TESTIMONY

ON

COST OF CAPITAL

FOR THE

The Alberta Utilities:

AltaGas Utilities Inc.
AltaLink Management Ltd.
ATCO Electric Ltd. (Distribution)
ATCO Electric Ltd. (Transmission)
ATCO Gas
ATCO Pipelines
ENMAX Power Corporation (Distribution)
ENMAX Power Corporation (Transmission)
EPCOR Distribution & Transmission Inc. (Distribution)
EPCOR Distribution & Transmission Inc. (Transmission)
FortisAlberta Inc.

Prepared by

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FOSTER ASSOCIATES, INC.

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I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

A. INTRODUCTION

My name is Kathleen C. McShane and my business address is One Church Street, Suite 101, Rockville, Maryland 20850. 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 am a Chartered Financial Analyst (1989). I have testified on issues related to cost of capital and various ratemaking issues on behalf of electric utilities, local gas distribution utilities, pipelines and telephone companies in more than 200 proceedings in Canada and the U.S., including the Alberta Utilities Commission ("AUC" or "Commission").

The purpose of my testimony is to:

1. Evaluate changes in business risk to which the Alberta Utilities[1] are exposed and assess the impact on the cost of capital;

2. Review the reasonableness of the capital structures adopted by the Commission for the Alberta Utilities in *Decision 2011-474*[2] and recommend any changes that are warranted;

3. Recommend a fair return on equity ("ROE") for the Alberta Utilities for 2013 and 2014; and

4. Provide my assessment of whether an automatic ROE adjustment mechanism to set the allowed ROE for years beyond 2014 is warranted, and if so, what form it should take.

[1] The Alberta Utilities include AltaGas Utilities Inc., AltaLink Management Ltd., ATCO Electric Ltd. (Distribution), ATCO Electric Ltd. (Transmission), ATCO Gas, ATCO Pipelines, ENMAX Power Corporation (Distribution), ENMAX Power Corporation (Transmission), EPCOR Distribution & Transmission Inc. (Distribution), EPCOR Distribution & Transmission Inc. (Transmission), and FortisAlberta Inc.

[2] AUC, *2011 Generic Cost of Capital Decision 2011-474*, December 8, 2011; hereafter referred to as "*Decision 2011-474*".

B. SUMMARY OF CONCLUSIONS

My principal conclusions are as follows:

1. With respect to broad cost of capital trends since the end of the oral portion of the 2011 generic cost of capital proceeding (hereafter referred to as "2011 GCOC"), which bear on the fair return:

    a) Risks to the global and Canadian financial system, as assessed by the Bank of Canada, although lower than they were in mid-2011, remain elevated.

    b) Long-term Government of Canada bond yields are lower than they were at the end of the oral portion of the 2011 GCOC proceeding, but higher than they were during most of the post-hearing period. The low levels of bond yields experienced in Canada since the latter half of 2011 have been the result of a confluence of global factors, including continued weak economic conditions, central bank decisions to keep short-term interest rates low, investor risk aversion/flight to safety and a shrinking pool of risk-free assets. As a result, the trend in long-term Government of Canada bond yields alone is not indicative of the trend in the market or utility costs of equity.

    c) Yields on high grade Canadian corporate bonds have largely tracked the movement in long-term Government of Canada bond yields. As a result, spreads in late 2013 are similar to what they were in mid-2011, indicating that the associated credit risk is not perceived to have changed materially.

    d) Forward earnings/price ratios for the S&P/TSX 60 indicate that the market cost of equity may be slightly lower than in mid-2011, but there does not appear to have been a material change in the equity market risk premium.

e) The persistently unsettled capital markets and the unstable relationships between the utility cost of equity and Government bond yields make it difficult to construct an ROE automatic adjustment mechanism that would successfully capture changes in the utility cost of equity.

2. With respect to trends in business risks:

a) Stemming from *Decision 2011-474* and the subsequent *UAD Decision*,[3] the Alberta Utilities face a stranded asset risk to which they were not previously exposed and for which they have not previously been compensated. The AUC's finding in the *UAD Decision* that extraordinary retirements are to the account of the shareholder appears to deviate from a key premise governing the estimation of the fair return, that is, the reasonable opportunity to recover prudently incurred costs. The increased uncertainty faced by equity investors arising from their potential responsibility for stranded assets translates into an increase in return requirement which needs to be recognized in the allowed return.

b) Risks to which the Transmission Facility Operators (TFOs) are subject are higher, resulting largely from political and regulatory developments that point to a less supportive regulatory environment.

c) The business risk of the Alberta electric and gas distribution utilities also has increased as a result of the adoption of price and revenue cap regulation effective January 1, 2013.

d) The business risks of ATCO Pipelines are higher than at the time of integration and at the 2011 GCOC proceeding due to increased uncertainty

[3] AUC, *Utility Asset Disposition, Decision 2013-417*, November 26, 2013, (hereafter referred to as "*UAD Decision*").

in market related conditions as they apply to the Alberta System as a whole and to ATCO Pipelines on a stand-alone basis.

e) Although there have been changes in the business risk faced by the Alberta Utilities, the relative risk rankings of the electric transmission, electric distribution and gas distribution utility sectors in Alberta have not changed since the 2011 GCOC. However, the differential has changed. The electric and gas distribution utilities are relatively more risky than the TFOs than at the time of the 2011 GCOC due to the former's adoption of performance-based regulation.

3. As regards capital structures:

a) While capital markets have improved since the 2011 GCOC proceeding, they have not returned to pre-crisis conditions and the risk of market disruption remains high.

b) The higher regulatory risk, which extends to all the utility sectors, directionally, points to higher common equity ratios for all of the Alberta Utilities.

c) An analysis of credit metrics using updated assumptions supports an across-the-board increase in common equity ratios of no less than two percentage points from the levels adopted in *Decision 2011-474.*

d) The relatively high levels of Contributions in Aid of Construction (CIAC) which are financing the Alberta Utilities' assets continue to expose them to higher levels of operating and financial leverage risk than their Canadian utility peers providing additional support for higher common equity ratios.

e) I recommend that the Commission adopt a two percentage point across-the-board increase in deemed common equity ratios for the Alberta Utilities.

f) I recommend that the Commission approve an increase in ATCO Pipelines' common equity ratio to a range of 42% to 47% (mid-point of 44.5%), reflecting a combination of the across-the-board increase and its increased business risks.

g) The recommended capital structures for each of the Alberta Utilities are:

Table 1

Utility	Recommended Equity Ratio
AltaGas Utilities	45.0%
AltaLink	39.0%
ATCO Electric Distribution	41.0%
ATCO Electric Transmission	39.0%
ATCO Gas	41.0%
ATCO Pipelines	44.5%
ENMAX Distribution	43.0%
ENMAX Transmission	39.0%
EPCOR Distribution	43.0%
EPCOR Transmission	39.0%
FortisAlberta	43.0%

4. The benchmark utility ROE for 2013 and 2014 is 10.5% based on the following.

a) A forecast normalized long-term Government of Canada bond yield of 4.0%;

b) A "bare-bones" cost of equity of 9.5% based on equity risk premium and discounted cash flow tests, summarized in the Table below:

Table 2

Summary of Benchmark Utility Cost of Equity	
Risk Premium Tests:	
Risk-Adjusted Equity Market	8.9%
Discounted Cash Flow-Based	9.6%
Historic Utility	10.625%
Discounted Cash Flow Tests:	
Constant Growth: U.S. Utilities	8.75%
Constant Growth: Canadian Utilities	10.8%
Three Stage: U.S. Utilities	8.8%
Three Stage: Canadian Utilities	9.5%
"Bare Bones" Cost of Equity	9.5%

c) An allowance of 1.0%, representing the mid-point of a range of approximately 0.50% to 1.40%. The lower end of the range represents a minimum allowance for financing flexibility. The upper end of the range is an adjustment for financial risk differences between the market value capital structures which underpin the cost of equity estimates and the book value capital structures to which the allowed ROE is applied.

5. The *UAD Decision*'s assignment of a stranded asset risk to shareholders represents a change in the regulatory model, corresponding to an increase in regulatory risk and an increase in the cost of equity, although, until the magnitude of the risk is better defined, it is difficult to accurately estimate the additional risk premium equity investors would ultimately demand as compensation for the actual consequences of stranded asset risk. Nevertheless, the *UAD Decision* has introduced a level of uncertainty for which equity investors will require additional compensation. The increased uncertainty should be compensated for in the allowed ROE, which can be expressed as a premium to the benchmark utility ROE. I have estimated the premium to compensate for the increased uncertainty alone created by the *UAD Decision* at approximately 1.25% to 1.5%, and recommend that the AUC adopt a premium to the benchmark utility ROE in that range. That premium is not, however, intended to represent the adjustment to the

ROE that would provide adequate compensation if major stranded asset related cost disallowances were to occur.

6. For the electric and gas distribution utilities, I recommend that the Commission approve a premium to the benchmark utility ROE to compensate for the additional risk related to the performance-based regulation. The ROE premium has been estimated at 0.75%.

7. The following table summarizes my recommended ROEs for the Alberta Utilities.

Table 3

	Transmission Facility Owners	**Electric and Gas Distributors**	**ATCO Pipelines**
Benchmark Utility ROE	10.5%	10.5%	10.5%
Premiums to Benchmark:			
UAD Decision Uncertainty	1.25% -1.5%%	1.25%-1.5%	1.25%-1.5%
PBR	N/A	0.75%	N/A
Recommended ROE	11.75%-12.0%	12.5%-12.75%	11.75%-12.0%

8. I recommend that the Commission not adopt an automatic adjustment formula in this proceeding. If, however, the Commission determines that an automatic adjustment formula is required for 2015 and beyond, the formula should adjust for both changes in the yield on long-term Government of Canada bonds and changes in the utility/government bond yield spread, similar to the formulas that are currently operating in Ontario and British Columbia.

II. BACKGROUND

In May 2013, the Commission established the process for a generic cost of capital ("2013 GCOC"), the fourth such proceeding to be conducted by the AUC or its predecessor.

The first GCOC proceeding ("2004 GCOC") resulted in *Decision 2004-052,*[4] which established a single generic ROE for Alberta utilities, a formula approach for determining the allowed ROE in subsequent years, and deemed common equity ratios for each of the applicant utilities.

