 46 basis points.[85]

The generic, mechanistic ROE including the AAM may require some reconsideration, if the FRS is to be achieved on a going forward basis

The work carried out by Concentric for the OEB and by National Economic Research Associates (NERA) for the CGA identifies concerns that sow a doubt as to the ability of the present design of the generic ROE to continuously meet the fair return standard. It is indisputable that this bold and widely-welcomed initiative of Canadian regulators has entrained and encouraged valuable public and private efficiencies. However, in exchange, the generic ROE has reduced the opportunities, present in previous practice, to periodically exercise oversight of this critical element in the revenue requirement, review the results of a variety of tests, apply informed judgments to them, and recalibrate their ROE awards in conformity with their understanding of the FRS. Even though regulators are willing to entertain applications for review of the generic approach, it remains that there are necessarily fewer examinations of the relevant data to ensure the generic formula plus the AAM continues to produce end results which meet the FRS.

Examination of the results of the generic approach, ex-post, suggests that, in an environment where interest rates have been, first, falling and then stabilizing at low levels, the generic ROE plus an AAM that tracks changes in expected bond yields in a ratio of 0.75 may have pulled ROEs down excessively in relation to the FRS and that, in the judgement of Concentric, "This may require consideration of additional qualitative and financial metrics in making the ROE determination."[86] In other words, what was found to be "fair and reasonable" or "just and reasonable" by careful examination of multiple tests and the appropriate exercise of informed judgment, may no longer be so after successive adjustments by admittedly-simple AAMs taking place in continuously changing economic and business conditions.

The remarkable convergence among Canadian gas utility regulators may be an obstacle to reappraisal of the ERP plus AAM approach to the generic ROE

The NEB in dealing with TransCanada's Fair Return Application dated 6 June 2001, centred on a novel After Tax Weighted Average Cost of Capital (ATWACC) approach, stated: "In summary, in the Board's view, the lack of regulatory precedent is not a barrier to the adoption of a new approach to regulation. However, in the absence of such precedent and in the absence of any support from stakeholders for the proposed change (meaning to the ATWACC approach—authors), the Board's analysis of the proposal should show a clear benefit to be derived from the new approach when compared with previous acceptable approaches."[87] As already noted, the Régie in 2007 was similarly faced with a novel approach proposed by Gaz Métroplitan, the Fama-French model which, according to the evidence, had never before been used in Canada and only once in the USA. The Régie decided not to retain Fama-French as a method of fixing the ROE because it had not been sufficiently examined to date to be used as a basis for fixing the rate of return of a distributor.[88]

In view of the foregoing, it is reasonable to pose the questions "Is there likely to be regulatory precedent and stakeholder support for initiatives by the gas utility industry for review of and change in the generic ROE?"

As to "regulatory precedent", it may not be easy for any Canadian regulator to "break ranks" with the rest, particularly after several have relatively recently reviewed their generic ROE practices and decided against major changes to them. Having taken place, regulatory convergence may be a powerful disincentive even for needed changes.

As to "stakeholder support", it appears that Canadian gas utility stakeholders are continuing in their virtually unanimous support of the respective regulators' established approaches. In the environment of generally-declining bond yields, the present design of the generic ROE has worked to the short-term economic advantage of industrial users, residential consumers, producers and shippers. This has generated an attitude, common in the regulatory world, of "what we have we hold". As long as the provision of safe and adequate service does not seem to be immediately at risk, this attitude is likely to continue. Broad stakeholder support for major revisions favourable to the utilities seems unlikely to materialize so long as utilities seem able to attract capital and avoid impairing their financial integrity. It appears doubtful, however, that the FRS is satisfied by these considerations alone if the end result is unfair relative to returns available from investments in companies of similar risk.

Desirable next steps It would be helpful if, at the same time as specific cases occasionally come before individual regulators,[89] some further studies of general application were to be carried out. It is not the purpose of this paper to propose an alternative framework for ROE determination. However, any reconsideration should clearly take place against the background of an *ex post* examination of the results of the generic approach in terms of the comparability of the resulting returns with non-utility and utility comparators. It must include the fundamentals of the present design, namely the choice of the risk-free rate, the appropriate measurement of the risk premium and the adjustment mechanism. And it cannot exclude consideration of the place of the DCF model, given its acceptability to a majority of North American regulators. Finally, in an era of North American economic and business integration, the question must be asked "Can Canadian gas utilities successfully compete for capital if their regulators continue to award lower returns on generally thinner equity shares than those enjoyed by the American industry?"

Absent such a reconsideration and consequent adjustment, in an environment of continuing very low interest rates and bond yields, the present generic ROE formula alone may not be protecting the public interest in the provision by incumbent utilities of a robust, flexible natural gas delivery structure financially strong to support future sustainability of our energy economy.

ENDNOTES

[1] The jurisdiction is Alberta. The test is the traditional comparable earnings one. See under heading 2 “Application”, subheading “Alberta” on page 16.
[2] The word “stakeholder” has become an undefined term of art, particularly in NEB decisions on applications reflecting negotiated settlements, where it may be used as a synonym for parties to those settlements. In this paper, by “stakeholders” are meant parties, other than utility managements and shareholders, who have an economic interest in gas utility rates or tolls and who routinely take part in related regulatory proceedings and in settlement discussions. In this definition, depending on the nature of the utility, “stakeholder” can mean gas producer; shipper; exporter; industrial, commercial or residential consumer; or provincial government.
[3] An example may be the application to the NEB by Gazoduc TransQuébec & Maritimes (TQM) for Cost of Capital for 2007 and 2008, revised filing December 18, 2007, the first such application by that company since 1994. However, because of the complexity of the issues involved in this application and because of language considerations, a longer than normal hearing process is required. The hearing is presently scheduled to commence 23 September 2008, which means that a decision on this hearing would not be released until early 2009. See National Energy Board letter to TQM of 22 January 2008, file OF-Tolls-Group1-T201-2007-03 01.
[4] *Return on Equity: Allowed Returns for Canadian Gas Utilities*. A Discussion Paper Developed by the Canadian Gas Association. Summer 2007. 20 pages in bilingual format.
[5] The Lamont decision relates to “…a fair return…on the capital invested in its enterprise…” (S.C.R., 1929, page 193). However, the costs of debt and any preferred shares, assuming they are prudently incurred, are usually taken as a cost to be flowed directly through to rates via the cost of service. The ROE is therefore the salient variable in the fair return on the (total) capital invested in the enterprise. The discussion in this paper relates entirely to regulators’ awards for the return on the owners’ equity investment. It does not extend to consideration of what those awards mean in terms of return on the total capital invested by the utility in question even though, and the authors acknowledge this, the entire focus of the Lamont decision is on return on the total capital.
[6] By “Canadian gas utility regulators” is meant the relevant regulatory boards and commissions of Alberta, British Columbia, Canada, Manitoba, Ontario and Quebec.
[7] National Energy Board (NEB). Reasons for Decision (RfD). In the Matter of the Application under Part IV of the National Energy Board Act of Trans-Canada Pipelines Limited, RH-1-70, December 1971, pages 6 – 6 to 6 – 9.
[8] NEB, RfD, TransCanada et al. Cost of Capital. RH-2-94, March 1995.
[9] NEB, RfD, TransCanada PipeLines Limited. Cost of Capital (Fair Return Application of 6 June 2001). RH-4-2001, June 2002, pages 8-12.
[10] NEB, RfD, TransCanada PipeLines Limited. Review of RH-4-2001 Cost of Capital Decision. RH-R-1-2002, February 2003, Chapter 3: Fair Return Standard, pages 6-12.
[11] NEB, RfD, TransCanada PipeLines Limited. Cost of Capital. RH-2-2004 Phase II, April 2005, Chapter 2 Legal Framework for Determining a Fair Return, pages 8-20. In this context, the NEB noted the finding of the Federal Court of Appeal in TransCanada’s unsuccessful appeal of the Board’s 2002 decision. The Court, the Board stated, found that the impact of any resulting toll increases on customers is not a relevant consideration in the determination of the required rate of return on equity.
[12] Since January 1, 2008 the economic regulatory functions of the former EUB in respect of investor-owned and certain municipally-owned utilities are being exercised by the Alberta Utilities Commission (AUC).
[13] Energy and Utilities Board (EUB), Decision 2004-052, Generic Cost of Capital, July 2, 2004, Section 3.2 Relevant Judicial Decisions, pages 12-13.
[14] The principal American Supreme Court decisions are *Bluefield Water Works & Improvement Company vs. Public Service Commission of The State of West Virginia et al 262 U.S. 679 [1923]* (Bluefield) and *Federal Power Commission et al vs. Hope Natural Gas Co., 320 U.S.591* [1944] (Hope). They are cited by the NEB in RH-1-70 (op.cit.) at 6 – 8 and 6 – 9, RH-4-2001 (op.cit.) at page 8 and RH-2-2004 (op.cit.) at pages 14-16.

[15] This is borne out by the Alberta Board in EUB Decision 2004-052 (op.cit.) where after quoting from Northwestern, Hope and Bluefield, it stated at page 13 that "The Board notes that no party took issue with the general consensus that in order for a return to be fair, it must meet the tests of "comparable investment", "capital attraction" and "financial integrity" described in the above decisions.

[16] « La Régie accepte…que l'évaluation du coût des capitaux propres sur base présumée doit reposer sur le principe fondamental du coût d'opportunité de marché des capitaux propres…La Régie est d'avis que le taux de rendement accordé au Distributeur doit lui permettre d'assurer et de maintenir sa capacité d'attirer les fonds à des conditions raisonnables » Source : Régie de l'Énergie du Québec. Hydro-Québec. D-2003-93. 2 mars 2003, à la page 70. The same principles had earlier been expressed in Régie de l'Énergie du Québec. Hydro-Québec. D-2002-95. 30 avril 2002, à la page 163. These were admittedly electric utility cases, however since the Régie uses essentially the same methodology to determine its ROE awards for Québec gas utilities, it is reasonable to suppose that it does so in pursuit of the same principles of opportunity cost of capital and capital attraction as it applies to the electrical sector.

[17] Manitoba Public Utilities Board Act. Centra Gas Manitoba Inc. General Rate Application. Order No. 99/07, July 27, 2007, page 65.

[18] Ontario Energy Board (OEB) Compendium to Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities (OEB Compendium). Chapter 2: Current OEB Approach, page 2, which reads in part "The Board's objective in setting the rate of return on rate base is to ensure that the utility is provided with a fair return which enables it to meet its obligations and maintain its capability of attracting capital".

[19] By way of example, TransCanada PipeLines averaged one such application to the NEB per 18 months in the period 1971-1994 inclusive.

[20] The NEB in RH-4-2001 (op.cit.) at page ix (Glossary of Terms) characterizes the ERP method as a family of models that includes CAPM and ECAPM (Empirical Capital Assets Pricing Model). See also RH-4-2001 page 48, second paragraph.

[21] OEB, op.cit.

[22] NEB, RH-1-70 op cit, page 6 – 6.

[23] NEB, op cit, pages 6 – 2 and 6 – 3.

[24] The application of informed judgement is similarly a constant in American regulators' decisions in utility rate cases. Consider the following from the California Commission's December 15, 2005 Decision 05-12-043 on the Test Year 2006 Return on Equity for the Major Utilities (Pacific Gas and Electric [PG&E], Southern California Edison [SCE] and San Diego Gas and Electric [SDG&E]). At page 23, the Commission stated "In the final analysis, it is the application of informed judgment, not the precision of financial models, which is the key to selecting a specific ROE estimate. We affirmed this view in D.89-10-031, which established ROEs for GTE California, Inc. and Pacific Bell, noting that we continue to view the financial models with considerable skepticism." The Commission then uses the term "informed judgment" eight times in respect of its own decision-taking. As a matter of interest the resulting ROE awards for 2006 were, for PG&E 11.35%; for SCE 11.60%; and for SDG&E 10.70%.

[25] NEB, RfD, TransCanada PipeLines Limited, RH-3-76, December 1976 page 4 – 13.

[26] NEB, RfD, Interprovincial Pipeline Limited, RH-2-76, December 1977, page 6 – 23.

[27] NEB, RH-2-76, op cit, page 6 – 26.

[28] NEB, RfD, TransCanada PipeLines Limited, RH-1-78, July 1978, page 5 – 9.

[29] Ibid.

[30] NEB, RfD, TransCanada PipeLines Limited, RH-4-81, Phase I, August 1981, pages 4 – 5 and 4 – 6.

[31] NEB, RfD, TransCanada PipeLines Limited, RH-3-1982, July 1982, pages 3 – 10 to 3 – 12.

[32] NEB, RfD, TransCanada PipeLines Limited RH-4-93, June 1994, page 27.

[33] BC Utilities Commission, Decision in the matter of Terasen et al, March 2, 2006, page 45.

[34] This statement is from an article by Dr. Jeff D. Makholm in Public Utilities Fortnightly, May 15, 2003, pages 12-18, "In Defense of the 'Gold Standard'". The fuller context is as follows: "The fair rate of return became a hotly contested issue in the early 1970s…The DCF and CAPM methods got their start at this time and have survived nearly unchanged as the primary rate of return methods, with the DCF the virtual default method in practically all U.S. regulatory jurisdictions." (Makholm, page 14, column 1).

[35] OEB, op cit, page 8.

[36] BC Utilities Commission, Decision in the matter of Return on Common Equity, BC Gas Utility et al, June 10, 1994, see especially pages 17-18.

[37] NEB, RfD, RH-2-94, TransCanada et al, Cost of Capital, March 1995.
[38] Manitoba Public Utilities Board Act, Order No.49/95, May 5, 1995 in an application by Centra Gas Manitoba Inc. The Manitoba Board in that decision reserved the right to require a full ROE hearing prior to the 1997 test year as a result of unusual or significant changes in the economy. However such a hearing did not take place. Centra Gas Manitoba was acquired by Manitoba Hydro, a provincial crown corporation, in 1999 and the ROE was subsequently replaced by a provision for a net income as part of Centra's costs, the allowed net income would not exceed the allowed return on equity under the Rate Base/Rate of Return methodology—see Manitoba Public Utilities Board Act, Order No. 103/05, July 12, 2005 in an Application by Centra Gas Manitoba Inc, page 40.
[39] OEB, Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities, March 1997 (not page numbered).
[40] OEB, Compendium, op cit, page 24, Section 5.1 Rationale for Draft Guidelines, Rationale for Adopting Formula ROE.
[41] EUB, Decision 2004-052, op cit, pages 15-31, Section 4.2 ROE Methodology and 2004 ROE.
[42] EUB, op cit, page 23.
[43] EUB, op.cit, Section 4.2.7 Other Measures of Comparable Investment, pages 24-30.
[44] The CE test was not the only one with which the EUB had difficulties. Thus, it is noted that the Alberta Board in Decision 2004-052, concluded "…that the results of the ERP tests other than CAPM would generally support a 2004 ROE above the Board's CAPM estimate, but that for the reasons set out above only limited weight should be placed on the results of the ERP tests other than CAPM." EUB op.cit. page 23.
[45] EUB, op cit, pages 31-32, Section 4.3 Annual Adjustment Mechanism.
[46] The Régie had previously applied the ERP approach but without an automatic adjustment feature, see for example Régie du Gaz Naturel, Décision D-96-31, 9 octobre 1996, Gaz Métropolitain, pages 69-70, La prime de risque du marché.
[47] Régie de l'énergie, Décision D-2007-116, Gaz Métropolitan, page 23.
[48] Ibid, pages 23-24.
[49] BC Utilities Commission, Decision in the matter of Terasen et al, March 2, 2006, op cit.
[50] NEB RfDs in TransCanada PipeLines Limited: Cost of Capital. RH-4-2001, June 2002; RH-R-1-2002, Review of RH-4-2001 February 2003; Cost of Capital. RH-2-2004 Phase II, April 2005. The RH-R-1-2002 decision was unsuccessfully appealed to the Federal Court of Appeal by TransCanada PipeLines (2004 FCA 149).
[51] BC Utilities Commission, op cit, page 52. Note that, while intending to give primary weight to the application and results of the ERP method, the Commission stated that it would need to apply judgment to the evidence before it.
[52] NEB RfD, TransCanada PipeLines Limited, RH-4-2001, pages 45-56.
[53] It may be noted that the EUB in Decision E99099, 1999/2000 Electric Tariff Applications, 25 November 1999 decided to "use both the traditional method and a modified ATWACC as tools to arrive at the fair return for (a number of electric utilities) with primary weight placed on the traditional method." (see page 328). The ATWACC evidence, which was accepted by the EUB with some modifications to its results, was submitted by the same witness (Dr.Vilbert) whose methodology and results were rejected by the NEB in RH-4-2001.
[54] NEB RfD, RH-R-1-2002, op cit, pages 11-12 Legal Obligation to use the FRS.
[55] NEB RfD, RH-2-2004, op.cit., page 19.
[56] Ibid.
[57] BCUC, Decision in Terasen et al, March 2, 2006, page 46.
[58] The degree of convergence as reflected in the annual ROE awards is remarkable. Thus, for year 2008 the range of ROEs is only about 50 basis points (bp) with La Régie at 8.91% (Gaz Métro) and the OEB at 8.39% and the EUB, NEB and the BCUC in the middle of the range with 8.75%, 8.71% and 8.62% respectively. Contrast this with the spread of 65 bp in the awards by one American regulator to three utilities for one year (footnote 25).
[59] The case is TransCanada's Canadian mainline. The negotiated settlement of March 2007 relates to the period 2007-2011 inclusive and provides that, during the Term, TransCanada will not pursue litigation of the NEB RH-2-94 ROE formula on behalf of… its Mainline System—see TransCanada PipeLines,

Application to the NEB, March 14, 2007: Application for Approval of a Negotiated Mainline Tolls Settlement and 2007 Mainline Tolls. Page 5 of 13, item 19. This Negotiated Settlement was approved by the NEB on 31 May 2007 by Order TG-06-2007.

[60] American regulators routinely cite their legal standard for fair return, essentially the Bluefield and Hope cases which are sometimes referred to also by Canadian regulators (examples: Alberta Board, NEB, see pages 11-12 above). The California Commission does so in the following terms in case D-05-12-043 (Test Year 2006 Return on Equity for the Major Energy Utilities) “The legal standard for setting the fair rate of return has been established by the United States Supreme Court in the Bluefield and Hope cases. The Bluefield decision states that a public utility is entitled to earn a return upon the value of its property employed for the convenience of the public and sets forth parameters to assess a reasonable return. Such return should be 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 attended by corresponding risks and uncertainties. That return should also be reasonably sufficient to assure confidence in the financial soundness of the utility, and adequate, under efficient management, to maintain and support its credit and to enable it to raise the money necessary for the proper discharge of its public duties. The Hope decision reinforces the Bluefield decision and emphasizes that such returns should be sufficient to cover operating expenses and capital costs of the business. The capital cost of business includes debt service and stock dividends. The return should also be commensurate with returns available on alternative investments of comparable risks.

[61] A sampling of relatively recent cases finds that the California Commission received and used DCF, CAPM and MRP evidence in case D-05-12-043 (see footnote 24), the Illinois Commerce Commission accepted DCF and CAPM evidence in a September 2005, once-in-a-decade decision on Northern Illinois Gas Company’s rates; the New York Public Service Commission (NYPSC) received CAPM, CE, DCF and ERP evidence, found CE and ERP not to be particularly useful, and gave a 50/50 weighting to CAPM and DCF in a 2007 National Fuel Gas rate case (Case 07-G-0141).

[62] See above, text page 15 and footnote 34.

[63] NEB, Letter Decision, RH-2-95, December 1995. The TransCanada settlement covered the period 1 January 1996 through 31 December 1999.

[64] NEB, RfD, Westcoast Energy Inc., RH-2-97, Part II, August 1997. The Westcoast settlement covered the period 1 January 1997 through December 31, 2001.

[65] NEB, Compilation of Key Documents Related to the Board’s RH-2-95 Decisions, TransCanada, June 1996, page 19, sub Article 1, item 1.2, v).

[66] NEB, RH-2-97, op cit, page 1, sub Article 1, item 1.2, (f).

[67] EUB, Decision 2005-057, NOVA Gas Transmission Ltd., 2005-2007 Revenue Requirement Settlement, July 7, 2005, see page 2 thereof.

[68] BCUC Order G-51-03 of 29 July 2003 for the initial term.

[69] BCUC Order G-33-07 of 23 March 2007 for the extension.

[70] “TransCanada PipeLines. Annual Report, 1996. Letter to Shareholders, page 4, final paragraph.

[71] Supra, page 9.

[72] Makholm, Jeff D., op cit, page 18, column 1.

[73] CPUC, D-05-12-043 on Test Year 2006 Return on Equity for the major energy utilities, Findings of Fact, paragraph 16.

[74] It is acknowledged that the Canadian “0.75 ratio” to forecasted changes in long Canadas has this effect.

[75] National Economic Research Associates (NERA). Allowed Return on (Gas Utility) Equity in Canada and the United States: An Economic, Financial and Institutional Analysis. Ken Gordon, Jeff Makholm, Wayne Olsen, November 2007. Tax differences are dealt with on page 13, business risk on pages 24-25 and regulatory risk on pages 25-32.

[76] Concentric Energy Advisors concluded for the OEB that “(6) On the whole, there are no evident fundamental differences in the business and operating risks facing Ontario utilities as compared to those facing U.S. companies or other provinces’ utilities that would explain the difference in ROEs.” See Concentric op. cit., Section VII Conclusions and Summary of Findings, paragraph (6) on page 57.

[77] *Alliance Pipeline Ltd* (Alliance) filed on 31 October 2007 its normal annual toll revisions to become effective 1 January 2008 The NEB filing ID is A16816. Alliance noted that the filed-for tolls reflect a base return on equity of 12%, subject to an incentive adjustment, on a deemed capital structure that provides for 30% equity. These are the same numbers as appeared in Alliance’s original certificate application to the

NEB which was approved in November 1998 in GH-3-97. At the time of writing, Alliance's 2008 tolls are still interim.
Emera Brunswick Pipeline Company Ltd. reached a negotiated agreement for a monthly fixed toll that would cover all fixed charges including an equity return typically in the 11 to 14 percent range. NEB RfD Emera Brunswick Pipeline Company Ltd., GH-1-2006, May 2007, Section 7.1 Tolls and Tariffs, page 76
Mackenzie Valley Gas Pipeline, Section 3.1 of the August 2004 application in GH-1-2004 which is still under consideration presents toll principles that include a deemed capital structure based on 30% equity and an ROE equal to the NEB multi-pipeline ROE plus 2.21% for the initial 10 years, see page 3-4
Maritimes and Northeast Pipeline filed on 28 December 2007 a negotiated toll settlement for the calendar year 2008 which embodies an allowed ROE of 11.66 per cent on a deemed equity of 31.18%. NEB filing ID A17299.

[78] The seminal NEB decision in TransCanada's first rate application, RH-1-70 of December 1971 contains some important language relating to both points.
First, as to mechanistic approaches, the Board stated at page 6 – 6 "The final conclusion as to what is enough but not too much in the way of return, and rate of return, is not precisely supportable on a mathematical basis. If it were, one computer and a few programmers could replace all the regulatory boards in North America and dispense undeniable justice instantaneously."
Second, as to the exercise of judgment, the Board said at pages 6 – 2 and 6 – 3 that "Many tests and techniques for assisting the process of reaching a just decision have been used, but no single test is conclusive nor is any group of them definitive: whatever tests may be used, in the last analysis the adjudicating body can not escape the responsibility of exercising judgment as to what, in a stated set of circumstances, is a just and reasonable return or rate of return, or what is a range of justness and reasonableness of return or rate of return." These early comments by the NEB in a sense echo the view expressed by the SCC in Lamont where, in 1929 S.C.R., at page 199, the Court stated "The question of a fair rate of return on a risky investment is largely a matter of opinion, and is hardly capable of being reduced to certainty by evidence, and appears to be on one of the things entrusted by the statute to the judgment of the Board."

[79] Note that, in applying its automatic mechanism to adjust the rate of return on common equity, the BCUC initially advised the affected companies that it had "…reviewed the performance of the automatic mechanism to adjust the rate of return…and has determined that the mechanism has performed favourably." (Letters L-61-96, December 2, 1996; L-73-97 of December 2, 1997; L-89-98 of December 4, 1998). After 1998, however, the references to review and to favourable performance were dropped and the annual notification letters now simply state that "…the Commission has determined that the current ROE automatic adjustment mechanism results in an allowed return of…" (example: Letter L-93-07 of November 22, 2007). Essentially the same approach is followed by the EUB (Example: Order U2007-347 of 30 November 2007) and NEB (Example: Letter of 29 November 2007, File OF-TollsGen-RRCE 02).

[80] EUB Decision 2004-052, July 2, 2004, page 34.

[81] CGA op cit, Section 3: Maintaining a Fair Return, pages 14-17.

[82] NERA, op cit, particularly pages 7 – 11.

[83] Note that the EUB, in giving its reasons for establishing a standardized approach for setting an ROE, stated "An applicant is also free to apply to the Board to review the ROE formula in the manner provided for in this Decision. Even without an application by a particular party, the ROE formula will be subject to review in certain circumstances and in any event will be considered for review after five years." See EUB, Decision 2004-052, op.cit., page 8.

[84] A scan of Bank of Canada published comments for the past few years points to the following as rate-affecting monetary policy factors: economic growth; utilization of economic capacity; demand on the economy, domestic and export; inflation rates and inflation risks; U.S. economy and major sectors; global economy and major components EU, Japan, China; global markets, including commodity markets (e.g. energy), and their balances; Canada/USA exchange rates and the influence on the Canadian economy; cost of credit to firms and households; state of financial markets, Canada and abroad. These notes are based mainly on reading the Bank of Canada's semi-annual Monetary Report and Update available online at http://www.bank-banque-canada.ca/en/mpr/mpr_previous.html.

[85] Concentric Energy Advisors. A Comparative Analysis of Return on Equity of Natural Gas Utilities. Prepared for the OEB. June 14, 2007, pages 18-19. Concentric correctly point out that, "…as interest rates

have declined dramatically in Canada in the past ten years, one would expect the OEB formula to yield accordingly lower authorized ROEs. The formula, however, is symmetrical, and ROEs will most likely recover at a faster rate in Ontario than in the U.S., when interest rates begin to rise. In fact, if interest rates continue to steadily rise, the OEB adjustment formula could surpass and yield higher results than historical data suggest U.S. authorized returns would reach under the same circumstances."

[86] Ibid, page 57, last sentence in item 5.

[87] NEB, Rfd, RH-4-2001, heading Regulatory Precedent, at page 43.

[88] Régie de l'énergie. Décision D-2007-116., pages 23-24.

[89] The example has already been given of the 17 December 2007 application to the NEB by Gazoduc Trans-Québec et Maritimes for cost of capital determination for the years 2007 and 2008. See footnote 3, which also notes the lengthy hearing process which this application may involve, extending over about a 13-month period.

BMO Capital Markets

Pipelines/ Gas & Electric Utilities

Industry Rating Pipelines: **Market Perform**

Industry Rating Gas & Electric Utilities: **Market Perform**

December 7, 2006
Toronto, Ontario

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2007 ROEs Decline to Unprecedented Levels; Ontario Gets Reprieve

Highlights

- The ugly got uglier – actual 2007 allowed ROEs declined by an average of 0.37% versus the average allowed return on equity for 2006. The average actual allowed return on equity in 2007 is 8.65% versus 9.01% in 2006.
- The announced allowed returns are fully reflected in our diluted EPS estimates over the 2007 and 2008 forecast period.
- Although we believe that the allowed returns established by the automatic adjustment mechanisms set out herein likely violate the Fair Return Standard and are confiscatory, they are in line with expectations and therefore neutral to our outlook.
- Companies with material exposure to these automatic adjustment mechanisms include Canadian Utilities Limited, Pacific Northern Gas, Gaz Metro L.P., Fortis Inc. and TransCanada Corporation. Companies with limited exposure to ROE adjustment mechanisms include: Enbridge Inc., Duke Energy, and TransAlta Corporation.
- There are a number of companies in our coverage universe with no exposure to these automatic adjustment mechanisms: Caribbean Utilities, and Emera Inc. The pipeline and power trusts/limited partnerships in our coverage universe generally do not have a material exposure to these mechanisms.
- On November 23, the Ontario Energy Board abandoned its generic licence amendment proceeding, the purpose of which, among other things, was to codify its approach to determining the allowed return on equity. The Board has also rejected the implementation of an alternative approach to determine the allowed return on equity for Ontario's local electricity distribution utilities. We believe that this alternative approach was seriously flawed and had no basis in reality.
- We rate the units of Fort Chicago Energy Partners, LP, Inter Pipeline Fund, and Northland Power Income Fund Outperform. We also rate the shares of Pacific Northern Gas Ltd., and Caribbean Utilities Co. Ltd. Outperform.
- We remain restricted on the units of Calpine Power Income Fund.

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The allowed rates of return on equity (ROE) for many of the pipeline and energy utility companies in our coverage universe are established by an automatic adjustment mechanism in the fall of each year and are highly dependent on forecast interest rates for the prospective fiscal period. As discussed below, the 2007 allowed ROEs for various jurisdictions have now been established and allowed ROEs, on a cumulative basis, have reached unprecedented lows.

A. The Calculations

Table 1 sets out the key variables that drive each of the automatic adjustment mechanisms, by regulator.

***Table 1**: Key Input Assumptions*

Regulator	Year Formula Effective	Month of Consensus Economics	Base GOC Yield	Equity Risk Premium	Adjustment Factor	2004A ROE	2005A ROE	2006A ROE	2007E ROE	Change 2007 vs. 2006
National Energy Board	1995	November	9.25%	3.00%	75%	9.56%	9.46%	8.88%	8.46%	-0.42%
British Columbia Utilities Commission - Terasen Gas (BCGU)	2006	November	5.25%	3.90%	75%	9.15%	9.03%	8.80%	8.37%	-0.43%
British Columbia Utilities Commission - Terasen Gas (Centra)	2006	November	5.25%	4.60%	75%	9.65%	9.53%	9.50%	9.07%	-0.43%
British Columbia Utilities Commission - PNG West Division/Tumbler Ridge	2006	November	5.25%	4.55%	75%	9.80%	9.68%	9.45%	9.02%	-0.43%
British Columbia Utilities Commission - PNG Ft. St. John/Dawson Creek/FortisBC	2006	November	5.25%	4.30%	75%	9.55%	9.43%	9.20%	8.77%	-0.43%
Alberta Energy and Utilities Board	2005	November	5.68%	3.92%	75%	9.60%	9.50%	8.93%	8.51%	-0.42%
Ontario Energy Board - Enbridge Gas Distribution	1998	October	7.25%	3.40%	75%	9.69%	9.57%	8.74%	8.39%	-0.35%
Ontario Energy Board - Union Gas[1]	1998	October	7.25%	3.55%	75%	9.62%	9.63%	8.92%	8.53%	-0.39%
Regie de l'energie[2]	1999	August	5.76%	3.84%	75%	9.45%	9.69%	8.95%	8.73%	-0.22%
Nova Scotia Utilities and Review Board	Formula Not Presently In Use									
Island Regulatory and Appeals Commission										
Newfoundland and Labrador Board of Commissioners of Public Utilities[3]	2000	Oct/Nov	5.60%	4.15%	80%	9.75%	9.24%	8.77%	8.60%	-0.17%

Notes:

(1) Issue of Consensus Economics used to calculate allowed ROE has varied.
October stipulated in June 29, 2006 Reasons for Decision re: 2007 Rates.

(2) Excludes 0.57% of Allowed Incentive Return in 2003, 1.51% in 2004, 1.95% in 2005, 0.38% in 2006, and approximately 0.75% in 2007

(3) Return on Equity for Newfoundland Power Inc. Fixed for two-years at 9.75% in decision dated June 20, 2003. Total Return Calculation methodology.

Source: BMO Capital Markets

As set out in Table 1, the allowed ROEs established for the 2007 period are an average of 0.37% lower than in 2006. The primary reason for the decline in allowed return is the precipitous drop in the implied forecast 30-year bond yield arising from: (i) reduction in the underlying Consensus Estimate for 2007 versus 2006 to 4.15% from 4.55%; and (ii) decline in the observed spreads between the 10-year and 30-year government of Canada bond yields, as published in the National Post throughout October of 2006 versus a similar period in 2005, to approximately 7 basis points from approximately 23 basis points.

Tables 2, 3, and 4 highlight the calculation of the allowed 2007 actual ROE for the National Energy Board (NEB), Alberta Energy and Utility Board (AEUB), and the British Columbia Utilities Commission (BCUC). Table 5 highlights our estimate of the allowed return on equity for Enbridge Gas Distribution, as per the automatic adjustment mechanism notionally used by the Ontario Energy Board (OEB). We note that that the OEB, unlike its utility peer group, does not publish or release the calculation for the allowed return for the utilities subject to its purview. We note that the formulas appear to vary between Union Gas and Enbridge Gas Distribution and also between the electricity and natural gas sectors.

***Table 2**: Calculation of the 2007 Actual ROE – Multi-Pipeline Cost of Capital*

Description		
2006 Calculated Return on Equity		8.88%
2006 Forecast Yield		4.78%
November 2006 Consensus Forecast - 3 Months Out		4.10%
November 2006 Consensus Forecast - 3 Months Out		4.20%
	Average	4.15%
Average Spread between 10-year and 30-year GOCs[1]		0.07%
Forecast Long-Term (30-year) GOC Bond Yield - 2007		4.22%
	2007 Forecast Yield	4.22%
	Less: 2006 Forecast Yield	4.78%
	Difference	-0.56%
	Times 75% Adjustment Factor	-0.42%
	Plus: 2006 Approved Return on Equity	8.88%
	Equals 2007E Approved Return on Equity	8.46%

Note:
(1) Calculated by using the 10-year and 30-year Government of Canada bond yields published daily in the National Post throughout October of the current year
Source: BMO Capital Markets

***Table 3**: Calculation of the 2007 Actual ROE – AEUB*

Description		
Calculated Return on Equity Per Decision		9.60%
Forecast Yield Per Decision		5.68%
November 2006 Consensus Forecast - 3 Months Out		4.10%
November 2006 Consensus Forecast - 3 Months Out		4.20%
	Average	4.15%
Average Spread between 10-year and 30-year GOCs[2]		0.07%
Forecast Long-Term (30-year) GOC Bond Yield - 2007		4.22%
	2007 Forecast Yield	4.22%
	Less: 2006 Forecast Yield	5.68%
	Difference	-1.46%
	Times 75% Adjustment Factor	-1.10%
	Plus: Approved Return on Equity	9.60%
	Equals 2007E Approved Return on Equity	8.51%

Note:
(2) Calculated by using the 10-year and 30-year Government of Canada bond yields published daily in the National Post throughout October of the current year
Source: BMO Capital Markets

***Table 4**: Calculation of the 2007 Actual ROE – BCUC*

Description		
2006 Calculated Return on Equity		8.80%
November 2006 Consensus Forecast - 3 Months Out		4.10%
November 2006 Consensus Forecast - 3 Months Out		4.20%
	Average	4.15%
Average Spread between 10-year and 30-year GOCs		0.07%
Forecast Long-Term (30-year) GOC Bond Yield - 2007		4.22%
	Benchmark Return per G-14-06	9.145%
	Long-Term (30-year)GOC Bond Yield Decision	5.25%
	2007 Forecast Yield	4.22%
	Less: Bond Yield from Decision	5.25%
	Difference	-1.03%
	Times 75% Adjustment Factor	-0.77%
	Plus: Approved Return on Equity Decision	9.145%
	Equals 2007E Approved Return on Equity	8.37%

Source: BMO Capital Markets

***Table 5**: Calculation of the 2007E ROE for Enbridge Gas Distribution – OEB*

Description		
2006 Calculated Return on Equity		8.74%
2006 Forecast Yield		4.70%
November 2006 Consensus Forecast - 3 Months Out		4.10%
November 2006 Consensus Forecast - 12 Months Out		4.20%
	Average	4.15%
Average Spread between 10-year and 30-year GOCs		0.08%
Forecast Long-Term (30-year) GOC Bond Yield - 2006		4.23%
	2007 Forecast Yield	4.23%
	Less: 2006 Forecast Yield	4.70%
	Difference	-0.47%
	Times 75% Adjustment Factor	-0.35%
	Plus: 2006 Approved Return on Equity	8.74%
	Equals 2007E Approved Return on Equity	8.39%

Source: BMO Capital Markets

B. Allowed Returns are Confiscatory

We believe on a collective basis, that the allowed returns as established by the formulas highlighted above are confiscatory and likely violate the Fair Return Standard. This standard, as established by Canada's Supreme Court and accepted by the National Energy Board in 1971, states that a fair or reasonable rate of return should:

1. be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable earnings standard);
2. enable the financial integrity of the regulated enterprise to be maintained and permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the financial integrity and capital attraction standards); and
3. achieve fairness from the viewpoint of the customers and from the viewpoint of present and prospective investors (appropriate balance of customer and investor interests).

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.

- The continued reliance on a derived 30-year government of Canada bond yield may not be a relevant proxy for the cost of debt (and/or a proxy for the risk free rate) for two key reasons: (i) the observed and anticipated reduction in the supply of government of Canada securities and the continued conversation in the financial market that the government may cease to issue debt securities at the long end of the curve may result in distortions in the market cost of these securities and thus the observed yields; and (ii) that corporate debt issuers do not have access to the debt capital market at government yield levels.

- 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. For example, On September 16, 2003, Fortis Inc. announced that it planned to acquire the assets of Aquila British Columbia and Aquila Alberta for $1.36 billion, including assumed debt. The company financed the transaction by assuming approximately $689 million of utility debt and issued approximately $170 million of holdco debt, $200 million of holdco preferred shares and new equity of approximately $350 million. Despite the levered nature of the transaction and the prospect for above average rate base growth at the two target utilities, the common shares of Fortis Inc. declined by 5% at the time the transaction was announced and the transaction was initially widely expected to be dilutive until 2006.

- None of the pipeline projects highlighted in our May 24, 2006, report entitled "Exchanging Fire", save and except the Canadian portion of the Southern Access Pipeline (with an approximate cost of $160 million versus an estimated cost to Enbridge of projects currently permitted and/or under way of $8 billion), are expected to earn the National Energy Board multi-pipeline decision return on equity. We note that in many instances, the market-based tolling arrangements with shippers result in a risk profile similar to that of the benchmark pipeline, the TransCanada Mainline pipeline.

- 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 or last resort and fulfil 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 order 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.

C. Ontario Gets a Reprieve

On November 23, the Ontario Energy Board (OEB) issued a notice to participants regarding its Multi-year Electricity Distribution Rate Setting Plan, including the Cost of Capital, 2nd Generation Incentive Regulation Mechanism and Generic Licence Amendment Proceeding. The Board indicated that, pursuant to Staff and Panel recommendations, the Board discontinue its code-based approach (November 17 and November 20, 2006 respectively); that in the interests of achieving a more timely setting of electricity distribution rates for the 2007 rate year, the Board will instead implement its cost of capital and 2nd generation incentive regulation policies by means of guidelines. As a result, the Board discontinued the generic licence amendment proceeding, which was commenced on the Board's own motion.

On November 30, the Board issued a Draft Report on the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors and Associated Guidelines. The draft report details the Board's policies on cost of capital and 2nd generation incentive regulation, and draws on the work of Board staff and the input of interest parties since this consultation was initiated in April 2006. Also included are guidelines to assist parties in understanding how the policies will be implemented and information for distributors in preparing their rate applications for the 2007 rate year.

The Draft Report contains the following highlights with respect to the cost of equity capital and deemed capital structure:

- The Board has determined that the current approach to setting ROE will be maintained. The ROE will be determined based on the Long Canada Bond Forecast rate plus an equity risk premium. The Board's current approach has been in place for six years. The consultation process undertaken by the Board included a review of one method that would have required more time and greater costs for its implementation. We also note that the range of ROE produced by this alternative method was unacceptably low; well below the various rates of return discussed previously. The Board concluded that none of the approaches reviewed is better than the Board's current method.
- The Board's method will continue to include an implicit premium of 50 basis points (0.5%) for floatation and transaction costs.

- The current method was established in 1999 as part of a review of cost of capital. The ROE calculated at that time is the starting point for the calculation and is 9.35% (as per Hydro One Network Inc.'s RP-1998-0001 Decision). This formula is ROE_t = 9.35% + 0.75 ($LCBF_t$ – 5.50%). The Long Canada Bond Forecast will use the average of the January consensus forecast of the 10-year Government of Canada bond yield 3 months ahead and 12 months ahead plus the difference between the observed yields on the 30-year Government of Canada bond yield and the 10-year Government of Canada bond yield as published by the Bank of Canada during the month of January (2007).
- No incentive returns for capital investments are appropriate at this time.
- No earnings sharing mechanisms are appropriate for second generation incentive rate making.
- The Board will include an adjustment to rates in 2008, 2009 and 2010 to transition distributors from their existing capital structures to a single deemed capital structure of 40% equity and 60% debt:
  - For distributors starting at equity of 35%, the equity component will move in equal increments over two years until it reaches 40%.
  - For distributors starting at equity of 45%, the equity component will move in equal increments over two years until it reaches 40%; and
  - For distributors starting at equity of 50%, the equity component will move in equal increments over three years until it reaches 40%.