The second GCOC proceeding ("2009 GCOC'), resulted in the AUC's *Generic Cost of Capital Decision 2009-216*,[5] which discontinued the annual adjustment formula and set a generic allowed ROE for both 2009 and 2010 determined on a *de novo* basis, i.e., independent of the ROE adjustment formula results. Additionally, the Commission decided to implement a two percentage point across-the-board increase in the utilities' deemed equity ratios, with adjustments for sector-specific and company-specific factors.

In the 2011 GCOC proceeding, culminating in *Decision 2011-474,* the AUC conducted a full review of cost of capital matters, including capital structure and the allowed ROE for 2011, whether a formula should be reinstated for the 2012 allowed ROE, or, in the absence of a formula, how to set the allowed ROE for 2012. In *Decision 2011-474*, the AUC set a generic ROE for 2011 and 2012 at 8.75% (a reduction of 25 basis points from the prior decision). The Commission reaffirmed the previously established equity ratios, with the exception of adjustments related to company-specific circumstances and determined that those equity ratios would remain in place until changed by the Commission in a subsequent generic proceeding or by application to the Commission by either the utility or intervenors. The AUC decided not to adopt a formula due to the continuing credit market volatility, although it was prepared to revisit

[4] Alberta Energy and Utilities Board ("EUB"), *Generic Cost of Capital AltaGas Utilities Inc, AltaLink Management Ltd., ATCO Electric Ltd. (Distribution), ATCO Electric Ltd. (Transmission), ATCO Gas, ATCO Pipelines, ENMAX Power Corporation (Distribution), EPCOR Distribution Inc., EPCOR Transmission Inc., FortisAlberta (formerly Aquila Networks) and NOVA Gas Transmission Ltd., Decision 2004-052*, July 2, 2004; hereafter referred to as "*Decision 2004-052".*

[5] AUC, *2009 Generic Cost of Capital, Decision 2009-216*, November 12, 2009; hereafter referred to as "*Decision 2009-216"*.

the re-introduction of an ROE formula once the credit markets were more predictable and it could be confident that the relationships implied in the formula would continue.

The 2013 GCOC proceeding entails a full review of cost of capital matters, including capital structure for each utility, the allowed ROE for 2013 and 2014, consideration of whether the Commission should return to a formula approach for establishing the ROE for 2015 and beyond, and if so, what form the formula approach should take.

III. FAIR RETURN STANDARD

The standards for a fair return arise from legal precedents[6] which are echoed in numerous regulatory decisions across North America, including the AUC's *Decision 2009-216*. 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. 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 *Decision 2009-216*:

> The Commission notes with approval the following description by the ATCO Utilities of how the three factors or criteria of the fairness standard are assessed:

[6] The principal seminal court cases in Canada and the U.S. establishing the standards, each cited in *Decision 2009-216*, 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 the ATCO Utilities' view, the assertion that the three-part test is "simply three ways of looking at the same thing" fails to recognize the critical fact that there are differing tests which help to "triangulate" a Fair Return. Each may have greater or lesser relevance depending upon the economic landscape upon which the tests are conducted. The frailty of reliance on only a single leg of the three legged stool for stability and reliability of the result over changing economic conditions should be obvious. (page 28)

The Commission also stated:

> After review and consideration of the legislation and the evidence, legal argument and case law referred to in this proceeding, the Commission reiterates its agreement that there are three criteria or factors to be employed in determining a fair rate of return. Each criterion or factor must be applied by the Commission when determining a fair return, but what constitutes a fair return (including capital structure) is a matter of judgment for the Commission, exercised after weighing all of the evidence and argument in the context of the facts observed in the marketplace. (page 28)

Further, as the Federal Court of Appeal held in *TransCanada PipeLines Ltd. v. National Energy Board et al.*, [2004] F.C.A. 149, the required rate of return must be based on the cost of equity. The impact on customers of any rate increases cannot be a factor in the determination of the cost of equity capital.

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. Fair compensation for 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 necessary expansion and innovation, potentially degrading the quality of service or depriving existing customers from the benefit of lower unit costs that might be achieved from growth. In short, if a utility is not provided the opportunity to earn a fair return, it may be prevented from making the requisite level of investments in the existing infrastructure in order to reliably provide utility services to its customers.

The application of the fair return standard goes hand in hand with the application of the stand-alone principle, which the Commission has previously endorsed.[7] The stand-alone principle stands for the concept that the fair return should represent the cost of capital that would be faced by a regulated entity raising capital in the public markets on the strength of its own business and financial risk parameters, in other words, as if it were operating as an independent entity. Adherence to the stand-alone principle ensures that the focus of the determination of a fair return is on the use of capital, i.e., the opportunity cost, not the source of, the capital.[8]

IV. DETERMINANTS OF THE COST OF CAPITAL AND THE FAIR RETURN

The overriding economic principle guiding the fair return is the opportunity cost principle. The opportunity cost of capital represents the expected return foregone when a decision is made to commit capital to an alternative investment of comparable risk. It represents the return investors require to commit capital to a specific investment and the cost to the firm of attracting and retaining capital. Satisfying the fair return standard means allowing a return commensurate with the opportunity cost of capital.

A utility's overall cost of capital represents the weighted average cost of the various sources of capital that it uses to finance its rate base assets. The weights represent the proportion of each source of funds used to finance the rate base assets and the cost of each source of funds represents what the company must pay for each type of capital it uses, including debt and common equity.

[7] Public Utilities Board of Alberta, *In the Matter of The Alberta Gas Trunk Line Company Act*, Decision C78221 (December 1978), pages 19-27; Alberta Energy and Utilities Board, *Genco and Disco 2000 Pool Price Deferral Accounts Proceeding*, *Decision 2001-92 (December 2001)*, pages 24-25; Alberta Utilities Commission, *2009 Generic Cost of Capital*, *Decision 2009-216 (November 2009)*, page 7.

[8] To illustrate using ATCO Pipelines as an example, although its business risks have changed due to its integration with NGTL and are affected by the risks of NGTL, they should be assessed from the perspective of an investor in ATCO Pipelines on a stand-alone basis.

For utilities that are regulated on an original cost rate base, as is typical in Canada, including Alberta, and in the U.S., the cost of debt, in most cases, is an embedded cost, or weighted average of the costs that were determined at the time the debt was issued.

The utility cost of equity is a forward-looking cost, which, in accordance with the opportunity cost principle articulated above, represents the return that an equity shareholder expects to earn on an equity investment. It also represents the return that an equity investor requires in order to commit equity funds to or retain equity funds in an equity investment. From the perspective of the firm, it represents the cost that must be paid in order to attract and retain equity funding.

The combined business and financial risks of the regulated firm are the main determinants of its overall cost of capital. In layman's terms, risk is the possibility of suffering harm, or loss. The financial economics definition of risk is based on the notion that (1) the outcome of an investment decision is uncertain; i.e., there are various possible outcomes; (2) probabilities of those outcomes can be ascertained; and (3) the financial consequences of the outcomes can be measured. In other words, the probability that investors' future returns will fall short of their expected returns is measurable. However, as the predecessor to the AUC recognized, with respect to business risk, its assessment is subjective.[9] The subjective, or qualitative, nature of business risk reflects, in part, that the uncertainty of future outcomes does not lend itself to an objective assignment of probabilities.

Business risk relates to the uncertainty of future earnings and the risk of not earning the return that investors expect that arises from the fundamental characteristics of the business, including the market, competitive, supply, operating, political and regulatory environment in which the firm operates. Business risk thus relates largely to the assets of the firm.

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[9] Alberta Energy and Utilities Board, *Generic Cost of Capital, Decision 2004-052,* July 2004, page 35. The National Energy Board also recognized the qualitative nature of business risk in, *Reasons for Decision, Cost of Capital, RH-2-94,* March 1995 ("*Decision RH-2-94").* The NEB stated, "The Board has systematically assessed the various risk factors for each of the pipelines but has not found it possible to express, in any quantitative fashion, specific scores or weights to be given to risk factors. The determination of business risk, in our view, must necessarily involve a high degree of judgement, and the analysis is best expressed qualitatively." (page 24)

The cost of capital is also a function of financial risk. 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. Financial risk refers to the additional risk that is borne by the common equity shareholder because the firm is using debt to finance a portion of its assets. The capital structure, comprised of debt and equity, can be viewed as a summary measure of the financial risk of the firm. 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. As a result, the cost of equity, and thus the fair ROE depends on the capital structure.

There are effectively three approaches that can be used to determine the fair return. The first two approaches entail separate determinations of capital structure and return on equity. The third approach establishes an overall allowed rate of return without separately specifying the capital structure and return on equity.

The first approach either accepts the utility's actual capital structure for regulatory purposes or deems a capital structure that does not necessarily equate the total (fundamental business, regulatory and financial) risk of the "subject" regulated company to those of the proxy companies used to estimate the cost of equity. If, at the subject utility's actual or deemed capital structure, its total (business and financial) risk is higher or lower than that of the proxy companies, 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 second approach assesses the utility's fundamental business and regulatory risks, and then establishes a capital structure that will equate its total risk with that of the proxy companies. This approach permits the application of the proxy companies' cost of equity without adjustment for differential total risk.

The third approach establishes the overall return (combining capital structure, cost of debt and cost of equity) for proxy companies and applies that overall return to the subject company, adjusted as warranted for differences in total risk between the subject utility and the proxy companies.

All three approaches have been taken by regulators in Canada. The first approach has been used by the British Columbia Utilities Commission ("BCUC"), the Ontario Energy Board (OEB),[10] the National Energy Board ("NEB"),[11] and the Régie de l'énergie du Québec (Régie).[12] The second approach has been used by the AUC (and its predecessor)[13] and the NEB.[14] The third approach was utilized by the NEB in setting the allowed return on rate base for Trans Québec and Maritimes Pipelines Inc.[15]

The three approaches are equally valid as long as the overall return, i.e., the combination of capital structure and return on equity in the first two approaches, satisfies all three fair return requirements.

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 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.

Since its first generic cost of capital proceeding for the Alberta Utilities in 2004, the AUC's approach has essentially entailed (1) determining the relative business risk of the various utility sectors that are governed by the generic cost of capital decisions; (2) determining a "base line" common equity ratio for the sector based on the sectors' relative business risks and the objective

[10] The Ontario Energy Board historically awarded different returns on equity and capital structures for Enbridge Gas Distribution, Natural Resource Gas and Union Gas.

[11] National Energy Board, *Reasons for Decision, TransCanada PipeLines Limited, NOVA Gas Transmission Ltd., and Foothills Pipe Lines Ltd., RH-003-2011*, March 2013, hereafter referred to as "*Decision RH-003-2011*".

[12] The Régie has awarded different capital structures and returns on equity for Gazifère, Gaz Métro and Hydro Québec Distribution and Transmission.

[13] *Decision 2004-052*, *Decision 2009-21*6 and *Decision 2011-474*.

[14] National Energy Board, *Reasons for Decision, Cost of Capital, RH-2-94*, March 1995.

[15] National Energy Board, *Reasons for Decision, Trans Québec and Maritimes Pipelines Inc., RH-1-2008,* March 2009; hereafter referred to as *"Decision RH-1-2008"*.

of targeting a debt rating for the utilities in the A category; and (3) making adjustments to the "base line" equity ratio for utility-specific considerations; and (4) adopting the same "benchmark" ROE for each of the Alberta Utilities.

Relying on the concept of a "benchmark" utility ROE is useful for assessing general trends in the cost of equity over time. It can also provide a point of reference or common base from which differential ROEs can be estimated for individual utilities whose overall (business/regulatory plus financial) risk is higher or lower than the total risk captured in the benchmark utility ROE. While the AUC has traditionally used capital structure only to account for differences in business risk among the Alberta Utilities, that approach has its limitations. First, in principle, it constrains management's flexibility to choose its own capital structure, a decision that should be, within limits, within the purview of management. Second, using capital structure as the only adjusting variable for changes in business risk requires shareholders to commit additional equity regardless of their willingness or ability to do so or regardless of the necessity to reduce the financial risk in this manner. [16] With respect to the last, for a given level of business risk, there will be a range of equity ratios that will allow a utility to maintain debt ratings in the A category. Management and shareholders should retain some ability to trade off capital structure and ROE, as long as the combination of capital structure and ROE meets the three requirements of the fair return standard and is consistent with the objective of targeting debt ratings in the A category. Particularly where additional business risk results from the regulatory framework or model, as long as the deemed capital structure is set to allow access to capital on reasonable terms and conditions, it is appropriate, in my view, to provide compensation for the additional business risk in the form of a risk premium to the benchmark utility ROE.

[16] Requiring shareholders to commit additional equity to have the opportunity to earn an ROE regarded as too low is fundamentally incongruous and can be effectively regarded as trapped investment.

V. CAPITAL MARKET AND ECONOMIC CONDITIONS

This section addresses broad trends in economic and capital market conditions and the cost of capital since the oral portion of the 2011 GCOC proceeding ended at the beginning of July 2011. Its purpose is to compare the current state of, and risks in, the markets where the costs of the various forms of capital are determined, compared to the conditions which would have been salient to the Commission's determination of the capital structures and ROE for the Alberta Utilities in *Decision 2011-474*. This discussion is also intended to provide an appreciation of the protracted nature of the recovery from the global financial crisis and economic recession and of the recurrent bouts of capital market turbulence in the intervening period.

In brief, as of late 2013:

1. The systemic risks to the Canadian financial system, as assessed by the Bank of Canada in its most recent *Financial System Review* (FSR), are elevated, but have declined since mid-2011.[17]

2. Long-term Government of Canada bond yields are lower than they were at the end of the oral portion of the 2011 GCOC proceeding, but higher than they were during most of the post-hearing period. The low levels of bond yields experienced in Canada since the latter half of 2011 have been the result of a confluence of global factors, including continued weak economic conditions, central bank decisions to keep short-term interest rates low, investor risk aversion/flight to safety and a shrinking pool of risk-free assets. As a result, the trend in long-term Government of Canada bond yields alone is not indicative of the trend in the market or utility costs of equity.

3. Yields on high grade Canadian corporate bonds have largely tracked the movement in long-term Government of Canada bond yields. As a result, spreads

[17] The Bank of Canada ranks each of the individual risks it reviews and the overall level of risks as "very high", "high", "elevated" or "moderate".

in late 2013 are very similar to what they were in mid-2011, indicating that the associated credit risk is not perceived to have declined.

4. Forward earnings/price ratios for the S&P/TSX 60 indicate that the market cost of equity may be slightly lower than in mid-2011, but there does not appear to have been a material change in the equity market risk premium.

When the 2011 GCOC proceeding commenced in March 2011, there had been significant progress made in the recovery from the global financial crisis, both in the global economy and capital markets. By the close of the oral portion of the 2011 GCOC proceeding:

1. The 10-year and 30-year Government of Canada bond yields, which had fallen to lows of approximately 2.6% and 3.3% respectively during the crisis, hovered around 3.1% and 3.6% at the end of June 2011. The June 2011 Consensus Economics, *Consensus Forecasts* anticipated that the 10-year Canada bond yield would increase to 3.8% over the next year, suggesting a 12-month forward yield on the 30-year Canada bond of approximately 4.3%.

2. Spreads on investment grade long-term corporate debt (measured by the FTSE TMX Canada Long Corporate Index) had sky-rocketed from close to 100 basis points in early 2007 to almost 400 basis points in December 2008. By the end of June 2011, the spread had retreated to just over 180 basis points.

3. Spreads on the Bloomberg 30-year Canadian A-rated utility bond index, which had averaged approximately 95 basis points between 2003 and 2007, and which hit a peak of over 300 basis points in December 2008, had recovered to 145 basis points at the end of June 2011, corresponding to a yield of 5.0%.

4. During the financial crisis, the S&P/TSX Index had plummeted by 50% between late May 2008 and early March 2009. By the end of June 2011, the equity market

had recovered significantly, moving up over 70% from the market trough, about 15% below its 2008 market peak.

In its June 2011 semi-annual *Financial System Review* ("*FSR*"), the Bank of Canada noted decreased risk aversion in financial markets, evidenced by low yields on, and record bond issuance in, high yield (non-investment grade) debt, as well as low volatility in the equity markets. Nevertheless, in the Bank's view, risks to the financial system were still higher than in their six month earlier assessment, as the risk associated with global sovereign debt had edged higher and the risk associated with the low interest rate environment in advanced economies had increased with the growing popularity of riskier securities and strategies in both Canadian and global markets.

By the time of its July 2011 *Monetary Policy Report*, the Bank of Canada had identified several developments weighing on investor sentiment, including:

1. declines in equity market prices in both advanced and emerging economies during the prior three months in reaction to increasing uncertainty over the strength of the global recovery;

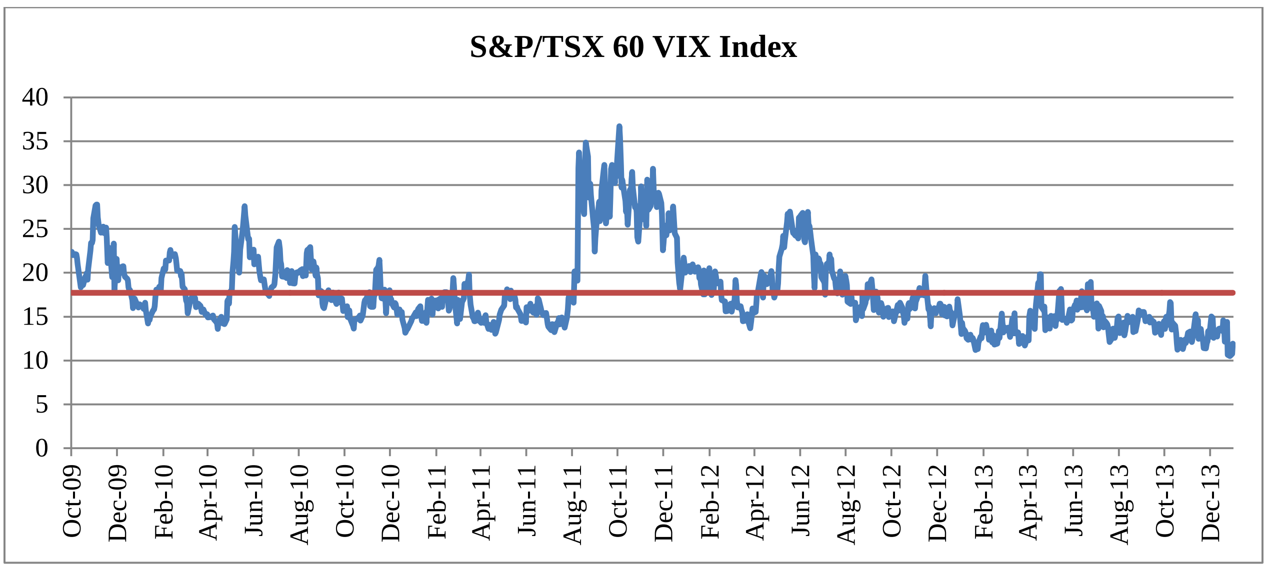
2. some deterioration in corporate credit markets;

3. a sharp reduction in bond issuance; and

4. shifting of capital into perceived safe haven assets and currencies, putting downward pressure on government bond yields in major advanced economies.

Over the next few months, a number of the risks with which the Bank of Canada had expressed concern in earlier reports were experienced. In its October 2011 *Monetary Policy Report*, the Bank of Canada referenced the acute fiscal and financial strains in Europe and concerns about the strength of global economic activity that had led to increased and significant financial market volatility, reduced business and consumer confidence, and an escalation of risk aversion. The increased volatility commencing in August 2011, illustrated in Chart 1 below by reference to the VIXC,[18] was triggered by a reassessment of the prospects for global economic growth, as well as heightened worries over debt sustainability in the euro area and uncertainty over the direction of fiscal policy in the United States. According to the Bank, the already negative tone in financial markets was exacerbated by numerous credit rating downgrades of sovereigns and global financial institutions. As the Bank noted, as a result, investment flows shifted toward safer and more liquid assets. Government bond yields in a number of advanced economies, where markets are most liquid and which are perceived to be better credit risks, had fallen sharply. At the same time, prices of riskier assets had declined significantly.