We believe that the following points are relevant about the draft guidelines:

- The current formula is not expected to result in a return on equity that is materially higher than the formulas previously discussed. We reiterate that the existing formulas result in an allowed return on equity that likely violates the Fair Return Standard and we believe them to be confiscatory.
- We are not convinced that a "one-size fits all" capital structure is appropriate and we are concerned that the Board's policy objectives of regulatory efficiency and LDC consolidation are driving force behind the single deemed capital structure approach. This may not be appropriate.
- We are not disappointed by the Board's decision to abandon the Licence Amendment proceeding and the rejection of the alternative approach to determining the return on equity. This latter item was seriously flawed and had no basis in reality. We set out our views on this approach in comments/reports dated June 27, August 8 and September 7, 2006.

D. Comparable Equity Securities

Canadian Gas Utilities

Company	TSX Ticker	Price (C$) 5-Dec-06	Shares O/S (mm)	Market Cap. (mm)	Earnings per Share 2004A	2005A	2006E	2007E	P/E Ratios 2004A	2005A	2006E	2007E	Dividend Rate	Yield	12-Month Target	Total Return	Rating
Duke Energy Corp. [2]	DUK [5]	$32.69	1089.6	$35,618	$1.32	$1.73	$1.78	$1.95	16.8	16.1	18.3	16.8	$1.28	3.9%	$32.00	1.8%	Market Perform
Enbridge Inc.	ENB	40.55	339.7	13,775	1.56	1.56	1.76	1.81	16.7	21.8	23.0	22.4	1.20	3.0%	40.00	1.6%	Market Perform
Enbridge Income Fund	ENF.UN	12.00	34.6	416	0.30	0.44	0.54	0.55	40.4	30.8	22.2	21.8	0.96	8.0%	11.50	3.8%	Market Perform
Fort Chicago Energy Partners L.P.	FCE.UN	10.75	133.7	1,437	0.74	0.59	0.64	0.47	14.1	20.9	16.8	22.9	0.93	8.7%	11.00	11.0%	Outperform
Gaz Métro [4]	GZM.UN	15.80	117.5	1,857	1.40	1.30	1.25	1.25	15.4	16.7	12.6	12.7	1.24	7.8%	16.50	12.3%	Market Perform
Inter Pipeline Fund	IPL.UN	8.39	199.5	1,674	0.46	0.48	0.67	0.48	17.6	20.1	12.5	17.5	0.84	10.0%	8.50	11.3%	Outperform
Pacific Northern Gas Ltd.	PNG	18.50	3.6	67	1.38	1.72	1.04	1.52	14.3	11.4	17.8	12.2	0.80	4.3%	20.00	12.4%	Outperform
Pembina Pipeline Income Fund	PIF.UN	15.60	121.9	1,902	0.53	0.65	0.81	0.84	23.5	22.0	19.3	18.6	1.32	8.4%	15.00	4.6%	Market Perform
TransCanada Corp.	TRP	39.38	487.7	19,206	1.55	1.70	1.86	1.89	17.9	19.1	21.2	20.8	1.33	3.4%	38.50	1.1%	Market Perform
Group Average (Excl. ENF, FCE, GZM, IPL and PIF)									**16.4**	**17.1**	**20.1**	**18.1**		**3.6%**		**4.2%**	

Canadian Electric Utilities

Company	TSX Ticker	Price (C$) 5-Dec-06	Shares O/S (mm)	Market Cap. (mm)	Earnings per Share 2004A	2005A	2006E	2007E	P/E Ratios 2004A	2005A	2006E	2007E	Dividend Rate	Yield	12-Month Target	Total Return	Rating
Caribbean Utilities Co. Ltd. [2, 3]	CUP.U	$12.44	25.2	$314	$0.77	$0.13	$0.87	$0.87	16.1	NMF	14.3	14.4	$0.66	5.3%	$13.00	9.8%	Outperform
Emera Inc.	EMA	22.91	110.4	2,528	1.16	1.04	1.15	1.14	15.7	18.2	19.9	20.1	0.89	3.9%	22.00	-0.1%	Market Perform
Fortis Inc.	FTS	28.80	103.4	2,979	0.99	1.10	1.28	1.39	15.6	18.6	22.5	20.7	0.78	2.7%	29.25	4.3%	Market Perform
Group Average									**15.8**	**18.4**	**18.9**	**18.4**		**4.0%**		**4.7%**	

Canadian Multi-Utilities

Company	TSX Ticker	Price (C$) 5-Dec-06	Shares O/S (mm)	Market Cap. (mm)	Earnings per Share 2004A	2005A	2006E	2007E	P/E Ratios 2004A	2005A	2006E	2007E	Dividend Rate	Yield	12-Month Target	Total Return	Rating
ATCO Ltd. [1]	ACO/X	$48.73	51.8	$2,525	$2.17	$2.46	$3.13	$2.77	11.7	14.4	15.6	17.6	$0.82	1.7%	NA	NA	NR
Atlantic Power Corporation [6]	ATP.UN	10.00	46.4	464	(0.57)	(0.01)	0.02	0.23	NMF	13.2	16.6	14.0	1.06	10.6%	$10.00	10.6%	Market Perform
Boralex Power Income Fund	BPT.UN	8.55	59.1	505	0.50	0.50	0.55	0.50	21.1	21.5	15.6	17.1	0.90	10.5%	9.00	15.8%	Market Perform
Calpine Power Income Fund	CF.UN	10.89	61.7	672	0.81	0.76	R	R	13.5	13.3	R	R	R	R	R	R	Restricted
Cdn Hydro Developers, Inc.	KHD	5.80	120.5	699	0.06	0.00	0.06	0.07	44.4	NMF	99.1	86.6	0.00	0.0%	5.60	-3.4%	Market Perform
Canadian Utilities Ltd.	CU	46.19	126.6	5,849	1.98	2.03	2.59	2.57	14.4	17.4	17.8	18.0	1.20	2.6%	42.00	-6.5%	Market Perform
Creststreet Power & Income Fund LP	CRS.UN	4.40	11.5	51		(0.54)	(0.00)	0.02		NMF	NMF	NMF	0.65	14.8%	4.25	11.4%	Underperform
EPCOR Power, L.P.	EP.UN	24.84	48.4	1,203	2.25	1.83	1.81	1.27	15.1	19.2	13.7	19.5	2.52	10.1%	25.50	12.8%	Market Perform
Great Lakes Hydro Income Fund	GLH.UN	18.75	48.3	905	1.03	0.75	1.08	1.03	16.5	25.0	17.3	18.2	1.25	6.7%	16.25	-6.7%	Underperform
Innergex Power Income Fund	IEF.UN	12.03	24.7	297	0.46	0.46	0.54	0.47	25.5	28.5	22.4	25.6	0.98	8.1%	11.50	3.7%	Market Perform
Northland Power Income Fund	NPI.UN	12.20	62.1	757	0.57	0.91	0.61	0.73	21.5	13.4	20.0	16.7	1.08	8.9%	13.00	15.4%	Outperform
Maxim Power Corp. [1]	MXG	6.80	43.9	299	0.50	0.30	0.21	0.24	7.6	24.3	32.4	28.3	0.00	0.0%	NA	NA	NR
TransAlta Corp.	TA	25.61	200.6	5,137	0.62	0.88	1.01	1.20	27.6	24.1	25.3	21.3	1.00	3.9%	22.00	-10.2%	Underperform
TransAlta Power L.P.	TPW.UN	7.10	75.1	533	0.48	(0.04)	0.49	0.37	19.8	NMF	14.4	19.0	0.80	11.2%	6.50	2.7%	Underperform
Group Average (Excl. KHD, MXG, IPS, LPs and Income Trusts)									**17.9**	**18.6**	**19.6**	**19.0**		**2.7%**		**-8.3%**	

Notes:

NA = Not Applicable, NMF = Not Meaningful, NR = Not Rated

[1] Estimates from First Call

[2] All figures in U.S. Dollars

[3] Caribbean Utilities' year-end is April 30

[4] Gaz Metro's year-end is Sept. 30

[5] Ticker on the New York Stock Exchange

[6] Represents Income Participating Securities (IPS). Share price, Market Cap and Dividend in C$; all else in US$.

Source: BMO Capital Markets

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Boralex Power Income Fund (BPT.UN-TSX)	11	Fortis Inc. (FTS-TSX)	2, 3, 7, 9, 10AC
Calpine Power Income Fund (CF.UN-TSX)	1, 3, 7, 10A	Gaz Metro Limited Partnership (GZM.UN-TSX)	1, 2, 3, 7, 9, 10AC
Canadian Hydro Developers Inc. (KHD-TSX)	2, 3, 7, 10A	Great Lakes Hydro Income Fund (GLH.UN-TSX)	
Canadian Utilities (CU-TSX)	2, 3, 7, 9, 10AC, 11, 12	Innergex Power Income Fund (IEF.UN-TSX)	9, 10C
Caribbean Utilities Co. Ltd. (CUP.U-TSX)	5, 7, 9, 10AB	Inter Pipeline Fund (IPL.UN-TSX)	2, 3, 7, 9, 10AC
Countryside Power Income Fund (COU.UN-TSX)		Macquarie Power Income Fund (MPT.UN-TSX)	
Creststreet Power & Inc. Fund (CRS.UN-TSX)	2, 3, 7, 10A	Northland Power Income Fund (NPI.UN-TSX)	2, 3, 7, 9, 10AC
Duke Energy Corp. (DUK-NYSE)	2, 3, 7, 9, 10AC	Pacific Northern Gas (PNG-TSX)	
Emera Inc. (EMA-TSX)	9, 10C	Pembina Pipeline Income Fund (PIF.UN-TSX)	9, 10C
Enbridge Inc. (ENB-TSX; ENB-NYSE)	2, 3, 4, 7, 9, 10AC	TransAlta Corporation (TA-TSX; TAC-NYSE)	2, 3, 4, 5, 7, 9, 10AC, 11, 12
Enbridge Income Fund (ENF.UN-TSX)		TransAlta Power L.P. (TPW.UN-TSX)	9, 10C
EPCOR Power, L.P. (EP.UN-TSX)	2, 3, 7, 9, 10AC	TransCanada Corporation (TRP-TSX; TRP-NYSE)	2, 3, 5, 7, 9, 10AC, 12

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R36881

A COMPARATIVE ANALYSIS OF RETURN ON EQUITY OF

NATURAL GAS UTILITIES

Prepared for:

The Ontario Energy Board

June 14, 2007

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APPENDICES

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I. INTRODUCTION

The Ontario Energy Board (the "Board" or "OEB") retained Concentric Energy Advisors ("CEA") pursuant to Request for Proposal ("RFP") RFPOEBRPD2007-0227, "A Review of the Return on Equity of Gas Utilities in Ontario". The Board indicated in the RFP that it was interested in investigating statements from natural gas utilities that the Return on Equity ("ROE") awards in Ontario are lower than those of surrounding jurisdictions. To perform this investigation, the Board has requested a report that provides a comparison of awarded ROEs in other jurisdictions to those awarded in Ontario, including an analysis of the forces that contribute to those differences. Specifically, the OEB requested a written report that:

(1) Compares recent ROE awards in jurisdictions outside of Ontario to those awarded by the Board for natural gas utilities in the Province;

(2) Provides a review and analysis of whether Canadian utilities compete for capital on the same basis as utilities in the U.S.; and

(3) Addresses whether stand-alone companies compete for capital on the same basis as subsidiaries of larger holding companies.

This report provides CEA's analysis and findings related to these topics. Throughout the analysis, the focus is on similarities and differences between Canadian and U.S. companies, as Canada and the U.S. are generally considered to be highly comparable from a business standpoint and have fairly integrated economies. To provide additional perspective, CEA has also conducted a limited survey of ROE awards and methodologies for gas utilities in the U.K., Australia, and the Netherlands.

CEA's research for this report is based on publicly available data, supplemented by interviews with knowledgeable sources regarding specific features of Ontario's gas utility regulation. The report is not intended to be a comprehensive examination of the ROE for any specific company, but rather an overall examination of the major factors contributing to differences between ROE awards in Ontario and those in other jurisdictions.

II. EXECUTIVE SUMMARY

A gap between allowed ROEs for Ontario gas distribution companies and U.S. gas utilities has developed over the last ten years, coincident with the implementation of the Board's "Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities" in 1997. The current ROE differential between Canada and the U.S. is in the range of 1.50 percent to 2.00 percent (*i.e.*, 150 to 200 basis points). The purpose of this report is to examine the factors leading to this difference in allowed returns.

To begin, CEA examines the historical, pre-1997 relationship between allowed ROEs in Ontario and those found in the U.S. This comparison suggests that ROEs were in approximate parity in 1997. Thereafter, a widening gap has developed placing Ontario ROEs below those in the U.S. CEA's analysis points to interest rate trends combined with differing ROE methodologies as the principal factors underlying this development. The relative decrease in allowed returns in Canada is directly related to the past ten-year decline in interest rates, and all else remaining equal, can be expected to narrow or reverse itself in a period of rising interest rates.

Beyond the important interest rate determinant, this report looks to the companies themselves, as well as the jurisdictions and countries in which they operate, to determine whether there are any fundamental differences between Ontario gas utilities and those in the U.S. that would further explain ROE differences. While the specific characteristics of individual gas utilities and their respective regulatory environments can lead to differences in allowed returns, there are no apparent fundamental differences between gas utilities in Ontario and those of the U.S. that would cause the sizable gap in ROEs. In other words, taken as a whole, U.S. gas utilities are not demonstrably riskier than Canadian gas utilities.

CEA also extends the analysis beyond Canada and the U.S., to determine whether other countries, specifically the U.K., Australia, and the Netherlands, might form an adequate basis of comparison and thus allow for a larger population of comparable companies. While the gas markets in these countries bear certain resemblances to those of Canada and the U.S., there are a few substantial differences that weaken the comparison. Thus, allowed returns in these countries are not considered adequate benchmarks against which to examine ROEs in Ontario.

As a result of the interplay between the Canadian and U.S. markets, Canadian utilities compete for capital essentially on the same basis as utilities in the U.S. In the current market environment, no fundamental differences were identified that would indicate a significant difference in investor required returns between the two markets. Capital flows efficiently between these two markets, and over the long-term, equity investors earn nearly identical returns. On the issue of subsidiaries competing for capital we find that subsidiaries of larger holding companies ultimately compete for capital much like stand alone companies, as they must compete among their affiliates for parental investment. Nonetheless, the parental obligation to invest necessary capital to maintain system integrity will typically provide the wholly owned subsidiary sufficient capital to sustain operations, where no such provision exists for stand alone utilities. Over time, however, the equity returns must ultimately reward the parent or investor at the same rate as a similar investment of comparable risk. This "comparability standard" is a guiding principle in both Canadian and U.S. utility regulation.

It is important to note that this report does not attempt to estimate the "correct" ROE for the Ontario gas distributors, nor does it discuss which ROE calculation methodology or rate-setting approach is most appropriate for the Province. Lastly, no suggestions regarding future policy are proposed. Rather, this report quantifies the differences in existing allowed ROEs between jurisdictions and countries, and discusses the factors that most likely explain the disparity.

The information provided in this report is based on independent research and analysis of publicly available information, but is also guided by interviews with, and documentation provided by, key market participants and regulatory agencies, including the OEB, the National Energy Board ("NEB"), representatives from Union Gas ("Union"), Enbridge Gas Distribution ("Enbridge"), and other Canadian gas distributors, the Canadian Gas

Association ("CGA"), an industry analyst, and individuals who have represented customer groups and other interested parties in prior ROE proceedings.

Remainder of the Report

The remainder of this report is made up of five sections. Section III provides background on the theory and practice of ROE, including the applicable precedent and approaches used by various regulatory boards in Canada, the U.S., and the other countries studied. Section IV contains a discussion of ROE methodologies and a comparison of awards across different jurisdictions, as well as an assessment of risk factors for the companies in the sample population, and a discussion of what significant differences exist between gas distributors in Ontario and those in other jurisdictions. Section V presents a discussion of competition for capital in Canada versus the U.S., and in Section VI we provide a comparable assessment of stand-alone versus subsidiary companies. Section VII contains our overall conclusions.

III. ROE BACKGROUND

The setting of ROE, as a component of the rate of return on rate base for a regulated entity such as a natural gas distributor, meets three essential objectives: (1) to provide a return consistent with other businesses having similar or comparable risks; (2) to be adequate to support credit quality and access to capital; and (3) to balance investor and consumer interests. A return that is adequate to attract equity capital at reasonable terms enables the utility to provide safe, reliable service while maintaining its financial integrity and providing just and reasonable rates. The ROE should be commensurate with the risks incurred by investors and comparable to the returns available elsewhere in the market for investments of equivalent risk. If a utility is allowed to earn its fair and reasonable ROE, both ratepayers and investors should benefit.

ROE Precedent:

The Supreme Court of Canada set out the fundamental requirements that a fair and reasonable return on capital should be met in its decision *re.: Northwestern Utilities vs. City of Edmonton,* 1929. As stated by Mr. Justice Lamont in that case:

> 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…. [1]

The NEB has further summarized its view that the fair return standard can be met by fulfilling three particular requirements. Specifically, a fair or reasonable return on capital should:

- Be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);
- Enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and

1 Northwestern Utilities v. City of Edmonton [1929] S.C.R. 186 (NUL 1929).

- Permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).[2]

For a more detailed discussion of significant ROE-related decisions in Canada and the U.S., please see Appendix C to this report.

In Canada, the NEB regulates interprovincial and international pipelines, and thus determines the allowed ROEs for pipeline companies. Regulatory boards at the provincial level, such as the OEB, regulate Canadian local distribution companies ("LDCs"). Similarly, in the U.S., the Federal Energy Regulatory Commission ("FERC") regulates energy-related interstate commerce, while state boards are responsible, for the most part, for the regulation of U.S. LDCs.

Over the past decade, the formulas used to determine ROE awards by the NEB and the Canadian provinces (including Ontario) have largely utilized the "risk premium" method. The basic mechanism involves summing the forecasted yield for the long Government of Canada bond (30-year) for the test year with an equity risk premium. Subsequent adjustments to the ROE are based upon the application of an adjustment factor (*e.g.*, 75 percent) to the year-over-year change in the long-term forecasted bond yield. This adjustment is added to/subtracted from the previous year's rate of return, to obtain the current year's ROE. The long-term bond yield forecast is determined by taking the average of the three month and twelve month 10-year Canadian Bond forecasts plus a historical yield spread between the ten-year and thirty-year bonds.

By contrast, ROEs in the U.S. are more typically determined through rate proceedings in which a variety of analytical techniques, including the Discounted Cash Flow ("DCF") Model (single and multi-stage), the Capital Asset Pricing Model ("CAPM"), risk premium, and comparable earnings analyses, are presented. The state utility commission or FERC (for cases involving interstate commerce) ultimately decides the ROE of the subject utility based upon the evidence in the proceeding.

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2 Reasons for Decision, TransCanada PipeLines Limited, RH-2-2004, Phase II, April 2005, Cost of Capital.

While this report focuses on companies in Canada and the U.S., for further comparison it also provides a high level review of the methodologies for setting returns and the resulting ROEs in the U.K., Australia, and the Netherlands.

<u>U.K.</u>

In the U.K., the Office of Gas and Electricity Markets ("Ofgem") has adopted a price control, or "price cap", method for regulation of gas distributors. An alternative approach to rate-of-return regulation, the price-cap methodology allows for price increases owing to inflation, but also accounts for increases in productivity by the utilities, and shares those benefits with ratepayers. Under the price control, the Ofgem, the U.K.'s regulatory body, sets the initial base price of the utilities assets for a five year period. Price caps and related mechanisms are also utilized selectively in U.S. jurisdictions and in Canadian provinces.

One aspect of calculating the initial price level in the U.K. is to determine the cost of capital for the utilities. In 2000/2001, Ofgem set the cost of capital (utilizing the CAPM method to calculate the equity return component of the cost of capital) for the only gas distribution company existing as of that date (National Grid). National Grid has since divested four of its eight distribution networks, but the price controls have been maintained for the new owners. The 2000/2001 price control was to be in place from 2001 to 2006, but was recently extended through 2008. The ROEs for the U.K. gas distributors are provided in Table 4 of this report.

<u>Australia</u>

In Australia, the local gas distribution networks are regulated by each state's applicable regulatory commission. Most Australian states surveyed operate in a restructured gas market, in which the regulator has committed to retail competition and has unbundled (segregated) the utility's distribution function from the natural gas supply function. Similar to Ontario, utilities in these jurisdictions must compete with gas marketers for retail customers, and are often 'providers of last resort'. Gas distribution companies are subject to price caps, with an annual adjustment for changes in inflation and productivity. For most jurisdictions the prices are reviewed every five years.

In Australia, the CAPM is heavily relied upon when setting the ROE component of the cost of capital. While in most instances the regulatory commissions focus on the overall cost of capital (as opposed to separately reporting the debt and equity returns, along with the capital structure), it is possible to apply the CAPM to calculate the implicit ROE utilizing the given parameters, as provided in Table 4.

Netherlands

In the Netherlands, there are 12 regional gas network companies, the vast majority of which are owned by municipalities. Gas distribution companies' rates are subject to price caps, with annual adjustments for inflation and changes in productivity. The Netherlands employs a "yardstick regime", whereby each company's rates for an upcoming period are dependent on overall industry averages for items such as costs and quality of service. The most recent price cap period in the Netherlands was for the period 2005 through 2007. The Netherlands Competition Authority ("NCA") released a report in December 2005 detailing the NCA's proposed methodology for setting the cost of capital for the next price cap period. In that report, the NCA stated, "the price cap to promote operational efficiency has the aim, amongst others, of ensuring that network managers in any event cannot obtain a return which is higher than that which is usual within the economy and ensuring that equivalent efficiency is promoted amongst network managers."[3]

In the Netherlands, the ROE component of the allowed cost of capital, as proposed by the NCA, is determined using the CAPM methodology. In its report, the NCA suggested a range of values for the various inputs of the CAPM, including an equity risk premium of between 4.0 percent and 6.0 percent, a Beta of between 0.47 and 0.74, and a risk-free rate of 3.8 percent to 4.3 percent, based on ten-year government bonds. Interestingly, in developing the Beta estimate, the NCA used a proxy group of comparison companies that included

[3] Netherlands Competition Authority, "Consultation Document on the Cost of Capital for Regional Network Managers," December 2005, at p. 6.

Australian, Canadian, Spanish, U.K., and U.S. companies. The resulting range of ROEs is provided in Table 4 to this report.

IV. COMPARISON OF ROE METHODOLOGIES AND AWARDS

Discussion of ROE Methodologies:

Methodological approaches differ in determining ROE, but the primary drivers of investor returns (interest rates and risk) are represented in each alternative methodology. While the scope of this report does not include an analysis of the merits or appropriateness of each methodology, it is useful to understand the differing influences of alternative methodologies. Ideally, alternative methodologies would yield comparable results. However, some methods are more influenced by certain economic and business specific factors than others. For example, the DCF approach is the predominant approach for setting ROEs in the U.S. Under this approach, the ROE is determined by adding the expected dividend yield to the long term projected growth in dividends. That formula is the functional equivalent of the rate of return on equity, which when used to discount the expected cash flows associated with stock ownership (*i.e.*, the receipt of dividends in perpetuity), yields the current stock price (typically measured as an average over a reasonable period of time). Under the DCF approach, therefore, the ROE result is a function of annualized dividends, current stock prices, and anticipated long term growth.

The CAPM is a risk premium approach that specifies the required ROE for a given security as a function of the risk free rate of return, plus a risk premium that represents the non-diversifiable (sometimes referred to as "systematic") risk of the security. Non-diversifiable risk represents the variability in returns of a given security due to the combined macroeconomic forces in the economy. The fundamental notion underlying the CAPM is that risk adverse investors will require higher returns for assuming additional risk. This non-diversifiable risk is measured in terms of a company's Beta, or the covariance of the subject company's return relative to the broader market. Beta, therefore, is a measure of the extent to which the Company's returns are influenced by the same macroeconomic risks as the broader market, and thus can not be reduced by diversification. The CAPM formula is given by the following equation:

$$k_e = r_f + \beta (r_m - r_f)$$

The risk premium (r_m - r_f) portion of the CAPM is generally determined by subtracting the historical risk free rate from historical market returns.[4] The resulting ROE derived by the CAPM approach is driven by the current level of interest rates and the historical relationship between equity returns and risk free investments for the broader market.

An alternative equity risk premium approach is generally a statistically derived measure of the linear historical relationship between interest rates and the equity risk premium for the specific industry sector. Generally, for regulated utilities, this risk premium is calculated as the difference between authorized returns and the prevailing corporate or risk free bond yield. Using a corporate bond rate, the risk premium and recommended ROE would be given by the following formulas.

$$RP = a + (X_{RP} \times b_c), \text{ and}$$

$$k_e = b_c + RP$$

Where:

RP = the risk premium

a = the constant term in determining the risk premium, derived using an ordinary least squares regression model

X_{RP} = the slope coefficient for the change in risk premium for a given change in the bond yield (this is generally negative indicating an inverse relationship), and

b_c = the corporate bond yield.

As this formula indicates, the risk premium is a function of interest rates. Generally, as can be observed in U.S. and Ontario data, the risk premium decreases as interest rates increase. The resulting impact on ROE takes into account both the change in interest rates and the effect on the risk premium. With the typical estimation of this model, as interest rates change, the ROE changes by only a fraction of the change.

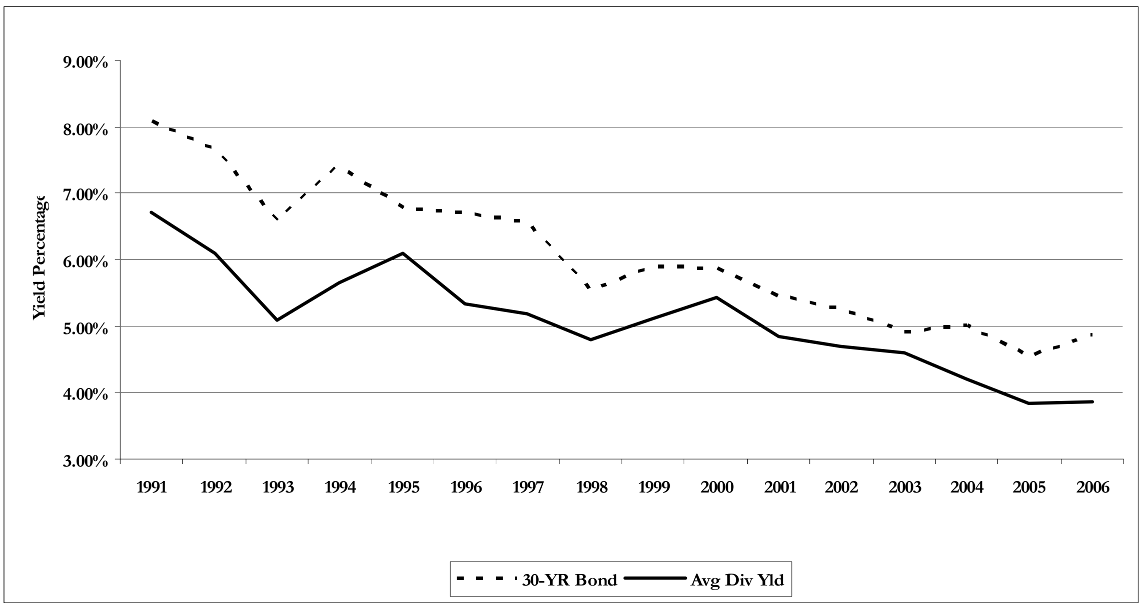
To understand why ROEs resulting from the DCF method might differ from a risk premium approach, such as the mechanism employed by the OEB, or a CAPM or other

4 It should be noted that the determination of the market equity risk premium is a hotly contested subject among experts and academics. There are several competing theories as to what the appropriate forward looking equity risk premium should be.

alternative equity risk premium approach, it is important to understand the relationship between utility dividend yields and bond yields.

There is significant academic research that establishes that utility stock prices are inversely related to the level of interest rates, and likewise that dividend yields and the level of interest rates are positively correlated. Chart 1 depicts the strong positive relationship between average annual 30-year U.S. Treasury yields and the average annual dividend yields for a representative group of U.S. gas distribution utilities.

CHART 1: COMPARISON OF U.S. GAS UTILITY DIVIDEND YIELDS AND U.S. 30-YEAR BOND YIELDS FOR THE PERIOD 1991 – 2006[5]



This strong positive relationship is attributed both to the capital (and debt) intensive nature of a utility, such that a decrease in debt capital costs will result in higher earnings and higher stock prices (lowering dividend yields), and to the fact that utilities' equity returns compete with debt yields in capital markets, as utilities are generally considered among investors to be relatively stable, lower risk investments.

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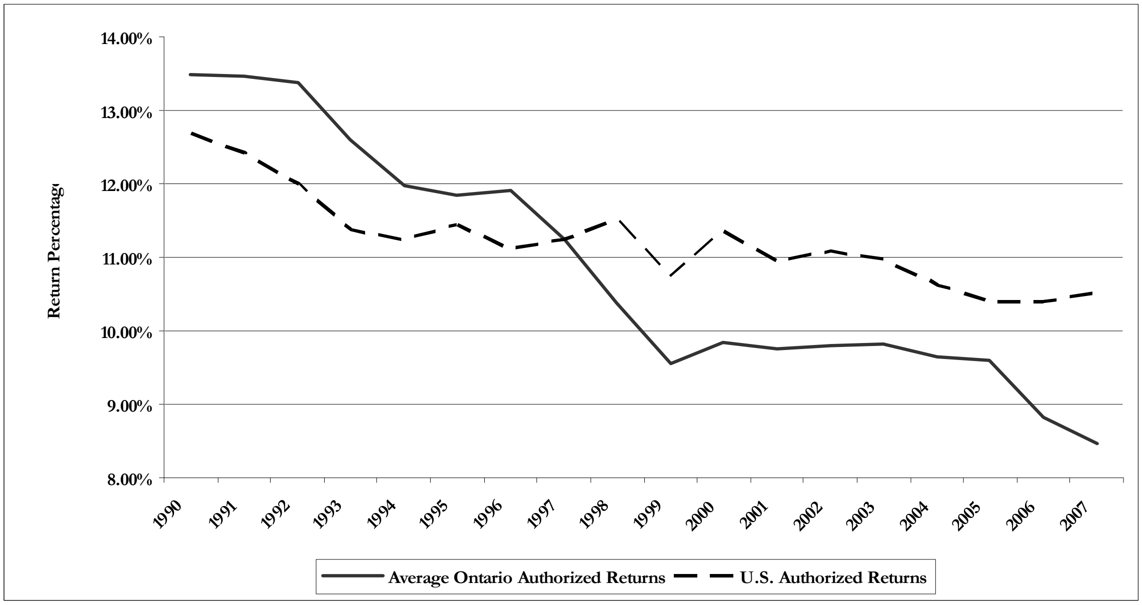
5 Dividend yields are represented for the average of all 15 natural gas distribution utilities covered by the Value Line Investment Survey's March 16, 2007 publication. 30-Year Treasury bond yields obtained from Yahoo! Finance.

There is a measurable relationship between the utility equity risk premium and the prevailing bond yield. With this typical relationship, as interest rates rise utility stock prices tend to fall and, accordingly, dividend yields rise. When stock prices behave in accordance with their historical behavior to movements in interest rates, the DCF methodologies and the risk premium methodologies will yield comparable results. However, stock prices and growth rates do not always move in accordance with historical norms, relative to interest rates, which creates differences between historical risk premium methodologies and the DCF approach. Economic factors that affect the utility sector, but not the broader market, such as stock price inflation due to speculation of merger and acquisition activities, or conversely, a sector-specific credit contraction such as that which occurred during the Enron bankruptcy, would yield a much different DCF result than that of an alternative risk premium approach. In short, the DCF approach is influenced to a substantial degree by industry specific factors that are reflected in stock prices, but are not accounted for by the level of interest rates.

<u>Comparison of U.S. and Ontario Risk Premium Models</u>

U.S. authorized returns and Ontario authorized returns were virtually in parity at the time the OEB implemented the ROE adjustment mechanism in 1997. Subsequently, U.S. and Canadian bond yields have declined significantly, and correspondingly the respective authorized returns declined as well. For example, the Canadian Long Bond yield decreased from 10.69 percent to 4.18 percent from 1990 to 2007, a difference of 651 basis points. The U.S. 30-year Treasury yield decreased from 8.62 percent to 4.81 percent, for the same period, a drop of 381 basis points. As shown in Chart 2, the more exaggerated decline in the Canadian Long Bond yield, coupled with the greater interest rate sensitivity of the OEB's ROE adjustment mechanism (discussed in further detail below), has led to a greater drop in Canadian authorized returns relative to U.S. authorized returns.

CHART 2: U.S. AUTHORIZED RETURNS VS. ONTARIO AUTHORIZED RETURNS – GAS DISTRIBUTION UTILITIES 1990 - 2007[6]



The OEB mechanism for adjusting ROE is most closely related to the previously described risk premium approach. By definition, the adjustment factor of 0.75 for a given change in interest rates implies that Ontario authorized ROEs are highly correlated to changes in bond yields and that the risk premium moves inversely to interest rates by a factor of 0.25 (1 - 0.75). Table 1 shows an illustrative example of how the OEB formula is applied.

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6 Authorized return data for the Ontario Utilities was provided by the respective Ontario utilities. Return data was available for Union Gas and Enbridge from 1985-2007. Return data was available for Centra from 1990-1997, prior to its consolidation with Union in 1997. Average annual U.S. authorized return data was available for the period 1990-2007, per RRA Associates, through the SNL database.

TABLE 1: MOST RECENT ROE AWARDS FOR ONTARIO GAS UTILITIES

	OEB Adjustment Mechanism
Allowed ROE for test year 1	9.78%
Test Year 2 Long Canada forecast (30-year)	4.00%
Test Year 1 Long Canada forecast (30-year)	5.00%
Change in Interest Rates	-1.00%
Adjustment Factor/Slope Coefficient	0.75
Adjustment to ROE	-0.75%
ROE for Test Year 2	9.03%

An analysis of historical authorized returns in Ontario prior to the implementation of the ROE adjustment formula (from 1985 through 1997), reveals that authorized returns exhibited greater sensitivity to changes in interest rates than the currently prescribed 0.75 adjustment factor inherently assumes.[7] In the U.S., the risk premium has been more sensitive to changes in interest rates such that ROEs themselves are less affected by changes in long-term interest rates.

To understand the historical relationship of long term bond yields and authorized returns in the U.S. and Ontario, a series of regressions were performed on Ontario and U.S. data, using similar parameters. The first regression described the relationship of the risk premium for regulated utilities as a function of prevailing long term bond yields. The annual risk premium was derived by subtracting the annual average long term bond yield from the concurrent average authorized return. The second regression model described the relationship of the respective authorized return (as opposed to the risk premium) as a function of the prevailing long term bond yield. The time period reviewed for the Ontario utilities was prior to the OEB's implementation of its mechanical ROE formula, from 1985 to 1997. This time period was selected in order to characterize the relationship of Ontario authorized returns and bond yields, without respect to the returns produced by the adjustment mechanism

7 Prior to 1997, per the Board's "Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities", at page 2, ROE for gas distributors in Ontario was set much the same as it is in the U.S. today, through rate proceedings. In the rate proceedings leading up to the "Draft Guidelines" issuance, "experts relied principally on [the equity risk premium approach], followed by [the comparable earnings approach] and then DCF. The CAPM is typically given the least weight, if it is relied on at all." [Clarification added].

subsequent to 1997. Similar analyses were performed on U.S. data, although the time period selected for the U.S. models was from 1990 to 2007. Though the autocorrelation present in these data sets would prohibit the inference of the impact on ROE of a given change in bond yields (at a 95 percent confidence level), the results do provide descriptive insight as to the historical relationship between interest rates and authorized returns in each market.[8] The results of these regression models are provided in Table 2:

TABLE 2: REGRESSION RESULTS – RISK PREMIUMS AND AUTHORIZED RETURNS AS A FUNCTION OF BOND YIELDS – ONTARIO VS. U.S.

	Intercept	t-stat$_{\alpha}$	X	t-stat$_{x}$	R^2
Risk Premium Regression Model = Intercept + (X * bond yield) = Risk Premium					
Ontario Data from 1985 – 1997	0.0546	3.1822	-0.1383	-0.7402	0.0474
U.S. Data from 1990 – 2007	0.0838	22.2059	-0.5365	-8.8984	0.8214
Authorized Return Regression Model = Intercept + (X * bond yield) = Authorized Return					
Ontario Data from 1985 – 1997	0.0546	3.1822	0.8617	4.6132	0.6593
U.S. Data from 1990 – 2007	0.0838	22.2059	0.4635	7.6862	0.7869

As the regression results illustrate, both the U.S. and the Ontario risk premiums reflect negative coefficients implying that changes in the risk premium have been inversely related to changes in interest rates. However, the Ontario risk premium coefficient is associated with a low level of statistical confidence. The Ontario risk premium coefficient is informative, however, in that it has a much weaker relationship to interest rates than is the case in the U.S., *i.e.*, -0.14 (and insignificant) in Ontario versus -0.54 in the U.S.

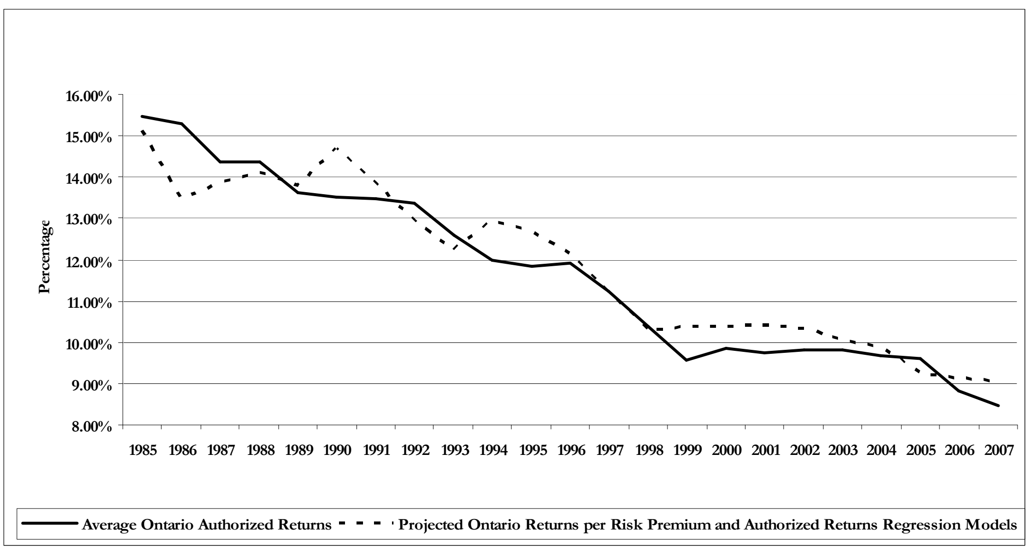
While the Ontario risk premium appears to have a much weaker link to interest rates than in the U.S., the Ontario authorized returns appear to have been more sensitive to interest rate fluctuations than in the U.S. The regression results above imply differences in interest rate sensitivity of the two models in that the variable coefficient for interest rates in the Ontario

8 *See* Plane and Oppermann, Business and Economic Statistics, Revised Edition at 395, where the authors state: "…There is one particular difficulty that arises in the analysis of time series that limits many of the techniques of statistical inference …. The difficulty is that the individual observations in a time series often depend on previous observations….This phenomenon, called serial correlation, causes most time series to be descriptive rather than inferential."

model is 0.86 where as the U.S. coefficient is 0.46. (That is, for every one percentage point change in interest rates, the Ontario ROEs change by 86 basis points while U.S. ROEs change by 46 basis points).