Chart 1



Source: https://www.m-x.ca/indicesmx_vixc_en.php

In its December 2011 *FSR*, the Bank of Canada judged that the risks to the stability of Canada's financial system were high and had increased markedly over the past six months. In the Bank's assessment, over the prior six months, the risks associated with global sovereign debt and an economic downturn in advanced economies had risen; the risks associated with global

[18] The S&P/TSX 60 VIX Index (VIXC) was introduced by the Montréal Stock Exchange in October 2010, with historical data available from October 1, 2009. It replaced the MVX, which had been introduced in 2002 to measure the market expectation of stock market volatility over the next month. The MVX, and now the VIXC, has been described as a good proxy of investor sentiment for the Canadian equity market: the higher the index, the greater the risk of market turmoil. A rising index reflects the heightened fears of investors for the coming month. Similar to the MVX, the VIXC measures the market's expectation of stock market volatility over the next month.

imbalances,[19] Canadian household finances and the low interest rate environment were unchanged from six months previously.

In both its June 2012 and December 2012 *FSR*s, the Bank concluded that, overall, systemic risks to the financial system had not moderated; it considered that the principal threat to domestic financial stability remained the risk associated with sovereign debt in the euro area.

In the December 2012 *FSR*, the Bank concluded that "despite weakening economic activity in advanced and emerging-market economies, global financial conditions have improved" since its June 2012 report largely, due to "substantial policy actions by major central banks", specifically the Federal Reserve and the European Central Bank. The global recovery, the Bank noted, was fragile and uneven. Canada was growing moderately, with "domestic factors offsetting global headwinds". However, it also noted that investor sentiment remained fragile and "traditional measures of financial market volatility (such as the VIX)" may not accurately capture uncertainty since they may be influenced by the extraordinary liquidity provided by central banks. The Bank cited continued low trading volumes across a number of asset classes and continuation of relatively high yields on long-term bonds in some parts of the euro-area as indicators that investor uncertainty remained elevated. In addition, the Bank pointed to short-term yields in some European countries that were near or below zero, as evidence that the demand for safe and liquid assets remained unusually strong.

In the June 2013 *FSR*, the Bank noted that global financial conditions had improved in the first half of the year, although the pace of global economic recovery continued to be subdued. With accommodative policy actions by major central banks and reduced uncertainty about U.S. fiscal policy during the prior six months, both sovereign and corporate bond yields remained low and global equity markets improved, with some equity markets reaching historic highs. As in earlier reports, the Bank considered that the most important risk to financial stability in Canada continues to stem from the euro area. While lower than six months previously, this key risk was assessed by the Bank as remaining at a very high level. As regards risks emanating from

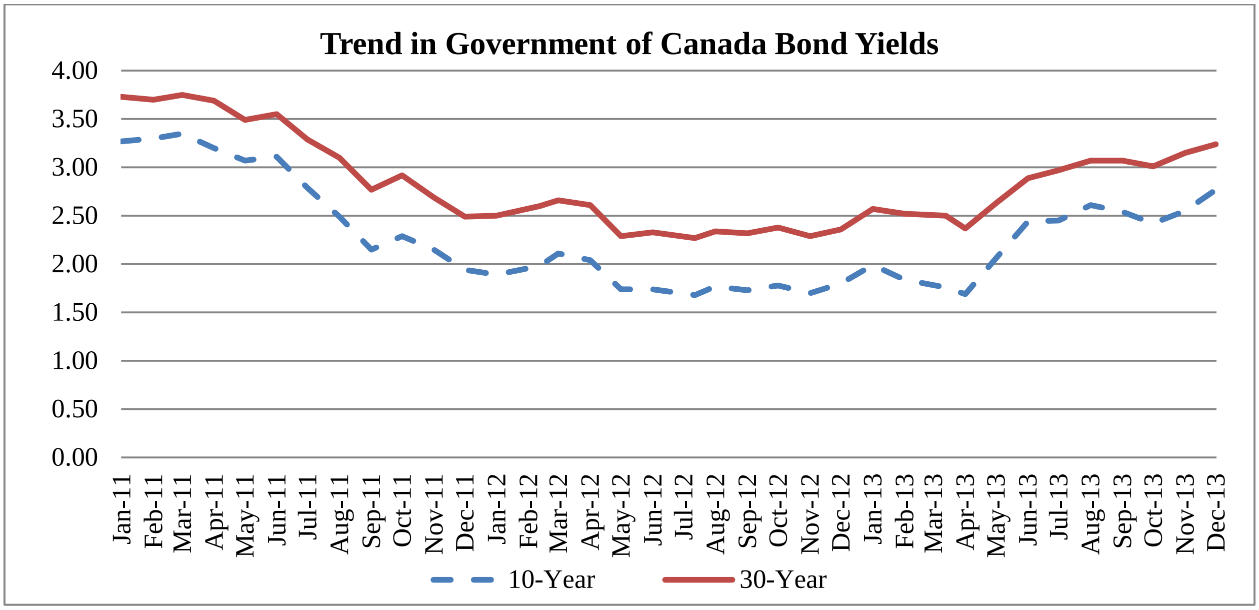
[19] Global imbalances refer to imbalances between savings and investment in the world economies, as reflected in the significant distortions among current account balances, e.g., the large and persistent current account deficit in the U.S. and surplus in China.

domestic sources, the growth rate of household credit in Canada continued to slow and housing market activity (e.g., housing starts, home price increases) moderated, reducing the risk related to Canadian household finances and the housing market. As a result of the changes to these two factors, the Bank concluded that overall risks to the stability of the Canadian financial system had decreased from six months earlier, but remained "high".

In its December 2013 *FSR*, the Bank concluded that the overall risk to the stability of the Canadian financial system had declined from "high" to "elevated". The principal reason for the reduction in risk was the continued stabilization of the euro area, reducing the likelihood of a euro-area financial crisis. The Bank also cited increases in long-term interest rates in most advanced economies, which should improve the financial position of institutional investors with long-duration liabilities, and help moderate household borrowing. Nevertheless, the Bank considered that significant vulnerabilities remain. The euro-area financial system remains fragile, and the region is still open to a renewed bout of financial turmoil. Domestically, the high level of household indebtedness and imbalances in some segments of the housing market make Canada vulnerable to an adverse macroeconomic shock and sharp correction in the housing market. In advanced economies, the persistence of low levels of interest rates would continue to provide an incentive for excess risk taking, which, when central banks terminate unconventional monetary policy initiatives, could lead to higher than optimal interest rates and capital market turbulence. Finally, the Bank identified as a new risk the financial vulnerabilities in emerging market economies, including the sensitivity of countries dependent on external financing to increases in interest rates in advanced economies and building vulnerabilities in China's financial system.

At the end of December 2013, the 30-year Government of Canada bond yield was 3.2%, approximately 1.0% higher than the 2.2% low reached in late July 2012. Chart 2 below shows the trends in 10-year and 30-year Government of Canada bond yields from the beginning of 2011 to the end of December 2013.

Chart 2



Source: http://www.bankofcanada.ca/rates/interest-rates/lookup-bond-yields/

As noted above, while the yields on Government of Canada bond yields have risen, they remain low not only relative to history, but also relative to levels forecast to prevail over the longer-term. From 1976 (the first year 30-year Canada bond yields were reported) to the end of December 2013, the yield on 30-year Canada bonds averaged just under 8%.[20]

With respect to the forecasts, Consensus Economics, *Consensus Forecasts* (October 2013) anticipates that the 10-year Government of Canada bond yield will rise from its mid-October 2013 (date of survey) level of 2.6% to 4.6% by 2019-2023, as shown in Table 4.[21]

Table 4

Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2019-2023**
10-year Canada	2.9%[1/]	3.6%	4.1%	4.5%	4.6%	4.6%

[1/] Average of January and October 2013.

Source: Consensus Economics, *Consensus Forecasts*, October 2013.

[20] The average yield since 1919 on the Government of Canada marketable bonds – Over 10 Years series has been just under 6%.

[21] Consensus Economics issues long-term forecasts of key economic indicators, including the 10-year Government of Canada bond yield, twice a year, in April and October.

With an average historical spread between 30-year and 10-year Government of Canada bonds of 35 basis points, the corresponding yield on 30-year Canada bonds anticipated to prevail over the longer term is approximately 5.0%.

The relatively low levels of Government of Canada bond yields that continue to persist reflect a confluence of factors, including the Bank of Canada's decisions to maintain its overnight rate at historically low levels,[22] the relatively subdued pace of the global economic recovery, and investor demand for safe haven assets. With respect to the last, with the numerous ratings downgrades of sovereign bonds that have taken place in the euro area over the past several years, the supply of safe haven assets has shrunk,[23] and a scarcity value attributed to high grade sovereign bonds (including those of Canada, the U.S., the U.K. and Germany) that have been viewed as least affected by the eurozone debt crisis. [24]

High grade corporate bond yields were also impacted by the smaller pool of highly rated sovereign bonds, as investors sought relatively safe fixed income alternatives. The yield on the Bloomberg 30-year A-rated Canadian utility index reached a low of 3.74% in late September 2012, compared to 5.0% at the end of June 2011. Similar to Government of Canada bonds, utility bond yields have trended upward since the beginning of 2013; the yield on the 30-year A-rated utility bond index at the end of December 2013 was 4.6%. The corresponding spread with

[22] During the financial crisis, the Bank of Canada lowered its policy (overnight) rate to 0.25%. As recovery began, the Bank raised the rate three times, reaching 1% in September 2010. The 1% policy rate has now been confirmed 26 times, most recently in December 2013.