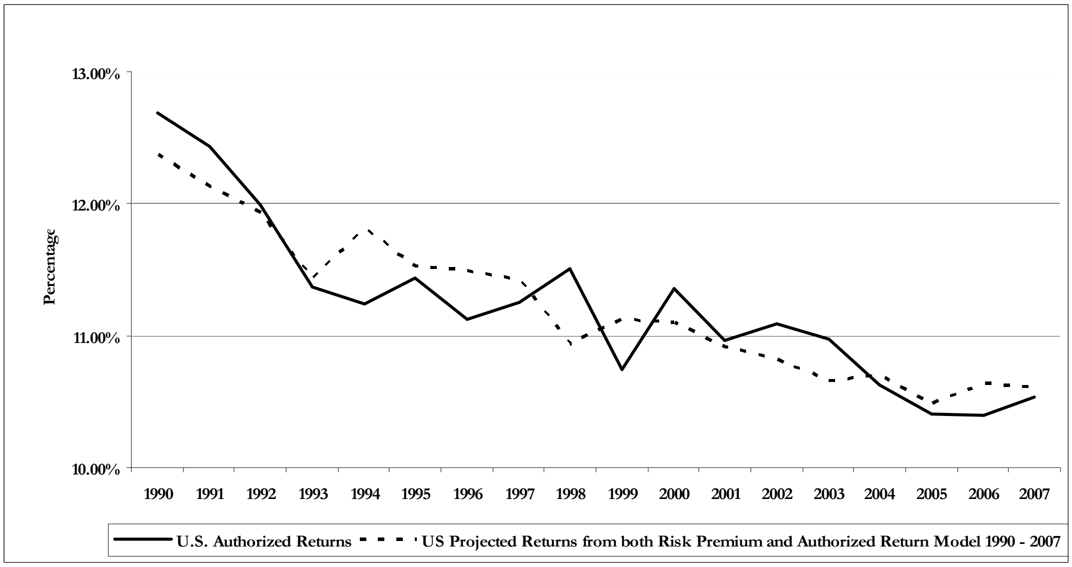
To assess whether the above regression models are informative in projecting authorized returns, CEA back-tested each of the models against actual data. Below are graphs for the U.S. and Ontario authorized returns that compare the actual returns to the estimated returns based on the respective Ontario and U.S. regression models. Charts 3 and 4 illustrate this comparison, showing that both regression models reasonably describe respective U.S. and Ontario authorized return issuances by the level of long term government bond yields, and may be informative in estimating the level of returns that would typically be authorized in each country for a given level of interest rates.

CHART 3: AVERAGE ONTARIO AUTHORIZED RETURNS VS. PROJECTED RETURNS PER REGRESSION MODEL – GAS DISTRIBUTION UTILITIES 1985 - 2007[9]



9 Authorized return data for the Ontario Utilities was provided by the respective Ontario utilities. Return data was available for Union Gas and Enbridge from 1985-2007. Return data was available for Centra from 1990-1997, prior to its consolidation with Union in 1997. Canadian Long Bond data was obtained from the Bank of Canada.

CHART 4: AVERAGE U.S. ACTUAL AUTHORIZED RETURNS VERSUS PROJECTED RETURNS PER REGRESSION MODEL 1990 - 2007[10]



To summarize, the OEB's factor of 0.75 used in its automatic ROE adjustment mechanism is reasonably close to what the above analysis on Ontario data suggests is the historical relationship between Canadian Long Bonds and gas utility authorized returns. Specifically, the above analysis suggests these variables are historically correlated by a factor of 0.86 in contrast to the 0.75 used in the OEB adjustment formula. These results differ markedly from the model describing U.S. data, which suggests a coefficient between authorized returns and interest rates of 0.46. The reason for the difference between the Ontario coefficient of 0.86, implied by the regression model, and the historical U.S. implied factor of 0.46, is subject to speculation, but may be due in part to Canada's historical reliance on the risk premium approach in establishing authorized ROEs, as well as the use of a test year and less frequent ROE determinations in the U.S. (as opposed to the more frequent ROE determinations in Ontario). However, the difference in the interest rate sensitivity explained by the U.S. regression model and the Ontario adjustment mechanism at least partially explains the recent disparity between U.S. authorized returns and Ontario authorized returns. As interest rates have declined dramatically in Canada in the past ten years, one would expect the OEB formula to yield accordingly lower authorized ROEs.

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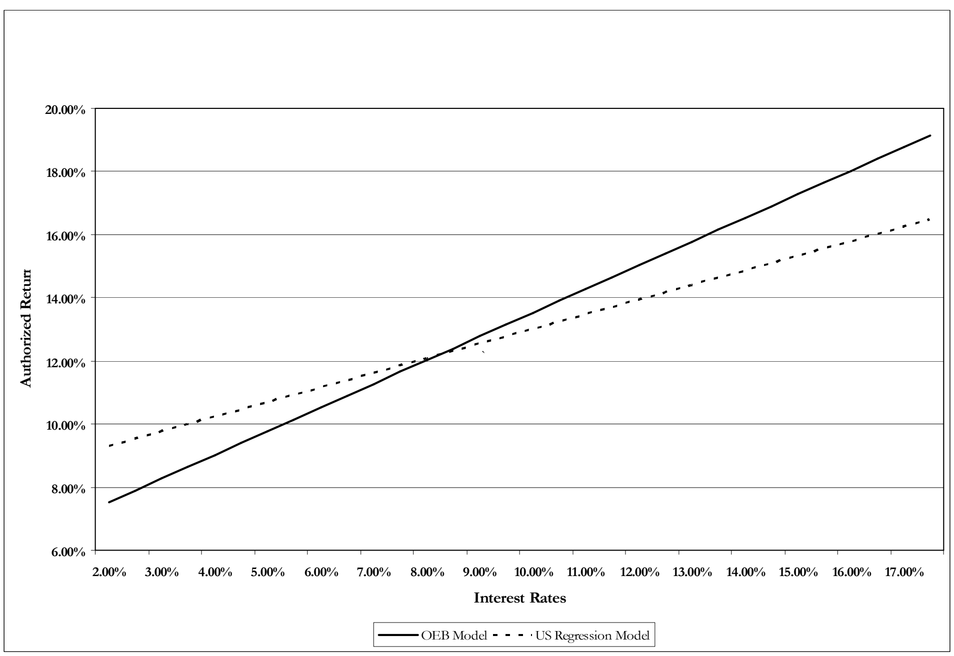
10 U.S. authorized return data was available from 1990 to 2007, per RRA Associates, through the SNL database. 30-Year Treasury yield data was obtained from Yahoo! Finance.

The formula, however, is symmetrical, and ROEs will most likely recover at a faster rate in Ontario than in the U.S., when interest rates begin to rise. In fact, if interest rates continue to steadily rise, the OEB adjustment formula could surpass and yield higher results than historical data suggest U.S. authorized returns would reach under the same circumstances. Below is a sensitivity analysis between U.S. authorized returns per the above regression model and the OEB adjustment formula. As Chart 5 illustrates, there is a greater difference between U.S. and Ontario returns at extreme high and low interest rates. It is important to note, however, that over the range of interest rates from 4.00 percent to 6.00 percent (a range of projected rates that is within the bounds of consensus forecasts), the OEB model yields results that are consistently and significantly below those implied by the U.S. regression model.

CHART 5: SENSITIVITY ANALYSIS – ROE DETERMINED BY OEB FORMULA VS. U.S. REGRESSION MODEL OF AUTHORIZED RETURNS EXPLAINED BY 30-YEAR TREASURY BOND YIELDS[11]



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11 Chart 5 assumes the U.S. and the Canadian long term government bond yields are in parity. U.S. authorized returns are calculated based upon the regression equation, $k= 0.0838 + (0.4635 \times i)$. The OEB adjustment formula assumes that the formula would yield a return of 12.25 percent when long Canada bond yields are 8.30 percent, as was the case when the mechanism was first proposed. The OEB model formula takes the change in the Canadian Long Bond for the period x 0.75, plus the previous return, so that when interest rates are at 8.30 percent, the ROE is 12.25 percent.

Quantification of Inter-jurisdictional Differences in ROE:

Beyond the methodological differences addressed in the prior section, the OEB requested that CEA examine other factors that explain differences in ROEs between Ontario and other jurisdictions. CEA began this portion of the analysis with the premise that a reasonable and practical benchmark against which to compare allowed ROEs in Ontario is a range of recently authorized ROEs for other gas distribution utility companies both in Canada and abroad. While there are a multitude of jurisdictional and company-specific business, operating, financial, and regulatory risks that must be taken into consideration when evaluating individual utility ROEs and estimating the equity returns expected by investors, CEA believes the ROEs awarded by a broad base of other regulatory commissions can form an adequate starting point for comparison.

To begin its analysis, CEA gathered data from approximately 50 different rate cases in Canada and the U.S. from 2005 to the present, including: (1) the utilities receiving the ROE awards and the jurisdictions in which they operate; and (2) the authorized ROEs and capital structures. CEA also gathered summary level data regarding ROE methodologies and allowed returns in the U.K., Australia, and the Netherlands. A summary of this data is presented in Tables 3, 4, and 5, and detailed information for all the Canadian and U.S. companies studied can be found in Exhibit 1. As discussed in greater detail later in this report, CEA narrowed the U.S. group of companies to a subset of companies more comparable to the Ontario gas distributors on the basis of size, degree of non-gas distribution (*e.g.*, electric or steam) operations, and credit rating (see the "Revised Comparison" discussion in this section of the report for a discussion of the process used to limit the population of U.S. companies to a more comparable group). The results for these eight companies are also presented in Table 4.

TABLE 3: MOST RECENT ROE AWARDS FOR ONTARIO GAS UTILITIES

Utility	2006 ROE/Equity Ratio	2007 ROE/Equity Ratio
Enbridge Gas Distribution	8.74% / 35.00%	8.39% / 35.00%[12]
Union Gas	8.89% / 35.00%	8.54% / 36.00%

[12] Per Enbridge Gas Distribution Inc.'s 2006 Annual Information Form, the company has requested an equity percentage of 38 percent in its pending 2007 rate application.

TABLE 4: MOST RECENT ROE AWARDS FOR GAS UTILITIES IN OTHER JURISDICTIONS

Jurisdiction	Utilities Receiving Recent ROE Awards	Average ROE /Equity %[A]	Primary Method for Setting ROE	Adjustment Mechanism
Canada				
British Columbia (PNG and Terasen)	5	8.85% / 37.40%	ERP/DCF[B]	Annual Adj.
Gaz Metropolitain – Québec.	1	8.95%[C] / 38.50%	CAPM/ERP[D]	Annual Adj.
Alberta (ATCO and Alta)	2	8.51% / 39.00%	CAPM[E]	Annual Adj.[F]
Canada (average)[G]	8	8.78% / 38.00%		
United States (average)	34	10.35% / 48.00%	DCF[H]	Case-by-Case
United States (average of 8 comparable cos.)	8	10.40% / 46.44%	DCF	Case-by-Case
U.K (estimated)[I]	4	6.25%[J] / 37.50%	CAPM	Fixed (5 Year Period)
Australia (estimated)[K]	8	11.70% - 12.70% / 40.00% - 45.00%	CAPM	Fixed (5 Year Period)
Netherlands (estimated)[L]	12	7.00% / 40.00%	CAPM	Fixed (3-5 Years)

Notes to Table:

[**A**] ROE award based on most recent award for applicable utilities.

[**B**] *See*, British Columbia Utilities Commission, "In the Matter of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism," Decision, March 2, 2006.

[**C**] 8.95 percent for Gaz Met does not include an adder to ROE of 0.38 percent, which represents an incentive amount based on expected productivity gains. *See*, Gaz Métro Limited Partnership, Analyst Annual Meeting Presentation, December 13, 2005.

[**D**] Per a representative at Regie de L'Energie, ROE was last reviewed in decision D-99-11, R-3397-98, in which the "the Regie put most of the weight towards [the] Capital Asset Pricing Model and the Equity Risk Premium."

[**E**] In its 2004 Generic Cost of Capital proceeding, the Alberta EUB relied on the CAPM, using other ERP methodologies as a check on reasonableness. *See* Alberta EUB, Decision 2004-052, July 2, 2004.

[**F**] Changes in an ROE, while annual, only take effect if a utility files an application for a change in rates for the applicable test year. *See*, ATCO Ltd. 2006 Annual Information Form, at p. 8.

[**G**] CEA purposefully omitted certain other provinces in Canada due to a general lack of comparability. For example, Enbridge Gas New Brunswick, with an ROE award of 13.00 percent, was not included due to its status as a "developing" distribution company. The group of Canadian companies studied by CEA appears to be consistent with groups used in ROE regulatory proceedings and by analysts.

[**H**] In CEA's experience, jurisdictions in the U.S. often rely on the DCF model, using other methodologies to validate the DCF results. The FERC's favored approach is a form of the DCF model.

[**I**] Rates of return will be reset for the 2008-2014 period. The 6.25 percent ROE was recently re-affirmed for an additional year-long period, after it was set to lapse in 2007. In a recent discussion regarding the cost of capital for U.K. gas distributors, the Ofgem stated, "Since this is a one year control, and we have explained that we will review the cost of capital for the main control, we are not sending any signal regarding long-term returns, so long-term investment decisions should not be unduly affected." *See*, Ofgem, "Gas Distribution Price Control Review One Year Control Final Proposals," December 4, 2006, at p. 31.

[**J**] The "Vanilla WACC" (equal to the pre-tax cost of debt plus the after tax cost of equity, adjusted for capitalization), was set at 5.25 percent, with 62.5 percent debt and a cost of debt of 4.65 percent. The implied ROE is thus 6.25 percent after-tax.

[**K**] Australian price cap reviews are performed every five years. Based on the most recent price cap reviews in the states surveyed, the range of implicit nominal ROEs range from 11.7 percent in Victoria (based on an October 2002 review) to 12.7 percent in Western Australia (based on a June 2000 review). The average for this group is 12.1 percent. The regulatory commission of New South Wales provides a range of parameters for which the ROE can be calculated, resulting in an implicit ROE range of 10.1 percent to 12.2 percent.

[**L**] In its report, the NCA suggested a range of values for the various inputs of the CAPM, including an equity risk premium of between 4.0 and 6.0 percent, a Beta of between 0.47 and 0.74, and a risk-free rate of 3.8 percent to 4.3 percent, based on ten-year government bonds. The resulting range of ROEs (based on an equity percentage of 40 percent), is from approximately 5.7 percent to 8.7 percent, with an average of 7.0 percent. It is important to note that this range of ROEs is based on proposed parameters for the CAPM provided by the NCA.

TABLE 5: ROE AND EQUITY PERCENTAGE DIFFERENTIALS

	ONTARIO (AVERAGE OF ENBRIDGE AND UNION)	OTHER CANADIAN PROVINCES	U.S.	U.S. (8 COMPARABLE COMPANIES)
ROE	8.82% ('06) 8.47% ('07)	9.15% ('06) 8.77% ('07)	10.35% ('05 – present)	10.40% ('05 – present)
Ontario ROE Differential[13]	--	(.33%) ('06) (.31%) ('07)	(1.53%) ('06) (1.89%) ('07)	(1.58%) ('06) (1.94%) ('07)
Equity %	35.50% (2007)	37.94%	48.00%	46.44%
Ontario Equity % Differential	--	(2.44%)	(12.50%)	(10.94%)

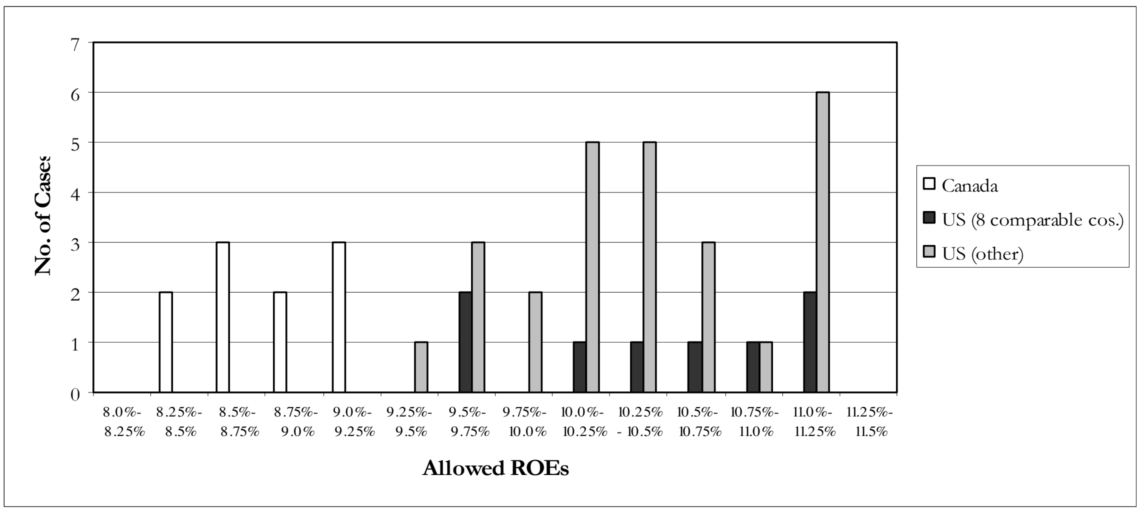
As can be seen in Table 5, the two major gas distribution utilities in Ontario have an average 2007 ROE of 8.47 percent, as compared to an average 2006 ROE of 8.82 percent. For the remaining provinces in Canada, the average ROE is 8.77 percent for 2007 and 9.15 percent for 2006. In the U.S., the overall average allowed ROE is 10.35 percent, and for a subgroup of more comparable U.S. companies (as discussed in more detail later in the report), the average ROE is 10.40 percent.

Chart 6 represents a histogram of allowed ROEs in Canada (for the five provinces studied) and the U.S. (for the group of eight comparable companies and for the remainder of the U.S. group). The two major gas distribution utilities in Ontario have 2007 ROEs of 8.39 percent for Enbridge, and 8.54 percent for Union, as compared to 2006 ROEs of 8.74 percent and 8.89 percent. For the remaining provinces in Canada, the ROEs range from 8.37 percent for Terasen's British Columbia operations to 9.07 percent for Terasen's Vancouver Island

13 Due to the fact that the majority of U.S. companies adjust their ROEs on a case-by-case basis, depending on the timing of their rate cases, as opposed to the annual adjustment mechanism in place in Ontario and other Canadian jurisdictions, CEA has presented comparisons of U.S. ROEs to both 2006 and 2007 allowed ROEs in Canada. The breakdown by year of the U.S. rate cases is as follows: 2005 – 20 rates cases, average ROE of 10.35 percent; 2006 – 11 rate cases, average ROE of 10.32 percent; 2007 – 3 rate cases, average ROE of 10.53 percent.

operations (a 70 basis point spread). In the U.S., the recently allowed ROEs range from 9.45 percent for CenterPoint Energy Resource's Arkansas operations, to 11.20 percent for two utilities in Wisconsin (a 175 basis point spread), with a mean of 10.35 percent, and a median of 10.40 percent. For a subgroup of more comparable U.S. companies (as discussed later in the report), the range is from 9.50 percent for Southwest Gas Corp. in Arizona to 11.20 percent for Wisconsin Gas (a 170 basis point spread), with a mean of 10.40 percent and a median of 10.46 percent.

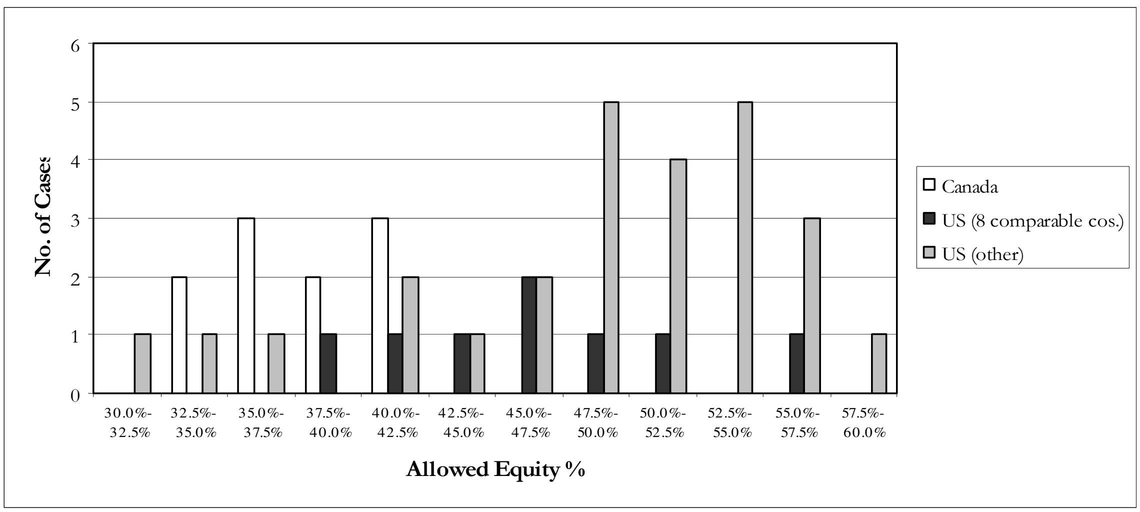
CHART 6: HISTOGRAM OF ALLOWED ROEs IN CANADA AND THE U.S.



As can be seen in Chart 6, there is no overlap between the ranges of Canadian and U.S. ROEs, with Canadian ROEs being fairly evenly distributed between 8.25 percent and 9.25 percent, and U.S. ROEs clustering between 10.00 percent and 10.50 percent, with the mode (eight of the 34 total cases) being 11.00 percent. It is important to note that while the Canadian and U.S. ROE ranges do not overlap, the ranges themselves are also quite different, in terms of spread from top to bottom (*i.e.*, the 70 basis point spread in Canada versus the 170 to 175 basis point spread in the U.S.). Possible reasons for this additional divergence are provided in the Jurisdictional Analysis discussion presented later in this report.

CEA also gathered data related to the allowed equity percentages of the companies analyzed. The allowed equity percentages in 2007 are 35.00 percent and 36.00 percent for Enbridge and Union, respectively, although Enbridge has requested a 38.00 percent equity ratio in its pending rate case. As shown in Exhibit 1, equity ratios in other Canadian provinces range from 37.00 percent to 39.00 percent, and those in the U.S. are 31.80 percent on the low end, for CenterPoint Energy Resource's Arkansas operations,[14] and 60.00 percent on the high end, for Wisconsin Public Service Corporation, with a mean and median of approximately 48.00 percent. The companies in the group of eight comparable U.S. gas distributors have equity percentages ranging from 39.31 percent for Michigan Consolidated Gas to 56.37 percent for Northern Illinois Gas, with a mean of 46.44 percent and a median of 46.77 percent. Summary level information is provided in Table 5, and Chart 7 shows the distribution of allowed equity percentages in Canada and the U.S.

CHART 7: HISTOGRAM OF ALLOWED EQUITY PERCENTAGES IN CANADA AND THE U.S.



While there is some overlap between the allowed equity ratios in Canada and the U.S., the Canadian equity ratios are narrowly gathered between 32.50 percent and 42.50 percent, while the U.S. equity ratios are well spread throughout the range, with the most instances between 47.50 percent and 55.00 percent.

Chart 8 presents a scatter plot of ROEs and equity percentages in Canada and the U.S.

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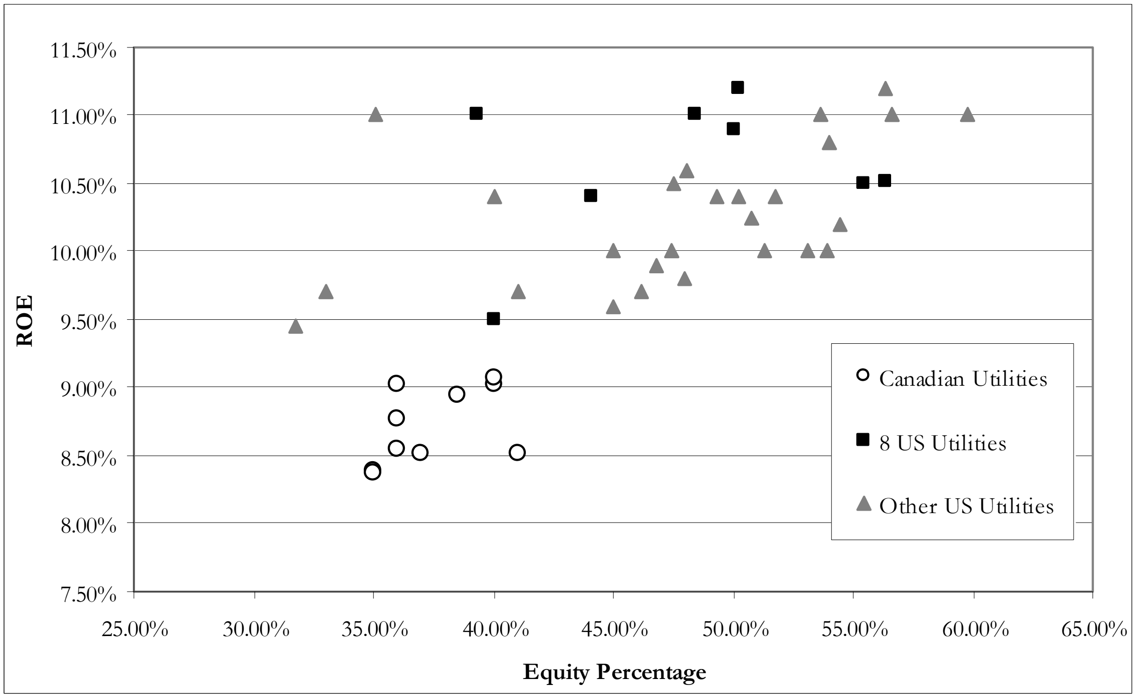
14 It is worthy to note that Arkansas uses the Modified Balance Sheet Adjustment, which is unique among U.S. regulatory jurisdictions.

CHART 8: SCATTER PLOT OF ALLOWED ROES VS. ALLOWED CAP STRUCTURE



While pictorially Chart 8 may suggest a positive relationship between ROEs and equity percentages that runs counter to expectations (as, in general, financial theory would suggest that as equity ratios decrease, the cost of equity increases), a closer look at the data suggests that no such conclusion can be drawn. Table 6 shows the regression results for Canada and the U.S., based on the data presented in Chart 8, illustrating that in Canada, there is not a statistically significant relationship between equity ratios and ROEs (based on a t-statistic of 1.51), while in the U.S., a statistically significant relationship exists, but with little explanatory value (based on an R^2 of .186).

TABLE 6: REGRESSION RESULTS COMPARING ROES TO EQUITY RATIOS

	Intercept	t-stat$_\alpha$	X	t-stat$_x$	R^2
Canadian Data	.065	4.44	.059	1.51	.222
U.S. Data	.088	14.87	.033	2.70	.186

Assessment of Inter-jurisdictional Differences in ROE:

The fact that a disparity exists between ROEs for gas utilities in Ontario and other jurisdictions, particularly the U.S., is not disputed. As stated earlier, the OEB requested that CEA seek to gain an understanding of why the difference exists, and if there is some explanatory justification beyond the methodology employed in Ontario versus other jurisdictions. As return on equity is a measure of the return that investors seek for a given amount of risk, the key question is:

> ***Are gas distribution companies in other jurisdictions more risky than those in Ontario, as would be indicated by higher ROEs applied to larger equity percentages, and visa-versa?***

A key issue is therefore assessing comparative risk. To perform this assessment, CEA gathered further data regarding fundamental operating, financial, regulatory and business risks for the companies that were included in the analyses discussed earlier in this report.

Company-Specific Data

Both Dominion Bond Rating Service ("DBRS") and Standard & Poor's ("S&P") cite a series of factors used to determine the business risk of an LDC.[15] Table 7 is a summary of the factors provided by these two ratings agencies.

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[15] *See*, Dominion Bond Rating Service, "Rating Utilities (Electric, Pipelines & Gas Distribution)", March 9, 2005; Standard & Poor's, "Key Credit Factors for U.S. Natural Gas Distributors," November 2006.

TABLE 7: DBRS AND S&P BUSINESS RISK FACTORS

DBRS	S&P
• Regulatory factors • Competitive environment • Supply/demand considerations • Regulated vs. non-regulated activities • Domestic vs. foreign operations • Capital spending program • Coverage ratios • Qualitative factors such as customer mix, economic strength in the service territory, and management expertise	• Regulation • Weather protection • Earnings sharing • Allowed ROE • Other regulatory factors • Financial protection from affiliates • Markets and competition (including service territory growth, saturation, customer mix, protection against bypass, and economic strength) • Factors related to supply, storage, system condition, and hedging • Management

Similarly, in developing a comparable, or "proxy", group of companies for the purposes of evaluating and estimating the required return on equity for utility companies, including gas distribution companies, various screening criteria and metrics of risk are used to arrive at a group of companies that are fundamentally comparable to the subject company. More specifically, when estimating the ROE for a regulated gas distribution company, such as Enbridge or Union, a combination of screening criteria typically is used by financial experts to identify utilities with similar business, financial, and regulatory risks. These criteria may include:

- *Similar Operating and Financial Characteristics*: The analyst uses companies that exhibit operating and financial characteristics similar to the subject company in that they have a specified percentage of regulated operations, and regulated natural gas operations contribute a majority of revenues and net income;

- *Credit Rating*: If the subject company is rated BBB- or above by Standard & Poor's, or a similar ratings agency, each selected company has senior bond and/or corporate credit ratings that are investment grade;
- *Beta*: The analyst may include only those companies with Betas that are within a reasonable range of the group average;
- *Customer Mix*: A concentration of customers in one particular class, such as large industrial customers, has certain risk ramifications, and thus customer mix by volume or revenue within certain ranges can assist in defining the proxy group;
- *Other*: Depending on specific details regarding the subject company and the environment in which it operates, other screens related to regulatory restructuring, geography, or other pertinent criteria may be employed.

While not all of this data is available for the companies studied, CEA gathered as much data as was publicly available along the lines discussed above. Beta, for example, is calculated using individual company stock returns as compared to the returns of a broader index. As the majority of the companies studied as part of this report are subsidiaries of larger corporations, no trading data is available at the subsidiary level, and thus Beta cannot be calculated.[16] In addition, where financial or other information was not available for companies in the study (for example, if the company were a small subsidiary for which no financial data were available), CEA used parent-level information, and applied it to the subsidiary based on reasonable assumptions of relative size.

CEA also recognizes the correlation between the size of a company and its investors' required returns. The financial and academic communities have long accepted the proposition that the cost of equity for small firms is subject to a "size effect."[17] While empirical evidence of the size effect often is based on studies of industries beyond regulated

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16 As an alternative, the Beta of a parent company may be used by a financial analyst as a proxy for that of a subsidiary in those cases in which the parent's operations are representative of the subsidiary's operations. However, in cases in which the parent has subsidiary affiliates with substantially different risk profiles (such as a holding company with a mix of regulated and unregulated subsidiaries), this approximation becomes less justifiable.

17 *See* Mario Levis, "The record on small companies: A review of the evidence," *Journal of Asset Management 2* (March 2002):368-397, for a review of literature relating to the size effect.

utilities, utility analysts also have noted the risks associated with small market capitalizations. Specifically, Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.[18]

Small size, therefore, leads to two categories of increased risk for investors: (1) liquidity risk (*i.e.*, the risk of not being able to sell one's shares in a timely manner due to the relatively thin market for the securities); and, (2) fundamental business risks. For this reason, CEA also gathered information for each company related the size of its operations. As the majority of the companies in our sample population are subsidiaries of larger corporations, all with differing types of regulated and unregulated affiliated companies, CEA could not gather market capitalization data, nor did we think applying an assumed market-to-book ratio to each of the companies would provide for a meaningful analysis. For that reason, CEA collected information related to book capitalization, total revenue, total customers, and gas throughput as proxies for the relative size of the individual companies.

CEA notes that the Board also requested that CEA gain an understanding of how varying degrees of forecasted capital expenditures might affect ROE. As this type of data is inconsistently available for the companies studied, it is difficult to perform a quantitative analysis from which any conclusions can be drawn. CEA has discovered in previous cases, however, that heightened capital requirements increase business risk for companies in several ways: (1) risk of cost under recovery associated with project cost over runs and/or poor performance of the new facilities; and (2) capital requirements to finance new construction can result in downward pressure on the Company's credit rating. Market data indicate that investors recognize these risks and discount the valuation multiples of companies with high ratios of capital expenditures to net plant. That is, the financial community acknowledges the risks associated with substantial capital expenditures and reflects those risks in lower valuation multiples, and therefore, higher required returns.

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18 Michael Annin, "Equity and the Small-Stock Effect," *Public Utilities Fortnightly*, October 15, 1995.

In addition, as this is a study of *comparative* risk, as opposed to *absolute* risk, CEA has specifically not gathered information related to factors that by and large affect all gas utilities. For the most part, these factors include comparative costs between natural gas and other energy sources, as well as the effect of declining use due to improved efficiency in gas appliances and equipment.[19]

For Canadian companies, data was gathered from information provided by the OEB, Annual Information Forms and Annual Reports, company websites, and discussions with and documentation from company representatives and other market participants. In total, CEA studied ten Canadian gas utilities, including Enbridge and Union in Ontario, Gaz Metropolitain in Québec, three divisions of Pacific Northern Gas, Ltd. and two divisions of Terasen in British Columbia, and AltaGas Utility and ATCO in Alberta.

For U.S. companies, rate case and company data was gathered from the SNL Interactive database, the Regulatory Research Associates database, and company filings and websites. CEA studied 37 rate cases for 34 companies in 22 different states. For companies that had two or more decided rate proceedings in the past two years, CEA used the most recent proceeding for comparative purposes.

A full list of data sources is provided in Appendix B. The full data set of companies and rate proceedings is presented in Exhibits 1 and 2 to this report. A summary of the allowed ROEs is provided in Tables 4 and 5, and a summary of the remaining data is presented in Table 8.

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19 CEA recognizes that cost competition and declining use may affect some utilities more than others. However, an in depth analysis of these factors is outside the scope of this report.

TABLE 8: COMPARISON OF OPERATIONAL AND FINANCIAL DATA[20]

Company/ Jurisdiction	Most Recent ROE	Allowed Equity %	% Regulated Rev./% Gas Distribution Rev.	Book Value (million $CAD)	Total Revenue (million $CAD)	Gas Distribution Revenue (million $CAD, 2006)	Total Gas Dist. Customers (millions)	Gas Volume Sold (billion cubic meters, 2006)	Customer Mix	Credit Rating (DBRS/ S&P)
Enbridge Gas Distribution	8.39%	35%	100%/98%	$4,779	$3,016	$2,958	1.8	4.4 dist 7.1 trans 11.6 total	Ind 5% Com 23% Res 47% Whls 2% Trans 23%	A/A-
Union Gas	8.54%	36%	100%/91%	3,442	2,079	2,046	1.3	13.2 dist 20.6 trans 34.0 total	Ind 12% Com 20% Res 7% Whls 0% Trans 61%	A/BBB+
U.S (average of 34 companies)	10.35%	48%	84%/36%	2,882	2,238	1,175	.6	3.3	Ind 15% Com 19% Res 42% Whls 2% Trans 22%	BBB+ (average S&P rating of utilities)
U.S (average of 8 comparable companies – see discussion below)	10.40%	46.44%	89%/60%	2,767	2,418	1,307	1.1	5.2	Ind 11% Com 20% Res 47% Whls 0% Trans 22%	BBB+ (average S&P rating of utilities)

20 As noted previously, certain data for the U.S. companies in the analysis are estimates based on data at the parent company or reporting segment level, allocated to the subject company based on a best estimate of the subject company's contribution to the overall parent or segment.

As a whole, based on the metrics presented above, the gas distribution companies in the U.S. can be seen to be largely comparable to Enbridge and Union. Notably, all of the companies in sample group, with the exception of Arkansas Western Gas Company, Consumers Energy, and Avista Corp. have investment grade ratings from S&P as of the writing of this report.

There are, however, a few notable differences between the Ontario utilities and those in other jurisdictions:

- *Size*: Enbridge and Union are comparatively larger than the majority of the other companies in the data set, when using total customers and total gas throughput as a basis of comparison, as well as book value.[21]

- *Diversification of Services and Non-regulated Affiliates*: Certain companies in the group have diversified operations, including electric operations and non-regulated operations. This is in contrast to Enbridge and Union, which are almost 100 percent regulated gas distributors. As noted by DBRS, "Companies that generate most of their earnings from regulated activities are typically more stable and predictable than those that have significant non-regulated operations."[22]

- *Approach to Setting ROE*: While ROE is an output of the rate-setting process, the approach used (formulaic versus case-by-case) may have some explanatory value in estimating investors' expected returns. In particular, there is some evidence from the market that the use of a formula for setting ROE provides for a more certain return (inasmuch as the only variable is the forecasted bond yield) than the case-by-case approach, regardless of the outcome of the calculation.

  For instance, S&P, in a review of Ontario's electric utilities, recently stated:

  > The stability, transparency, consistency, and timeliness of the Ontario regulatory regime and framework have been steadily improving as a result of ongoing amendments to the Ontario Energy Board Act…The OEB's decision to maintain its 1998 formula for determining ROEs

21 For entities for which book value was not available (*i.e.*, subsidiaries of larger companies for which SEC reported financials are not available), CEA estimated book value by utilizing the book value of the parent company or reporting entity, and applying it to the subsidiary based upon an approximation of the subsidiary's relative size to the larger company.

22 Dominion Bond Rating Service, "Rating Utilities (Electric, Pipelines & Gas Distribution)", March 9, 2005.

> allowed for in the rate-setting process, while disappointing for equity holders and not likely to encourage privatization, is another example of stability and consistency."[23]

Inherent in these comments is the distinction between debt holders, who place significant emphasis on certainty, and equity investors, who are equally concerned with the adequacy of their return.

Additionally, in a presentation at a CAMPUT meeting in January of 2005, S&P cited regulatory clarity and certainty as affecting business risk and thus credit ratings.[24]

CIBC World Markets mirrored these statements in a recent research report on Spectra Energy Corporation, the parent of Union Gas. CIBC referred to Spectra overall as operating in a "stable" regulatory environment, and added, "Investments in Union Gas are low risk with capital cost and return on this capital pre-approved by the regulator. As such, we see Union Gas' regulated operations outside of storage as having a low earnings growth profile but a low-risk profile as well that generates stable cash flow."[25]

Thus, as shown above, market analysts look favorably upon regulatory certainty, but it should be noted that the predictability of authorized returns does not outweigh the necessity of an adequate return to attract needed capital.

- *Market Dynamics in Non-Canadian and Non-U.S. Countries*: While Canada and the U.S. are considered highly comparable, both economically and in terms of regulatory structure, there are fundamental differences in market dynamics

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23 Standard & Poor's, "Shining a Light on the Positive Outlooks for Ontario Electricity Distributors," March 26, 2007.

24 Standard & Poor's, "Attracting Capital – How Does Canada's Regulatory Environment Compare Internationally," CAMPUT Financial Seminar, January 14, 2005. It should be noted, also, that in the same presentation, S&P cited Canadian regulatory boards as a whole as providing for relatively more "consistency and predictability" than other countries' regulators, although Canadian regulators are, "slow to adapt to changes in external factors."

25 CIBC World Markets, "Spectra Energy Corporation, Attractive Energy Infrastructure Play; Commodity Headwinds a Near-term Issue," January 11, 2007.

in the other countries that CEA investigated (*i.e.*, the U.K., Australia, and the Netherlands). Whether it be regulatory framework (gas distributors in the U.K., Australia, and the Netherlands are currently operating under differing forms of price control regulation), ownership structure (the majority of gas utilities in the Netherlands are municipally owned, while all of the U.K. – approximately 22 million gas distribution customers – was until recently served by a single company, National Grid[26]), accounting rules, geography and climate, or other factors, the differing markets and regulatory environments in which these countries' gas distributors operate weaken the basis for comparison.

Revised Comparison

To further the analysis, CEA developed a more refined comparison group that could be considered to be more similar to Enbridge and Union based upon size and corporate structure (as measured by percentage of unregulated operations). By excluding certain less comparable companies, the resulting group could be considered to have business and operating profiles more similar to the Ontario utilities. It is important to note that the resulting group of eight "comparable companies" is not equivalent to a "proxy group" of comparable companies typically used in ROE analysis. In regards to the latter, in estimating the ROE for a company, a group of publicly-traded companies displaying similar characteristics to the subject company is analyzed using one or more of the approaches discussed above (*i.e.*, the DCF, CAPM, etc.) to develop a range of reasonable ROEs. In this case, however, we are beginning with a group of companies for which the ROE has already been estimated (*i.e.*, the allowed ROE), and then narrowing that group down to a subset of companies that are comparable to Enbridge and Union, based on certain criteria. Due to the fact that the data set is highly dependent on which companies have been awarded ROEs in the recent past, and also contains a large number of subsidiary companies for which accurate

26 The current cost of capital in the U.K. was established in 2000/2001. In 2005, National Grid divested a large portion of its operating segments, cutting National Grid's distribution segment in half. The U.K. gas distribution price control, along with the associated cost of capital, however, was kept in place for the legacy companies. The fact that the cost of capital was set under a significantly different market structure, and is currently under review in the U.K., may indicate that the allowed ROE in the U.K. is not indicative of current market dynamics.

financial and operational data is unavailable, it can not be expected that this "comparables group" would yield definitive ROE results against which to benchmark Enbridge and Union's allowed returns. The purpose of this analysis, therefore, is not to provide an implied range of reasonable ROEs to apply to Enbridge and Union, but rather to more accurately quantify the existing difference in allowed ROEs.