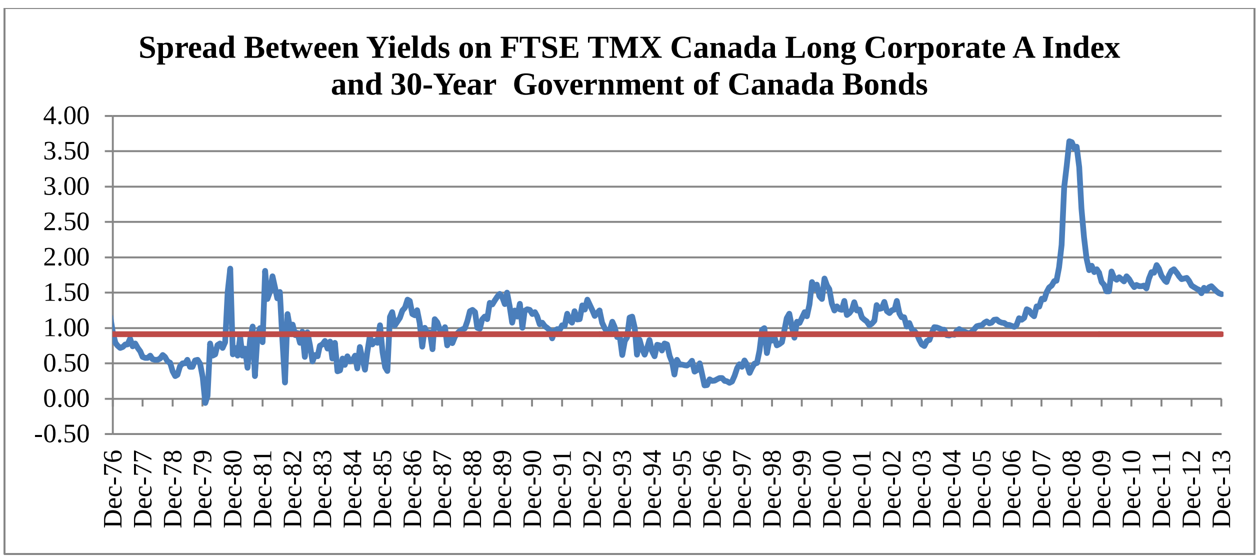
[23] Barclay's *Equity Gilt Study 2012* concluded that "An important reason for these low yields is the structural decrease in the supply of risk-free assets that is not likely to be corrected in the next few years." In its April 2012 *Global Financial Stability Report*, the International Monetary Fund (IMF) found that "the number of sovereigns whose debt is considered safe is declining -- taking potentially $9 trillion in safe assets out of the market by 2016 (roughly 16 percent of the projected total). These developments will put upward pricing pressures on the remaining assets considered safe." While not mentioning Canada specifically, the IMF's April 2013 *Fiscal Monitor: Fiscal Adjustment in an Uncertain World* stated that, while the interest rate had risen sharply in countries under market pressure (i.e., facing sovereign risk as captured in the interest rate), it had fallen in countries benefiting from safe-haven flows (p. 18).

[24] The effects on safe haven asset prices during "flights to quality" arising from uncertain market conditions are exacerbated by demographic trends, i.e., the aging of the population, and a corresponding shift of investment into fixed income securities. As baby boomers have aged and the ratio of retirees to active workers in the U.S. has increased, there has been a "strong trend in mutual fund flows that suggests investors have begun earnestly diversifying their portfolios toward fixed-income products, in many cases away from equity funds." (Tom Roseen, Lipper Funds, March 1, 2012) Lipper reported in early 2013 that, over the prior three years, mutual fund investors had invested almost $5 into fixed income funds for every $1 invested in equity funds. By comparison, in the three years following the 2001/2002 equity market collapse, almost $15 was invested in equity markets for every $1 invested in fixed income markets.

the long-term Government of Canada bond yield, at 136 basis points, was modestly lower than the prevailing spread at the close of the oral portion of the 2011 GCOC proceeding but higher than pre-financial crisis spreads.[25] The average spread between the yields on the Bloomberg 30-year A-rated Canadian utility bond index and the 30-year Government of Canada bond from March 2002 to December 2007 was 100 basis points.

Chart 3 below demonstrates the persistence of higher spreads for high grade corporate bonds since the financial crisis by reference to yield spreads between yields on long-term A-rated corporate bonds and the 30-year Canada bond since 1976. Since the beginning of 2011, the spread has averaged 165 basis points. At the end of December 2013, it was 148 basis points, or close to 60 basis points higher than its 1976 to 2007 (pre-crisis) average of 91 basis points.

Chart 3



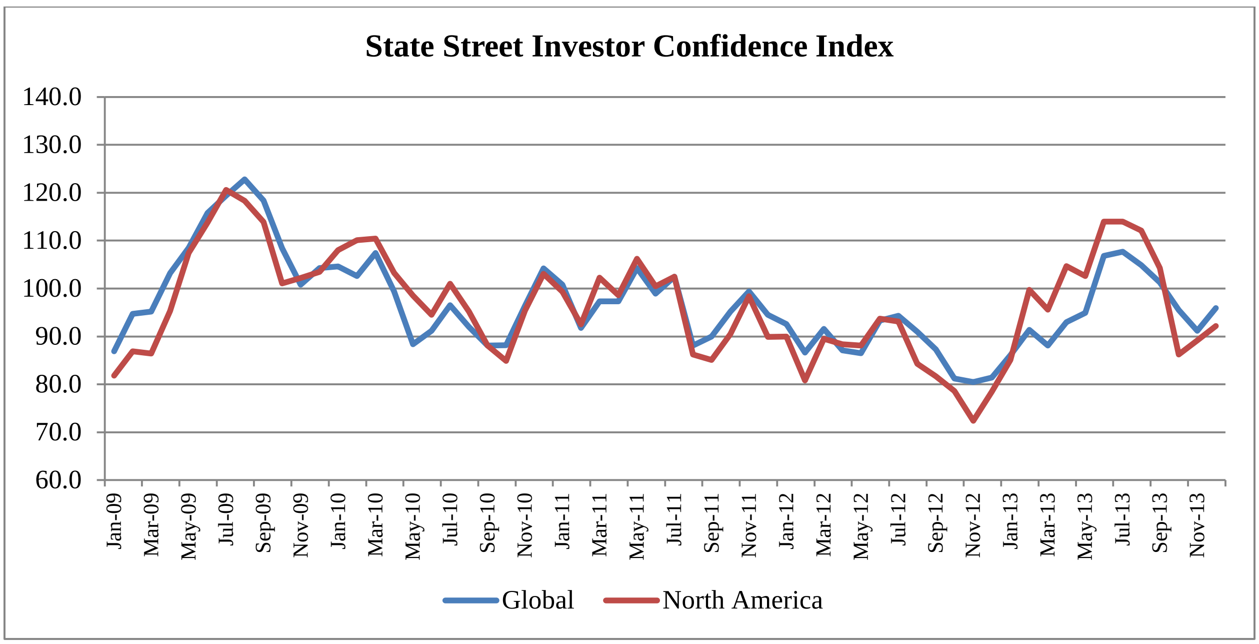
Source: http://www.bankofcanada.ca/rates/interest-rates/lookup-bond-yields/ and FTSE TMX Global Debt Capital Markets, *Debt Market Indices.*

[25] The primary market spreads, i.e., the spreads required by investors for new issues, have been somewhat higher. In mid-September 2013, AltaLink LP, CU Inc., and FortisAlberta each issued new long-term debt at spreads of 160 to 165 basis points.

A comparison of equity market indicators in mid-2011 and late 2013 shows the following:

With respect to expected equity market volatility, the VIXC averaged 13 during December 2013, lower than its June 2011 average of 16 (Chart 1 above).[26] The benign levels of the VIXC in Canada (and the VIX in the U.S.) reflect the continued stimulative monetary policy which is supporting equity markets. At the end of December 2013, both the global and North American investor confidence levels, as measured by the State Street Investor Confidence Global and North American Indices, were slightly lower than their June 2011 levels.[27] Chart 4 below shows the Global and North American investor confidence levels from the beginning of 2009 to December 2013.

Chart 4



Source: http://statestreetglobalmarkets.com/research/investorconfidenceindex/

[26] As the VIXC data only start in 2009, there is no long-term history for comparison. The MVX data, which cover 2002 to 2010, are not comparable to the VIXC data.

[27] State Street Investor Confidence Global and North American Indices represent a quantitative assessment of investors' risk appetite, by measuring the actual and changing levels of risk contained in investment portfolios. The indices use "the aggregated portfolios of the world's most sophisticated investors, representing approximately 15 percent of the world's investable securities." The higher the index value is, the higher is investor confidence. A level of 100 is considered neutral, that is, it represents the level at which investors are neither increasing nor decreasing their allocations to risky assets.

High yield bonds can provide a perspective on the trends in equity market return requirements. High yield bonds are considered to have characteristics of debt as well as equity, the latter due in large part to their higher default risk, higher sensitivity to the business cycle and closer connection to the underlying fundamental risks of the issuers than high grade corporate bonds. The yield on the FTSE TMX Canada Overall High Yield Bond Index, designed to be a broad measure of the Canadian non-investment grade fixed income market, was 7.4% at the end of December 2013, somewhat higher than its 6.8% end of June 2011 level, indicating, in isolation, a slightly higher equity market return requirement.

With respect to the equity market, over much of the period since the 2011 GCOC proceeding, the S&P/TSX Composite generally drifted lower. The market hit a post-crisis peak of 14,270 in early April 2011 (compared to its June 2008 all-time high of 15,073), but, from late July 2011 until mid-October 2013, did not exceed 13,000. At the end of December 2013, the S&P/TSX Composite was only modestly higher than it had been at the end of June 2011. With higher dividends being paid by the companies in the composite in late 2013, but a similar price level, the dividend yield for the composite was 0.50% higher than in mid-2011, as shown in Table 5 below.

Table 5 below also presents forward earnings/price (E/P) ratios for the S&P/TSX Composite. The forward E/P ratios, the inverse of the P/E ratios, provide a rough guide to the direction in the market cost of equity over this time period. The forward E/P ratio of the S&P/TSX Composite decreased from approximately 7.2% to 6.4%, suggesting that the market cost of equity was somewhat lower at the end of December 2013 than it was in mid-2011. With forecast 10-year Government of Canada bond yields lower in December 2013 than in June 2011, the implication is that the late 2013 equity market risk premium is not materially different from its mid-2011 level.