This group of eight companies met the following criteria:

(1) Either between 500,000 to 2,200,000 gas distribution customers, or between three to approximately ten billion cubic meters in annual gas throughput (or both);

(2) Gas operations contribute at least approximately 40 percent of total revenues;

(3) A minimum BBB- (*i.e.*, investment grade) credit rating from S&P; and

(4) The companies currently have no earnings sharing mechanism in place. Similar to Enbridge and Union, therefore, shareholders are at risk for any deficiency in earnings below the allowed return, but also get to keep any amount exceeding the return.

Based on these screening criteria, the narrowed group of U.S. utilities contained the following companies[27]:

- Southwest Gas Corp. (Arizona)
- Atlanta Gas Light Company (Georgia)
- Northern Illinois Gas Company (Illinois)
- Michigan Consolidated Gas Company (Michigan)
- CenterPoint Energy Resources (Minnesota)
- Public Service Electric Gas (New Jersey)
- Puget Sound Energy, Inc. (Washington)
- Wisconsin Gas LLC (Wisconsin)

[27] With the exception of Atlanta Gas Light Company, all the companies in the narrowed group entered into their most recent rate proceeding under their own volition, generally seeking increases in rates. Atlanta Gas Light Company had a three-year performance-based ratemaking ("PBR") mechanism in place for the period of 2002 to 2005, after the expiration of which it was required to file a rate case. The PBR plan was not re-authorized.

The resulting ROE from this revised group is 10.40 percent with a 46.44 percent equity ratio, as shown in Table 9.

TABLE 9: MOST RECENT ROE AWARDS FOR U.S. GAS UTILITIES

Sample Group	2007 ROE
Entire Group of 34 U.S. Companies	10.35% / 48.00%
Revised Group of 8 U.S. Companies	10.40% / 46.44%

Conclusion Regarding Company-Specific Data

The first conclusion that can be drawn from the comparison of financial and operational profiles of gas distribution companies in Canada and the U.S. is that there are many similarities between these two groups of companies (*i.e.*, Canadian and U.S. gas distributors), and the ranges of sizes, types and number of customers, and credit ratings largely overlap. The largest difference, as shown in Table 8, is in amount of gas throughput. Enbridge, a pure distribution company, has nearly double the average gas throughput for the eight U.S. comparable companies, and Union's distribution throughput is similarly greater than that of the U.S. group. However, while this is one measure of the size of the companies, based on other metrics of size, such as book value and total revenue, the groups can be seen to be similar, especially in a direct comparison of Union to the U.S. companies. In other words, it does not appear that the Ontario gas distributors taken together are notably less risky from the standpoint of business and operational risk, and any differences in the metrics studied above do not appear to justify the overall ROE differential.

The second conclusion that can be drawn stems from the fact that, when certain less comparable companies were excluded from the overall U.S. group, the average ROE remains essentially unchanged. What this tells us is that while the screening criteria employed are important in analyzing the risk of a regulated enterprise (for the reasons discussed earlier), the relative risk level of an individual utility is based on a combination of these and many other, sometimes subtle, differences in business and operating profiles.

In terms of the difference between Ontario gas distributors and other Canadian gas distributors, it is important to note that differences in allowed ROEs are largely a function of equity risk premiums set at various points in time over the last ten years, and are subject to different provincial regulatory environments and business risks.

Due to the fact that company-specific data do not appear to explain the gap between inter-jurisdictional ROEs, CEA expanded the analysis to include territory and country-specific factors, as discussed below. Specifically, CEA addressed: (1) differences in rate design and rate stabilizing mechanisms; and (2) macro-economic factors.

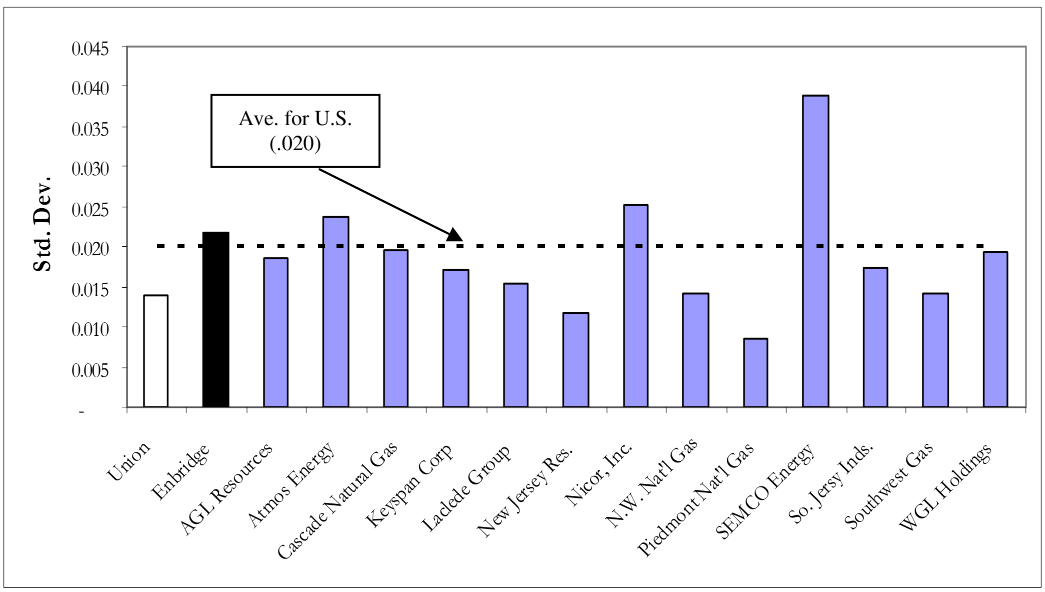
Jurisdictional Analysis

- *Rate Design and Rate Stabilization*: A common risk for gas utilities is under or over-recovery of revenue from ratepayers owing to changes in consumption, and variability in commodity costs. In addition, utility earnings can vary owing to these and other un-forecasted changes in revenues and costs. Across the companies studied as part of this report, there are many different forms of rate and cost stabilization mechanisms aimed at ensuring the utilities will be better able to earn forecasted revenues and recover forecasted costs. For example, some of the companies have weather normalization clauses that protect them from climatic variability; others are allowed to employ rate stabilization and cost deferral accounts to ensure rate and cost recovery.

  In a determination of the effect on earnings of different rate and earnings stabilization methods, weighing the various stabilizing mechanisms employed in the different jurisdictions against one another may not result in an "apples to apples" comparison, especially if all of the counterbalancing components of a company's rate design are not taken into account. Thus, to test whether the Ontario gas distributors have on the whole more stable earnings than their U.S. counterparts (and thus could be considered less risky), CEA analyzed recent earnings history for Enbridge and Union (as provided by the companies), as well as a group of U.S. gas utilities, to determine if there was a difference in variability in actual returns to equity holders.

As noted previously, there is not historical financial data readily available for the eight U.S. comparable companies since the majority of them are subsidiaries of larger holding companies. Thus, as a proxy for this group, CEA used the 15 gas utilities classified by Value Line as Natural Gas Distribution companies, as the required data is readily available. From this group, CEA removed two companies, Southern Union and UGI Corp., because they had relatively low percentages of gas operations as compared to total operations, and thus their earnings variability may be unduly affected by electric or other operations.[28] Chart 9 shows the variance in actual ROE for Enbridge, Union, and the 13 U.S. companies for the period 1997 to 2006.

CHART 9: ACTUAL ROE VARIABILITY FOR ONTARIO AND U.S. GAS DISTRIBUTORS, 1997 TO 2006



As shown in Chart 9, while the variability in ROE for the U.S. companies, as measured by the standard deviation in ROE, encompasses a large range of results (from .0084 to .0389), the average of .020, as measured by the square root of the mean variance, is not significantly different than that of Enbridge, while it is greater than that of Union. If SEMCO, a clear outlier, were to be removed from the U.S. group, the average would decrease to .018. Additionally, more than one-fourth of the U.S. companies (four of 13), fall at or below Union. Thus, while volatility in

[28] Southern Union reported, on average for 2005 and 2006, 36% of revenues and -11% of operating income to be earned from gas distribution operations. Similarly, UGI, on average over the past two years, derived only 11% of revenue and 17% of net income from their gas utility business.

earnings may affect the individual risk of U.S. utilities, or Ontario utilities for that matter, there is not a consistent difference across the markets that would explain the market-wide difference in average allowed ROEs.

As mentioned above, differences in volatility of actual ROEs between individual utilities can be attributed to a myriad of factors. These include but are not limited to: regulatory environment, revenue stabilization mechanisms (*e.g.,* weather normalization adjustments), operational environments, growth rates of territory and local economies, capital expenditures and associated uncertainties (*e.g.*, expansion projects), stability and significance of other business units, and corporate management.[29] The analysis performed above, as presented in Chart 9, was designed to account for the sum total of all of these factors on earnings, as opposed to weighing the individual influence of any one risk factor. For instance, in New Jersey, both New Jersey Resources and South Jersey Industries implemented conservation incentive programs in 2006, allowing the companies to promote energy conservation while insulating them from the negative impact of reduced customer usage (as a result of warmer weather, higher prices, or more efficient heating equipment, etc.). However, actual returns for New Jersey Resources decreased by 4.50 percent in 2006, from 17.00 percent to 12.50 percent, while those for South Jersey Industries increased by 3.90 percent, from 12.40 percent to 16.30 percent. Assuming the conservation incentive programs would have similar effects on each company's earnings, this difference in the directional movements of actual ROEs must be due to other factors. This demonstrates the need to analyze the overall effect of the many competing influences listed above in establishing the relative risk of a gas utility.

As noted above, the variability in earnings, measured by standard deviation, among the U.S. gas distributors in this analysis, ranges from 0.0084 (Piedmont) to .0389 (SEMCO). A similarly wide range of U.S. allowed ROEs was noted earlier in this

[29] While ability to recover commodity costs would also influence earnings, it is CEA's understanding that these 13 U.S. companies studied, as well as Union and Enbridge, all have at least some form of gas cost recovery mechanisms in place.

report. This may be explained in part by differences in approach to ROE setting in the U.S. versus Canada. Generally, U.S. commissions rely on the qualitative aspects of the rate proceeding, as well as quantitative aspects. Moreover, the lesser frequency of rate proceedings in the U.S. often requires consideration of the projection of capital requirements beyond one year in determining ROE. This is in contrast to the approach most widely used in Canada, whereby ROE is adjusted annually based on a purely quantitative calculation.

Economic Analysis

- *Tax Law*: Tax law can play a role in investors' expected returns, particularly as it relates to the taxation of dividends. This is especially true for utilities, as they typically have relatively high dividend payout ratios. Canada and the U.S. have varying degrees of favorable tax rates or tax credits related to dividend payments to individuals. In Canada, for instance, while corporations pay dividends with after-tax income, individuals receive a tax credit related to dividend income. Under the 2005 enhanced dividend tax credit, individuals receive a non-refundable tax credit of more than one-fourth of the dividend value. Depending on an individual's marginal tax rate, the dividend tax credit can result in effective tax rates on dividends as low as 3 percent, but up to 30 percent. In the U.S., most dividends are taxed at a maximum rate of 15 percent for individuals (referred to below as the "dividend tax cut") effective with the passage of the Jobs and Growth Tax Relief Reconciliation Act of 2003. This favorable rate is currently set to expire after 2010, if not renewed.

  It is important to note that the tax advantages related to dividends may be diminished or not available to international investors. Cross-border taxation of dividends also differs depending on the direction of the investment (*i.e.*, a U.S. investment in a Canadian security, a Canadian investment in a U.K. security, etc.), as well as the type of account in which the investment is held (*i.e.*, retirement versus taxable).[30] Similarly, institutional investors tend to constitute a large portion of utility

[30] For a description of cross-border taxation of dividends, *see*, Susan E.K. Christoffersen, et al., "Crossborder dividend taxation and the preferences of taxable and nontaxable investors: Evidence from Canada," *Journal of Financial Economics*, August 24, 2004.

stock ownership of U.S. utilities. Since many of those institutions are tax-exempt investors, it is not clear that the dividend tax cut beneficially affected all utility investors. Moreover, many U.S. investors hold utility stocks in tax-advantaged 401-k accounts; here again, the effect of the dividend tax cut on current income is not definitive.

Thus, the true effect of dividend taxation, if any, requires knowledge of the individual investor's tax position. In and of itself, it is not evident that the dividend tax rules in one country versus another would lead to differences in ROE on a comparative basis.

- *Other Macroeconomic Factors*: Table 10 provides data for Canada and the U.S. regarding indicators of economic growth and stability, as well as market returns.

TABLE 10: MACROECONOMIC FACTORS[31]

	GDP Growth		Return on:		CPI		Exchange Rate
	Canada	U.S.	S&P/TSX (TSE 300)	S&P 500	Canada	U.S.	
1981	3.05	2.50	(0.14)	(0.10)	12.40	10.32	0.83
1982	(2.94)	(1.90)	0.02	0.15	10.90	6.16	0.81
1983	2.75	4.50	0.29	0.17	5.80	3.21	0.81
1984	5.67	7.20	(0.06)	0.01	4.30	4.32	0.77
1985	5.40	4.10	0.21	0.26	4.00	3.56	0.73
1986	2.64	3.50	0.06	0.15	4.10	1.86	0.72
1987	4.10	3.40	0.03	0.02	4.40	3.65	0.75
1988	4.86	4.10	0.07	0.12	4.00	4.14	0.81
1989	2.54	3.50	0.17	0.27	5.00	4.82	0.85
1990	0.27	1.90	(0.18)	(0.07)	4.80	5.40	0.86
1991	(1.87)	(0.20)	0.08	0.26	5.60	4.21	0.87
1992	0.91	3.30	(0.05)	0.04	1.50	3.01	0.83
1993	2.30	2.70	0.29	0.07	1.80	2.99	0.78
1994	4.73	4.00	(0.02)	(0.02)	0.20	2.56	0.73
1995	2.77	2.50	0.12	0.34	2.20	2.83	0.73
1996	1.54	3.70	0.26	0.20	1.60	2.95	0.73
1997	4.37	4.50	0.13	0.31	1.60	2.29	0.72
1998	3.31	4.20	(0.03)	0.27	0.90	1.56	0.67
1999	4.54	4.50	0.30	0.20	1.70	2.21	0.67
2000	4.68	3.70	0.03	(0.10)	2.70	3.36	0.67
2001	1.50	0.80	(0.14)	(0.13)	2.60	2.85	0.65
2002	3.90	1.60	(0.14)	(0.23)	2.20	1.58	0.64
2003	2.60	2.50	0.24	0.26	2.80	2.28	0.72
2004	2.50	3.90	0.12	0.09	1.90	2.66	0.77
2005	3.10	3.20	0.22	0.03	2.20	3.39	0.83
2006	1.90	3.30	0.15	0.14	2.00	3.23	0.88
25 Year Ave.	2.74	3.12	0.08	0.11	3.58	3.52	
10 Year Ave.	3.24	3.22	0.09	0.08	2.06	2.54	
5 Year Ave.	2.80	2.90	0.12	0.06	2.22	2.63	
Standard Deviation			0.145	0.152			
Correlation	0.81		0.65		0.87		

As can be seen in Table 10, the correlation between GDP growth in the two countries is quite high, as is the correlation between the consumer price indices for each country, indicating that these metrics tend to vary together over time between the two countries. For returns on broad market indices (*i.e.*, the Toronto Stock Exchange/S&P and the S&P 500), the correlation is not as robust; however, there still is a strong positive correlation. In addition, the returns on these two indices show a similar volatility as measured by their standard deviations. Based on these macroeconomic factors, there are no obvious

31 Sources: Canada GDP, Exchange Rate, and CPI – Statistics Canada as of April 17, 2007; U.S. GDP – U.S. Bureau of Economic Analysis as of March 29, 2007; S&P 500 returns – Yahoo! Finance; S&P/TSX (TSE 300) –Yahoo! Finance (2000-2007), finance.sauder.ubc.ca/courses/comm472/TSE300.xls (pre-2000); U.S. CPI – U.S. Bureau of Labor Statistics.

dissimilarities between Canada and the U.S. (*i.e.*, in terms of volatility in growth, inflation, or exchange rates) which could explain significant differences in investors' expectations. Based on the past five years, investors in the Toronto exchange stocks have enjoyed a six percent greater return than those investing in the U.S. S&P 500. Over the long term, however, returns in the respective markets have been more similar. Furthermore, the magnitude and significance of trade between the two countries would indicate the integration of the two markets. In 2006, Canada exported 81.6 percent of its total exports to the U.S. and imported from the U.S. 54.9 percent of its total imports.[32]

[32] Strategis, Industry Canada, February 2007.

V. COMPETITION FOR CAPITAL IN CANADA VERSUS THE U.S.

A company's access to capital is a key consideration in setting a fair return. Without access to capital (at reasonable cost rates), a utility would be challenged to maintain its basic systems, and ultimately system integrity would be jeopardized, let alone any future capital expansion plans. Companies obtain capital in a variety of ways, through debt or equity issuances, or in the form of equity infusions from their parent. Regardless of where capital is coming from, there is a cost for providing that capital that compensates either the creditor, the investor, or the parent for the risk they take on in providing capital to the entity, and that compensation should be no less than what could be received by an alternative investment target of comparable risk.

This section of the report examines whether capital for utility investment between the Canadian and U.S. markets is integrated, and whether Canadian companies must compete with U.S. companies for capital. To answer this question, consideration has been given to three primary questions: (1) Are there fundamental differences between the securities markets of the U.S. and Canada that would result in corresponding differences in the countries' required returns? (2) Do the investment bases in U.S. and Canadian gas utilities suggest that the markets are integrated? (3) Is capital migrating to jurisdictions with the higher returns? In the following section, those questions will be analyzed and discussed.

<u>International Market Return on Equity – Canada vs. U.S.</u>

Morningstar, Inc. (formerly Ibbotson Associates) identifies several methods for determining the international cost of capital, highlighting differences between countries. Of those methodologies described by Morningstar, four are employed below to ascertain if there are fundamental differences in the required returns between Canada and the U.S. that are attributable to the countries' equity markets themselves. Such differences would address inflation, political risk, exchange rate risk, and other macroeconomic factors.

The first methodology employed is the "International CAPM". Morningstar states that the principles of the CAPM can also be applied to the international market. The definition of the market portfolio can be expanded to include the equity markets of all countries of the world. Morningstar's International CAPM model uses the country specific risk free rate and Beta, and uses an equity risk premium calculated on a world wide basis.[33] Beta is estimated using the world equity market as the benchmark. Morningstar determined the world equity risk premium to be 7.73 percent, and the Betas for the U.S. and Canada are determined to be 0.99 and 0.96, respectively.[34] Using both countries current respective long term government bonds for the risk free rate results in an ROE for the U.S. of 12.45 percent and for Canada, 11.62 percent, 83 basis points below the U.S.[35]:

U.S. CAPM = 4.80 + 0.99 (7.73) = 12.45%

Canada CAPM = 4.20 + .96 (7.73) = 11.62%

A second approach to estimating the required return in international markets, put forward by Morningstar, is the "Country Risk Rating Model", which takes into account a forward-looking measure of risk for alternative markets. This approach uses a linear regression model on a sample of returns as the dependent variable and the natural log of country credit ratings as the independent variable. This analysis indicates that the U.S. required equity return should be 16 basis points lower than that of the Canadian return, based upon the relationship of the relative country credit rating and historical returns:

U.S. credit rating = 94.5, U.S. required equity return = 10.60%[36]

Canada credit rating = 93.7, Canadian required equity return = 10.76%[37]

A third approach to estimating the international required return on equity, according to Morningstar, uses a spread methodology, between countries. This approach adds a country specific spread to a cost of equity determined from more conventional means. The spread between long term government bonds is added or subtracted to the U.S. cost of equity estimate obtained through a normal CAPM assuming a market Beta of 1.00. This approach results in a 60 basis point spread, where the U.S. long term government bond is 60 basis points above its Canadian counterpart:

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33 Morningstar relied upon the Morgan Stanley Capital International (MSCI) world index as a proxy for world markets, *see* SBBI Morningstar 2007 Yearbook, Valuation Edition, at p. 178.

34 SBBI Morningstar 2007 Yearbook, Valuation Edition, at p. 179.

35 Taking the average monthly bond yield for the preceding 12 months, results in increases in the U.S. and Canada risk free rates of 5 basis points and 4 basis points, respectively, resulting in a negligible impact on the ROE. Hence, for purposes of this analysis, current spot yields are reasonably representative of 12 month averages.

36 SBBI Morningstar 2007 Yearbook, Valuation Edition, at p. 181.

37 Ibid.

U.S. Required Equity Return = 4.80 + 1 (7.13) = 11.93%

Spread = U.S. 30-Year Treasuries – Canada Long Bond = 4.80% - 4.20% = 0.60%

Canadian Equity Return = 11.93% - .60% = 11.33%

The last of the methodologies proposed by Morningstar is a "Relative Standard Deviation Model". In this model, the standard deviation of international markets is indexed to the standard deviation of the U.S. market. Countries with higher standard deviations than the U.S. are given a higher equity risk premium in proportion to their relative standard deviation. Morningstar's study indicates that the Canadian standard deviation relative to the U.S. market is 1.25[38], hence Canada's risk premium should be the product of the U.S. risk premium and the Canada/U.S. index, or 7.13 x 1.25 = 8.91. This increased risk premium would yield a higher Canadian return than that in the U.S. by 117 basis points (13.11 percent - 11.94 percent), derived below:

U.S. Required Equity Return = 4.80 + 1 (7.13) = 11.93%

Canadian Required Equity Return = 4.20 + 1(8.91) = 13.11%

The four Morningstar approaches identified above are summarized in the Table 11:

TABLE 11: INTERNATIONAL COST OF CAPITAL SUMMARY

Morningstar Methodology	U.S. Return	Canadian Return	Difference
International CAPM	12.45%	11.62%	0.83%
Country Risk Rating Model	10.60%	10.76%	(0.16%)
Country-Spread Model	11.93%	11.33%	0.60%
Relative Standard Deviation Model	11.93%	13.11%	(1.18%)
Average – Arithmetic	11.73%	11.71%	0.02%
Average – Geometric	11.71%	11.67%	0.04%

As Table 11 indicates, the four international cost of capital methodologies yield diverse results depending on the drivers of the methodology employed (*i.e.*, bond yields or relative risk metrics), with results ranging from a Canadian required return exceeding the U.S. required return by 118 basis points, to a U.S. required return exceeding the Canadian

38 Ibid., at p. 183.

required return by 83 basis points. However, the arithmetic and geometric average of all approaches indicate nearly identical results for both the Canadian and the U.S. required returns, with the average difference of all methods being between two and four basis points. These results imply that the impact of the currently lower Canadian bond yield is offset by the increased relative risk of Canadian returns (as determined under these methodologies).[39] As a result, there do not appear to be determinative market differences between the U.S. equities market and the Canadian equities market at this time to justify any sustained differences in required returns on equity.

In a 2002 study performed by Dimson, Marsh and Staunton, the authors indicate that when deriving a forward looking projection of required return on equity from a purely historical estimate of the risk premium, it is necessary to "reverse-engineer" the facts that impacted stock returns over the past 102 years, backing out factors that could not be anticipated to be recurring in the future, such as unanticipated growth or diminished business risk through technological advances. To this point, the authors state:

> While there are obviously differences in risk between markets, this is unlikely to account for cross-sectional differences in historical premia. Indeed much of the cross-country variation in historical equity premia is attributable to country-specific historical events that will not recur. When making future projections, there is a strong case, particularly given the increasingly international nature of capital markets, for taking a global rather than a country by country approach to determining the prospective equity risk premium…
>
> ...Indeed it is difficult to infer expected premia from any analysis of historical excess returns. It may be better to use a "normal" equity premium most of the time, and to deviate from this prediction only when there are compelling economic reasons to suppose expected premia are unusually high or low.[40]

The current disparity between Canadian and U.S. long term bond yields is informative at least in part in understanding the recent differences in authorized ROE's in the U.S. and

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39 According to the Country Risk Rating Model and the Relative Standard Deviation Model Canadian returns should be higher than those of the U.S. Consideration of the lower Canadian bond yield in the International CAPM Model and the Country-Spread Model, indicates that Canadian returns should be lower than U.S. returns. As such, it appears that the higher risk of Canadian returns as evidenced by the credit rating and standard deviation of Canadian returns, is mitigated by the lower bond yield relative to that of the U.S.

40 Elroy Dimson, Paul Marsh and Mike Staunton, Global Evidence on the Equity Risk Premium, Copyright September 2002.

Canada. Historically, however, as discussed below, these bond yields have been highly correlated, and based on historical performance, the current spread may not be sustainable.

Bond Yields

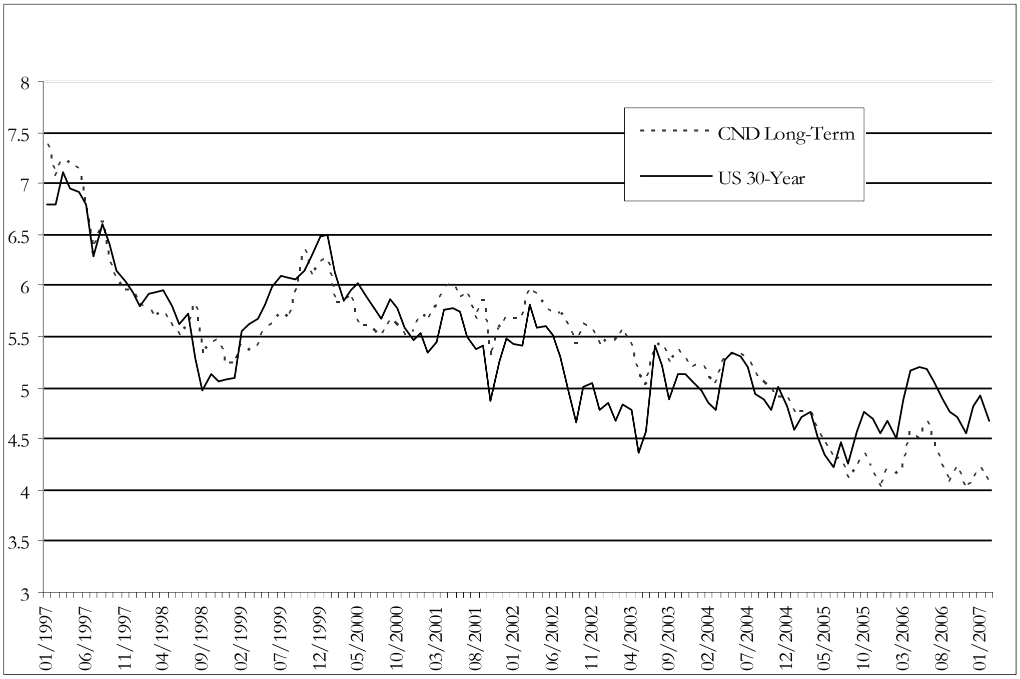
The correlation between the Canadian and U.S. Treasury bonds was noted by the NEB in its decision establishing an ROE formula for NEB-regulated pipelines. "[T]he Board is of the view that inflationary expectations in the U.S. are likely to put upward pressure on U.S. interest rates. This, in turn, is likely to exert upward pressure on Canadian interest rates."[41]

While the spread between Canadian and U.S. long-term bond yields has averaged three and two basis points over the past five and ten-year periods, respectively (with Canadian bond yields exceeding U.S. yields, on average), Canadian bond yields have decreased relative to U.S. bond yields over the past year. In addition, the forecast ten-year bond rate is 4.15 percent in Canada, as compared to the 4.85 percent forecast for the U.S. ten-year Note.[42] Inasmuch as this spread is expected to continue, it accounts for some of the current difference in ROEs between Canada and U.S. However, as the two yields have historically been very highly correlated, with a minimal spread between them, the difference in yields may not persist over the long run.

41 National Energy Board, Reasons for Decisions, RH-2-94, March 1995, at p. 6.

42 The ROE formula in Ontario uses the average of the three and 12 month forward ten-year Canadian bond forecasts, plus the historical spread between the ten and the 30-year bonds. For an approximation of the ten-year U.S. Note forecast of 4.85 percent, CEA used an average of the three and 12 month forward ten-year Treasury Note as supplied by Blue Chip Economic Indicators, October 10, 2006.

CHART 10: COMPARISON OF YIELDS ON THE CANADIAN LONG-TERM BOND VS. THE U.S. 30-YEAR BOND



<u>Investor Base of Canadian Gas Utilities</u>

CEA has found evidence that there is a high degree of integration of the capital markets between the U.S. and Canada, though there appears to be evidence of a "home country" bias for investors, in that investors tend to seek investments in their home countries before investing abroad, using foreign holdings as a means of balancing portfolios. This may be due in part to preferential tax treatment encouraging local investment or reluctance on the part of the investor to invest in unfamiliar territory. Nonetheless, there is substantial institutional investment flowing across borders.

For example, according to a December 2003 CGA study, the average pension fund in Canada was invested 56 percent in equities and 44 percent in debt and other instruments, or roughly 60 percent equity and 40 percent debt. The assumed asset allocation was 35 percent Canadian equities, 12.5 percent U.S. equities, 12.5 percent International equities, and 40 percent bonds.[43] Similarly, the capitalization of Enbridge further illustrates the bias towards

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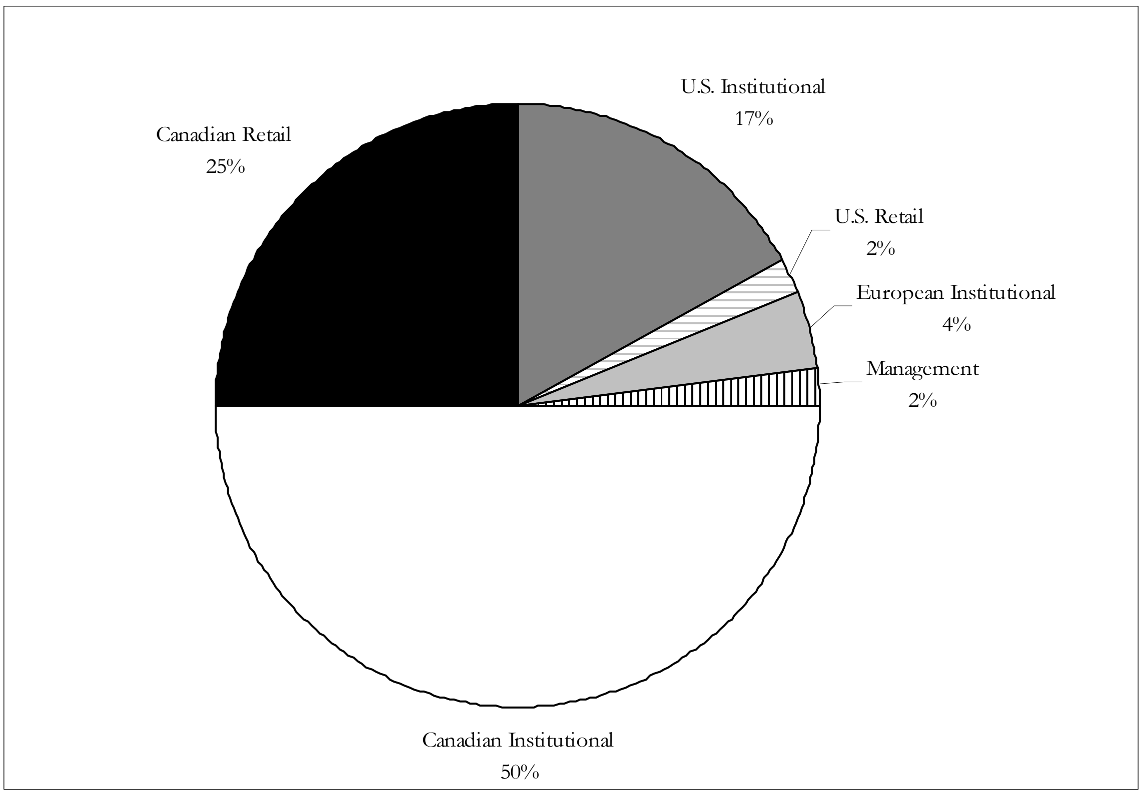
[43] Andrews, Doug, An Examination of the Equity Risk Premium Assumed by Canadian Pension Plan Sponsors, July 2004, at p. 4.

investing in local companies, as indicated by a breakdown of the investor base in Enbridge Inc. As can be seen in Chart 11, 75 percent of Enbridge Inc.'s equity investors are Canadian. However, the U.S. share of investment is still significant at 19 percent of Enbridge's investor base. It is worthy to note that U.S. investors do play a significant role in the capitalization of Canadian companies. Even though the U.S. share is a minority, one could argue that in order to attract this incremental capital, Canadian companies are competing on the margin for the same capital as U.S. gas utilities.

CHART 11: ENBRIDGE INC. INVESTOR BASE[44]



Migration of Capital across U.S. and Canadian Border

The question remains, if the current differences between the Canadian and the U.S. equities markets are completely offsetting, and there is significant integration between U.S. and Canadian markets, how is it that Ontario utilities are not required to meet U.S. higher returns to attract capital in Ontario? Through interviews with key market participants and representatives of customer groups, and other individuals with past involvement in ROE

[44] Source: Enbridge Inc.

proceedings, as well as analysis of the factors discussed above, there appear to be four primary reasons why capital is retained in Canada: (1) the home country bias; (2) Canadians perceive the U.S. regulatory environment to be more unpredictable than the Canadian regulatory environment; (3) most Canadian investor owned utilities are part of a greater holding company structure, where the parent has an obligation to maintain system integrity; and (4) market participants recognize the reciprocity of the ROE adjustment mechanism, and believe that returns are currently at the bottom.

On the issue of home country biases, some of the individuals among those surveyed for this study indicated that the average Canadian retail investor would not invest across the border to the U.S., despite the fact that returns might be higher. This may be due in part to tax incentives that are lost when investing in a foreign company. Further, pension funds have various internal restrictions that limit investment in foreign nations, to keep jobs and income in Canada. As such, large investors such as pension funds and mutual funds have prescribed investment levels in foreign markets.

To the second point of relative risk between the Canadian and the U.S. regulatory environments, certain of the individuals who were interviewed as part of this study alluded to the greater unpredictability of the U.S. regulatory environment versus that of Canada. The California energy crisis and changing and evolving regulatory structures in the U.S. were mentioned in discussions of relative risk of the U.S. versus the Canadian utility markets. It seems that despite the lower ROEs, the Canadian regulators are perceived by investors and analysts as being highly supportive. Some participants offered that even though current ROEs in Ontario were low, the protection afforded by the OEB to enable the utility to actually earn the authorized return was much more certain than in the U.S. Nothing was identified in this analysis to justify a differential between U.S. and Canadian returns on the basis of relative risk. Nonetheless, Canadian investors apparently perceive greater risk in investing in a U.S. utility versus that of a Canadian utility, and prefer to hold investments in their home country, where they believe returns are currently low but are not subject to the same risks of non-recovery as those of U.S. returns.

With respect to the third point, the natural gas distribution sector in Ontario and throughout much of Canada is comprised of several gas utilities that are part of a larger holding company structure. Though utilities that are part of a holding company structure may issue debt at the utility level, the flow of equity capital to these utilities typically comes from the parent in the way of equity infusions. While it is true that companies in a holding company structure compete for capital in much the same way as stand alone companies, an equity holder in a stand alone company can sell that investment, whereas there is little risk that utilities in a holding company structure would not be provided adequate capital by the parent to sustain their operations.

As many market participants stated during the survey phase of this study, a company makes a strategic commitment when deciding to invest in gas distribution in Canada. Most of the holding companies with Canadian utilities have diverse energy portfolios with a blend of returns. Even in an environment of lower allowed returns, key market participants indicated that they would either stay the course and provide all the capital necessary to provide a safe and efficient gas distribution system, or they would make a case to the regulatory authorities for regulatory relief. Few market participants indicated that they would divert capital to higher return jurisdictions, in order to minimize the effect of low returns. None indicated that they had considered abandoning utility operations in Canada due to the current return environment. As one key market participant stated, "you are either in the game or you are not". Thus, the regulator is largely in the driver's seat in this relationship, relying on principals of a fair return in setting allowed returns.

With respect to the final point, market participants recognize the symmetrical nature of the OEB adjustment mechanism and believe that interest rates are at historical lows and eventually will rebound. As demonstrated earlier in this report, the ROE adjustment mechanism may in fact be approaching its lowest point and its greatest disparity from U.S. returns. While CEA did not perform an analysis of the effect of allowed returns on the financial integrity of regulated utilities or on customers' rates, we do note that, all else being equal, at extremely low interest rates and correspondingly low returns, unexpected earnings variations (*i.e.*, deviations from those conditions that would have been anticipated when setting rates) will generally have a more pronounced effect on the financial condition of the utilities, as those deviations would be applied to a smaller earnings base. Accordingly, in an extreme low (or high) interest rate environment (*i.e.*, at those points in which the ROEs in Canada and the U.S. would most greatly diverge), further consideration is warranted to assess whether the allowed return is consistent with the established standards.

VI. Competition for Capital for Stand-Alone Companies Versus Subsidiaries

In general, subsidiaries of larger corporations compete for capital in much the same way that stand-alone entities would. Specifically, investment decisions at the parent level involve seeking a certain amount of return for a given amount of risk, much the same as investment decisions are made by investors when buying stakes in stand-alone companies or purchasing assets. Inasmuch as one subsidiary can provide a better return to the parent than another subsidiary of comparable risk, it is reasonable to assume the parent would prefer to invest in the more profitable company, all else being equal.

One important distinction, however, between stand-alone and subsidiary investments is the difference in relative liquidity of the investments. A parent company may have to accept lower returns from a subsidiary than it would demand from "outside", or third party, investments, especially if the parent has no easy, cost-effective method for exiting the business. In the words of one industry participant, a parent company is not going to let a subsidiary "flounder" because it offers substandard returns. In some ways, this effect is compounded for a utility company, in that it must maintain safe, dependable operations. However, a parent company would most likely seek to minimize additional capital investment in its underperforming subsidiary if a more attractive return were available elsewhere.

Additionally, affiliated companies can generate certain types of tax savings that stand-alone entities cannot. These tax savings can materialize in the form of one affiliated company being able to offset its taxable income with a loss from the operations of another affiliate. It is important to realize, however, that these tax savings do not affect the relative risk of the individual affiliated companies, and there is much debate as to the degree that these savings can and should affect the cost of capital at the subsidiary level.[45]

To test whether a "stand-alone" premium exists within the companies studied as part of this report, CEA segregated the Canadian and U.S. companies into stand-alone and subsidiary

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45 Please note that CEA is not offering an opinion regarding the issue of consolidated taxes as it pertains to utility rate-making in this report.

groupings. As stated previously, there are a multitude of jurisdictional and company-specific business, operating, financial, and regulatory risks that must be taken into consideration when evaluating individual utility ROEs and estimating the equity returns expected by investors. However, because the data set used comprises the entire population of recently set ROEs for gas distribution companies in Canada and the U.S., CEA used this as a starting point to determine if any discernible trend exists. A summary of these results is presented in Table 12.

TABLE 12: ROES FOR STAND-ALONE VERSUS SUBSIDIARY COMPANIES

Utility Group	Stand-Alone	Subsidiary
Canada	8.94% (average for PNG companies)	8.62% (7 subsidiaries)
U.S.	9.86% (6 companies)	10.46% (28 subsidiaries)

As shown, the lone stand-alone company in Canada, Pacific Northern Gas ("PNG"), has, on average for its operating divisions, a higher allowed ROE than the remainder of the Canadian utilities, all of which are subsidiaries of larger corporations.[46] It should be noted, however, that PNG, with its three gas distribution companies, is known as being generally riskier than other Canadian utilities, due to its relative small size and reliance on large customers.

Conversely, in the U.S., over the last two years, stand-alone companies have, on average, been awarded lower ROEs than subsidiary companies. The spread between the mean ROEs of these two groups is 60 basis points. These conflicting results demonstrate two things: (1) that while corporate structure may influence ROE, its effect is not consistent within this group of companies; and (2) there are many other factors with greater effects on ROE. This result is consistent with the "independent firm approach" to ratemaking, whereby the subsidiary is treated as if it was an independent firm and requires the subsidiary to earn its stand-alone cost of equity. Required rates of return are thus considered a function of the risk of the asset, regardless of stock ownership.

46 PNG is comprised of three divisions each with separate ROEs. However, as PNG has no other active operations, the company is considered "stand-alone" for purposes of this analysis.

VII. Conclusions and Summary of Findings

Based on the foregoing analyses, CEA's general conclusions are as follows:

(1) The average ROEs for Enbridge and Union (8.82 percent for 2006 and 8.47 percent for 2007) are approximately 150 to 185 basis points (1.50 percent to 1.85 percent) lower than average allowed U.S. ROEs for gas distribution utilities. When certain U.S. companies that are less comparable to the Ontario utilities are excluded from the comparison, the gap between Canadian and U.S. ROEs remains relatively constant, at between approximately 160 and 200 basis points.

(2) While the ranges of ROEs in Canada and the U.S. do not overlap, allowed returns in the U.S. are dispersed over a wider spectrum than in Canada, from 9.45 percent to 11.20 percent in the U.S. (*i.e.*, 175 basis points) versus from 8.37 percent to 9.07 percent in Canada (*i.e.*, 70 basis points). The range of ROEs for the narrower group of more comparable U.S. utilities is from 9.50 percent to 11.20 percent (*i.e.*, 170 basis points), roughly equivalent to that of the larger U.S. group.

(3) Enbridge and Union also have lower allowed equity ratios than U.S. companies, on average. Enbridge and Union's allowed equity percentages are currently 35.00 percent and 36.00 percent, as compared to 46.00 percent on average for the eight comparable U.S. companies (48.00 percent for the entire U.S. group). In general, financial theory would suggest that as equity ratios decrease, the cost of equity increases.

(4) The OEB's formulaic adjustment factor of .75 is reasonably reflective of the historical (*i.e.*, pre-1997) relationship between Canadian authorized returns and long term government bond yields. It also is significantly more sensitive to changes in interest rates than is suggested by regression results based on U.S. data. The difference in the interest rate sensitivity of each, the U.S. regression model and the Ontario adjustment mechanism, at least partially explains the recent disparity between U.S. authorized returns and Ontario authorized returns. The OEB ROE adjustment mechanism, however, is

reciprocal; as interest rates recover ROEs will rise at a faster rate in Ontario than in the U.S. Ontario authorized returns could eventually surpass U.S. authorized returns, if interest rates rise above the point at which they were when the mechanism was established in 1997.

(5) Through our research, CEA has identified a strong positive historical relationship between long term Canadian Bond yields and Canadian authorized returns. The ROE adjustment formula employed by the OEB appropriately characterizes that historical relationship. While CEA did not perform an analysis of the effect of allowed returns on the financial integrity of regulated utilities or on customers' rates, we do note that, all else being equal, at extremely low interest rates and correspondingly low returns, unexpected earnings variations (*i.e.*, deviations from those conditions that would have been anticipated when setting rates) will generally have a more pronounced effect on the financial condition of the utilities, as those deviations would be applied to a smaller earnings base. Accordingly, in an extreme low (or high) interest rate environment (*i.e.*, at those points in which the ROEs in Canada and the U.S. would most greatly diverge), further consideration is warranted to assess whether the allowed return is consistent with the established standards. This may require the consideration of additional qualitative and financial metrics in making the ROE determination.

(6) On the whole, there are no evident fundamental differences in the business and operating risks facing Ontario utilities as compared to those facing U.S. companies or other provinces' utilities that would explain the difference in ROEs.

(7) Other market related distinctions and resulting financial risk differences, particularly between Canada and the U.S., do exist. These factors, including differences in market structure, investor bases, regulatory environments, and other economic factors may have an impact on investors' return requirements for Canadian versus U.S. utility investments. However, through analysis and interviews with key market participants, representatives of customer groups, and other individuals with past involvement in ROE

proceedings in Canada and the U.S., these differences are determined to be negligible.

(8) While the gas markets in the U.K., the Netherlands, and Australia bear certain resemblances to those of Canada and the U.S., there are a few substantial differences that weaken the comparison. Thus, allowed returns in these countries are not considered adequate benchmarks against which to examine ROEs in Ontario.

(9) As a result of the interplay between the Canadian and U.S. markets, Canadian utilities compete for capital essentially on the same basis as utilities in the U.S.

(10) CEA concludes that stand-alone companies compete for capital just as subsidiaries of larger holding companies do, as the latter must compete among their affiliates for parental investment. Nonetheless, the parental obligation to invest necessary capital to maintain system integrity will typically provide the wholly owned subsidiary sufficient capital to sustain operations, where no such provision exists for stand alone utilities as external investors have no similar obligation to invest. Thus, one could argue that subsidiaries enjoy the benefit of more patient capital, but over time, the equity returns must ultimately reward the parent for investments of comparable risk.

VIII. LIST OF APPENDICES

Appendix A – Listing of market participants interviewed

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Appendix C – Discussion of significant ROE-related decisions in Canada and the U.S.

IX. LIST OF EXHIBITS

Exhibit 1 – "ROE Database" of Canadian and U.S. gas distribution companies

Exhibit 2 – Complete listing of U.S. gas distribution ROE awards, 2005 to present

Appendix A
Listing of Individuals Interviewed

As part of the research phase of this report, CEA interviewed many market participants, consumer group representatives, and other individuals with past or current involvement in ROE proceedings in Ontario and other jurisdictions. In addition, while not listed here, we would also like to thank the many individuals at the OEB, other regulatory boards, and companies who provided us documentation and other information during the process.

- Professor Laurence Booth, CIT Chair in Structured Finance, Rotman School of Management, University of Toronto
- Brad Boyle, Treasurer, Enbridge Gas Distribution Inc.
- R. J. Campbell, Manager, Regulatory Policy & Research, Enbridge Gas Distribution Inc.
- Bryan Gormley, Director, Policy & Economics, Canadian Gas Association
- Mike Packer, Director, Regulatory Affairs, Union Gas Limited
- Jay Shepherd, Counsel to the School Energy Coalition, Shibley Righton LLP
- Karen J. Taylor, Managing Director, Pipelines & Utilities Equity Research, BMO Capital Markets
- Peter Thompson Q.C., Counsel for the Industrial Gas Users Association, Borden, Ladner, Gervais LLP.
- An additional market participant who requested to remain anonymous.

APPENDIX B
LISTING OF DATA SOURCES AND DOCUMENTS CONSIDERED

Canada

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22. National Energy Board, Reasons for Decisions, RH-2-94, March 1995.

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25. New Brunswick Board of Commissioners of Public Utilities, Decision in the Matter of an Application by Enbridge Gas New Brunswick Inc. for Approval of its Rates and Tariffs, June 23, 2000.

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APPENDIX C
DISCUSSION OF SIGNIFICANT ROE-RELATED DECISIONS IN CANADA AND THE U.S.

The United States Supreme Court's precedent-setting *Hope* and *Bluefield* decisions established the standards for determining the fairness and reasonableness of a utility's allowed return on common equity. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; and (2) adequacy of the return to support credit quality and access to capital.

The *Hope* and *Bluefield* cases read, in pertinent part:

> 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 adequate, under efficient and economic management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[47]
>
> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory…[48]
>
> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the 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.[49]

The Supreme Court of Canada in *Northwestern Utilities vs. City of Edmonton* established a similar definition of fair return. As stated by Mr. Justice Lamont in that case:

> 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

[47] Bluefield Waterworks & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 1923, at 692-693 ("Bluefield").

[48] Id., at 690-692.

[49] Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 1944, at 603 ("Hope").

> 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…[50]

The standards set out in these court cases are endorsed and used by the Federal Court of Canada and the NEB.[51] In its December 1971 Decision, the NEB concluded as follows in respect of the framework for consideration of an appropriate rate of return for TransCanada:

> The Board is of the opinion that in respect of rate regulation, its powers and responsibilities include on the one hand a responsibility to prevent exploitation of monopolistic opportunity to charge excessive prices, and equally include on the other hand the responsibility so to conduct the regulatory function that the regulated enterprise has the opportunity to recover its reasonable expenses, and to earn a reasonable return on capital usefully employed in providing utility service. Further, it holds that to be reasonable such return should be comparable with the return available from the application of the capital to other enterprises of like risk. The Board accepts that, with qualifications, the rate of return is the concept perhaps most commonly used to project for some future period the ratio of return which has been found appropriate for the capital employed usefully by a regulated enterprise in providing utility service in a defined test period. The expectation is that, pending major changes, that ratio will provide a return, notwithstanding changes in the amount of capital invested, which will be fair both from the viewpoint of the customers and from the viewpoint of present and prospective investors.

An example of how the NEB describes their utilization of the fair return standard is seen in the RH-2-2004 (Phase II) proceeding.[52]

> The Board is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:
>
> - be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);
> - enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and

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50 Northwestern Utilities v. City of Edmonton [1929] S.C.R. 186 (NUL 1929)

51 *See* TransCanada PipeLines Limited v. Canada (National Energy Board), [2004] F.C.A. 149, paragraphs 35 and 36; AO-1-RH-1-70 Reasons for Decision, pp. 6-6 through 6-9; RH-4-2001 Decision, pages 10-12.

52 Reasons for Decision, TransCanada PipeLines Limited, RH-2-2004, Phase II, April 2005, Cost of Capital.

- permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).[53]

Capital Structure:

The U.S. Supreme Court and various utility commissions have long recognized the role of capital structure in the development of a just and reasonable rate of return for a regulated utility. In particular, a utility's leverage, or debt ratio, has been explicitly recognized as an important element in determining a just and reasonable rate of return:

> Although the determination of whether bonds or stocks should be issued is for management, the matter of debt ratio is not exclusively within its province. Debt ratios substantially affect the manner and cost of obtaining new capital. It is therefore an important factor in the rate of return and must necessarily come within the authority of the body charged by law with the duty of fixing a just and reasonable rate of return.[54]

The NEB, in the RH-2-94 Multi-Pipeline Cost of Capital Decision, established the ROE for a benchmark pipeline to be applied to all pipelines in that hearing. It then determined that any risk differentials between the pipelines could be accounted for by adjusting the common equity ratio.[55]

The NEB stated that, "case law establishes that it is the overall return on capital to the company which ought to meet the comparable investment, financial integrity and capital attraction requirements of the fair return standard." Yet they indicated that this does not in the NEB's view, "require that the Board make the necessary determinations solely by means of examining evidence on overall return."[56]

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[53] Id., at p. 17.

[54] New England Telephone & Telegraph Co. v. State, 98 N.H. 211, 220, 97 A.2d 213, 1953, at 220-221 citing New England Tel. & Tel. Co. v. Department of Pub. Util., (Mass.) 327 Mass. 81, 97 N.E. 2d 509, 514; Petitions of New England Tel. & Tel. Co. 116 Vt. 480, A.2d 671 and Chesapeake & Potomac Tel. Co. v. Public Service Comm'n, (Md.) 201 Md. 170, 93 A..2d 249, 257.

[55] RH-2-94, at p.25.

[56] Reasons for Decision, TransCanada PipeLines Limited, RH-2-2004, Phase II, April 2005, Cost of Capital, at p. 19.

					Parent Company							Customer Mix [1]								
Company	Jurisdiction	Most Recent ROE	Date	Allowed Equity %	Percent Regulated Revenue	Percent Regulated Net Income	Percent Gas Distribution Revenue	Book Value (million $CAD)	Total Revenue (million $CAD)	Gas Distribution Revenue (million $CAD)	Total Gas Distribution Customers	Ind.	Comm.	Res.	Whlsl & Other	Trans-portation	Gas Volume Sold (10^9m^3)	Credit Rating (DBRS/ S&P)	Interest Cov. Ratio [2]	Un-bundled
CANADIAN COMPANIES																				
Enbridge Gas Distribution [3]	Ontario, CAN	8.39%	2007	35.00%	100%	100%	98%	$4,779	$3,016	$2,958	1,819,765	5%	23%	47%	2%	23%	11.55	A/A-	1.84	Y
Union Gas	Ontario, CAN	8.54%	2007	36.00%	100%	100%	91%	$3,442	$2,079	$2,046	1,268,000	12%	20%	7%	0%	61%	13.21	A/BBB+	1.91	Y
PNG, Ltd. (PNG West Division)	BC, CAN	9.02%	2007	40.00%	100%	100%	89%	$157	$139	$124	39,511	10%	22%	25%	0%	43%	0.33	BBB/BBB	2.47	Y
PNG, Ltd. (PNG Tumbler Ridge)	BC, CAN	9.02%	2007	36.00%	100%	100%	89%	[4]	[4]	[4]	[4]	[4]	[4]	[4]	[4]	[4]	[4]	BBB/BBB	[4]	Y
PNG, Ltd. (PNG Ft. St. John/Dawson Creek/FortisBC)	BC, CAN	8.77%	2007	36.00%	100%	100%	89%	[4]	[4]	[4]	[4]	[4]	[4]	[4]	[4]	[4]	[4]	BBB/BBB	[4]	Y
Terasen Gas Inc. (BCGU)	BC, CAN	8.37%	2007	35.00%	98%	100%	86%	$2,468	$1,525	$1,525	815,000	2%	18%	31%	0%	48%	5.72	A/A	2.06	Y
Terasen Gas (Vancouver Island) Inc.	BC, CAN	9.07%	2007	40.00%	98%	100%	86%	$2,124	[5]	$216	89,400	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	N
Gaz Metropolitain	Québec, CAN	8.95%	2006	38.50%	97%	100%	94%	$2,358	$2,004	$1,886	205,903	[5]	[5]	[5]	[5]	[5]	[5]	A/A	2.13	Y
Alta	Alberta, CAN	8.51%	2007	41.00%	100%	100%	100%	$151	$131	$126	63,532	1%	35%	64%	0%	0%	0.31	BBB	2.44	Y
ATCO [6]	Alberta, CAN	8.51%	2007	37.00%	38%	30%	31%	$4,123	$2,861	$903	969,877	7%	45%	48%	0%	0%	5.90	A/A	3.52	Y
AVERAGES		**8.72%**		**37.45%**	**93%**	**93%**	**85%**	**$2,450**	**$1,679**	**$1,223**	**658,874**	**6%**	**27%**	**37%**	**0%**	**29%**	**6.17**	**A-**	**2.34**	
Median		**8.86%**		**37.75%**																
Minimum		**8.37%**		**35.00%**																
Maximum		**9.07%**		**41.00%**																
U.S. COMPANIES [7]																				
U.S. Companies Determined to be More Comparable to Enbridge and Union																				
Southwest Gas Corp.	Arizona, U.S.	9.50%	2006	40.00%	85%	85%	85%	$887	$775	$661	588,720	6%	18%	28%	0%	48%	2.28	BBB-	2.34	N
Atlanta Gas Light Company	Georgia, U.S.	10.90%	2005	47.93%	97%	81%	62%	$2,250	$2,068	$1,281	1,546,000	3%	3%	94%	0%	0%	5.98	BBB+	3.77	Y
Northern Illinois Gas Company	Illinois, U.S.	10.51%	2005	56.37%	86%	100%	85%	$1,753	$2,845	$2,423	2,166,000	1%	10%	42%	0%	47%	12.43	AA	2.32	Y
Michigan Consolidated Gas Company	Michigan, U.S.	11.00%	2005	39.31%	94%	94%	83%	$2,139	$2,101	$1,751	1,300,000	29%	29%	29%	0%	12%	3.82	BBB	1.96	Y
CenterPoint Energy Resources	Minnesota, U.S.	9.71%	2006	46.14%	48%	26%	48%	$929	$1,456	$23.98	521,199	30%	30%	40%	0%	0%	1.78	BBB	2.83	N
Public Service Electric Gas	New Jersey, U.S.	10.00%	2006	47.40%	98%	98%	40%	$5,932	$5,465	$2,212.12	1,700,000	4%	36%	60%	0%	0%	8.98	BBB	2.29	Y
Puget Sound Energy, Inc.	Washington, U.S.	10.40%	2007	44.13%	100%	99%	39%	$5,982	$3,372	$1,300	713,000	4%	22%	49%	0%	25%	3.07	BBB-	1.89	N
Wisconsin Gas LLC	Wisconsin, U.S.	11.20%	2006	50.20%	100%	100%	36%	$2,268	$1,258	$803	588,800	11%	11%	36%	0%	43%	3.45	A-	3.82	N
AVERAGES		**10.40%**		**46.44%**	**89%**	**85%**	**60%**	**$2,767**	**$2,418**	**$1,307**	**1,140,465**	**11%**	**20%**	**47%**	**0%**	**22%**	**5.22**	**BBB+**	**2.65**	
Median		**10.46%**		**46.77%**																
Minimum		**9.50%**		**39.31%**																
Maximum		**11.20%**		**56.37%**																

EXHIBIT 1 - ROE Database of Canadian and U.S. Gas Distribution Companies

					Parent Company							Customer Mix [1]								
Company	Jurisdiction	Most Recent ROE	Date	Allowed Equity %	Percent Regulated Revenue	Percent Regulated Net Income	Percent Gas Distribution Revenue	Book Value (million $CAD)	Total Revenue (million $CAD)	Gas Distribution Revenue (million $CAD)	Total Gas Distribution Customers	Ind.	Comm.	Res.	Whlsl & Other	Trans-portation	Gas Volume Sold ($10^9 m^3$)	Credit Rating (DBRS/ S&P)	Interest Cov. Ratio [2]	Un-bundled
Other U.S. Companies																				
Arkansas Oklahoma Gas Corp.	Arkansas, U.S.	9.70%	2005	41.04%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N
Arkansas Western Gas Company	Arkansas, U.S.	9.70%	2005	33.03%	23%	2%	2%	$413	$200	$200	151,000	26%	22%	34%	0%	18%	0.62	BB+	22.01	N
CenterPoint Energy Resources	Arkansas, U.S.	9.45%	2005	31.80%	51%	65%	48%	$929	$1,456	$24	521,199	30%	30%	40%	0%	0%	1.78	BBB	2.83	N
Public Service Company of CO	Colorado, U.S.	10.50%	2006	55.49%	99%	95%	33%	$6,183	$4,416	$1,464	1,255,330	8%	8%	35%	0%	49%	6.99	BBB	2.53	Partial
Southern Connecticut Gas Company	Connecticut, U.S.	10.00%	2005	51.28%	90%	99%	32%	$477	$364	$1,970	176,000	N/A	N/A	N/A	N/A	N/A	N/A	BBB+	2.35	N
Illinois Power Company	Illinois, U.S.	10.00%	2005	53.09%	89%	70%	13%	$2,711	$1,966	$630	430,000	19%	24%	57%	0%	0%	1.29	BBB+	4.68	Y
Interstate Power & Light Company	Iowa, U.S.	10.40%	2005	49.35%	96%	100%	20%	$2,650	$2,037	$417	239,372	6%	17%	24%	0%	53%	1.76	BBB+	4.37	N
Duke Energy Kentucky, Inc.	Kentucky, U.S.	10.20%	2005	54.45%	45%	45%	15%	$4,793	$1,874	$5,248	250,000	N/A	N/A	N/A	N/A	N/A	N/A	BBB+	12.52	Partial
Entergy Gulf States, Inc.	Louisiana, U.S.	10.50%	2005	47.52%	84%	61%	2%	$5,351	$4,270	$98	92,000	N/A	N/A	N/A	N/A	N/A	0.19	BBB	3.08	N
Baltimore Gas and Electric Company	Maryland, U.S.	11.00%	2005	48.40%	100%	100%	30%	$4,155	$3,499	$1,044	640,600	18%	32%	32%	0%	17%	3.26	BBB+	1.38	Y
Bay State Gas Company	Massachusetts, U.S.	10.00%	2005	53.95%	80%	68%	63%	$1,328	$363	$5,452	337,502	44%	20%	29%	0%	7%	2.34	BBB	2.25	Y
Consumers Energy Company	Michigan, U.S.	11.00%	2006	35.06%	99%	100%	41%	$8,372	$6,639	$2,755	1,714,000	N/A	N/A	N/A	N/A	N/A	8.75	BB	1.58	Y
Northern States Power Company - MN	Minnesota, U.S.	10.40%	2005	50.24%	100%	93%	19%	$5,234	$4,206	$864	418,994	22%	22%	43%	2%	11%	2.02	BBB	3.65	N
Central Hudson Gas & Electric	New York, U.S.	9.60%	2006	45.00%	66%	79%	16%	$845	$765	$181	367,000	N/A	N/A	N/A	N/A	N/A	N/A	A	3.76	Y
Orange & Rockland Utilities, Inc.	New York, U.S.	9.80%	2006	48.00%	100%	100%	29%	$989	$949	$675	125,589	5%	5%	63%		26%	0.35	A	2.64	Y
Vectren Energy Delivery Ohio	Ohio, U.S.	10.60%	2005	48.10%	81%	84%	60%	$933	$663	$401	318,000	47%	27%	27%	0%	0%	1.45	A-	2.46	Y
Oklahoma Natural Gas Co	Oklahoma, U.S.	9.90%	2005	46.76%	16%	14%	16%	$2,863	$5,436	$895	800,047	0%	9%	29%	8%	54%	10.74	BBB	2.16	N
PPL Gas Utilities Corp	Pennsylvania, U.S.	10.40%	2007	51.79%	69%	39%	5%	$7,244	$3,844	N/A	110,000	N/A	N/A	N/A	N/A	N/A	N/A	BBB	3.46	Y
South Carolina Electric & Gas	South Carolina, U.S.	10.25%	2005	50.75%	100%	100%	21%	$5,750	$2,775	$586	297,165	41%	28%	25%	0%	6%	1.23	A-	3.34	N
Virginia Natural Gas, Inc.	Virginia, U.S.	10.00%	2006	44.96%	97%	81%	62%	$525	$365	$1,702	264,000	4%	4%	92%	0%	0%	0.93	BBB+	3.77	Y
Avista Corp.	Washington, U.S.	10.40%	2005	40.00%	84%	89%	41%	$1,850	$1,386	$604	304,000	2%	19%	31%	25%	24%	1.78	BB+	2.12	N
Madison Gas and Electric Company	Wisconsin, U.S.	11.00%	2005	56.65%	103%	74%	40%	$794	$589	$237	138,000	4%	38%	55%	0%	3%	N/A	AA-	5.55	N
Wisconsin Public Service Corp	Wisconsin, U.S.	11.00%	2005	59.73%	100%	92%	31%	$449	$349	$515	306,293	10%	10%	30%	0%	50%	1.94	A+	3.60	N
Northern States Power Co-WI	Wisconsin, U.S.	11.00%	2006	53.66%	100%	101%	21%	$941	$853	$173	100,000	22%	22%	32%	5%	18%	0.50	BBB+	3.89	N
Wisconsin Electric Power Company	Wisconsin, U.S.	11.20%	2006	56.34%	100%	100%	19%	$5,199	$3,617	$685	452,600	12%	12%	39%	0%	38%	2.30	A-	6.12	N
Wisconsin Power and Light Co	Wisconsin, U.S.	10.80%	2007	54.00%	100%	100%	20%	$1,984	$1,626	$318	182,098	2%	19%	26%	0%	53%	1.23	A-	31.88	N
AVERAGES		**10.34%**		**48.48%**	**83%**	**78%**	**28%**	**$2,918**	**$2,180**	**$1,131**	**399,632**	**17%**	**19%**	**39%**	**2%**	**22%**	**2.57**	**BBB+**	**3.14**	
Median		**10.40%**		**49.80%**																
Minimum		**9.45%**		**31.80%**																
Maximum		**11.20%**		**59.73%**																
ALL U.S. - AVERAGES		**10.35%**		**48.00%**	**84%**	**80%**	**36%**	**$2,882**	**$2,238**	**$1,175**	**579,228**	**15%**	**19%**	**42%**	**2%**	**22%**	**3.33**	**BBB+**	**2.98**	
ALL U.S. - Median		**10.40%**		**48.10%**																
ALL U.S. - Minimum		**9.45%**		**31.80%**																
ALL U.S. - Maximum		**11.20%**		**59.73%**																

Company	Jurisdiction	Most Recent ROE	Date	Allowed Equity %	Parent Company: Percent Regulated Revenue	Parent Company: Percent Regulated Net Income	Percent Gas Distribution Revenue	Book Value (million $CAD)	Total Revenue (million $CAD)	Gas Distribution Revenue (million $CAD)	Total Gas Distribution Customers	Customer Mix [1]: Ind.	Customer Mix [1]: Comm.	Customer Mix [1]: Res.	Customer Mix [1]: Whlsl & Other	Customer Mix [1]: Trans-portation	Gas Volume Sold (10^9m^3)	Credit Rating (DBRS/ S&P)	Interest Cov. Ratio [2]	Un-bundled

Notes:

[1] Customer mix is based on the best available information for each of the companies analyzed. For the most part, customer mix is based on volume of throughput per customer class. Where throughput information was not available, revenue by customer class was used. If neither of these types of information was available, CEA used number of customers by customer class. Enbridge's customer mix is based on revenue by customer type, based on Enbridge's 2007 test year rate case, EB-2006-0034, Exhibit C3, Tab 1, Schedule 1, p. 2. Union's customer mix is based on total 2007 forecast throughput for industrial, commercial, and residential customers, taking into account the approximate percentage of transportation throughput based on Union's 2006 MD&A. See EB-2005-0520, Exhibit C1, Summary Schedule 1, and Union Gas 2006 Annual Report.

[2] The mean interest coverage ratio for the U.S. companies is 4.8 times, but includes certain outlier data, such as 22 times for Arkansas Western Gas Company, 31.9 times for Wisconsin Power and Light Co, and 12.5 times for Duke Energy Kentucky. For this reason, CEA excluded the outlier data to arrive at the presented mean.

[3] While technically a gas distribution company, Enbridge classifies certain of it revenues as "transportation" revenues. Per Enbridge's 2006 Annual Information Form, "Under the transportation service, arrangement, a customer supplies natural gas at a TransCanada receipt point in western Canada or at a TransCanada delivery point in Ontario, and [Enbridge] redelivers an equal amount of gas to the customer's end-use location."

[4] Certain of Pacific Northern Gas, Ltd.'s information was presented at the holding company level only. For purposes of this table, that information is provided under PNG's West Division.

[5] Certain of Terasen Gas Inc.'s information was presented at the holding company level only. For purposes of this table, that information is provided under Terasen Gas Inc.

[6] Transportation volumes were unavailable for ATCO.

[7] Note: for U.S subsidiary companies for which financial statements were not available at the subsidiary level, CEA approximated book value and total revenue based on an estimate of the subsidiary's total contribution to the parent's consolidated operations. Estimates were made based on the best available data, which included customer numbers, revenue, and fixed assets.

EXHIBIT 2 - Complete Listing of U.S. Gas Distribution ROE Awards, 2005 to Present

State	Company	Case Identification	Date	Rate Increase ($M)	Return on Rate Base(%)	Return on Equity (%)	Equity /Total Cap (%)
Arizona	Southwest Gas Corp.	D-G-01551A-04-0876	2/15/2006	49.3	8.40%	9.50%	40.00%
Arkansas	CenterPoint Energy Resources	D-04-121-U	9/19/2005	-11.3	5.31%	9.45%	31.80%
Arkansas	Arkansas Western Gas Co.	D-04-176-U	11/2/2005	4.6	5.93%	9.70%	33.03%
Arkansas	Arkansas Oklahoma Gas Corp.	D-05-006-U	12/9/2005	4.4	6.61%	9.70%	41.04%
Colorado	Public Service Co. of CO	D-05S-264G	1/19/2006	22.5	8.70%	10.50%	55.49%
Connecticut	Southern Connecticut Gas Co.	D-05-03-17PH01	12/28/2005	26.7	8.85%	10.00%	51.28%
Georgia	Atlanta Gas Light Co.	D-18638-U	6/10/2005	0.0	8.53%	10.90%	47.93%
Illinois	Illinois Power Co.	D-04-0476	5/17/2005	11.3	8.18%	10.00%	53.09%
Illinois	Northern Illinois Gas Co.	D-04-0779	9/30/2005	54.2	8.85%	10.51%	56.37%
Iowa	Interstate Power & Light Co.	D-RPU-05-1	10/14/2005	14.0	8.68%	10.40%	49.35%
Kentucky	Duke Energy Kentucky Inc.	C-2005-00042	12/22/2005	8.1	8.10%	10.20%	54.45%
Louisiana	Entergy Gulf States Inc.	D-U-28035	7/6/2005	5.8	8.11%	10.50%	47.52%
Maryland	Baltimore Gas and Electric Co.	C-9036	12/21/2005	35.6	8.49%	11.00%	48.40%
Massachusetts	Bay State Gas Co.	DTE-05-27	11/30/2005	11.1	8.22%	10.00%	53.95%
Michigan	Michigan Consolidated Gas Co.	C-U-13898	4/28/2005	60.8	7.19%	11.00%	39.31%
Michigan	Consumers Energy Co.	C-U-14547	11/21/2006	80.8	6.69%	11.00%	35.06%
Minnesota	Northern States Power Co. - MN	D-G-002-GR-04-1511	8/11/2005	5.8	8.76%	10.40%	50.24%
Minnesota	CenterPoint Energy Resources	D-G-008/GR-051380	11/2/2006	21.0	7.54%	9.71%	46.14%
New Jersey	Public Service Electric Gas	D-GR05100845	11/9/2006	40.0	7.96%	10.00%	47.40%
New York	Central Hudson Gas & Electric	C-05-G-0935	7/24/2006	8.0	7.05%	9.60%	45.00%
New York	Orange & Rockland Utlts Inc.	C-05-G-1494	10/18/2006	12.0	7.99%	9.80%	48.00%
Ohio	Vectren Energy Delivery Ohio	C-04-571-GA-AIR	4/13/2005	15.7	8.94%	10.60%	48.10%
Oklahoma	Oklahoma Natural Gas Co	Ca-PUD-200400610	10/4/2005	57.5	8.74%	9.90%	46.76%
Pennsylvania	PPL Gas Utilities Corp	C-R-00061398	2/8/2007	8.1	8.44%	10.40%	51.79%
South Carolina	South Carolina Electric & Gas	D-2005-113-G	10/31/2005	22.9	8.43%	10.25%	50.75%
Virginia	Virginia Natural Gas Inc.	C-PUE-2005-00057	7/24/2006	0.0	7.83%	10.00%	44.96%
Washington	Avista Corp.	D-UE-05-0483	12/21/2005	1.0	9.11%	10.40%	40.00%
Washington	Puget Sound Energy Inc.	D-UG-060267	1/5/2007	29.5	8.40%	10.40%	44.13%
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-114	12/12/2005	3.8	8.88%	11.00%	56.65%
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-117 (elec.)	12/22/2005	7.2	8.83%	11.00%	59.73%
Wisconsin	Northern States Power Co-WI	D-4220-UR-114 (gas)	1/5/2006	3.9	9.97%	11.00%	53.66%
Wisconsin	Wisconsin Electric Power Co.	D-05-UR-102 (WEP-GAS)	1/25/2006	21.4	8.94%	11.20%	56.34%
Wisconsin	Wisconsin Gas LLC	D-05-UR-102 (WG)	1/25/2006	38.7	11.38%	11.20%	50.20%
Wisconsin	Wisconsin Power and Light Co	D.6680-UR-115 (gas)	1/11/2007	1.0	NA	10.80%	54.00%

Source: Regulatory Research Associates.

Allowed Return on Equity in Canada and the United States

An Economic, Financial and Institutional Analysis

National Economic Research Associates, Inc.
Kenneth Gordon, Ph.D
Jeff D. Makholm, Ph.D

Marsh & McLennan Companies

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This study was commissioned by the Canadian Gas Association.

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I. INTRODUCTION[1]

Canada and the United States have almost hundred-year histories of regulating investor-owned utilities. This shared experience is different from almost all of the rest of the world, where the appearance of investor-owned (i.e., private) utilities came only with the privatization wave of the late 20th century. The regulatory laws, mechanisms and institutions in those other countries are new—and in many cases untested. But longstanding regulatory institutions in Canada and the US have for decades been helping to provide safe and adequate services to the public at reasonable prices while ensuring that the companies involved remain "going concerns" with sufficient credit worthiness to attract the capital needed to maintain and expand their facilities.

Over the past decade, however, a significant difference has appeared in the regulatory practices between Canada and the US. In an effort to improve regulatory efficiency, Canadian regulators—first in British Columbia, then more widely—moved away from the case-by-case approach to determining the fair return on equity (ROE) for utility rate making purposes. Canadian regulators adopted generic, formula-based approaches to deriving the admittedly elusive fair ROE. US regulators in the 1980s and 1990s made two tries at generic, formula-based approaches to setting the ROE (one at the federal level and one in the State of New York), but, in the end, did not abandon their longstanding, case-by-case methods that rested on two existing and long-accepted financial theories.

The apparent efficiency of bypassing case-by-case evidentiary proceedings with a generic formula may have foretold a new and more efficient method of deriving regulated rates generally—except for one thing. The current Canadian generic ROE formula appears to have created a persistent divergence between allowed gas utility returns in Canada and the US. Since 1998, ROEs used to make regulated tariffs have been, on average, 100 to 150 basis points lower than in the US. That is, in dozens of evidentiary proceedings since 1998, US regulators have allowed their companies to set tariffs reflecting ROEs that were on average substantially higher than for their Canadian formula-driven ROE counterparts.

The purpose of this report is to analyze the root causes of this disparity between Canadian and US ROEs that has apparently been propelled—either directly or indirectly—by the Canadian ROE adjustment formula. Since the "appropriate" level of ROE is driven by the risk/return requirements of those utility investor-owners, the obvious question is whether Canadian utilities face sufficiently less risk than their US counterparts. Conversely, we investigate whether the difference in allowed returns for ratemaking is merely a symptom of a structurally inflexible formula rather than an indicator of underlying risk differences. If it is the latter, then Canadian regulators have indeed streamlined rate cases for the better. If the former, then perhaps the formula has had unintended consequences and is in need of updating better to reflect the market's judgment on the cost of equity of regulated Canadian utilities.

[1] This report was written by NERA's Kenneth Gordon, Special Consultant and former Chairman of the Department of Public Utilities Massachusetts and the Public Utility Commission in Maine and Jeff D. Makholm, Senior Vice President. They were supported by Ryan Knight at NERA.

It is important to state at the outset how we approach examining this divergence   We cannot automatically presume that the burden falls on Canadian regulators to justify the persistently lower average ROEs than those granted by their US counterparts. Nevertheless, it is the group of Canadian regulators that changed course in the last decade, led by those regulators using the generic formula for streamlined regulatory procedures. Those regulators in the US who failed to find a suitable way to streamline their ROE procedures continued on the former path common to both Canadian and the US regulation—to examine anew, in every tariff case, expert evidence on ROE for the company in question for the relevant period of time. We do not believe that either Canadian or US regulators would consider the results of those case-by-case evidentiary procedures to be biased on a large scale. They are perhaps expensive, time consuming or overwrought—but not biased. Therefore, it is natural—and again to us justifiable—to subject the new Canadian generic formula to the test of bias. If we find that Canadian and US utilities face comparable operating environments and risk to investors, then it is natural to question the efficacy of the new Canadian formula approach to the ROE, not the traditional path US regulators still hold. It is therefore not prejudgment that prompts us to examine underlying justifications for the new and lower Canadian ROEs, but practicality. We do not question whether US regulators (or Canadian regulators up to the adoption of the new formula) were incapable of deriving "just and reasonable" tariffs. What we do question is whether, based on underlying risk factors, the new Canadian generic ROE formula can do likewise.

Canadian regulators have acknowledged in rate cases that a disparity exists between Canadian and US allowed ROEs, but have not concluded whether or not the disparity warrants action.[2] For example, the regulator in Quebec, the Regie de l'Energie, stated in 2007, "[i]n the Regie's view, even though rates of return allowed in the United States are clearly higher on average than those allowed in Canada, the evidence does not make it possible to conclude that there is any prejudice to or unfair treatment of the distributor.... The evidence does not make it possible to compare the overall differences that may exist in the institutional, economic and financial contexts of the two countries and their impact on the opportunities they provide for investors." [3]

Unfortunately, nothing surrounding the required ROE for the purpose of making regulated tariffs is an easy discussion. Unlike the other elements of tariff setting (operating costs, maintenance costs, administrative expenses or the interest rates on utility bonds) the ROE is not directly observable. The required ROE is a function of investor *expectations*. Those expectations remain complex functions of how investors believe that price regulation, along with the utility's other circumstances, will work to allow them a return on the capital that they devote to serving the public. Given the complexity associated with discussion of the fair ROE, this report will examine the root of the post-1998 differences in permitted ROEs. Those differences stem either from corresponding differences in risk in Canada versus the US or from more banal causes relating to the operation of the generic ROE formula itself vis-à-vis investors' genuine risk-driven expectations.

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[2] *See*: Ontario Energy Board (OEB) *A Review of the Board's Guidelines for Establishing Return on Equity* RP-2002-0158 (2004) ¶ 122. *See* also: Alberta Energy Board (EUB) *Generic Cost of Capital* Decision 2004-052 (2004) pgs 25-27.

[3] Regie de l'Energie, *Decision: Application to Modify the Tariffs of Gaz Metro Ltd*. D-2007-116 (2007) §4.1.10.

The report concludes that the regulatory environments in Canada and the US are highly similar and directly comparable. Since the world's first utility commission regulatory statute was written in the US in 1907 in Wisconsin, that general form has been widely copied in all states and provinces in Canada and the US.[4] These two national jurisdictions thus share a common heritage that is quite different, for example, from the newly-privatized regulatory jurisdictions in the rest of the world. Those jurisdictions overseas regulate their investor-owned utilities on an institutional basis quite different than in Canada and the US—two countries that share the longest, largest and most unencumbered trade border in the world. It is thus a fair question to compare and contrast Canadian and US utilities with each other to examine how their regulators deal with them and, in particular, derive the ROEs used to set their regulated tariffs.

Section II contains our Executive Summary. In **Section III**, we examine the evident divergence between allowed returns in Canada and the US that propels this study. In **Section IV**, we compare the methods used for setting base ROEs in Canada to the case-by-case methods still used by US utility regulators, despite two highly visible attempts to create generic formulas there. In **Section V**, we examine the sources of risk for regulated utilities and any apparent differences between investor-owned utilities in Canada and the US that might, in principle, explain the wedge in ROEs that has appeared since 1998.

[4] That statute was drafted by John R. Commons, a professor of economics at the University of Wisconsin and 10 years later the President of the American Economic Association.

II. EXECUTIVE SUMMARY

In the introduction to this report, we stated that we do not automatically presume that the burden falls on Canadian regulators to justify the persistently lower ROEs allowed relative to their US counterparts. First, those numbers may not fairly gauge the treatment of Canadian gas distributors on the part of regulators. Second, those ROEs may combine with other aspects of Canadian financial markets or regulatory procedures that do not generalize to the US. Third, the relative ROEs may reflect business, regulatory, or financial risk differences for Canadian gas distributors versus their US counterparts.

Taking these elements into account, however, it is our opinion that the generic Canadian formula itself should be the subject of scrutiny. The formula works like an "autopilot" for setting new Canadian ROEs that uses long bonds as the only contemporary gauge of financial markets—instead of directly targeting equity costs. If the new autopilot has been setting a different course than the case-by-case "human" pilots that previously characterized Canadian ROE, and still characterize US ROE setting, then the autopilot should bear the burden of showing that it is not biased. We cannot conclude going in that the group of independent regulators setting their own ROEs on a case-by-case basis are the ones to be exhibiting a bias.

Figure 1 in our report, showing a marked split in the allowed ROEs in Canada and the US, demands the examination of three issues regarding the meaning and comparability of the relative ROEs before the question of whether the Canadian formula has exhibited a bias in recent years can be addressed:

- We explain that under both Canadian and US regulatory methods, the ROE is the measure of cost of capital that enters the formula to make "just and reasonable" rates. It is the measure of compensation allowed for the capital that investors devote to the service of the public *at the time rates are set*. What happens afterward—in other words, what the utilities actually achieve in profitability—is a different matter. The actual returns reflect many things including management effectiveness, sales growth, the weather, macroeconomic considerations, changes in capital costs, etc. But regulatory treatment of investor-owners is tightly bound to the ROE. We conclude that allowed ROE is the proper metric for comparison.

- We find that the regulatory institutions and customs for setting regulated prices for investor-owned Canadian and US utilities are very alike. That is, in accounting, administrative procedures, regulatory legislation, and basic constitutional protections of private property, little or nothing separates the average Canadian from the average US regulatory jurisdictions, unlike newly-privatized utilities in new regulatory jurisdictions overseas, where regulatory institutions are young (and largely untested),. There are of course differences in regulatory treatment from province to province and from state to state. But we find generally that there is no persistent difference in regulatory legislation or rule making between Canada and the

US.[5] As such, the cost of equity capital is comparable between the two countries as long as the risk of gas distributors is the same or similar on both sides of the border.

- We examine the definition of risk to investors of placing their capital at the use of the public, for which the ROE provides compensatory payment. We look at how those risks could be different in Canada versus the US. What we find is that the basic sources of risk—regulatory, business and financial—are comparable with respect to both jurisdictions. Objective and disinterested analyses of the relative risks between Canadian and US utilities are rare, but what we have found points to no smaller risks in Canada. As such, we conclude that there is no objective evidence showing that business or regulatory risks are sufficiently lower in Canada to account for the divergences shown in **Figure 1**.