Table 5

S&P/TSX Composite		
	June 2011	**December 2013**
Price Index	13,300	13,621
Dividend Yield	2.5%	3.0%
Forward P/E [1/]	13.8X	15.7X
Forward Earnings Yield (E/P)	7.2%	6.4%
Forecast 10-year Canada Yield	3.6%	3.0%
E/P less forecast 10-year Canada Yield	3.6%	3.4%

[1/] Forward P/E ratio for the Composite estimated as market-value weighted average of the forward P/E ratios for the equities in the S&P/TSX Composite published by Thomson Reuters Datastream.

Source: Consensus Economics, *Consensus Forecasts*, June 2011 and December 2013, Thomson Reuters Datastream, *TSX Review*.

As regards the cost of equity capital for utilities and the implication of the observed decline in long-term Canada bond yields, before the onset of the financial crisis, publicly-traded Canadian utility dividend yields generally tracked the long-term Government of Canada bond yield. From 1998-2007, the median dividend yield of the five major publicly-traded Canadian utilities[28] was, on average, 25% **lower** than the corresponding yield on the 30-year Government of Canada bond. Following the onset of the financial crisis in 2008, the ratio of utility dividend yields to long-term Canada bond yields rose markedly, reaching a peak of 60% higher than the 30-year Canada bond yield in June 2012. At the end of December 2013, the median Canadian utility dividend yield was approximately 17% higher than the corresponding 30-year Canada bond yield.[29]

It bears noting that, if the pre-crisis relationship between utility dividend yields and the yield on the 30-year Canada bond were still valid, at the end of December 2013 30-year Canada bond

[28] Canadian Utilities Limited, Emera Inc., Enbridge Inc., Fortis Inc., and TransCanada Corporation. Excludes Valener Inc., as it was previously a limited partnership (Gaz Métro LP), which converted to a conventional corporation in September 2010. Hereafter referred to as the "five major publicly-traded Canadian utilities".

[29] The ratio of Canadian utility dividend yields to A-rated utility bond yields is also higher than it was pre-crisis. At the end of December 2013, the ratio was approximately 82%, compared to approximately 60% from March 2002 (the starting date of the Bloomberg 30-year Canadian A-rated utility bond index) to the end of 2007.

yield of 3.2%, the corresponding Canadian utility dividend yield should be approximately 2.4% (75% of 3.2%). Instead, it is 3.8%.[30]

The observed change in the relationship between Canadian utility dividend yields (which represent a significant component of the cost of equity[31]) and long-term Government of Canada bond yields represents compelling support for the following conclusions:

1. The estimation of the benchmark utility ROE should be based on multiple tests, including tests which are not benchmarked to the long-term Government of Canada bond yield.

2. In the application of equity risk premium tests that are benchmarked to the long-term Government of Canada bond yield, the abnormally low level of recent and forecast long-term Government of Canada bond yields needs to be taken into account in the assessment of what constitutes an appropriate equity risk premium.

3. In light of the persistently unsettled capital markets and the continuation of unstable relationships between the utility cost of equity and Government bond yields, it is, in my view, difficult to construct an automatic adjustment mechanism for return on equity at this time that would successfully capture prospective changes in the utility cost of equity. In particular, an automatic adjustment formula tied to changes in government bond yields has the potential to unfairly suppress the allowed ROE.[32]

[30] Alternatively, based on the pre-crisis relationship, all other things equal, the observed 3.8% utility dividend yield would correspond to a 30-year Canada bond yield of approximately 5.1% (3.8%/0.75), rather than the much lower end of December 2013 yield of 3.2%.

[31] The utility cost of equity can be estimated as the sum of the expected dividend yield and the expected growth in dividends. For a utility with approximately industry average long-run growth potential, the dividend yield component can account for approximately one-half the total estimated cost of equity.

[32] In November 2010 and November 2011 the Régie implemented automatic adjustment formulas for Gazifère and Gaz Métro respectively that change the allowed ROE by 75% of the change in forecast 30-year Government of Canada bond yields and 50% of the change in long-term A-rated utility bond yield spreads. The initial ROEs and formulas were set such that, at the same forecast long-term Canada bond yield and spread, their allowed ROEs would be identical. Gaz Métro's allowed ROE for 2012 was set at 8.9%, reflecting a forecast long-term Government of Canada bond yield of 4.0% and a utility bond yield spread of 150 basis points. For 2013, due to the operation of the automatic adjustment formula, Gazifère's allowed ROE is 7.82%. In contrast, the Régie suspended the automatic adjustment formula for Gaz Métro for 2013, i.e., its allowed ROE for 2013 remained at 8.9%. The

VI. TRENDS IN BUSINESS RISKS OF THE ALBERTA UTILITIES

A. BUSINESS RISK OVERVIEW

Business risks can generally be categorized as follows:[33]

1. Market Demand Risk

   Market demand risk relates to the size of the market for the regulated firm's services and the ability of the regulated firm to capture market share. The principal market demand risks for a regulated firm reflect the demographics of the area it serves, the diversity of the economy, economic growth potential, geography/weather, customer concentration, and trends in customer consumption and throughput.

2. Competitive Risk

   Competitive risk refers to the business risk arising from competition for customers and throughput due to the existence of, or potential for, alternatives to the regulated firm's services. Competitive risks include the regulated firm's cost structure; e.g., a high cost structure has the potential to lead to customer and throughput attrition and to the development of lower cost alternatives.

Régie has since suspended the formula for both utilities for 2014; the allowed ROEs for both utilities will be set at the levels originally specified in their 2010 and 2011 decisions, 9.1% for Gazifère and 8.9% for Gaz Métro.

[33] With the exception of political risk, the business risk categories are those that have been used by the National Energy Board in its business risk assessments of Group 1 pipelines (e.g., NEB, *Reasons for Decision*, *TransCanada PipeLines Limited.*, *RH-2-2004*, *Phase II* (April 2005), page 26, and *Reasons for Decision*, *Trans Québec and Maritimes Pipelines Inc.*, *RH-1-2008* (March 2009), page 30. The NEB's business risk assessments have considered political risk, which I have set out as a separate risk category, as part of competitive risk (e.g., RH-1-2008).

3. Supply Risk

Supply risk relates to the physical availability of the commodities required to deliver service to end use customers. Supply risk includes exposure to supply interruption. Thus, for gas utilities, it includes the degree of reliance on a single supply basin and/or pipeline and the availability of storage. Supply risk for a pipeline relates to the risk that the lack of physical availability of the commodity at competitive prices will negatively impact the pipeline's earning generating capability.

4. Operating Risk

Operating risk encompasses the physical risks to the revenue generating capabilities of the regulated firm's system arising from technical and operational factors, including asset concentration, service area geography and weather.

5. Political Risk

Political risk relates to the potential for government to intervene directly in the regulatory process or negatively impact regulated operations through policy, legislation and/or regulations relating to such issues as tax, energy and environmental policies, industry structure, and safety regulations.[34]

[34] S&P has stated: "Governments change, government policies change, views on ownership change, economic circumstances change… Politics by definition is populist, expedient, and capricious, and creditors should not dismiss the likelihood of change." (Standard & Poor's, *Credit FAQ: Implied Government Support as a Rating Factor for Hydro One Inc. and Ontario Power Generation Inc*., October 20, 2005) While S&P's statements were made in a specific context, i.e., the risk related to future financial support by the province of Ontario of its Crown utilities, the references to the potential for political change as it relates to the risks of regulated firms are more broadly applicable.

6. Regulatory Risk

> Regulatory risk relates to the framework that determines how the fundamental business risks are allocated between customers and shareholders. Regulatory risk can be considered either as a component of business risk or as a separate risk category. The regulatory framework is dynamic: it is subject to change as a result of shifts in regulatory philosophy, government policies, including energy policy, and underlying fundamental business risk factors, e.g., the competitive environment.

While the categorization of business risks provides a useful foundation for their assessment, the risk categories are overlapping, inter-related and inter-dependent.[35] A change in one category or type of business risk can have a subsequent impact on another type or category of business risk. To illustrate, high market demand risk may lead to significant customer loss, in turn, raising the utility's cost structure, leading to higher competitive risk. Alternatively, high supply risk may lower customer demand, increasing market demand risk.

The business risks of a regulated firm have both short-term and longer-term aspects. Short-term business risks relate primarily to year-to-year variability in earnings due to the combination of fundamental underlying economic factors and the existing regulatory or contractual framework. Long-term business risks include factors that may negatively impact the long-run viability of the firm and that impair the ability of the shareholders to fully recover their invested capital and a compensatory return thereon. As regulated utilities and pipelines represent irreversible capital-intensive investments whose committed capital is recovered over an extended period of time, it is the long-term business risks that are of primary concern to an investor.

The following sections focus on the trends and changes in business risks to which the Alberta Utilities are exposed and that are of sufficient materiality to impact the utilities' overall cost of capital.

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[35] The NEB noted in its, *RH-2-2004, Phase II* decision, "The various forms of risk are related, and the boundaries between them are subjective. What one party may consider a source of market risk may be viewed by another as part of competitive risk."

B. STRANDED ASSET RISK

In *Decision 2011-474*, the Commission raised the issue of stranded asset risk, specifically, which stakeholders should bear the risk of stranded utility assets. The issue of stranded asset risk arose in the 2011 GCOC proceeding in the context of Transmission Facility Owners' (TFOs') assets, i.e., who is at risk in the case of a credit default by a customer who has adopted Rider I.[36] The AUC found that, with respect to assets financed by Rider I, "…when a utility asset is stranded and is no longer required to be used for utility service, any outstanding costs related to that asset cannot be recovered from other customers." (para. 542) More broadly, the AUC then extended that conclusion to any assets deemed stranded for any reason, stating "the Commission considers that any stranded assets, regardless of the reason for being stranded, should not remain in rate base. The utilities must bear the risk where the assets are no longer required for the provision of utility service." (para. 545)[37] Although the AUC imposed stranded asset risk on the Alberta Utilities in *Decision 2011-474*, it did not provide compensation for that risk, nor did my evidence in that proceeding discuss that risk.

S&P noted subsequent to *Decision 2011-474*:

> We expect many, if not all, of the regulated utilities to seek clarification and challenge aspects of the Alberta's GCOC decisions relating to stranded assets. Although we are not aware of any material assets exposed to stranding risk in the near term, exposing regulated utilities to stranded asset risk would weaken their business risk profiles, and be a departure from what we view as a relatively low-risk environment for regulated utilities in Alberta.[38]

[36] Rider I would provide market participants with the option of amortizing contributions in aid of construction over a period of up to 20 years rather than paying contributions in advance. As such the contributions in aid of construction are financed by the TFOs.

[37] In the *UAD Decision*, para. 85, the AUC confirmed that, in *Decision 2011-474*, it had "determined that utility shareholders rather than ratepayers, are at risk with respect to stranded transmission facility owner (TFO) assets (paragraphs 251 and 252 of Decision 2011-474), and extended these comments to any stranded gas or electric transmission or distribution assets (paragraphs 542 to 545)."

[38] Standard and Poor's, *Industry Report Card: Growth Poses Biggest Challenge To An Otherwise Stable Canadian Midstream And Utility Sector*, February 15, 2012, page 4. ScotiaBank analysts concluded that "We remain disturbed by the AUC's position on stranded assets, as shoehorned into the December 8th Cost of Capital decision, though we expect a vigorous appeal from all affected T&D companies." ScotiaBank, *Fixed Income Research: Corporate Bond Morning Notes*, February 23, 2012.

In *Decision 2012-154*,[39] the Commission determined that there had been no broad analysis of the stranded asset issue and who bears the risk in the 2011 GCOC, and concluded that it should be addressed in a generic proceeding. In October 2012, the AUC recommenced the Utility Asset Disposition Proceeding, which had been suspended in 2008, which would determine who bears the responsibility for the costs of stranded assets. The final issues list for the proceeding indicated that, to the extent that shareholders are determined to be liable for stranded assets, any change in risk to the utility will be assessed as part of the 2013 GCOC proceeding.

In the *UAD Decision*, the AUC confirmed the position taken in *Decision 2011-474* as regards responsibility for stranded assets, stating that the "costs of all utility assets of both gas and electric utilities that are no longer used or required to be used for utility service must be removed from customer rates. All revenues generated by, and all costs associated with, such assets that are no longer used or required to be used for utility service are for the account of the utility shareholder." (para. 283) The AUC decided that shareholders are not at risk for recovery of costs related to ordinary asset retirements, where ordinary retirements result from causes reasonably assumed to have been contemplated in prior depreciation provisions (para. 304). However, under-recovery or over-recovery of capital investment on extraordinary retirements is to the account of the shareholder (para. 304). The AUC then broadly asserted that extraordinary retirements could include, according to the decision, obsolete property, property to be abandoned, overdeveloped property and more facilities than necessary for future needs, property used for non-utility purposes and surplus land (para. 303) and property that should be removed from rate base because of circumstances including unusual casualties (fire, storm, flood, etc.), sudden and complete obsolescence, or unexpected and permanent shutdown of an entire operating assembly or plant (para. 327).

The AUC's findings with respect to the responsibility for stranded assets, characterized as extraordinary retirements in the UAD Decision, appeared to deviate, in my view, from a key underlying premise of the determination of the fair return historically in Alberta. A fundamental premise that has governed the estimation of the fair return is that rates are to provide the utilities

[39] AUC, *Decision on Request for Review and Variance of AUC 2011-474 2011 Generic Cost of Capital Decision 2012-154*, June 4, 2012.

the opportunity to recover their prudently incurred costs. The AUC's finding in the *UAD Decision* that extraordinary retirements are to the account of the shareholder, potentially disallowing the recovery of prudently incurred costs, is at odds with that premise and at odds with mainstream regulatory practice throughout North America, including past practice in Alberta.[40] Further, the decision introduces subjectivity as regards what would constitute an extraordinary retirement.

From an equity investor's perspective, the potential that the Alberta Utilities will be denied the ability to recover prudently incurred costs represents a risk for which previously allowed returns have not provided compensation. The magnitude of that risk is difficult to quantify, in part due to the ambiguity of the *UAD Decision*. Nevertheless, the increased uncertainty faced by equity investors arising from their potential responsibility for stranded assets translates into an increase in return requirement which needs to be recognized in the allowed return. Indeed, arguably, the Alberta Utilities have been subject to that risk since 2011.

C. TRENDS IN BUSINESS RISK FOR ELECTRIC TRANSMISSION UTILITIES

Since the 2011 GCOC, the significant capital build in the electric transmission sector in Alberta has been the key driver for several initiatives that have raised the risks, primarily regulatory risks, of the Alberta TFOs. The major developments are summarized below.

In July 2013, Section 46 of the Transmission Regulation, which operationalizes sections of the Electric Utilities Act ("EU Act") relevant to the regulation of electric transmission in Alberta was amended. The AUC described its interpretation of the amendment in AUC, *ATCO Electric Ltd., 2013-2014 Transmission General Tariff Application, Decision 2013-358*, September 24, 2013, at paras. 377 and 378, as follows:

[40] A recent study for the Edison Electric Institute, discussing the restructuring of the electric utility industry in the U.S. during the 1990s, stated, "In virtually every jurisdiction stranded cost recovery was allowed, **because it was necessary to honor the regulatory compact**, and was consistent with the development of efficient competition (emphasis added)." Dr. Karl McDermott, *Cost of Service Regulation in the Investor-Owned Electric Utility Industry: An Adaptation*, December 2012.

> 377. As well, until July 25, 2013, Section 46(1) of the Transmission Regulation required the Commission to consider the majority of transmission costs incurred by the TFO to be prudent, unless an interested party satisfied the Commission that the costs were unreasonable. These stakeholders, and not the TFO, had to demonstrate that the costs captured pursuant to Section 46 of the Transmission Regulation were imprudent, and the Commission was required to exercise forbearance unless an interested party has demonstrated that these costs were unreasonable.
>
> 378. Effective July 25, 2013, the government passed an amendment to Section 46(1) of the Transmission Regulation which removed the presumption of prudence for project costs incurred by the TFOs. With the removal of this presumption, TFOs must demonstrate the prudence of the costs they have incurred for these transmission projects.

In 2013, the Department of Energy also proposed a new Transmission Cost Management Policy which would give the AUC the authority to determine an approved cost estimate ("ACE") no later than 180 days after the permit and license is issued for a transmission project. In addition, this policy seeks to establish a Cost Oversight Manager ("COM") office within the AUC to review and opine on the cost estimate prepared by a TFO. In short, TFO project costs incurred below the AUC's approved cost estimate would be deemed to be prudent for the purpose of subsequent Direct Assigned Capital Deferral Applications ("DACDA"). To be allowed to recover any costs incurred above the approved cost estimate, a TFO would need to demonstrate that the cost overrun was due to circumstances beyond its control and could not reasonably have been foreseen when the AUC approved the cost estimate. In addition, prior to completion of construction, the TFO would also have the option to apply for an increase to the approved cost estimate.

As of January 2014, the Transmission Cost Management policy, including the ACE and the COM, are still the subject of ongoing consultation with industry. Amendments to the Transmission Regulation that would operationalize a new policy have not yet been made. The current uncertainty surrounding the scope of this policy, how amendments to the Transmission Regulation will be made to implement the policy and how the policy changes might affect the extension of project in-service dates and project cost disallowances increases regulatory risk.

With respect to Contributions in Aid of Construction ("CIAC"), the Commission indicated in *Decision 2011-474* that the approved Rider I will likely result in a reduction in the TFOs' CIAC levels. Rider I was deferred, pending the outcome of the UADR proceeding, and there has been no new proposal made. Further, in *Decision 2011-474*, the AUC stated that it had initiated the Electric Transmission Contribution Policy proceeding, whose outcome would likely affect the level of CIAC for the electric TFOs. In *Decision 2012-362*,[41] the Commission decided not to make any changes to the AESO's contribution policy. Thus, to date, there has been no resolution to the level of CIAC-financed assets being constructed, managed and operated by the TFOs. Between 2010 and 2014, the dollars of CIAC-financed TFO assets will have more than tripled, from approximately $350 million to close to $1.2 billion.[42]

The substantial system requirements that have been identified have led the Province to promote competitive electric transmission, which has advanced significantly since the 2011 GCOC. Specifically, section 24 of the Transmission Regulation was amended in 2012 to establish a competitive process for certain transmission projects designated under the EU Act as critical transmission infrastructure ("CTI"). In February 2013, the AUC approved, with conditions, the AESO's proposed competitive process to determine eligibility for application to the AUC for the construction and operation of these designated critical transmission infrastructure projects.[43] The competitive process for the first designated CTI project, the Fort McMurray West 500 kV Transmission Project, was initiated in mid-2013. In addition, in response to the Critical Transmission Review Committee Report, *Powering Our Economy*, dated February 2012, the Government of Alberta announced that all future major transmission projects should be awarded using a competitive procurement process. The Department of Energy is therefore currently consulting with industry on the scope of a major projects definition to which the competitive procurement process would extend in the future from the currently designated CTI projects.

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[41] AUC, *Alberta Electric System Operator, 2012 Construction Contribution Policy, Decision 2012-362*, December 28, 2012.

[42] See also Section VII.E below for further discussion of CIAC.

[43] AUC, *Alberta Electric System Operator Competitive Process Pursuant to Section 24.2(2) of the Transmission Regulation Part B: Final Determination*, *Decision 2013-044*, February 14, 2013.

The introduction of competitive transmission in Alberta is intended to promote the operation of competitive market forces in an area that has historically been governed by traditional principles of rate base/rate of return cost of service regulation.

The extension of the competitive procurement process to as yet undefined major transmission projects in Alberta raises several potential business risk implications for incumbent TFOs, including risks to their growth prospects and potential reduction of control over the operational efficiency of their individual systems, as projects in their traditional service area could be constructed and operated by other TFOs.