With this analysis, our conclusion is inescapable. The Canadian ROEs produced by the generic Canadian ROE formula are biased downward. The formula has, since its inception, ridden on autopilot the declining Canadian long-bond interest rates (the cost of a kind of debt) with no independent check on the cost of equity. The generic Canadian formula might not always be biased, and indeed in an era of stable interest rates and equity markets it may have held a true course for many years. But is has been overtaxed by the relatively unprecedented decline in interest rates since the late 1990s. The uncorrected, un-calibrated formula—not risk differences or inherent Canadian regulatory differences—has driven the divergence between observed Canadian and US ROEs.

The manifest remedies are either to return to "human" pilots (representing case-by-case ROE determinations) or re-calibrate the Canadian generic formula by re-examining the current relationship between the contemporaneous cost of debt and gas utility equity. Given the similarity in the jurisdictions, the institutions of regulation and capital markets, it would be useful in our opinion to employ both Canadian and US gas utility equities in such an analysis, along with both of the main cost of equity models (DCF and CAPM). Without a new calibration, it is likely that as long as the interest rates in Canada and the US remain low, the generic ROE formula will continue to fly off course—essentially treating Canadian utility investors unfairly and slowly taxing their financial health in this era of low interest rates.

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[5] If one threw all 63 federal and provincial/state regulatory statutes (13 for Canada, 51 from the US) into one pile with all the names blacked out, we would challenge anyone to sort them into a Canadian or US pile based on their content alone.

III. AN EVIDENT DISPARITY IN CANADIAN AND US ALLOWED RETURNS

This report is propelled by the need to examine the persistent gap between the allowed returns on equity for ratemaking purposes between Canadian and US regulators.[6] This section examines what the divergence is and where it comes from. It examines whether the ROE figures in Canada and the US are both a reasonable and comparable metric for determining effective regulatory control over profitability in both countries, and also describes how the Canadian ROE formula works.

There are two key questions. First, does the divergence mean anything? Is the ROE (as opposed to earned returns) the right metric for comparison? Second, are the economies comparable enough (given differences in taxes, etc.—everything but regulatory risk) to permit ROE comparisons.

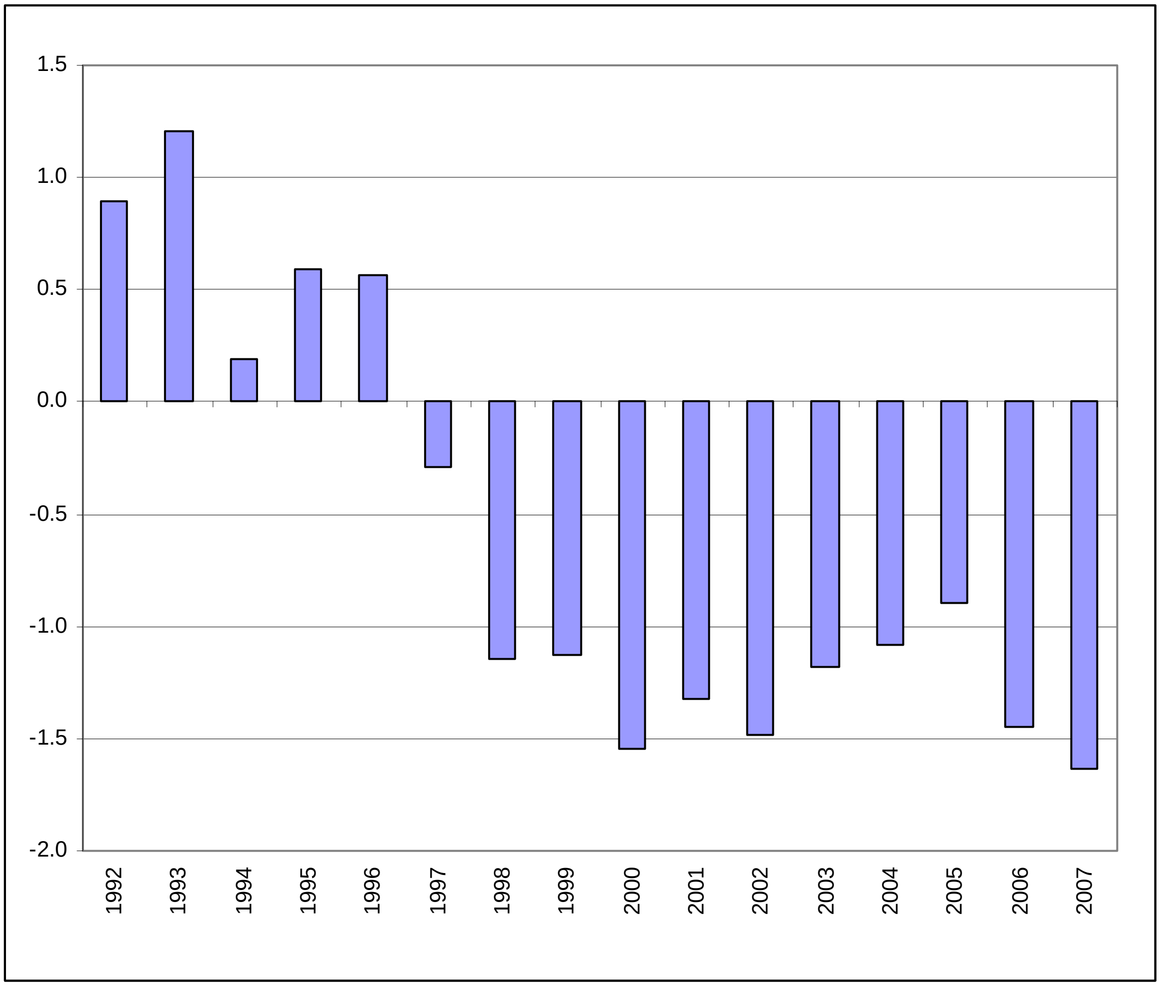
A. The Divergence between Canadian and US Allowed Returns for Ratemaking

Figure 1 shows that Canadian allowed returns were, at one time, higher than those allowed in the US, but that this changed during 1997. Since then, Canadian allowed returns have been markedly lower than those in the US.

Figure 1 was compiled using data submitted by members of the Canadian Gas Association (CGA) for Canada and data gathered from Regulatory Research Associates for the US. The CGA submitted data for 8 Canadian LDCs, although data were not available for every LDC for every year. The number of rate case decisions for US LDCs for which Regulatory Research Associates data were available varies from 10 in 1999 to 42 in 1993. The data used to construct Figure 1 is presented in **Table 1** below.

[6] It is important to keep in mind that "allowed returns" (i.e., ROE) means the rate of return equity, permitted in a rate case proceeding, to form a component of regulated prices. It does not refer to an attempt by regulators to control the return on capital actually earned by utilities once those rates are set. Ratemaking in Canadian and US jurisdictions is generally a *prospective* exercise.

Figure 1: Allowed Return Average Differential (Canada-US) for Gas Distribution Utilities, 1992-2007



Source: Canadian Gas Association, Regulatory Research Associates.

- **Figure 1** was generated by subtracting the average allowed US ROE from the average allowed Canadian ROE for each year. This differential for Canada ranges from 121 basis points above US ROEs in 1993 to 164 basis points below in 2007. Starting in 1997, the differential has been consistently negative; indicating that, over the past decade, average allowed US ROEs are higher on average than those in Canada. These average allowed ROEs for both countries are presented on **Table** 1.

Table 1: Canada-US Average Allowed Return Differential, 1992-2007

	Canada	US	Difference
1992	12.88	11.98	0.89
1993	12.58	11.37	1.21
1994	11.44	11.24	0.19
1995	12.03	11.44	0.59
1996	11.68	11.12	0.56
1997	11.01	11.31	-0.29
1998	10.38	11.52	-1.15
1999	9.52	10.64	-1.12
2000	9.80	11.35	-1.55
2001	9.64	10.96	-1.32
2002	9.61	11.10	-1.48
2003	9.79	10.97	-1.18
2004	9.55	10.63	-1.08
2005	9.52	10.41	-0.89
2006	8.99	10.43	-1.45
2007	8.71	10.35	-1.64

By the simple metric of average ROEs in Canada and the US, a clear disparity has emerged. This disparity was the subject of a recent report by Concentric Energy Advisors, which examined the disparity between Ontario LDCs and US LDCs in particular. The Concentric Report concludes that Canadian ROEs were more sensitive to the drop in bond yields over this period than were US ROEs.[7] Further, the Concentric Report suggests that this sensitivity arose through the adoption of an automatic adjustment mechanism that explicitly ties Canadian ROEs to long-bond prices.[8]

B. Is Allowed ROE the Proper Metrics for the Comparison of the Treatment of Utilities by their Regulators?

A threshold question is whether the figures in Table 1 mean anything in terms of assessing regulatory treatment in Canada versus the US. That is, given the unique economic and financial contexts of each country, are ROEs structurally different such that an allowed return in the Canada does not mean the same thing as an allowed return in the US?

Three issues arise in answering this question. First, is the ROE the proper metric, as opposed to the return that the utilities in question have actually achieved during the period of time the rates were in effect? It is a question that arises often in comparison of ROEs. Second, does capital flow freely between countries? If capital does not flow between countries, allowed returns are

[7] Concentric Energy Advisors, "A Comparative Analysis of Return on Equity of Natural Gas Utilities," prepared for Ontario Energy Board (2007). p. 2.

[8] *Id.*, p. 56.

likely to not be comparable as capital costs would reflect strictly national macroeconomic considerations. Third, given the distinct tax and financial environments, such as differences in country-specific interest rates, are allowed returns similar indicators in both Canada and the US? This section examines these issues in turn.

1. Allowed ROEs versus Achieved Returns

Is the allowed ROE the proper metric, or are the returns that the utilities in question have actually achieved during the period of time the rates were in effect the relevant indicator? We readily conclude that the answer is yes: allowed ROEs are the proper metric. Both in Canada and the US, the general manner of regulatory control is for regulators to set *reasonable rates* and then allow utilities to do the best they can to make a business and earn a reasonable return against those rates. That is to say, utilities in Canada and the US are not cost-plus businesses that can appeal to cover costs after the fact. Utilities are not confined to any particular return. There are admittedly exceptions (which we consider idiosyncrasies) to this general statement—but the character of ratemaking control in both countries is prospective.

For over a century, both in Canada and the US, the pull between private enterprise and the public welfare has been settled just this way: regulators deem the return to be considered "just and reasonable" and the private utility subsequently does its best to profit—until such time as the regulator or the utility request that the question of the forward-looking just and reasonable rates should be adjudicated again.

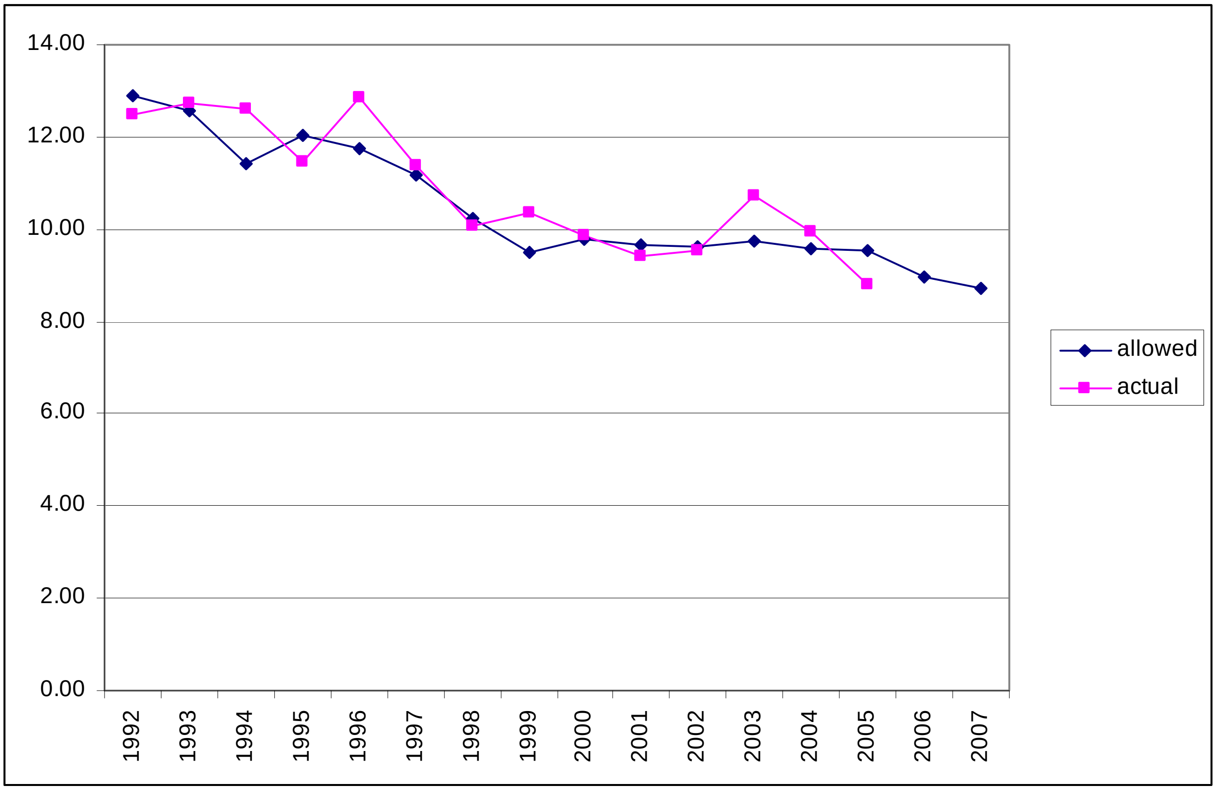
It follows that if the ratemaking mechanisms defined by regulatory legislation and rulemaking (*i.e.*, how costs are added together and then divided by measured sales to form the rate) are the same in Canada and the US, then the allowed ROEs are directly comparable. After the fact, some utilities may profit more than others (*e.g.*, those in fast-growing service territories versus slow-growing ones).[9] Or there may be some times when it is easier than others for utilities to profit (*i.e.*, when capital costs are generally falling rather than rising against a fixed set of just and reasonable rates). But with the commonality of ratemaking mechanisms in Canada and the US, the role of the allowed ROE is the same. Hence, its comparability across jurisdictions is proper.

If ratemaking procedures and operating conditions are comparable in Canada and the US, there would be no reason to expect utilities in either country would regularly earn more than the allowed ROE. **Figure 2** shows that, as we would expect, given our review of the mechanisms of rate regulation in Canada, earned returns have been both above and below allowed returns in

[9] There is a comparison between returns for Canadian and US regulated pipelines, offered in NEB RH-2-2004 by CAPP (the Canadian Associate of Petroleum Producers) that might seem to suggest a persistent success in achieved returns for Canadian companies versus their US counterparts (although we have not looked closely into the sources or particular reasons for those results reported by CAPP). We note, however, that these are returns obtained by federally-regulated interstate pipeline companies, not local gas utilities. Those pipeline companies do not have the public service obligations or stable customer base of distribution companies, and they are not informative to the comparison of the Canadian versus US *utility* ROEs. *See:* NEB, *Reasons for Decision* RH-2-2004 Phase II (2005), Figure 5-1.

Canada since the inception of the formula. In our experience, this pattern of allowed versus actual ROEs, reflecting occasional average divergences, is characteristic of utilities in the US as well.

Figure 2: Allowed versus Earned Returns For Gas Distributors in Canada, 1992-2007



Source: Canadian Gas Association

We show **Figure 2** merely as a way of dealing again with the statement that earned returns—an *ex post* measure of utility performance against a fixed set of "just and reasonable rates"—is not exceptional in Canada. There is nothing, to us, in **Figure 2** that removes the reasonable use of **Figure 1** as a reason to question whether Canadian ROE methods lately have been causing a divergence in the fair return between Canada and the US.

2. Capital Flows

There is no doubt that Canada and the US can experience unique macroeconomic conditions (interest rates, inflation, GDP growth, etc.). That said, Canada and the US share the longest, largest and most open trade border in the world. There has not been a shot fired in anger across this border since 1812. Canada-US trade is open, with few import or export taxes or tariffs.

Energy trade in North America is governed by the North American Free Trade Agreement (NAFTA), the Canada-US Free Trade Agreement (FTA), and the General Agreement on Tariffs and Trade (GATT). Among other things, NAFTA has "provided the building block for the emergence of a cooperative North American market for energy goods."[10]

Today, there are:

- 35 cross-border natural gas pipelines between the US, Canada, and Mexico.
- 22 cross-border oil and petroleum product pipelines.
- 51 cross-border electric transmission lines.

These facilities physically bind Canada and the US together.[11] This physical integration is matched by capital market integration as well. Since deregulation of the wellhead price of natural gas (1985 in Canada, 1981 in US), trade in this "increasingly significant sector" would be based on "internationally-recognized, non-discriminatory market access principles."[12] With competitive markets for the gas commodity and for transport capacity, shippers can negotiate for gas supplies and pipeline space on transmission systems in both Canada and the US, searching for the most economical mix of commodity and transport costs. The situation between Canada and the US is remarkable—unlike many parts of the world, where pipelines are not built if it means passing through other countries.

There does appear to be a preference for domestic investment, especially by pension funds and other "trustee investments," which could result in segmented capital markets. However, many Canadian firms are cross-listed on US exchanges—including Enbridge. As identified by the Concentric report, US investors do play a significant, albeit less prominent, role in the capitalization of Canadian utilities.[13] To the extent that the trustee investments in Canadian utilities represent a structural barrier to investing outside the country, then the cross-border equity investments from the US are a marginal source of funds.[14] Furthermore, some Canadian utilities and their parent companies engage in business in the US and abroad, indicating that utility companies are not regionalized.

One test of the comparability of allowed utility returns is the cost of capital for non-utility firms in Canada and the US. It may be that there are structural differences in the cost of capital

[10] *See:* North American Energy Working Group, "North American Natural Gas Vision," Experts Group on Natural Gas Trade and Interconnections, January 2005: http://www2.nrcan.gc.ca/es/es/naewg/NANaturalGasVision_e.cfm (Accessed on October 28, 2007).

[11] *Id.*, p. 34.

[12] *Id.*, p. 10.

[13] Concentric, s*upra* note 4 p. 50.

[14] Under the efficient markets hypothesis, the marginal investor sets the price for a security. To the extent that this hypothesis holds, it may be that US investors are leading the valuation of Canadian firms. *See:* Ibbotson, R.G. and G.P. Brinson, *Global Investing: The Professional's Guide to the World Capital Markets*, McGraw-Hill: New York (1993), p. 37-41.

between Canada and the US that would result in a categorically lower cost of capital for Canadian firms, reflecting a lower opportunity cost of investment for Canadian utilities.

In an attempt to address this question, a 2007 study by researchers at the Bank of Canada estimated a cost of capital 30-50 basis points *higher* for Canadian firms than US firms, all else equal. The study estimated cost of capital based on a forward-looking, discounted cash flow (DCF) analysis of Canadian and US firms from 1988 to 2006.[15] This study takes into account forward-looking investor expectations, and is evidence that the cost of capital does not appear to be categorically lower in Canada.

3. Tax Differences

Differences in tax laws have been proposed in some previous discussions about the differences in recent Canadian and US allowed returns as a potentially confounding factor in Canada-US comparisons. Tax rates facing Canadian and US investors are indeed different, both for domestic and cross-border investments. However, it is the practice of Canadian and US regulators to set allowed ROEs on a pre-tax basis, permitting income taxes for the utility, as such, to enter the ratemaking formula as a pass through expense in permitted rates.[16] In other words, income taxes are treated in both jurisdictions as a measurable expense when grossing up the pre-income-tax ROE to calculate a post-income-tax figure for use in setting consumers charges. Therefore, as the income tax treatment is similar, if the institutional, financial and economic risk environments are comparable, ROEs are comparable as well, regardless of differences in taxation.

4. Macroeconomic Interest Rates

If interest rates forecasts are substantially lower in Canada, the apparent disparity in allowed returns may simply be a byproduct of lower underlying capital cost rates, and there may be no difference in the relevant fair ROE awarded by Canadian and US regulators.

As **Figure 3** shows, interest rates have been in rough parity since the beginning of the divergence, and US long-bond yields were even below Canada's for much of the time. This would indicate that macroeconomic interest rates are not driving the divergence since 1998 (although they may account for some of the positive divergence before that time), given that US interest rates have been both above and below Canada's rates during the period of interest.

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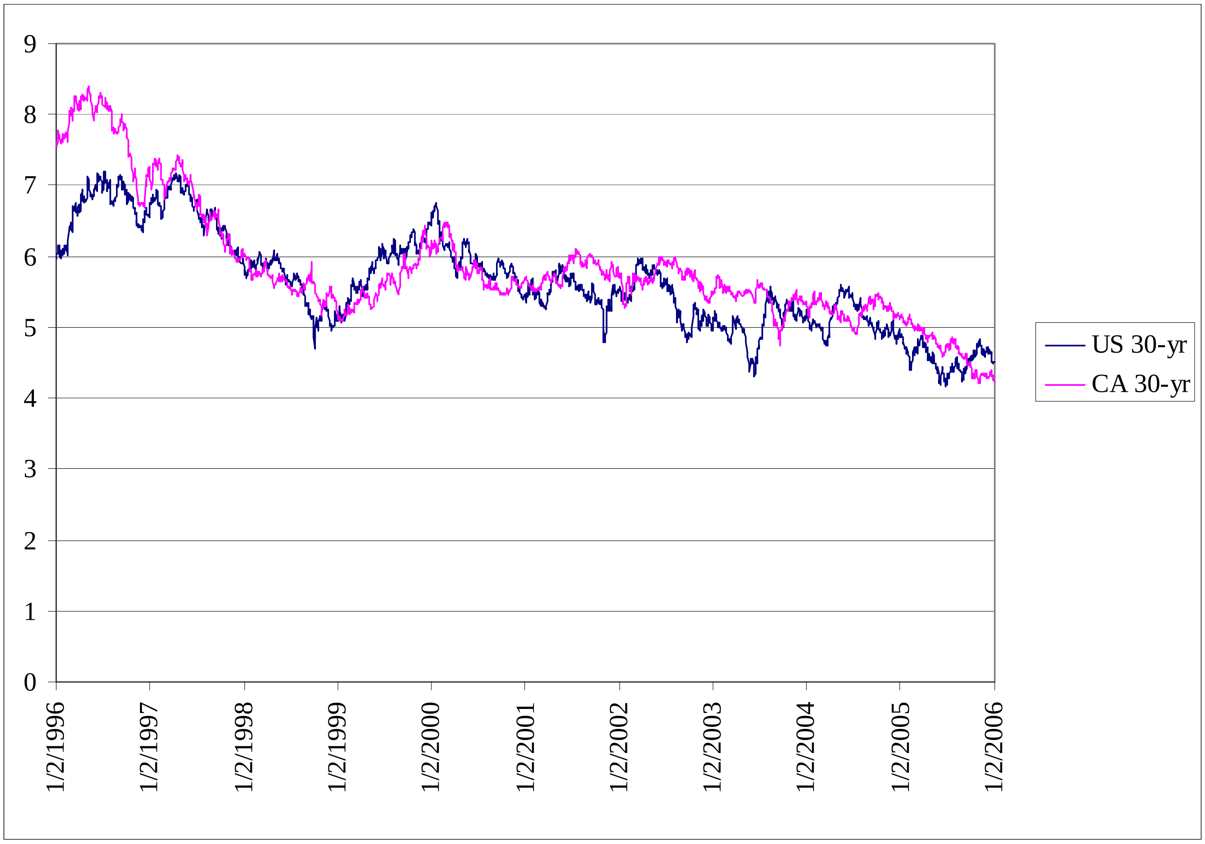
[15] Witmer, J. and Zorn, L. "Estimating and Comparing the Implied Cost of Equity for Canadian and U.S. Firms" Bank of Canada Working Paper 2007-48 (2007). Available at: http://www.bank-banque-canada.ca/en/res/wp/2007/wp07-48.pdf (Accessed on 11/15/07).

[16] The income taxes on dividends or capital gains for individual investors are not a subject of concern to Canadian or US regulators—only the income taxes that form a part of compensatory rates for the utility.

Figure 3: Long-Term Bond Yields in Canada and the United States (1996-2006)



Source: US Treasury Department and Bloomberg

C. The Source and Form of the New Canadian ROE Methods

Beginning in 1994, Canadian regulators—first some, then others—have adopted automatic adjustment mechanisms for setting the ROE in utility rates based on a fixed spread with observed movements in Canadian interest rates on long bonds. In these jurisdictions, the ROE is automatically adjusted annually based on movements in long-term bond forecasts.

The approach used by the NEB, Ontario, Quebec and Alberta is to establish a "benchmark" ROE that is applied to all utilities, with individual business risks taken into account when the capital structure is "deemed."[17] The generic ROE is then adjusted annually as follows:

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[17] Capital structures are "deemed" in Canada based on relative business risk. An LDC with more business risk will be deemed a higher equity ratio in its capital structure to raise the overall weighted average cost of capital. This contrasts with the US, where LDCs are predominantly allowed to choose their capital structure within a band of reasonableness.]

1. The forecast yields on 3 and 12 month out 10-year Canadian bonds are obtained from the most recent forecast by Consensus Economics.

2. These two forecasts are then averaged.

3. To get an estimate for a 30-year forecast, the result is adjusted to reflect the actual spread between 10-year and 30-year bonds in the previous month as reported in *The Financial Post*.

4. This estimated 30-year forecast is subtracted from the previous years' forecast.

5. The difference is multiplied by 0.75.

6. The new ROE is previous years' ROE plus (minus) the result.

Some provinces may use a slightly different adjustment, but the process is largely similar. The ROE adjustment is shown in Equation 1.

$$ROE_t = ROE_{t-1} + .75(Forecast_t - Forecast_{t-1}) \quad \textbf{(1)}$$

Using this formula, the following rates would result from a benchmark ROE of 12 percent based on interest rates of 8 percent if interest rates were to fall.

Table 2: Hypothetical Formula-Based ROEs

Bond forecast	Allowed ROE
8.00	12.00
7.00	11.25
6.00	10.50
5.00	9.75
4.00	9.00
3.00	8.25

The formula approach was first introduced in British Columbia in 1994 before being adopted by Manitoba and the NEB in 1995. Ontario adopted the NEB approach for 1997, and was followed by Quebec in 1999. Finally, Alberta adopted formula adjustments in 2004.

Table 3: Major Jurisdictions Implementing Formula-Based ROEs

Regulator	Jurisdiction	Case ID	Year
British Columbia Utility Commission (BCUC)	British Columbia	Decision in the Matter of Return on Common Equity, June 10, 1994	1994
National Energy Board (NEB)	Federal	Reasons for Decision re: RH2-94 Cost of Capital, March 1995	1995
Public Utilities Board of Manitoba (PUBM)	Manitoba	PUB Order 49/95	1995
Ontario Energy Board (OEB)	Ontario	Draft Guidelines on a Forumla-Based Retun on Common Equity for Regulated Companies	1997
Regie de l'Energie	Quebec	D-99-11	1999
Alberta Energy Utilities Board (EUB)	Alberta	2004-052	2004

The 0.75 adjustment factor arose out of the 1995 NEB formula decision. The formula is based on the historical observation that allowed returns tend to move in the same direction as long-term bond yields. There was a desire to protect utility customers from high bond yields and shareholders from low bond yields, so the NEB decided to weight the ROE movement by 0.75 times the change in bond prices. Previously, Manitoba had used a 0.8 adjustment, while British Columbia made one-to-one adjustments if bond prices moved outside of a certain band.

Before the formula can be applied, a base ROE must be calculated. The benchmark ROE may be arrived at in a variety of ways, and is set in a manner similar to the setting of ROEs in the US. Equity risk premium (ERP) analysis, capital asset pricing model (CAPM) analysis and, less often, comparable earning analysis are all taken into consideration. Notably, the DCF method is given little to no weight, for a variety of reasons. For example, the NEB has acknowledged that the DCF test is theoretically sound, but raised concerns about practical difficulties.[18]

Not all major Canadian jurisdictions had implemented formula-based ROEs when US and Canadian returns began to diverge. However, the jurisdictions retaining case-by-case analyses seemed to set ROEs in a manner that was highly sensitive to changes in the bond markets.[19] One could therefore view the "formula" jurisdictions as price leaders who set the standard for following the decline in bond prices in the setting of returns.

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[18] NEB, Reasons for Decision RH-2-94 (1994) §2.5.

[19] See, Alberta Energy and Utilities Board (EUB), *Canadian Western Natural Gas Co. Ltd. 1997 Return on Common Equity and Capital Strucutre and 1998 General Rate Application*, Decision 2000-9 (2000). On page 65, the EUB states, "[t]he Board notes that interest rates and bond yields have significantly declined during the time frame… Consequently, this significant reduction in interest rates will have a major impact on the determination of a fair return for a utility."

The unique feature of the Canadian ROE formula is that is sets a gap between Canadian long bonds and the fair ROE, as shown in **Figure** 3. The only reason that the ROE does not move in lock step with the long bond is the *notion* that the spread grows/shrinks with the move in the bond, by a quarter of the bond's movement. We say "notion" purposely, because the formula's tie between long bonds and ROE is not based on financial evidence on the contemporaneous spread between what the market requires as a return on bonds as opposed to a return on equity investments in Canadian utilities.

This last point bears emphasis. For those jurisdictions that have adopted the formula shown in Equation 1, or those jurisdictions led by those who do, the only new evidence determining ROE in utility rate cases is the movement in long-bond interest rates. Nothing in the application of the formula, as a factual matter, attempts to gauge contemporaneous equity cost rates. Rather, the formula adjusts ROEs based on the historical observation that allowed ROEs move in the same direction as bond yields.

In this fashion, the Canadian formula diverges from attempts in the US to streamline cost of capital proceedings by implementing a generic formula for the cost of capital. There have been two highly visible attempts to do such a thing in the US, by the Federal Energy Regulatory Commission (FERC) in the late 1980s and by the New York Public Service Commission (NYPSC) in the early 1990s.[20] In both of those cases, the target of the generic formulae was the cost of equity, using contemporaneous market information with theoretical models designed specifically to gauge equity costs.

Neither the FERC nor the NYPSC methods ultimately resulted in an abandonment of a case-by-case examination of the cost of equity. The FERC methods have streamlined somewhat the construction of the "proxy groups" for gathering market information on similarly-situated regulated firms and have basically set the form of the theoretical formula for combining stock yields plus analyst growth rates (in the "yield plus growth" or DCF formula). Those streamlines aside, the FERC generally dropped its pursuit of a generic formula by about 1992 over legal concerns that a company-specific record must support the finding of a fair return. The FERC since has not departed from a case-by-case examination of the cost of equity. The NYPSC formula, for its part, was created after a multi-month process costing some millions of dollars. It, too, centered on a formula for deriving the cost of equity (rather than the long bond rates plus a pre-determined spread), but it was never adopted formally by the NYPSC.

IV. THE TRADITIONAL CASE-BY-CASE METHODS OF CANADIAN AND US REGULATORS

Rate cases in the US are relatively standardized affairs. This is not to say that US commissions never err in their decisions, that all commission decisions are objective or that rate cases are

[20] FERC Order 442 *Generic Determination of Rate of Return for Public Utilities*, Docket No. RM85-19-000; New York Public Service Commission, *Generic Financing Proceeding, Case* No. 91-M-0509.

never protracted battles. Property rights and US regulation are continually evolving and have only reached their current state through experimentation and judicial rebuke.

In an attempt to relieve the regulatory burden the FERC intended to move to a generic ROE approach in the 1980s with Orders 420, 442 and 461, and similar efforts were made by the NYPSC and the Federal Communications Commission (FCC) in telecommunications. However, the generic ROE pursued in these cases was never applied extensively and fell into disuse. US ROEs are now determined the same way they have always been determined: through discounted cash flow (DFC) analysis that examines a comparable group similar to the utility in question.

US gas utilities generally do not generally undergo annual rate cases.[21] Rather, the ROE stands until either the utility requests a rate case or the commission judges that conditions have changed enough to warrant a re-examination of rates. To streamline rate cases, commissions have objectivity standards that include the need for a theoretical justification of the methods used and all subjective decisions are justified in the public record. These standards help to ease contention in rate cases and limit the discussion to manageable issues.

In this section we will explore the methods used for rate setting in a case-by-case environment. We begin with the most popular method in the US, the DCF, before examining the CAPM and other ERP methods. Finally, we discuss the role of capital structures in case-by-case ratemaking.

A. Discounted Cash Flow (DCF) or "Yield Plus Growth"

The most popular method used to determine the ROE among US regulatory commissions is to determine what future stream of common dividends investors expect on a case-by-case basis using discounted cash-flow (DCF) analysis. Its popularity is a function of its ease of use and comprehension by finders of fact not necessarily particularly versed in financial theories. At its most fundamental level, the DCF method endeavors to compute the cost of equity capital by summing the two sources of equity investor returns—the "yield" portion (meaning the dividend yield with respect to the stock price) and the "growth" portions—the rise in the stock price that investors expect to see. In a world of complicated ratemaking formulae and financial theories, it is no surprise that "yield plus growth" has an intrinsic appeal, particularly when there are many sorts of similar utilities by which to gauge the sum of these two common-sense factors that make up the ROE. The formal statement of the DCF methodology grew out of Professor Myron J. Gordon's work on stock valuation models, which was first published in complete form in 1962.[22]

Part of the DCF formula that may not appeal to analysts and regulators is the growth rate expected by investors. That growth rate is inherently inscrutable, and in small capital markets

[21] California has annual adjustments to rates, but that is a unique US jurisdiction and not in any way an indicator of what happens in the rest of the country. The tortured experience associated with the lead up and aftermath of the California energy crisis of 2000-2001 continues to cast regulatory procedures there in a unique light.

[22] *See* Gordon, M.J. *The Investment, Financing and Valuation of the Corporation* (Homewood, IL: Richard D. Irwin Inc., 1962; reprint, Westport, CT: Greenwood Press, Publishers, 1982).

(such as many utility jurisdictions overseas), it is very hard to gauge investor expectations and thus to apply the DCF model. But in the US, where the model retains its great popularity, a robust industry of independent stock market analysts helps greatly. Both in print and on the web, disinterested estimates of utility growth rates are readily available to assist in the calculation of DCF-derived ROE figures. Combining these publicly-available growth rate estimates with the availability of a number of similar-risk companies, in "proxy groups," allows regulators to enjoy the stabilizing influence of the law of large numbers in setting the ROE.[23] For practical-minded regulators looking for stable, understandable and objective evidence, its popularity is no surprise.

DCF analysis involves making selections at two key stages: first, the analyst selects a specific "proxy group" of utilities facing similar risks and then selects the various of inputs such as the growth rate. Many of the practical concerns of Canadian regulators over these selections have been addressed in US jurisdictions, and the regulatory burden of case-by-case ratemaking has been lightened by establishing consistent selection criteria at each stage. One concern unique to Canadian jurisdictions, however, is the applicability of proxy groups that contain US utilities.

Given the degree of capital market integration, the degree of cross-border gas trade, and the international presence of several Canadian LDCs, we believe that a proxy group that includes US utilities facing similar risks would be appropriate for Canadian utilities. We will examine in Section IV whether the risks facing Canadian utilities are, in fact, comparable to those facing US utilities but, so long as Canadian regulators are attentive to potential macroeconomic divergence, we see no economic or financial factor that would confound the use of proxy groups that include US utilities.

B. Equity Risk Premium (ERP) and the Capital Asset Pricing Model (CAPM)

Equity risk premium (ERP) analysis is based on the observation that it is more risky to hold equity than bonds. Assuming that investors are risk adverse, they will require a higher return to hold assets with higher risk. Equity returns therefore carry a premium over bond returns. If risk-free bond yields could be identified and the equity premium could be estimated, the cost of capital will result.

There are a wide variety of methods for estimating the cost of capital along these lines, the most popular of which is the capital asset pricing model (CAPM). The CAPM formula itself is rather straightforward. Its components are: (1) the risk free rate of return; (2) the market rate of return; and (3) the beta. These inputs are combined to estimate the ROE.

[23] In practical terms, the "law" describes the stability of a random variable, with repeated sampling. That is, given a sample of independent and identically distributed random variables, the sample average will approach and stay close to the true population average as the size of the sample increases. This is a long way of saying that the ROE results from a "proxy group" sample of similar utilities are more representative of the actual ROE than the ROE for a single company alone.

$$ROE = Risk\text{-}Free\ Rate + \beta(Market\ Return) \qquad \textbf{(2)}$$

Despite this algebraic simplicity, there are different methods to obtain each of these components and to compute the required rate of return. The effects of choosing one method over another can substantially change the required cost of capital. Because CAPM, with the exception of the beta term, does not have the "law of large numbers" properties in a comparable group that the DCF has, there is less reason to focus primarily on a comparable group rather than the utility in question, especially when the beta is significantly different from that of the proxy group.

The practical elements of the CAPM formula are full of contention. For example, the beta term relates the movement in an individual company stock price compared with that of the entire market for stocks. Greater relative movement vis-à-vis the market means a higher beta. Those betas published by investment analyst houses (such as *Value Line*, Merrill Lynch or others) make use of an adjustment procedure that moves "raw" betas toward 1.0. The "adjusted" published betas are generally the ones used by US regulators when they make reference to the CAPM.

The other area of contention is the market return—defined as the premium that the market for equities demands as a spread on the risk free rate. Market risk premiums are not published, but have to be derived. Some are based on historical achieved returns and others try to gauge investor expectations on future equity returns not unlike those who perform a DCF analysis. In rate case application of the CAPM, there is always dissension among interested parties regarding the size of the market risk premium, as its choice directly affects the level of "just and reasonable" rates. Practical-minded regulators wrestle with this issue.

- Despite these areas of contention, one benefit of the use of the CAPM is that the theory upon which it rests provides a relatively clear method for gauging the effect of increased leverage, or "gearing," on the cost of equity. It is well known in both financial theory and in practical investment circles that a high proportion of debt in the capital structure adds financial risk to the business risk facing a company—and raises both the cost of debt and equity. The CAPM model provides a theoretical method to compute the effect of different gearing on the ROE.[24] Indeed, in some prominent cases in the US, the this method has been used as the basis for regulators to grant higher equity costs to adjust for the use of greater gearing levels as deemed prudent by the regulator.[25]

[24] For the theoretical formula regarding the relationship between betas (and hence equity costs) and gearing, see: Copeland, T.E., and Weston, J.F., *Financial Theory and Corporate Policy, Third Edition*, Addison-Wesley, Reading, Massachusetts (1988), p. 457.

[25] For example, in the aftermath of the electricity utility restructuring in Texas, the Public Utility Commission there approved a 50 basis point "financial risk" premium to the cost of equity for all electricity distributors in the state to reflect its desire that the utilities all move toward a higher amount of debt in their capital structures (60 percent) reflecting the spin-off of their generating function. *See* Public Utility Commission of Texas, *Order No. 42: Intermin Order Establishing Return on Equity and Capital Structure*, Docket No. 22344 (2000).

CAPM is often used in US rate cases, but it is almost never used as the sole determinant of the cost of equity capital.[26] The judgment required in selecting parameters for the CAPM is no less significant than the judgment required for judicial use of the DCF, and the CAPM lacks the "central tendency" properties of DCF that smooth the results to yield a more reliable estimate.

C. Capital Structure

Modern financial theory suggests that there is a relatively wide zone of reasonableness for capital structures, with capital structures within that zone producing about the same cost of capital.[27] In the US, a utility's management is therefore granted a measure of discretion as to the type of capital raised. Having a solid level of financial integrity can provide rate stability and other benefits to customers, and commissions are reluctant to interfere with a utility's capital structure unless it is pushing the bounds of reasonableness.

In the US, the projected actual capital structure ratios of the utility at the time that new rates would go into effect are used to calculate a pre-tax weighted-average cost of capital. Because the rate proceeding will set rates to be charged for service in future periods, it is appropriate to base the capital structure components on the best available estimates for the period of time in which the rates will be in effect. Furthermore, the actual degree of leverage has important implications for ratemaking, as higher leverage raises financial risk and therefore the cost of capital.

Financial risk is the portion of total corporate risk over and above basic business risk that results from using debt.[28] Because equity investors are the residual claimants after the payment of debt, the cost of equity increases with higher debt ratios (*i.e.* with higher leverage). As a company increases the portion of debt in its capital structure, investors perceive a greater chance that there will not be sufficient returns available after the payment of fixed charges. Both the Modigliani-Miller theory, a the basis for the field of finance, and empirical tests of the theory confirm this inextricable link between capital structure and the cost of equity.[29]

The total cost of capital is therefore U-shaped with respect to capital structure. High equity percentages raise the WACC, but the WACC also increases at high debt percentages as investors seek higher returns on equity due to the increased financial risk.

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[26] One jurisdiction in our experience, Oregon, for some time in the 1990s and into the mid 2000s appeared to use the CAPM as the sole method for finding the ROE. It stopped that seemingly sole reliance in 2001. *See* Public Utilities Commission of Oregon, Order No. 01-777 (2001).

[27] *See* Morin, R., *Utilities' Cost of Capital*, PUR, Arlington, VA 1984, p. 268.

[28] Brigham, E.E., *Financial Management, Theory and Practice, Third Edition.*, The Dryden Press, Chicago (1982), p. 861.

[29] *See* Copeland, T.E. and Weston, J.F., *Financial Theory and Corporate Policy, Third Edition.*, Addison-Wesley, Reading MA (1988), Chapters 13 (theory) and 14 (empirical evidence and applications).

Hypothetical capital structures have been used in the US when it was judged that utilities were deviating from reasonable capital structures by either employing too much debt or equity in an effort to raise overall returns. Hypothetical capital structures may also be used if the utility is owned by a parent company that faces markedly difference risks from those faced by utilities and therefore carries a capital structure that would be inappropriate for a utility.

In such cases, the capital structure of a comparable group of utilities is used, on the basis that comparable groups' capital structures reflect the opportunity costs facing investors, satisfying the comparable investment standard. Very rarely would a capital structure be "deemed" in the US without consulting a comparable group and addressing why the actual capital structure chosen by the management is inappropriate.

V. RELATIVE RISK FOR CANADIAN AND US GAS UTILITIES

The previous two sections of this paper described how Canadian and US regulators have derived the ROE. This section investigates whether there is any justification for concluding that lower (higher) risks for utilities in Canada (the US) justify ten years of divergent returns.

In this section, then, we first examine more carefully which risks matter to utility investors. We then examine the practical boundaries to those risks for regulated utilities in Canada and the US and upon what legal and procedural foundations those risks rest. Finally, we examine whether there is any evidence available that allows us to conclude that the divergence in Table 1 stems from any persistently lower risk in Canada for gas distributors than that level we observe in the US.

A. What Risk Matters to Utility Equity Investors?

Any discussion of risk in the context of utilities invites controversy. Much of this, in our opinion, comes from a *colloquial* as opposed to a *technical* definition of risk in the context of ROE. In setting a fair compensation for investors in the ROE, the risks that matter are the ones for which those investors require compensation. Colloquially, all would agree that predicting the weather is *risky*, but to the extent that over time weather conforms tightly to averages, the rates set on average weather patterns carry no particular risk to investors' ability to recoup their cost of capital. That is to say, *weather risk* is not the same as *ROE risk*. For a natural monopoly gas utility whose costs are geared to serving customers with whatever local weather conditions exist, the weather does not stand between them and recouping their funds—and is not properly a part of the ROE.

Weather is merely one example of the need to focus on technical risk definitions in gauging the fairness of the ROE. While the cost of service may differ between US and Canadian utilities based on their distinct geographies and other factors, both can expect the opportunity to earn a fair rate of return that is based on the returns to an investment of comparable risk.

1. Regulatory Risk

The risk that a gas LDC faces is inherently intertwined with regulation. Gas LDCs are a natural monopoly—the only thing standing between an LDC and monopoly profits is regulation. The greatest risk to an LDC is the risk that the regulator will not allow the utility to recover prudent costs—including the cost of capital—in a timely manner.

2. Business Risk

The business risk faced by LDCs in Canada does not significantly differ from those in the US. There are forward-looking risks facing investors that are somewhat independent from regulatory risk. These risks are limited, however, as a utility has the right to call for a rate case if significant events (such as a recession) damage its ability to earn a reasonable return on its invested capital without an increase in prices—a recourse obviously not available to unregulated firms. Business risk is therefore an interaction between regulatory risk and the business environment and many business risks can be lessened, modified or even eliminated through various regulatory practices.

Forward-looking business risks include:

- *Long-Lived Assets*. Gas LDCs in Canada and the US connect to a multitude of consumers. Therefore, distributors are the ones charged with the planning of upgrades to networks that in many cases are decades old. The need for major expenditures to provide safe local service do not always follow rate case schedules, so there is often a lag between investments in long-lived assets and recovery of those costs in rates. Such risks in the cost of planning and engaging in ongoing local network maintenance are the same in both Canada and the US, and both utilize deferral accounts to mitigate this risk.

- *Risks of service interruptions*. Major or minor service interruptions are generally the responsibility of the distributor—as are the costs of remedying outages. Cracked gas mains, storm damage to electricity wires and sub-stations, are all the responsibility of the distributor, which can try to plan for—but cannot guarantee—the collection of all costs that are incurred.

- *Adequacy of depreciation*. The depreciation allowance included in distribution company rates is an estimate based on historic experience. Depreciation allowances may not consider economic obsolescence resulting from unanticipated technological change or potential large capital additions. As such, there is a risk that utility plant will be under-depreciated, and changes in technology or regulation may cause shareholders to bear the result of inadequate depreciation.

- *Risk of technological bypass*. Gas LDCs in Canada and the US are at risk of customers bypassing the network by switching fuels or adopting alternate technologies. If bypass is significant there is no guarantee that the remaining rates will be adjusted to recover the cost of abandoned or excess capacity.

- *Risk of the competitiveness of rates*. While LDCs are entitled to recover their actual, prudently-incurred cost of doing business, gas LDCs in Canada and the US are at risk for the continued viability of the overall business. Competitive pressures from distributed generation or alternate fuels could create a situation in which allowed revenues are not competitively viable.

- *Risk of timeliness and adequacy of allowed revenue levels*. Gas LDCs in Canada and the US face the need to increase distribution rates as costs increase. It is expensive and difficult to file for a small rate increase. Utilities would absorb such costs until they become large enough to justify the cost of a rate filing.

3. Financial Risk

Apart from the regulatory and business environments facing an LDC, investors face financial risk as well. Financial risk is the risk associated with carrying debt in the capital structure. Debt return (i.e., interest payments) are contractual obligations. Up to a point, raising utility funds with debt provides for a less expensive way to provide the capital needed to provide services to customers. But with greater proportions of debt, the risk that those interest payments will not be "covered" increases, and with it both the interest rate demanded by lenders and the return required by equity investors. This effect on required rates of return is well established and widely known.

Financial risk is generally taken into account in setting ROEs in US rate cases. To the extent that a regulated firm's capital structure mimics those of a group of its regulated peers, no adjustment is necessary for financial risk. One the other hand, if there is a difference between the firms in question and their peers, then an adjustment to reflect the differential financial risk may be necessary (as happened in a noteworthy case for all of the regulated electric distributors in Texas—where a 50 basis point premium for the ROE was permitted to reflect the regulator's desire for the distribution-only utilities to take on more debt).[30]

The question of financial risk appears to often be obscured in Canada, where the generic ROE is provided for all utilities in a jurisdiction, leaving the issues of financial risk to be deal with in a specific deemed capital structure to address the risks of a particular distributor.

B. What are the Practical Boundaries to Regulatory Risk?

With any investor-owned utility, the regulator and the utility have reciprocal obligations that are generally well recognized. That is, the utility operates the service and provides the capital needed to maintain and expand the facilities that allow the public to be adequately served. For its part, the regulator provides a stable regulatory environment, oversees the adequacy of services, and offers the utility a reasonable opportunity to earn a return on its investments.

[30] See Texas PUC, *Generic Issues Associated with Applications for Approval of Unbundled cost of Service Rates Pursuant to PURA §39.21 and PUC Subst. Rule §25.344*, Docket No. 22344.

Among its various duties, a key role for regulators is to signal, credibly, to investor-owned utilities' investors how their investments will be recovered in regulated charges.[31]

Such regulation is described in the economic literature as a "form of long-term contracting."[32] Canada and the US have proven over 100 years of natural gas regulatory history that they are able to honor the "long-term contract." The exact form of this long-term contracting has evolved throughout this history as regulators pushed against the regulatory boundaries, were reprimanded by courts, were given new direction through legislative action, and were chaired by individuals of various political inclinations as new executives were elected.

In mature regulatory jurisdictions with strong legal and administrative histories, such as Canada and the US, the regulatory compact represents a concatenation of: (1) strong primary legislation; (2) credible, comprehensive and transparent administrative procedures for making regulatory decisions and adjudicating disputes; (3) accounting regulation specifically designed for utility ratemaking; and (4) clear pathways for reliable judicial review of regulatory decisions. Newer regulatory jurisdictions around the world that do not have comparable bodies of regulatory precedent routinely use explicit contracts to express such principles.

1. Strong Primary Legislation

Canadian regulatory legislation is effectively very similar to that in the US, although Canada does not have all of the judicial precedent regarding the constitutional protection of private property that characterizes the US. Canada's regulatory compact is based instead on common law and "fundamental justice" but nevertheless does appear to be comparable the US in practice.[33] The US Constitution, especially the fifth and fourteenth amendments, provides the foundation that supports those protections in the US.

In Canada and the US, Supreme Court interpretations of this primary legislation define the legal limitations on regulators' ability to take action on charges that may damage the value of utility investors' property. The best known case is that of *Federal Power Commission v. Hope Natural*

[31] This mutuality of obligations is sometimes called the "regulatory bargain" or "regulatory compact," but those are merely convenient labels for how governments and investors have traditionally worked out how the public will be adequately served by private companies.

[32] Professor Oliver E. Williamson, an authority on the economics of transactions and regulation, noted that "[a]t the risk of oversimplification, regulation may be described contractually as a highly incomplete form of long-term contracting in which (1) the regulatee is assured an overall fair rate of return, in exchange for which (2) adaptations to changing circumstances are successively introduced without the costly haggling that attends such changes when parties to the contract enjoy greater autonomy." Williamson, O.E., *The Economic Institutions of Capitalism*, Free Press, New York (1985), p. 347. See also Victor Goldberg, Regulation and Administered Contracts, *Bell Journal Of Economics*, Vol. 7 (Autumn 1976): p. 426-448.

[33] Canada's equivalent to the US 14th Amendment, Section 7 of the Charter of Rights and Freedoms, states: "[e]veryone has the right to life, liberty and security of the person and the right not to be deprived thereof except in accordance with the principles of fundamental justice." As a relatively recent act, it remains to be seen exactly how "fundamental justice" will be interpreted but it has thus far been interpreted as more than simple procedural rights.

Gas, in which the Supreme Court set a standard for determining "just and reasonable" returns, a standard that has stood the test of time.[34] Canada and the US share a remarkably similar regulatory mandate and their "fair and reasonable" standards for utilities returns are almost identical. Indeed, Canada's *Northwestern Utilities v. City of Edmonton* anticipated the landmark US *Hope* case by fifteen years. Both established the opportunity cost of capital as the relevant standard by which utilities' returns should be judged.

The Supreme Court of Canada stated in *Northwestern Utilities*:

> 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…[35]

In the *Hope* decision, the US Supreme Court, by a vote of five to three, set a new standard for determining "just and reasonable" returns for investor-owned utilities.

> The return to the 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 attract capital.[36]

In *Bluefield*, an earlier case leading up to the *Hope* decision, the US Supreme Court defined the proper rate of return 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...[37]

In setting required revenues, a utility's returns would henceforth be measured by investors' possible earnings on alternative enterprises of similar risk. The Supreme Courts thus ruled that a utility's investments were safe from seizure (*i.e.*, a "taking") if regulators set charges to award returns consistent with investors' opportunity cost of

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[34] *Federal Power Commission v. Hope Natural Gas*, 320 US 591 (1944).

[35] *Northwest Utilities v. City of Edmonton*, S.C.R. 186 (NUL 1929).

[36] *Hope*, 320 US 591, 603 (1944).

[37] *Bluefield Waterworks & Improvement Co. v. Public Service Commission of the State of West Virginia et al.*, 262 US 679, 693 (1923). The *Hope* and *Bluefield* decisions refer to two Constitutional Amendments. The Fifth Amendment, as interpreted by the Court, gave the Court jurisdiction over Congress in such matters. The Fourteenth Amendment, under the Court's interpretation, gave it similar jurisdiction over the States.

capital. These limitations on the discretion of regulators were not academic exercises. For the purposes of the future gas market, the *Hope* and *Northwest Utilities* decisions were critical. They sharply limited investor or shipper uncertainty regarding the ability of regulators to act in a manner that would damage the value of the assets that investors would devote to regulated enterprises.

2. Credible, Comprehensive and Transparent Administrative Procedures

Predictable regulatory or tariff-making practices are unlikely without a clear set of administrative procedures that bind the way that the independent regulators conduct their business. Canada and the US both provide stability to their utility investors through strong administrative procedures.

An important tenet of Canadian administrative practices is the common law right to procedural fairness. The Supreme Court of Canada has held that judicial and quasi-judicial bodies, but also other administrative decision makers, must follow common law principles of procedural fairness that include the right to be heard and the right to be judged impartially. [38]

The 1946 Administrative Procedures Act guides regulatory procedures in the US. Similar to Canada, it requires regulators to hold hearings, warn participants of impending rule changes, to allow participation in regulatory proceedings from the affected parties and to accept evidence (subject to cross-examination in those hearings). The late US Senator Daniel Patrick Moynihan explained that:

> The APA rests on a constellation of ideas: government agencies should be required to keep the public informed of their organization, procedures, and rules; the public should be able to participate in the rule-making process; uniform standards should apply to all formal rule-making and adjudicatory proceedings; and judicial review should be available in certain circumstances. Taken together with the Freedom of Information Act, an amendment to the APA that was enacted in 1966 and added to in 1974, 1986, and 1996, the APA was intended to foster more open government through various procedural requirements and thus to promote greater accountability in decision making.[39]

These are precisely the elements of "due process" in the administration of regulation. Indeed, the legal inquiries that resulted in the Administrative Procedures Act arose out of the general judicial concern (arising in the US in the 1930s) that regulating prices of investor-owned companies *at any level* represented a potentially unconstitutional taking of private property. That

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[38] An important decision with regard to procedural fairness was *Nicholson v. Haldimand-Norfolk Reg. Police Commrs.*, where the Supreme Court of Canada significantly extended the rights to procedural fairness to non-judicial administrative decision makers and solidified the right to justification for a decision. *Nicholson v. Haldimand-Norfolk Reg. Police Commrs.*, [1979] 1 S.C.R. 311.

[39] Daniel Patrick Moynihan, *Secrecy: The American Experience* New Haven, Conn: Yale University Press, 1998, p. 157.

potential unconstitutionality, it was rightly thought, could only be prevented if a specific framework was applied for assuring the due process of regulatory decisions.

While Canada does not have an exact equivalent to the U.S. Administrative Practices Act of 1946, it does have an umbrella of provincial statutes, the charter(s) of the administrative decision maker(s), and the protection of common law, which includes previous interpretations as well as foundational justice and the founding principles of the constitution.[40] Through these channels, Canadian administrative procedures are equally well-established and effective as US procedures.

3. Accounting for Utility Ratemaking

The goals of effective and efficient regulation can be frustrated without a consistent, credible, and sustainable set of regulatory accounts. Strict accounting standards (*i.e*., the Uniform System of Accounts) rarely leave US or Canadian energy utilities and their regulators in major dispute over basic financial issues (like profitability, depreciation expenses or the admissibility of particular costs).

Strong and transparent accounting standards were established over half a century ago in Canada and the US, but such is not the case in other, supposedly "mature" jurisdictions. For example, a major component of the reviews of British Gas conducted in recent years by both Ofgas (the gas regulatory body before Ofgem was created) and the Monopolies and Mergers Commission concerned basic accounting and finance items in an environment with no regulatory accounting standards.[41] This confusion in the UK over British Gas's rate of profits on its capital stock and the depreciation allowed on billions of pounds sterling of transportation assets represents a major risk to utility investors that is absent in Canada and the US. Canadian and US accounting standards would never leave major assets in question, as was the case in the UK and elsewhere following privatization.

4. Reliable Judicial Review

Effective limits on regulatory authority in systems with well functioning regimes come from the judiciary and other paths of appeal. In both Canada and the US, the fundamental legal limitations on the ability of regulators to take actions that damage the holdings of utility investors (in some way or another) come from well-known Supreme Court decisions. The Courts in both countries have found that the property rights of investors in regulated companies,

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[40] The provincial administrative practices acts include: *Statutory Powers Procedure Act*, R.S.O. 1990, c. S.22 (Ont.); *Administrative Procedures Act*, R.S.A. 2000, c. A-3 (Alta.); *Administrative justice, An Act respecting*, R.S.Q. c. J-3 (QC).

[41] *The Economist* has referred to UK regulatory accounting as a "fiddly bit of guesswork." (See: "Don't you just love being in control?" *The Economist*, May 18th, 1996.)

as well as the rights of the customers they serve, require strict regulatory attention to invested capital.

C. What are the Elements of Canadian vs. US Regulatory Risk?

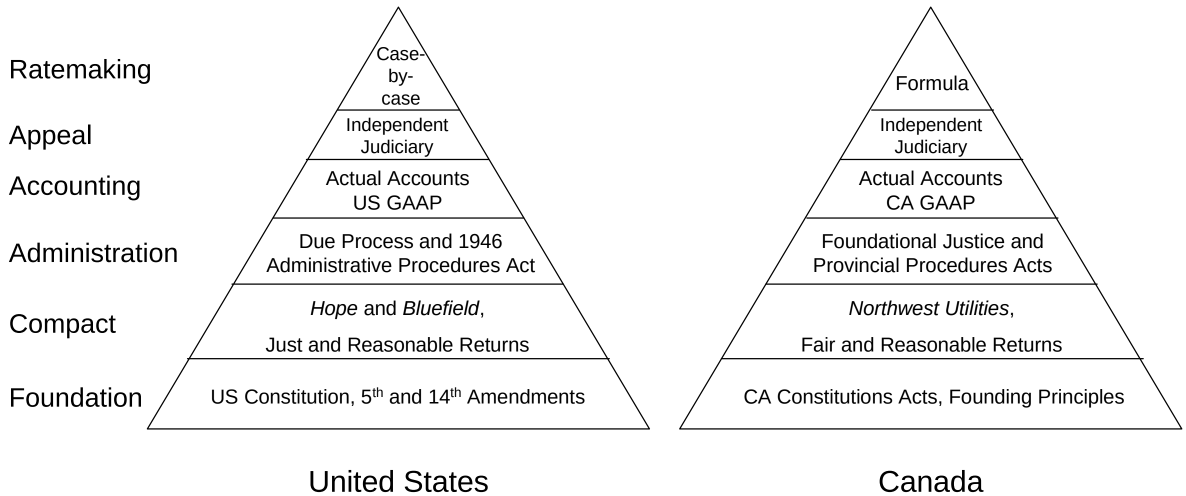
While Canada and the US share a credible regulatory environment, the exact regulatory foundations are admittedly not identical. However, the differences that do exist are more procedural than fundamental. The two jurisdictions engage in roughly the same practices, although they may go by slightly different names or receive more or less attention. The differing levels of attention does not imply that some practices are superior to others; rather, these differences arise from the dates the practices were implemented, the procedures used to handle the practices, and the emphasis placed on various practices in regulatory proceedings.

These principles are generally true of all regulatory jurisdictions in the US and Canada. Both equity investors and lenders generally give funds to utilities with the reasonable expectation the principles of obligations to be provided with a fair return will be honored. Even though the particular utility statutes may vary from jurisdiction to jurisdiction, and even though regulatory commissions may have different policies and precedents in different jurisdictions, investors anticipate the basic bargain between them and their regulator (who represents the public) will apply to their investments.

From the constitutional foundation through to administrative practices, accounting practices and judicial review, Canada and the US have virtually indistinguishable regulatory environments—so much so that the US *Hope* and *Bluefield* decisions are even cited in Canadian rate cases.[42] **Figure 4** illustrates the regulatory pyramid in Canada and the United states.

[42] See, for example, Alberta's *Generic Cost of Capital* decision, where the EUB stated, "[t]he Board concurs that the above decisions [*Northwestern*, *Hope*, and *Bluefield*] are the most relevant judicial authorities with respect to the establishment of a fair return for regulated utilities." Alberta Energy and Utilities Board, *Generic Cost of Capital* Decision 2004-052 (2005), p. 13.

Figure 4: Elements of Recent ROE Regulation in the US and Canada



Regulation in Canada and the US is founded on strong primary legislation that protects the rights of citizens. The constitution of Canada is an amalgam of codified acts and uncodified traditions and conventions.[43] The Constitutions Act, 1982 established a Charter of Rights and Freedoms, the Canadian equivalent to the US Bill of Rights. While the Charter extends many protections to Canadian citizens, including the right to "foundational justice," this Charter does not explicitly include the protection of property rights. A significant difference in the regulatory foundations is the strong constitutional protection of property rights in the United States afforded by the 5th and 14th amendments.

The regulatory compact in both countries is shaped by judicial decisions and includes the right to earn a "fair return" on investment, as determined by the opportunity cost of capital, which is termed the "comparable investment" standard. While the phrase, "regulatory compact," is not used as often in Canada as in the US, the concept is there. Indeed, the decisions that shape the US compact are cited in Canadian rate cases, and the Canadian decisions are widely recognized as establishing an effective compact that is very nearly identical to that of the US.[44]

While Canada does not have a single, federal administrative practices statue, administrative practices are highly refined in Canada and afford at least as much protection to investors as does the United States. The Canadian common law protection—enhanced by the introduction of foundation justice in the Charter of Rights and Freedoms and provincial administrative

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[43] The Preamble to the Constitution Act, 1867 states that the provinces shall have, "a Constitution similar in Principle to that of the United Kingdom."[43] This has been interpreted as stating that the practices of the United Kingdom that were common before the creation of the constitution form part of the Canadian constitution—for example, the practice of an independent judiciary has been constitutionally guaranteed under this argument. See *Provincial Judges Reference* [1997] 3 S.C.R. 3.

[44] Morin, R.A. *New Regulatory Finance*, Vienna, Virginia: Public Utilities Reports (2006), p. 12.

procedures acts—equals the US standard of due process and the Administrative Procedures Act of 1946 in its protection of investors' rights.

In both Canada and the US, regulatory accounting is sufficiently refined that actual accounts are used for ratemaking without contention, avoiding the regulatory conflicts that surround benchmarked costs or replacement value accounting. The right to use actual costs for intraprovincial/intrastate regulation comes from provincial and state statutes. While some provinces have "fair value" mandates and are not required to use book values, they do so nonetheless.[45] This is similar to the US, where five states have "fair value" statues but have defined fair value to be the book value, so it is a difference without a distinction.

There is a perception that Canadian judiciaries are reluctant to interfere with the decisions of utility regulators. However, US judiciaries also do not overturn regulatory decisions without a clear reason to do so, and judicial rebuke is the exception rather than the rule in the US. Most important is that clear pathways for appeal exist in both countries and appeals are conducted in a manner such that, should major grievances be raised, the judiciaries are capable of reaching a reasonable decision.

Canada and the US share similarly mature regulatory compacts, supported by well-established accounting, administrative and appellate procedures. They are unique in their advanced regulatory environment based on credible, actual accounts. The greatest risk-determinant for utilities, regulatory risk, is comparable in Canada and the US.

D. Does the Continued Ability to Raise Capital for Canadian Utilities Indicate that All is Well?

Figure 1 drove this examination of the foundations of the regulatory procedures and risk. It shows that the allowed ROE was persistently lower in Canada that in the US over the previous decade. To the extent that this divergence is found not to be the result of different Canadian regulatory practices or lower regulatory risk vis-à-vis the US, but the result of the use of Canada's formula, an obvious question arises: would this cause investors to withhold funds from Canadian utilities?

In other words, is there any evidence that the Canadian utilities whose returns make up **Figure 1** have been unable to raise funds? If the generic Canadian ROE formula rests too heavily on long bonds and ignores genuine equity capital costs, the most manifest evidence that this is detrimental would show up in a difficulty for those companies in raising new capital. Conversely, does the continued ability of these Canadian utilities to provide adequate services in and of itself refute any possibility that the formula-based ROE is biased or inadequate?

[45] The use of actual accounts in Canada was upheld in *B.C. Electric Co.*, where the court established that the book value of prudently incurred costs could be used to provide a fair return, despite a statute requiring that appraisal value be used. *B.C. Electric Co. Ltd. v. Public Utilities Commission et al.* (1957) 13 D.L.R. (2d) 589 (BCCA).

We conclude that as a practical matter the answers to these questions are no. Absence of evidence that Canadian utilities subject to the formula are barred from the market for funds does not constitute evidence that those ROEs are adequate in the market.

There are times in the not-so-recent past when persistently inadequate returns have appeared for utilities in general. During two periods of high inflation in the 1970s and 1980s, US utilities faced wholly inadequate returns. Inflation, coupled with the need to construct new generation and transmission capacity, ruined the ability of traditional regulatory procedures to provide utilities with a reasonable prospect of earning an adequate ROE. In short, the traditional methods of regulating rates, using a test year, created a lag in the ability to recoup ongoing, inflated, costs that visibly affected the financial health of utilities.

Evidence that the utilities were suffering was clear in the stock markets, as utility stocks slid in relation to their book values. During both periods, it was common for utility stocks to be trading below the equity book value of utility investments (roughly the equity "rate base"). When this happened, any new equity raised by these utilities would "dilute" the equity of existing shareholders—basically providing a subsidy to new equity investors from old ones.[46] Such a subsidy could not continue forever, as it would doom an investor enterprise. As it happened, however, the problem—as highly visible as it was—was only relatively temporary.

No equity investors would willingly sell proportional rights to the future returns on the equity rate base for a discount—but they did so during this period anyway. Why? Given their overriding obligations to provide safe, adequate and reliable service to customers, they had effectively no choice in the matter. Inflation pushed up the cost of new funds to the extent that it reflected a subsidy from existing shareholders, but nothing during the years of high inflation left utilities off the hook regarding their own responsibilities to serve the public.

Fixing the problem required either a change in regulatory procedures to deal with high inflation (for example, using inflation accounting like in European or Latin American countries), or an end to high inflation itself. When inflation dropped in the US, utilities returned to business-as-usual. The prospect of high inflation is still a risk to which utilities have generally no defense except a strong belief that the central bank will work to prevent its recurrence.[47] But in no fashion was the continued investment in US utility infrastructures in the 1970s and 1980s evidence that the ratemaking formula wasn't damaging investor interests in periods of high inflation.

Similarly, the evidence that Canadian investors continue to provide safe, adequate and reliable service to their consumers cannot be taken as evidence, in and of itself, that the formula-based returns reflected in **Figure 1** are fair. The utilities in Canada are a mixture of closely-held subsidiaries (without traded stocks of their own) and publicly-traded firms. If the ROEs based

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[46] See: Morin, R.A., *New Regulatory Finance,* Public Utilities Reports, Inc., Vienna, Virginia (2006), p. 364; and Hymay, L.S., *Americas Electric Utilities: Past, Present and Future,* Public Utilities Reports, Arlington, Virginia (1985), p. 262.

[47] Of course, bankruptcy is a defense against persistent confiscatory regulatory treatment, but that has only appeared rarely in the US, and then only in conjunction with other idiosyncratic events.

on the formula are unfair, it would be, in our opinion, beyond practical measures to try to discern objectively, as a separate matter, how it damaged the interest of investors. By its very nature the market's cost of equity is not easily and objectively measurable—which is precisely why regulators and analysis use indirect formulae like the DCF and CAPM. Reverse-engineering the effect of the Canadian generic formula is not a practical and objective possibility to measure the effect it has had on utility equity investments in Canada since around 1998.

Natural Gas Utility Return Determination in Canada:

Time For a New approach

A Discussion Paper Developed by the
Canadian Gas Association

April 2008

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Acronyms and Abbreviations

AAM	Automatic adjustment mechanism
CAPM	Capital asset pricing model
CE	Comparable earnings
CEA	Concentric Energy Advisors
DCF	Discounted cash flow
ERP	Equity risk premium
FCA	Federal Court of Appeal
FRS	Fair return standard
LDC	Local distribution companies
M/P	J.C. Major, R. Priddle
MRP	Market risk premium
NEB	National Energy Board
NERA	National Economic Research Associates
OEB	Ontario Energy Board
RfD	Reasons for decision
ROE	Rate of return on equity
S&P	Standard and Poor's
TSX	Toronto Stock Exchange

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Introduction

One of the most contentious, and long-lived issues for Canada's natural gas distribution industry is the determination of what a regulated utility should be allowed to earn on its investment in the equipment, operations, facilities and people required to provide natural gas services to the public.

Because natural gas utilities are not competitive free market enterprises, there is no "invisible hand" of an open market to keep costs and profits in check. Instead, it is up to the regulators and regulated utilities to determine the costs, risks and return of supporting the enterprise's operation.

While accounting records, purchase orders, payroll records and other documentation can accurately establish the costs expected for the utility, in the absence of competitive market pressures, it is not possible to directly observe the appropriate return to owners of a regulated utility.

Over the past year, the Canadian Gas Association (CGA) and other associations and utilities have been looking into the various aspects, issues and information surrounding the process of determining an appropriate return on capital. What many are finding is that since the adoption 14 years ago of a formulaic approach to determine fair returns, there have been a growing number of indications that the process is no longer producing appropriate results.

In June 2007, Concentric Energy Advisors (CEA) completed a report for the Ontario Energy Board that concluded that the current rate of return on equity (ROE) differential between Ontario/Canadian and comparable US gas utilities of 150 to 200 basis points was largely due to the formula itself and its reliance on trends in Canadian government bonds. It also found that there were no fundamental risk differences between Canadian and US natural gas distribution utilities that would warrant such a gap.

In February 2008, in a report commissioned by CGA, National Economic Research Associates Inc. (NERA) confirmed CEA's findings of a significant, systemic gap between comparable Canadian and US gas utilities. NERA also concluded that the gap was not warranted on risk differences and that the use of US comparisons were indeed valid given the shared Canada-US legal foundations and the integration of the two financial markets and economies.

In March 2008, CGA released a report entitled "The Fair Return Standard for Return on Investment by Canadian Gas Utilities: Meaning, Application, Results, Implications" (M/P) that focussed on the legal foundations of return determination in Canada. In the report, authors former Supreme Court Justice, John C. Major and former National Energy Board Chair, Roland Priddle reviewed the history of the Fair Return Standard (FRS) in Canada and the US. The authors conclude, among other things, that the mechanistic nature of the formula approach often suspends the use of informed judgement. The resulting gap that has developed between US and Canadian ROE awards, the report maintains, is an indication that the required standard for returns is no longer being met in Canada.

This paper reviews and summarizes a number of the observations made in the above-mentioned body of research regarding return determination for regulated natural gas utilities. It examines the issues and outstanding questions relating to return determination in the context of the economic, financial and business environment in Canada today and for the past 30 years. While many of the issues raised in the paper have arisen in regulatory proceedings over the past decade, several perspectives are new. Among these are the broader time perspective pertaining to the long trend away from the FRS, the importance of the need for considered regulatory judgment in the use of formula approaches and the appropriateness of the comparison with returns in US utilities. This paper is offered as a means of contributing such perspectives to the ongoing debate.

Section 1: Current Legal Underpinnings for Utility Return Determination

Given the lack of open market forces to drive the determination of returns for utility investors the process has instead been grounded in a legal determination of what constitutes "fair".

In 1929, the Supreme Court of Canada in Northwestern Utilities Ltd v. Edmonton [1929] S.C.R. 186 (Northwestern) defined the scope of the utilities' right to price their product and their right as a result to a fair return. The Court stated:

"*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.*"[1]

In 1994, the British Columbia Utilities Commission became the first regulator in Canada to adopt a generic formula approach to return determination. Then, in 1995, the NEB also adopted a generic cost of capital approach to setting utility returns. Other provincial regulatory boards have since followed suit and today apply an essentially uniform generic formula approach to setting returns.

In 2004, the Federal Court of Appeal (FCA) added some depth to the definition of fair return in TransCanada PipeLines v. Canadian National Energy Board 2004 F.C.A. 149, where the court confirmed that a fair return need not be modified out of deference to its impact upon customers. It was determined that regulators are free to use constructs like deferral accounts and other mechanisms to spread out the impact of commodity costs and weather impacts on the customer rates. However, the law explicitly states that regulators cannot simply reduce the return to the investor/owner as a mechanism to avoid potential increases in customer rates. Canadian law in effect requires that a fair return be provided for the services rendered by the utility. This "fair return standard" and its requirements remain in full legal effect today.

Further practical guidance as to how to functionally apply the FRS evolved from the National Energy Board (NEB) in its RH-2-2004 Phase II Decision, where it stated:

"*The Board is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:*

- *be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard);*
- *enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and*
- *permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).*"[2]

Notable in the legal definition of the FRS is the court's recognition that it is in the best interest of the utility and its customers to tie society's need for the essential service provided by the utility to the long-term viability of the utility.

The question then, is whether returns to Canadian natural gas utilities are meeting the required standards designed to ensure this long-term service and viability.

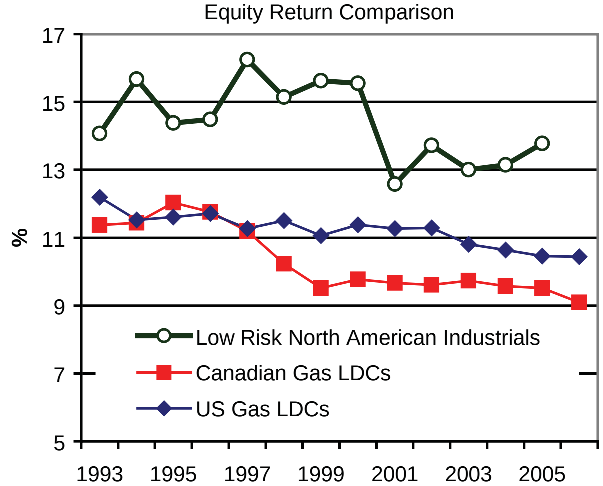
[1] Supreme Court of Canada in Northwestern Utilities Ltd v. Edmonton [1929] S.C.R. 186 (Northwestern).
[2] National Energy Board in RH-2-2004 Phase II Decision.

Section 2: Canadian Returns in Comparative Perspective

A simple illustration of the possible problem with utility return determination in Canada can be seen in a comparison of the returns to US natural gas utilities. (Fig. 1 & 2) In CGA's 2007 report entitled "Return on Equity: Allowed Returns for Canadian Gas Utilities" it was shown that a significant gap has emerged between Canadian and US returns.

Figure 1

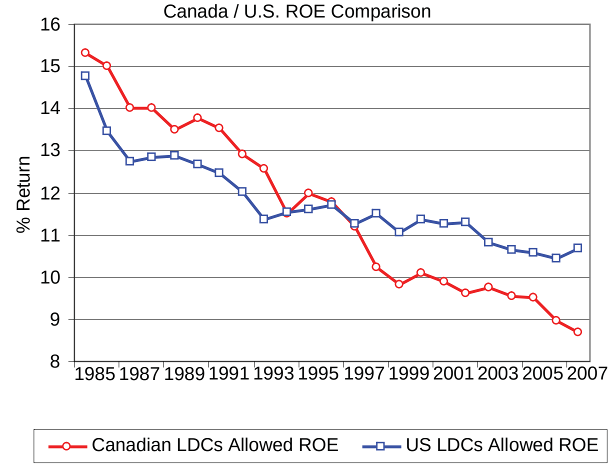
Equity Return Comparison



Source: Canadian Gas Association, S&P Insight

Figure 2

Canada / U.S. ROE Comparison



Source: CGA, Regulatory Research Associates (RRA)

Confirmation of this discrepancy came in an Ontario Energy Board (OEB) –commissioned report carried out by Concentric Energy Advisors (CEA). In their report, CEA shows (Fig. 3) that Canadian utilities are consistently and markedly below a reasonably constructed representative group of their US-based peers.

While it is possible to compare Canadian natural gas utilities only to each other, the uniform use of the formula approach to return determination in Canada makes such a comparison circular in both its logic and result. A Canadian peer group could potentially be made from a properly constructed group of low-risk industrial enterprises. However, efforts to introduce such comparisons have tended to founder on the difficulty in identifying enterprises that are sufficiently comparable to that of a natural gas utility.

Alternatively, one can reasonably ask whether US-based utilities are an acceptable peer/comparator group. This question was also addressed by the CEA report in which they state the following:

"*While specific characteristics of individual gas utilities and their respective regulatory environments can lead to differences in allowed returns, there are no apparent fundamental differences between gas utilities in Ontario and those in the US that would cause a sizable gap in ROE. In other words, taken as a whole, US gas utilities are not demonstrably riskier than Canadian gas utilities.*"[3]

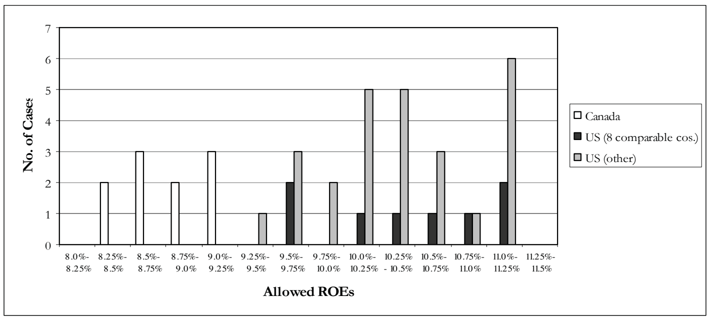
The issue of the appropriateness of comparison to US natural gas utilities was further investigated by NERA in their CGA-commissioned report entitled "Allowed Return on Equity in Canada and the United States: An Economic, Financial and Institutional Analysis". In their report, NERA concluded the following:

"*Canada and the United States have almost hundred-year histories of regulating investor-owned utilities. This shared experience is different from almost all the rest of the world, where the appearance of investor-owned (i.e. private) utilities came only with the privatization wave of the late 20th century.*" [...] "*These two national jurisdictions thus share a common heritage that is quite different, for example from the newly-privatized regulatory*

[3]"A Comparative Analysis of Return on Equity of Natural Gas Utilities," p. 2, prepared for the Ontario Energy Board by Concentric Energy Advisors, June 14, 2007.

Figure 3

CHART 6: HISTOGRAM OF ALLOWED ROES IN CANADA AND THE U.S.



jurisdictions in the rest of the world. Those jurisdictions overseas regulate their investor-owned utilities on an institutional basis quite different than in Canada and the US – two countries that share the longest, largest and most unencumbered trade border in the world. It is thus a fair question to compare and contrast Canadian and US utilities with each other to examine how their regulators deal with them and, in particular, derive the ROEs used to set their regulated tariffs."[4]

Further questions about the validity and meaning of a divergence between the Canadian and US allowed return levels are raised in a study published in the autumn 2007 edition of the Bank of Canada Review.[5] The study notes that the higher the risk to future returns, the higher those expected returns must be to compensate investors for taking those risks. According to the study, Canadian firms show a higher degree of financial leverage, a higher variability (dispersion) in future earnings, lower stock market liquidity and lower corporate taxes. Combined, these factors in part explain an observed higher cost for equity financing in Canada. Yet, since the introduction of the formula approach to return determination in Canada, utility returns have declined markedly as compared to their US counterparts, a move exactly contrary to that suggested by the Bank of Canada, CEA, NERA and others.

The comparability called for in the FRS appears to have diminished, at least in part, due to the difficulties, perceived and otherwise, in undertaking such an effort. In contrast, in the US, significant efforts are made to compare utility returns to an agreed peer group. Indeed, such comparisons are the very foundation for regulatory board return decisions in that country.

[4]"National Economic Research Associates Inc., "Allowed Return on Equity in Canada and the United States: An Economic, Financial and Institutional Analysis," p. 4, p. 6, February 2008.

[5] Estimating the Cost of Equity for Canadian and U.S. Firms, Bank of Canada Review, Autumn 2007.

Section 3: The Formula Approach and Changes in the Macro-Economy

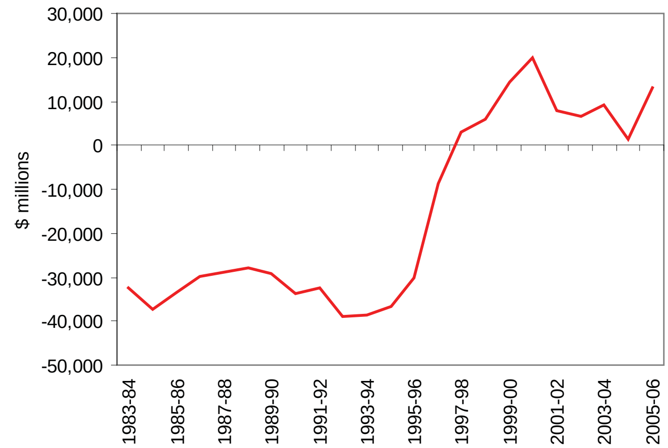
In the 14 years since the introduction of the formula approach to return determination in Canada the economic, financial, and business landscape has changed markedly. Of particular importance are the changes witnessed in the various measures that influence the formula-based approach, specifically, government debt levels, inflation, interest rates, and the performance of Canada's economy.

Some experts contend that it is counter-intuitive that such variables should be the driving factors behind return determination for Canadian gas utilities at all. In a recently published article, Roland Priddle, former Chair of the National Energy Board stated:

"It's now hard for me to see that long-term bond yields, driven by factors as disparate as governments' efforts to get budgetary deficits in hand, central bank' concerns (or not) about inflation…are somehow going to provide a continuing, reliable proxy for returns available in businesses presenting degrees of risk similar to gas pipelines and distribution enterprises."[6]

Figure 4

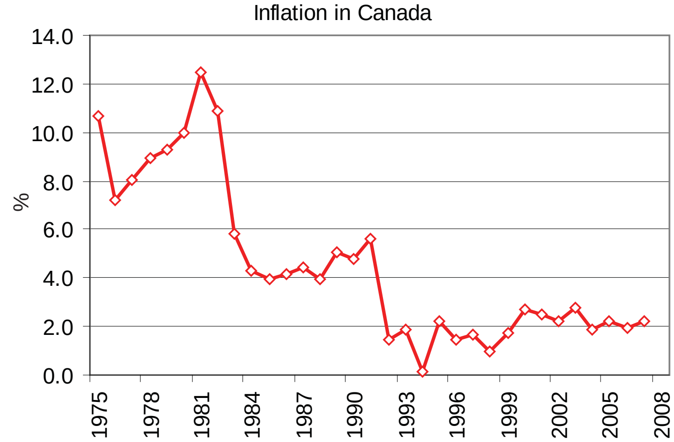
Canada's Federal Fiscal Position



Source: Finance Canada, Statistics Canada

Figure 5

Inflation in Canada



Source: Statistics Canada, Table 326-0021

Canada's Fiscal Deficit

In the 10 years immediately prior to the introduction of the formula approach, Canada regularly ran multi-billion dollar annual deficits, racking up massive amounts of government debt. Then, almost coincident with the introduction of the generic approach, Canada started to get its fiscal house in order. (Fig. 4)

With today's hindsight, we can now see that the financing requirements generated by these huge deficits meant that Canadian bond rates were necessarily quite high. Indeed from 1976 to the end of 1996, the average interest rate differential between Canadian and US long bonds was just shy of 150 basis points. In the 10 years from 1996 to the end of 2006, this differential has averaged just under 50 basis points.

Canada's Inflation

Inflation in Canada had also been roaring along in the late 1970's and early 1980's, at times at double digit levels. (Fig. 5) As a result as we entered the 1990's investors seemed to expect inflation and currency depreciation that was out of line with the anti-inflation monetary policy that was by then being consistently pursued by the authorities. The credibility of inflation policy was also undermined by large budget deficits and by political concerns about the possibility of Quebec separation. It was not until the second half of the decade that inflationary expectations were reined in as deficits were largely eliminated, inflation was kept low, and political uncertainty abated somewhat.

[6] Roland Priddle, "It's Time for the Next Evolution in Regulation," The Gas Journal of Canada (2007): A9.

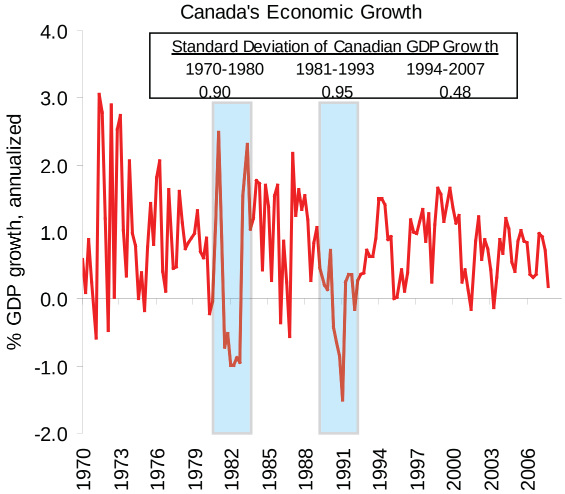
Canada's Economic Performance

The decade prior to the formula adoption also saw Canada's economy weather two large recessionary periods (Fig. 6), the first in the early 1980s, and then another in the early 1990s. These economic dislocations came on the heels of a very volatile pattern of economic growth that had characterised the 1970s. In general, in the 20 years prior to the adoption of the formula approach, there was twice as much volatility in Canada's economy compared to that seen in the 15 years since then.

Not surprisingly, these recessionary periods caused significant turmoil in terms of business risk, profitability, and the stability of corporate earnings.

Figure 6

Canada's Economic Growth



Source: Statistics Canada

Implications

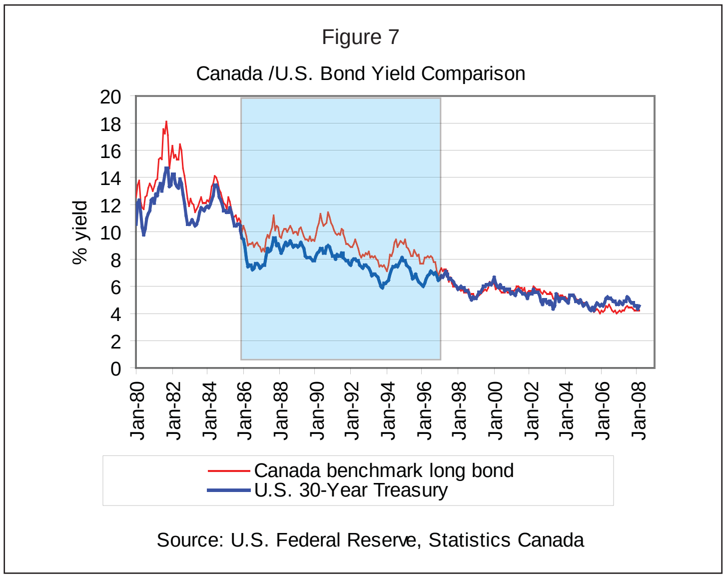
In sum, the formula approach was adopted at the end of a period whose macro-economic circumstances would subsequently prove to be atypical of the period over which the formula was destined to be applied. What this says about the future is of course unclear but it does underpin the contention that a formula left, in effect, on automatic pilot for an extended period risks producing outcomes which do not accurately reflect economic and business realities.

SECTION 4: IMPACTS ON RETURN DETERMINATION IN CANADA

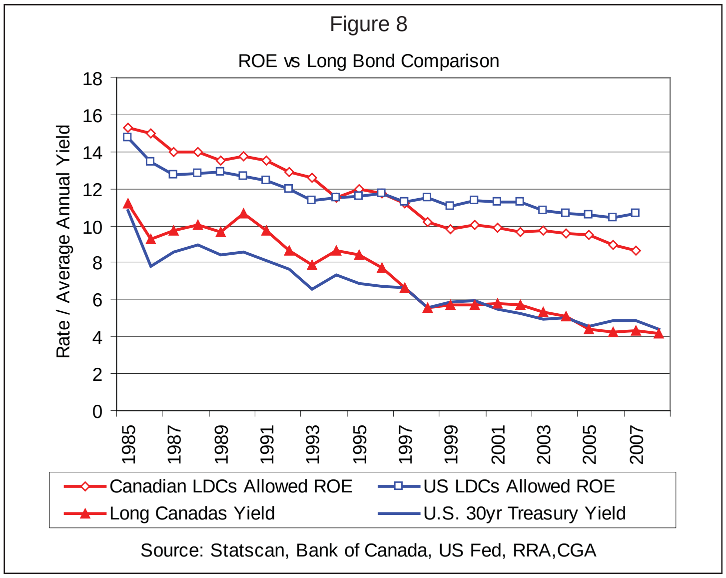
Bond Markets and Return Determination

The economic and market volatilities and instabilities of the 1980s and early 1990s had a profound influence on which methods and methodologies regulators and stakeholders saw as preferable. These influences were enunciated by the NEB in 1994 at its last rate hearing prior to the generic cost of capital proceeding where the Board found that:

"…in the light of recent and prevailing financial market conditions, neither the Discounted Cash Flow (DCF) test nor the Comparable Earnings (CE) test currently yield reliable results. … Accordingly these tests were given little or no weight in the Board's decision." Instead, the Board was of the view that "…the ERP [equity risk premium] was the primary measure of investors' required returns in the circumstances of this case." However, the Board was careful to state its view that these tests (CE, DCF) may prove useful under different economic conditions."[7]



In the face of this instability, Canadian regulators were pushed towards risk-based return determination methods that were based on the relatively "calm" bond market. The availability of credible historical data and independent credible forecasts certainly made this seem like a safer foundation for a formulaic approach to return determination.



What can now be seen with hindsight, however, is that government bonds yields in Canada in the early 1990s also had a number of risk elements that made them an equally poor basis for a formula approach to return determination. The same high government annual deficit and high inflation that contributed to volatility in equity comparisons were adding a "risk premium" to Canadian bond yields illustrated by the divergence from yields afforded their US equivalents. (Fig. 7, shaded area).

NERA addresses the impact in their report, wherein they concluded:

"The apparent efficiency of bypassing case-by-case evidentiary proceedings with a generic formula may have foretold a new and more efficient method of deriving regulated rates generally—except for one thing. The new Canadian generic ROE formula appears to have created a persistent divergence between allowed gas utility returns in Canada and the US.…That is, in dozens of evidentiary proceedings since 1998, US regulators have allowed their companies to set tariffs reflecting ROEs that were on average substantially higher than for their Canadian formula-driven ROE counterparts."[8]

[7] J.C. Major, R. Priddle "The Fair Return Standard for Return on Investment by Canadian Gas Utilities: Meaning, Application, Results, Implications", pg. 14, March 2008.
[8] National Economic Research Associates Inc., "Allowed Return on Equity in Canada and the United States: An Economic, Financial and Institutional Analysis," p. 4, February 2008.

This observation echoes CEA's findings that prior to the formula-approach, Ontario utilities exhibited the expected higher return as compared to their US counterparts. Figure 8 illustrates this point.

The NERA report picks up on this fact and goes on to explain that the explicit and independent use of comparative return information in the US confirms the validity and impartiality of those results, and that the counterintuitive Canadian result of lower returns, despite an equally risky basis, if not more so, illustrates the systemic downward bias in Canadian return determinations processes.

NERA concludes that it is the formula itself that is driving the result:

"*The Canadian ROEs produced by the generic Canadian ROE formula are biased downward. The formula has, since its inception, ridden on autopilot the declining Canadian long-bond interest rates (the cost of a kind of debt) with no independent check on the cost of equity. The generic Canadian formula might not always be biased, and indeed in an era of stable interest rates and equity markets it may have held a true course for many years. But it has been overtaxed by the relatively unprecedented decline in interest rates since the late 1990s. The uncorrected, un-calibrated formula—not risk differences or inherent Canadian regulatory differences—has driven the divergence between observed Canadian and US ROEs.*"[9]

The current form of Canadian formula approach, chosen because of the nature and circumstances of the equity market, bond market, and economic history that formed the very landscape of its birthplace, does not fit the circumstances of today.

[9] National Economic Research Associates Inc., "Allowed Return on Equity in Canada and the United States: An Economic, Financial and Institutional Analysis," p. 8, February 2008.

Section 5: Responding to the Impacts: Reconnecting to the Cost of Equity

Reestablishing the cost of equity in Canada

The now-favoured capital asset pricing model (CAPM) approach to return determination is driven by the current level of interest rates and the relationship between the risk-free rate of return and the return of the equity market.

But a simple ex-post check shows how the cost of equity has evolved along quite a different trajectory than the cost of debt (Fig. 9). As a result, the aforementioned influences related to the broader macro-economy appear to have caused utility returns, based essentially on the cost of debt, to track off course.

In the US, a more explicit consideration of cost of equity is commonly applied using peer/proxy group return methodologies of DCF and CE. As a result US gas utility returns do not track US long bond yields as closely (Fig. 10), and have remained more in line with the broader cost of equity in North America.

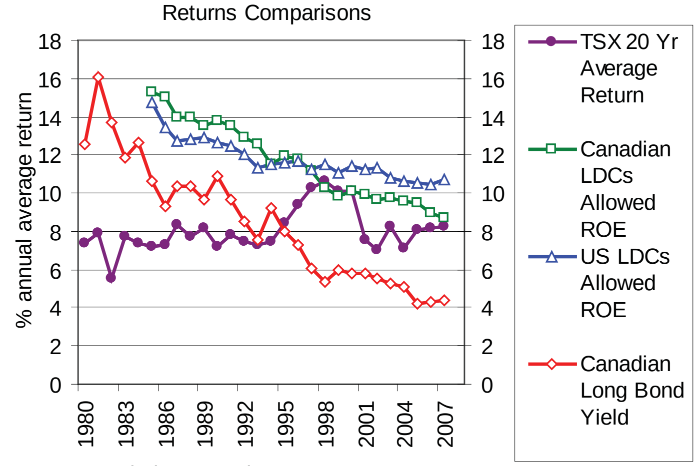
In the US, comparison-based methodologies benefit from the existence of a larger, more stable group of comparable publicly traded utilities. That said, as argued earlier, Canadian utilities are sufficiently comparable to the US to justify use of US peers/proxies in Canadian return determination. In their report CEA did just that, applying a standard US process to establish an acceptable peer group to accurately quantify the difference seen in Canadian and US returns and concluded:

"*There are many similarities between these two groups of companies (i.e., Canadian and US gas distributors) …and any differences in the metrics studied above do not appear to justify the overall ROE differential.*"[10]

What is also apparent is that the use of peer groups requires more judgement in the return determination process, a fact recognized by the NEB in 1971 when it observed the following:

Figure 9

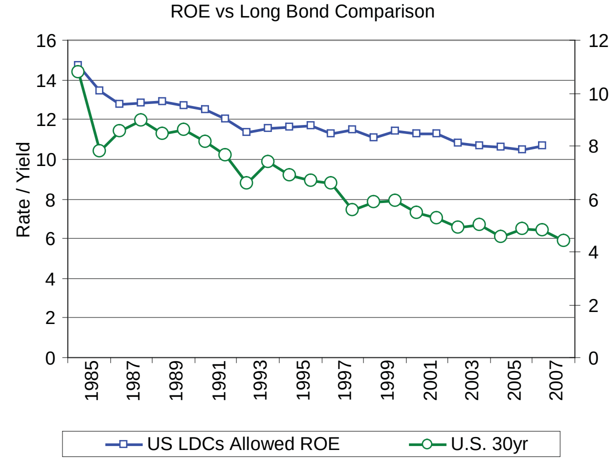
Returns Comparisons



Source: Statistics Canada; CGA

Figure 10

ROE vs Long Bond Comparison



Source: US Federal Reserve, RRA, CGA

"*Many tests and techniques for assisting the process of reaching a just decision have been used …but no single test is conclusive, nor is any group of them definitive: whatever test may be used, in the last analysis the adjudicating body cannot escape the responsibility of exercising judgement as to what, in a stated set of circumstances, is a just and reasonable return or rate of return*".[11]

[10] "A Comparative Analysis of Return on Equity of Natural Gas Utilities," p. 36, prepared for the Ontario Energy Board by Concentric Energy Advisors, June 14, 2007.

[11] J.C. Major, R. Priddle "The Fair Return Standard for Return on Investment by Canadian Gas Utilities: Meaning, Application, Results, Implications", pg. 13, March 2008.

To underscore the above point it is worth repeating how circumstances have changed and how these changing circumstances have undermined the validity of the formula. The formula is stable provided that there is a stable or at least predictable relationship between the cost of equity and the cost of debt – essentially the equity risk premium. Plausibly, and consistent with the evidence of the past 14 years the ERP will tend to compress in high interest rate circumstances and expand in low interest rate circumstances.

The automatic adjustment mechanism adjusts the annual allowed return by a fraction (currently 75% in most Canadian provinces) of the change seen in the long bond. However in their study, the CEA found that this factor is almost twice as large as the relationship seen between allowed returns and long bonds in the US where the two returns are not systematically linked to the each other. [12]

[12] "*… for every one percentage point change in interest rates, the Ontario ROEs change by 86 basis points while U.S. ROEs change by 46 basis points.*", A Comparative Analysis of Return on Equity of Natural Gas Utilities," prepared for the Ontario Energy Board by Concentric Energy Advisors, June 14, 2007, pp. 16-17.

Section 6: Objections Raised

Over the past year CGA has been discussing the issues around returns on capital with a wide range of stakeholders, regulators and policy makers. In these discussions several objections have been raised which we believe can be readily set aside. For that reason we have addressed them in the following section. The essential concern is set out in bold followed by our responses, most of which are based on the other research cited in the paper.

Canadian gas utilities can still raise money and have not shown any signs of distress so their returns must be okay. They do not "need" a higher return.

- The courts have confirmed that the law requires that the three pillars of the FRS be met. This ties together the consumers' need for viable long-term services and the long-term viability of the regulated utility. Regulated utilities must, as required by law, be allowed to earn a fair return on their investment having regard to their duty to provide service. They can neither easily divest nor responsibly stop providing services. This objection shows a lack of understanding of the fundamental nature of the legal rights and obligations of a regulated utility in Canada.

You just can't use the US for comparison; US utilities work under different fact circumstances, including a riskier investment environment.

- As NERA and CEA concluded, the US industry is highly comparable to Canada on a legal, financial, and risk basis. As such, there are no fundamental differences that would justify the persistent gap seen between returns in Canada and the US.
- In fact, Bank of Canada researchers observe that Canada is a higher risk environment and generally the cost of capital in Canada is actually higher than in the US. Canada's smaller, less liquid, more leveraged, and more variable earnings environment are the main reasons for this observation.

Even if US returns are higher there is no reason to conclude that Canadian returns are too low; rather US returns may be biased upward

- Given the wide dispersion of US returns (albeit all higher than Canadian) returns this assertion is counterintuitive. Quoting NERA: "*Those regulators in the US who failed to find a suitable way to streamline their ROE procedures continued on the former path common to both Canadian and US regulation – to examine anew, in every tariff case, expert evidence on ROE for the company in question for the relevant period of time. We do not believe that either Canadian or US regulators would consider the results of those case-by-case evidentiary procedures to be biased on a large scale. They are perhaps expensive, time consuming or overwrought – but not biased.*"[13]

New rate-setting mechanisms, like incentive-based rates, will allow utilities that are more productive to earn higher returns, so they do not need higher allowed returns.

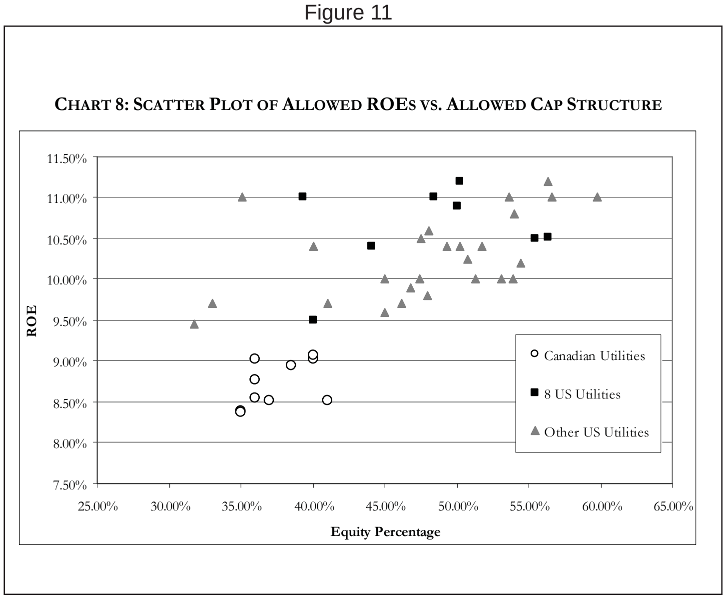
- As outlined by M/P "*Earnings from incentive agreements are rewards for extraordinary cost-savings and for entrepreneurship in devising service offerings that create value for which shippers (customers) are willing to pay. As the Federal Court of Appeal reminded in the 2004 TransCanada decision, the fair return must be determined independently of its impact upon resulting customer rates.*"[14]

Allowed returns are only a part of the total return available to Canadian utilities. They have received increases in their "equity thickness" that compensate them for their lower return on equity.

- In their report, CEA observes that Canadian utility allowed returns and equity thickness are both well below their US comparators (Fig. 11). This fact goes counter to the observed open market where higher leveraged equity investors seek higher

[13] National Economic Research Associates Inc., "Allowed Return on Equity in Canada and the United States: An Economic, Financial and Institutional Analysis," p. 5, February 2008.
[14] J.C. Major, R. Priddle "The Fair Return Standard for Return on Investment by Canadian Gas Utilities: Meaning, Application, Results, Implications", pg. 20, March 2008.

Figure 11



equity returns to compensate them for the extra risk of that leverage. It also runs counter to the fundamental legal principle that what is at issue is a "fair return on the total capital invested", a principle that dates back to the Northwest Utilities Case in 1929 and reaffirmed by the NEB since that time. Since, in Canada, both ROE and equity thickness are systematically lower than US comparators, the effect is to even further bias the return downward when looked at in the perspective of total return on capital.

Canadian utilities have a tax advantage on items like dividends from utilities that make our lower returns justified.

- CEA concludes in their report that "*In and of itself, it is not evident that the dividend tax rules in one country versus another would lead to differences in ROE on a comparative basis.*"[15]

Allowed return on equity masks the reality of what utilities actually earn and that would be a more valid basis for comparison.

- NERA concludes that "*…under both the Canadian and US regulatory methods, the ROE is the measure of cost of capital that enters the formula to make "just and reasonable" rates. It is the measure of compensation allowed for the capital that investors devote to the service of the public at the time the rates are set. What utilities actually achieve in profitability, however, is a different matter. The actual returns are a reflection of myriad factors, including management effectiveness, sales growth, macro-economic considerations, changes in capital costs, and even the weather. The regulatory treatment of investor-owners is tightly bound to the ROE. Clearly, ROE is the proper metric for comparison.*"[16]

Any changes to the determination of returns for Canadian utilities must preserve the results of past regulatory decisions. These decisions were made with full consideration of the facts of the time and as such are, by definition, fair.

- The authors of Canada's formula approach correctly expected a regular review of its results to ensure fairness. The systemic bias that has seen Canadian returns become disconnected from a reasonably formed comparator group indicates that the comparability called for in the FRS is not being maintained. This risks disconnecting the tie between the consumers' long-term need for viable energy services and the long-term viability of natural gas utilities in Canada. While some regulators have reviewed the formula since its inception and while many of the issues raised in this paper have indeed been brought forward already, the long term trends indicated in the CEA and NERA reports were not available at the time of those reviews. In addition, there has been controversy regarding the relevance

[15] "A Comparative Analysis of Return on Equity of Natural Gas Utilities," p. 41, prepared for the Ontario Energy Board by Concentric Energy Advisors, June 14, 2007.

[16] National Economic Research Associates Inc., "Allowed Return on Equity in Canada and the United States: An Economic, Financial and Institutional Analysis," p. 7, February 2008.

of comparisons with US LDC returns. By accepting the validity of a US comparator group regulators could resolve the dilemma such as that faced recently by BCUC who in their March 2, 2006 Decision accepted the principle that comparative returns should be considered but were unable to give weight to the proposition because of concerns about sample size, stating it was "*unable to give any weight to the Comparable Earnings of low-risk Canadian industrials in this proceeding, although it believes that this approach may play a role in future hearings.*"[17] Both the NERA and CEA reports address this issue and conclude firmly that the US comparison is valid.

[17] "Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism" British Columbia Utilities Commission Decision March 2006.

Conclusions

Various studies over the past year have confirmed a persistent divergence between returns awarded to Canadian natural gas utilities and those awarded to a plausible and reasonably formed comparator group. This divergence is primarily due to a systemic bias in the Canadian formula approach and is not explained by differences in the risks to Canadian utility investors nor is it due to a systematic bias in the return determination process employed for the comparator group.

The macro-economic and market circumstances that prevailed at the time when Canada was moving to a formula approach to utility return determination led stakeholders to seek a stable base such as the Canadian long bond. But in retrospect we see that those circumstances have changed significantly and the stability of the relationship between the cost of debt and the cost of equity has declined dramatically.

The systemic bias evident in Canadian formula-based utility return determination and the significant gap that has emerged between Canadian ROE and US ROE levels warrants a Canadian proceeding to redetermine the cost of equity to gas utilities and to establish an improved approach in future The following processes and principles would help ensure a sound and enduring approach.

- There is a need to rebase Canadian ROE's based on a comprehensive review of the cost of capital using all accepted approaches including comparison with a broad comparator group extending across all reasonably comparable industrial groups and jurisdictions including the US.

- There is a need to refresh the formula. In order to meet the requirements of transparency and stability the formula would need to be established on a reasonably stable and readily observable base with an adjustment factor that accounts as fully as possible for the changing relationship between the cost of equity and the cost of debt.

- The formula should be allowed to stand for no more than five years (and probably not less) after which there would need to be another comprehensive cost of capital review which brings in other methodologies and comparators.

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INDUSTRY | COMMENT

JANUARY 16, 2009

Energy Infrastructure

Allowed ROEs: The Formula Is Broken, but Will Regulators Fix It?

Investment Highlights

- **2009 Formula ROEs to Decline by Roughly 15 Basis Points.** Despite weak equity markets and rising corporate bond yields, the National Energy Board (NEB) and B.C. Utilities Commission (BCUC) formula-based allowed ROEs for 2009 decline by 14 bps and 15 bps, respectively. The Alberta Utilities Commission (AUC) will not set a 2009 generic ROE due to its upcoming review of the formula. For more information on the background and mechanics of the ROE formulas, please refer to our *ROE Outlook for 2009* report dated October 24, 2008.
- **Based on Current Data, the 2010 ROE Could Significantly Decline.** Using current market data as a proxy for the forecast data used in the formulas, we estimate that the 2010 allowed ROEs could decline by a further 67 basis points.
- **The Formula Is Broken...**With higher equity risk premiums and higher long bond yields for Energy Infrastructure companies that are trading at levels close to the allowed ROEs, it appears that the formula is broken. Forgetting the magnitude of change, it appears that the formula is producing a result that is directionally incorrect (i.e., ROEs declining yet corporate bond yields and equity risk premiums are rising).
- **...But Will Regulators Fix It?** Historically, there has been a reluctance to make changes to the ROE formula, although we believe that current market data makes it more difficult to justify the formula in its current form. The first crack at changes to the formula will be the NEB decision on Trans Quebec & Maritimes' (TQM) cost of capital proceeding, which is now expected to be issued by the end of March 2009 (delay from the originally anticipated timeline). If the NEB deviates from the ROE formula, we would expect provincial regulators to review their formulas as well.
- **From a Risk-Reward Perspective, We Would Focus on Companies with the Least Exposure to the Formula.** The two companies in our coverage universe with low exposures to the ROE formulas are Emera and Enbridge. Based on its lack of ROE exposure and strong defensive characteristics, we upgraded Emera this morning to Sector Perform (from Underperform)--please refer to our *Research Comment* this morning on Emera for further details. Enbridge remains ranked Outperform, Average Risk. We also favour TransCanada (Outperform, Average Risk), which has higher, but still relatively modest, exposure to the ROE formulas than Emera and Enbridge.

Priced as of prior trading day's market close, EST (unless otherwise noted).
All values in CAD unless otherwise noted.
For Required Disclosures, please see Page 6.

2009 Allowed ROEs to Decline by Roughly 15 Basis Points

The allowed ROE formulas used by some regulators in Canada have been set, and indicate a decline of roughly 15 basis points compared to 2008 levels.

- **National Energy Board (NEB):** The NEB's Multi-Pipeline ROE for 2009 will be 8.57% compared to 8.71% in 2008 (14 basis point decline).
- **British Columbia Utilities Commission (BCUC):** The BCUC's ROE for a low-risk benchmark utility for 2009 is 8.47% compared to 8.62% for 2008 (15 basis point decline).
- **Alberta Utilities Commission (AUC):** The AUC will not be confirming its generic ROE for 2009 due to its upcoming review of the formula. However, the mechanics of the formula are similar to that of the NEB and would have resulted in a similar decline for 2009 compared to 2008.

2010 Declines Could Be Significantly Higher

The allowed ROE formulas are set based on data in November, so a lot can happen between now and then. However, if current market data were used as a proxy for the inputs into the NEB formula for 2010, our analysis indicates that allowed ROEs could decline by roughly 67 basis points as shown in Exhibit 1. Changes to the BCUC and AUC formulas would be roughly similar to the NEB formula.

Exhibit 1: Estimated 2010 ROE Based on Current Market Data

NEB ROE Calculation	2008	2009	2010E*
Consensus economic forecast 10-yr bond yield (3 Months Out)	4.30%	3.70%	
Consensus economic forecast 10-yr bond yield (12 Months Out)	4.70%	4.00%	
Average	4.50%	3.85%	2.59%
Add: average basis point spread between 10-year and 30-year GOC bond	0.05%	0.51%	0.89%
Current year forecast of the 30-year GOC bond yield	4.55%	4.36%	3.48%
Previous year forecast of the 30-year GOC bond yield	4.22%	4.55%	4.36%
Difference between current year forecast and previous year bond yield	0.33%	-0.19%	-0.88%
Adjustment factor	0.75	0.75	0.75
	0.25%	-0.14%	-0.66%
Previous year ROE	8.46%	8.71%	8.57%
Current Year Forecast ROE	**8.71%**	**8.57%**	**7.90%**

* - For 2010, we use the current 10-yr bond yield and current spread between the 10-yr and 30-yr GOC

Source: National Energy Board; Bloomberg; RBC Capital Markets estimates

EPS in 2010 Could Meaningfully Decline

As shown in Exhibit 2, a 67 basis point decline in the formulas would cause EPS to meaningfully decline for several companies. Although there are nuances in some of the formulas (particularly the formula for Fortis' Newfoundland Power), we have used an across-the-board 67 basis point change as a proxy for all ROEs exposed to formulas.

We estimate that Fortis and Canadian Utilities would be most negatively impacted if formula-based ROEs were to significantly decline, while Emera (not shown as it has no formula-based ROE exposure) and Enbridge would have the lowest exposure.

Exhibit 2: Forecast EPS Sensitivity (In $MM except per share figures)

		2009 ROE	Change in ROE	Estimated Ratebase Impacted by Change	Deemed Equity	Earnings Impact	EPS Impact	EPS Impact (%)
Canadian Utilities	PPAs	8.64%	-0.67%	$977	$440	($2.9)	($0.023)	-0.80%
	Alberta Utilities Commission[1]	8.45%	-0.67%	4,649	1,736	(11.6)	(0.093)	-3.15%
	Total			$5,626	$2,175	($14.6)	($0.116)	-3.95%
ATCO	ROE exposure through 52.4% interest in Canadian Utilities (see above)						($0.250)	-3.06%
Enbridge[2]	National Energy Board	8.57%	-0.67%	$1,397	$629	($4.2)	($0.011)	-0.51%
	Noverco preferred shares	7.94%	-0.67%	182	182	(1.2)	(0.003)	-0.15%
	Total			$1,578	$811	($5.4)	($0.015)	-0.66%
Fortis	Alberta Utilities Commission[1]	8.45%	-0.67%	$1,349	$499	($3.3)	($0.020)	-1.28%
	BCUC	8.47%	-0.67%	3,930	1,447	(9.7)	(0.057)	-3.71%
	Newfoundland Power	8.95%	-0.67%	849	382	(2.6)	(0.015)	-0.98%
	Total			$6,129	$2,328	($15.6)	($0.092)	-5.97%
TransCanada	National Energy Board	8.57%	-0.67%	$7,893	$3,105	($20.8)	($0.033)	-1.46%
	Alberta Utilities Commission[1]	8.45%	-0.67%	4,612	1,614	(10.8)	(0.017)	-0.76%
	Total			$12,505	$4,720	($31.6)	($0.051)	-2.23%
TransAlta	PPAs	8.64%	-0.67%	$1,275	$574	($3.8)	($0.020)	-1.18%

Notes:
(1) For utilities regulated by the AUC, our analysis uses an estimate of the 2009 allowed ROE as the AUC will not be setting an ROE for 2009 due to its ongoing generic ROE proceeding.
(2) Per its 2008 settlement agreement, Enbridge Gas Distribution's allowed ROE will not change annually based on the OEB's formula.

Source: Bank of Canada; Financial Post; Bloomberg; various regulatory decisions; company reports; RBC Capital Markets estimates

What Will Regulators Do?

Historically, regulators have been reluctant to make changes to the ROE formula and we believe that there will be resistance to making changes in the future, despite the current market environment. There remains a possibility that regulators could choose to suspend the formula in 2010 (and potentially retroactively for 2009), or even correct the direction of the formula by increasing allowed ROEs from current levels. We believe that the upcoming NEB decision will be very important in gauging the future of the ROE formula. We do not believe that the upside from a potential change in the formula outweighs the downside risk of the status quo, and as such we favour names with lower exposure to the ROE formulas.

Energy Infrastructure Still a Solid Sector, but Lower Exposure to Formulas Is a Good Thing

- **Sector Has Strong Defensive Characteristics:** We continue to highlight that the sector has a good history of outperforming in down markets. Since 1975, the sector has outperformed the S&P/TSX Composite 7 out of 8 times in major market declines with an average annualized outperformance of 28%. Further, many of the stocks have unique credit market defensive attributes such as the ability to pass through debt funding costs to customers as part of the regulatory framework or provisions in customer contracts.
- **Lower Formula ROE Exposure Is a Good Thing:** Although there remains the potential for upside in allowed ROEs should the National Energy Board provide a positive decision on TQM's proceeding by the end of March, the potential for a significant decline in the formula-based ROE for 2010 causes us some concern.

At this stage of the cycle, we recommend that investors stick with the large cap names with the greatest trading liquidity, namely Enbridge and TransCanada. We believe these two stocks provide investors with the best ability to participate in a market rally due to their growth profiles, while still preserving a strong defensive component for portfolios. Further, by holding the names with the highest trading liquidity, investors will be able to most effectively rotate out of the sector when they want to re-position into more offensive names for a pending market rally. In addition, both companies have relatively low exposure to the allowed ROE formulas.

For more bearish investors concerned that equity and credit markets will significantly weaken over the coming year, we recommend the companies with the highest percentage of earnings derived from utilities operating under Canadian cost of service regulation, namely Emera and Fortis. Given its lower exposure to the ROE formula, we have a slight preference for Emera.

Exhibit 3: Large Cap Energy Infrastructure Coverage Universe

		PRICE	Normalized Basic EPS / *Normalized Fully Diluted EPS*				P/E Ratio			Current Dividend/	Current	1-Year		
	Ticker	15-Jan-09	FY07	FY08E	FY09E	FY10E	FY08E	FY09E	FY10E	Distrib.	Yield	Target	Recommendation	Risk
ATCO Ltd.	ACO.X	$37.44	$3.79	$4.32	$3.80	$4.00	8.7x	9.9x	9.4x	$0.94	2.5%	$40.00	Sector Perform	Above Average
			$3.76	*$4.29*	*$3.77*	*$3.97*								
Canadian Utilities	CU	$40.05	$2.74	$3.10	$2.94	$3.09	12.9x	13.6x	13.0x	$1.33	3.3%	$40.00	Underperform	Average
			$2.73	*$3.09*	*$2.93*	*$3.08*								
Emera	EMA	$22.38	$1.30	$1.31	$1.43	$1.48	17.1x	15.7x	15.1x	$1.01	4.5%	$23.00	Sector Perform	Average
			$1.27	*$1.28*	*$1.40*	*$1.45*								
Enbridge	ENB	$40.04	$1.77	$1.88	$2.22	$2.48	21.3x	18.0x	16.1x	$1.48	3.7%	$44.00	Outperform	Average
			$1.76	*$1.87*	*$2.21*	*$2.46*								
Fortis	FTS	$24.10	$1.33	$1.56	$1.54	$1.63	15.4x	15.6x	14.8x	$1.04	4.3%	$24.00	Sector Perform	Average
			$1.31	*$1.54*	*$1.52*	*$1.61*								
TransAlta Corp.	TA	$22.85	$1.33	$1.46	$1.69	$1.88	15.7x	13.5x	12.2x	$1.08	4.7%	$28.00	Sector Perform	Above Average
			$1.33	*$1.46*	*$1.69*	*$1.88*								
TransCanada	TRP	$34.24	$2.09	$2.37	$2.29	$2.47	14.4x	15.0x	13.9x	$1.44	4.2%	$40.00	Outperform	Average
			$2.08	*$2.36*	*$2.28*	*$2.46*								
Average:							**15.1x**	**14.5x**	**13.5x**		**3.9%**			

Source: RBC Capital Markets estimates

Price Target Justifications and Impediments

ATCO
Our price target for ATCO of $40.00 is based on a net asset value (NAV) framework given that its primary asset is its holdings in the publicly traded Canadian Utilities. In calculating our price target, we are reflecting a NAV discount of 18%, which is in line with the estimated average historical discount. A decline in Canadian Utilities' actual and/or expected share price would have negative implications for ATCO's NAV and, accordingly, its share price.

Canadian Utilities
Our price target for Canadian Utilities of $40.00 implies a forward P/E of 12.9x, and a required dividend yield of 3.80% based on a 12-month dividend distribution one year forward of $1.53. The forward P/E is an approximately 2x discount to the average P/E implied by our price targets for Canadian Utilities' peer group. The P/E discount is in line with historical averages. A 10 basis point change in the required dividend yield would affect our price target by approximately $1.00 per share. Factors that could have negative implications for Canadian Utilities' earnings and price target include negative regulatory decisions by the Alberta Utilities Commission, depressed prices for power in Alberta over an extended period, an acquisition that fails to gain the confidence of investors, and failure to meet long-term power purchase arrangement obligations.

Emera
Our price target for Emera of $23.00 implies a forward P/E of 15.5x, and a required dividend yield of 4.5% based on a 12-month dividend distribution one year forward of $1.05. A 10 basis point change in the required dividend yield would affect our price target by approximately $0.25 per share. Risks to our earnings estimates and price target include, but are not limited to, the following: unexpected losses from business development activities, the unsuccessful completion of the Brunswick Pipeline; actual returns or a risk profile for the Brunswick Pipeline that differs materially from our assumptions, and the impact of future regulatory decisions for NSPI and Bangor Hydro.

Enbridge
Our price target for Enbridge of $44.00 implies a forward P/E of 18x, and a required dividend yield of 3.50% based on a 12-month dividend distribution one year forward of $1.58. A 10 basis point change in the required dividend yield would affect our price target by approximately $1.25 per share. Our price target is based on the assumption that Enbridge can complete the list of projects that it is pursuing on attractive economic terms and that the company will continue to announce new projects that will help drive future annual EPS growth in the high single digits. The price target further assumes that the company's risk profile does not materially change.

Fortis
Our target price of $24.00 implies a forward P/E of 14.7x, and a required dividend yield of 4.75% based on a 12-month dividend distribution one year forward of $1.13. A 10 bp change in the required dividend yield would affect our price target by approximately $0.50 per share. The forward P/E multiple is in line with the average current multiple for the group, reflecting Fortis' slowing EPS growth profile that should approximate the average growth rate of the group over the next couple of years. In addition, the forward P/E used in our valuation is at the low end of the stock's 5-year historical P/E range (roughly 14x-20x), reflecting the weak equity markets

and the slowing EPS growth profile. The political environment in Belize, risk of punitive regulatory decisions, economic/tourism conditions in its service territories, operational or financial issues at newly acquired businesses or power prices in Ontario may have implications for our target price as well as our earnings and dividend estimates.

TransAlta

Our $28.00 price target implies a 7.5x 2010E EBITDA for the base operations plus a $5/share risked upside when the Alberta Power Purchase Arrangements expire in 2017 and 2020. The potential upside assumes an $80/MWh net realized power price and a 15% levered equity discount rate. Impediments to our price target include the takeover of the company, valuations for U.S. independent power producers, differences between actual results and our forecasts in the power market, coal costs at the Centralia and Alberta plants, results from trading activities, operational issues, and investor' acceptance of acquisitions and new projects. Note that our risk qualifier for TransAlta is Above Average.

TransCanada

Our price target for TransCanada of $40.00 implies a forward P/E of 16x, and a required dividend yield of 4.00% based on a forecast 12-month dividend distribution one year forward of $1.60. We estimate that a 10 basis point change in the required dividend yield would impact our price target by approximately $1.00 per share. The 16x forward P/E multiple is a roughly 2x discount to Enbridge, which is generally in line with the current discount and reflects modestly lower expected EPS growth in addition to the financing challenges relative to Enbridge over the next year. There is risk to our price target from reduced gas flows on the Canadian Mainline in addition to the company investing in new projects that fail to gain the support and confidence of its shareholders. TransCanada also has earnings exposure to power prices and gas prices. Prices that differ from our estimates could cause actual results to be lower than expected.

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