The Alberta TFOs also face more uncertainty related to potential deferred cost recovery than at the time of the 2011 GCOC. In June 2012, the *Transmission Cost Recovery Subcommittee Report*[44] ("*TCRS Report*") was issued, in which a number of transmission cost recovery alternatives were identified designed to minimize near-term rate shock and ensure that the costs associated with the sizeable transmission build in Alberta are allocated fairly between current and future ratepayers. Any alternative would have to be approved by the AUC. In January 2013, the AUC initiated a proceeding to examine alternative approaches that could mitigate impacts on ratepayers that could result from the forecast large electric transmission investments. In November 2013, the AUC announced that it would focus on two potential rate mitigation options identified in the *TCRS Report*, a rate cap and deferral of rates approach, as well as a rate base trending alternative that would defer recovery of some of the depreciation expense nearer to the end of the asset lives. These options would result in higher risk to shareholders than the current cost of service model, because recovery of their capital investment is pushed further into the future. The higher risk arising from this proceeding is compounded by the uncertainty introduced by the stranded cost pronouncements of the AUC in the *UAD Decision* requiring the removal from rate base assets that are obsolete or to be abandoned, that represent overdeveloped property or that represent more facilities than necessary for future needs, if those assets are not retired in the ordinary course.

[44] The Transmission Cost Recovery Subcommittee of the Transmission Facilities Cost Monitoring Committee (established by the Department of Energy in 2010) was formed in mid-2011 to explore and develop innovative approaches to cost recovery for new transmission facilities in Alberta.

In addition to these initiatives, other developments point to more detailed and extensive level of scrutiny of TFO management decisions by both the government and the regulator, including the involvement of the Transmission Facilities Cost Monitoring Committee in the management of TFO projects, indications by the Commission that it intends to take a more active role in the management and evaluation of the TFOs' construction program,[45] and the ordering by the Commission of investigations into management prudency issues, in the context of DACDA projects, for which the scope, process, and/or consequences are uncertain.[46]

The cumulative effect of these developments, compounded by the *UAD Decision*, is a trend toward a less predictable and supportive regulatory environment for the Alberta TFOs. These developments lead to heightened uncertainty for equity investors regarding recovery of investment at a time when unprecedented amounts of equity investment are required. As there have been no offsetting reductions in the fundamental demand, competitive, supply, or operating risks to which the electric TFOs are exposed, with the increase in regulatory risks, the TFOs face higher business risk than at the time of the 2011 GCOC.

D. TRENDS IN BUSINESS RISK FOR THE ELECTRIC AND GAS DISTRIBUTION UTILITIES

The principal change in business risk specific to the Alberta electric and gas distribution utilities since the 2011 GCOC is the implementation of performance-based regulation effective January 1, 2013.[47] The principal characteristics of the performance-based regulation adopted by the Commission in the *PBR Decision* are as follows:[48]

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[45]AUC, *ATCO Electric Ltd., 2013-2014 Transmission General Tariff Application, Decision 2013-358,* September 24, 2013, para. 380.

[46] AUC, *ATCO Electric Ltd., 2013-2014 Transmission General Tariff Application, Decision 2013-358,* September 24, 2013, paras. 401 and 819, AUC, AltaLink Management Ltd., *2013-2014 Transmission General Tariff Application*, *Decision 2013-407,* November 12, 2013, paras. 572, 577 and 1309-1312.

[47] ENMAX Distribution has operated under Formula-Based Rates (FBR), a form of performance-based regulation since 2007. The FBR scheme expired December 31, 2013. ENMAX Distribution filed a Cost of Service Application in July 2013 (Application No. 1609784, Proceeding ID. 2739) in order to establish Distribution Access Service rates ("base rates") for 2014 and will file a PBR Application in 2014 to set rates for subsequent years.

[48] AUC, *Rate Regulation Initiative Distribution Performance-Based Regulation, Decision 2012-237,* September 12, 2012; hereafter referred to as "*PBR Decision*".

1. An I-X style price setting mechanism, under which prices of regulated services change annually by a prescribed rate of inflation less a factor X that represents expected productivity growth.

2. A rate of inflation (I) based on a composite of Alberta labour cost inflation and Alberta CPI (to measure non-labour costs).

3. An X factor that reflects historic industry productivity growth (based primarily on U.S. cohorts) plus a stretch factor to account for the expectation that productivity growth will increase during transition from cost of service to performance-based regulation. A single X factor was adopted for all the Alberta distribution utilities (1.16% inclusive of a 0.2% stretch factor).

4. A price cap mechanism for the electric distribution utilities and a revenue per customer cap mechanism for the gas distribution utilities. The revenue per customer mechanism for the gas distributors is intended to account for the declining usage per customer which is characteristic of the natural gas distribution industry. Under the revenue per customer mechanism, annual revenues are indexed using the I-X mechanism and the corresponding rates set using forecast billing determinants.

5. Provision for Z factors to account for material exogenous events over which the utilities have no control and for which there is no other recovery/refund mechanism within the PBR plan.

6. Provision for a capital tracker mechanism (K factor), subject to meeting specific criteria.

7. Provision for Y factors, i.e., recurring expenses that are eligible for flow-through treatment because they meet specified criteria (e.g., municipal taxes, transmission system access fees).

8. Going in rates based on 2012 approved rates, with adjustments to the approved rates in exceptional circumstances only.

9. Ability to reopen and review the PBR plan under certain circumstances, including an actual ROE that is 300 basis points higher or lower than the approved ROE for two consecutive years or 500 basis points higher or lower than the approved ROE for a single year.

10. Ability to implement an efficiency carry-over, i.e., a carry-over of earnings above the allowed ROE arising from productivity gains, after completion of the initial PBR term, subject to a maximum of 0.5%.

11. No earnings sharing mechanism.

12. An initial term of five years.

The comprehensive PBR plan imposed by the Commission exposes the Alberta distribution utilities to higher risk than cost of service regulation, for several reasons:

1. Under cost of service regulation in Alberta, utilities typically have had rates set for two year test periods, although there was no prohibition against a single test year. Under the price/revenue cap plan adopted by the AUC, rates are constrained by the rate of inflation net of the productivity factors built into the plan for a period of five years. Under the cost of service model, if costs increased faster than revenues, the negative impacts on earnings were limited to the test period. Under the adopted PBR plan, not only are earnings likely to be more volatile than under cost of service, the negative impact on earnings if costs increase faster than revenues can extend over the full term of the plan, in this case up to five years.

2. Under cost of service regulation, a utility's revenue requirement is set to allow recovery of the utility's own costs. Under the price/revenue cap plan adopted for the Alberta utilities, prices are to a large extent decoupled from the utility's own costs, which raises the uncertainty of cost recovery relative to a cost of service environment. The ability to flow through certain recurring costs (Y factors) or seek approval for recovery of exogenous event related costs (Z factors) mitigates the risk, but does not reduce it to the cost of service model level.

3. The Y and Z factor costs are subject to meeting specific criteria, including specific materiality thresholds, i.e., equal to or higher than 40 basis points of after-tax return on equity for each event, which are not cumulative, but must be met for every event. Individually, the events may not meet the threshold, and thus not be eligible for Y or Z factor treatment, but together, the effect could be significant.

4. The rate of inflation that is prescribed for purposes of the I-X price mechanism may deviate materially from the actual rate of increase in costs experienced by the utility over the term of the PBR. Further, the PBR formula utilizes the prior year's rate of inflation and does not adjust ("true-up") for deviations from the actual rate experienced.

5. Under the parameters specified for the PBR plan for the Alberta distribution utilities, the utilities must achieve productivity gains in excess of the 1.16% X factor (which includes a "stretch" above long-term U.S. utility industry average productivity) in order to earn their allowed returns. Continuing to achieve productivity gains becomes more difficult over time. In that context, in its recent determination that it would continue with price cap regulation, the OEB set the productivity factor for the electric distributors at zero, acknowledging that the

achieved productivity growth of the Ontario electric distribution sector has likely slowed in recent years.[49]

6. The PBR plan is not subject to reopening and review without significant under-earning having occurred. As S&P has noted, "However, utilities ROEs may deteriorate to levels associated with lower credit ratings before reaching threshold levels that may lead to a reopener of a PBR plan."[50]

7. The Alberta PBR plan does not permit a flow through of changes in cost of capital, either cost of debt or allowed return on equity, as the Commission concluded that changes in the cost of capital are captured in the I factor, stating, "it is the Commission's view that financing rates are a function of interest rates in the economy as a whole, which themselves are ultimately reflected in the rate of inflation." (*PBR Decision*, para. 177) With prevailing interest rates reflecting abnormally low real rates of return, that premise may not hold. Over the next five years, interest rates are expected to rise materially, as economic growth normalizes, but rates of inflation in the economy generally are expected to remain stable. In fact, this phenomenon has already been observed, with the one percentage point rise in long-term Government of Canada bond yields over the past 18 months corresponding to a decline in the rate of inflation (CPI inflation of 1.5% in 2012 versus approximately 1% in 2013). The lack of a mechanism to adjust for changes in the cost of debt or equity in these circumstances exposes the Alberta distribution utilities to the risk that rates under PBR will not provide a reasonable opportunity to earn a fair return.[51]

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[49] OEB, *Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, EB-2010-0379*, November 2013.

[50] S&P, *Credit FAQ: How The Alberta Utilities Commission's Rate Regulation Initiative Will Affect Alberta Utilities' Credit Quality*, November 30, 2012.

[51] This risk is separate from potential for a higher cost of capital than anticipated due to factors beyond management's control, e.g., higher regulatory risk, including PBR risk. If the Alberta distribution utilities were to experience a debt downgrade and/or a higher cost of capital due to higher risk (before the plan reopener is triggered), the increased cost would not be captured in the I factor. As such, I would expect that the Alberta distribution utilities would be able to apply for Z factor treatment of the increased cost of capital.(AUC, *Rate Regulation Initiative, Distribution Performance-Based Regulation, Decision on Preliminary Question, Requests for Review and Variance of AUC Decision 2012-237, Decision 2013-071*, March 4, 2013, para. 69).

Over the term of the PBR plan, the Alberta distribution utilities anticipate that they will be required to commit significant amounts of capital to address both system growth and system replacement. The Commission has recognized that costs associated with all capital expenditures may not be recovered through the I-X mechanism. Similar to the Y and Z factors, the Commission has established criteria, including two further materiality thresholds, which must be met to qualify for K factor funding.

For projects whose capital expenditures will be covered by the capital trackers, the timing of true ups (between costs determined to be prudently incurred and forecasts) will be similar to the cost of service model in Alberta. For capital expenditures that are not covered by the capital trackers, they may not be recoverable under the PBR formula and true-up of incurred costs will not occur until rebasing, thus increasing the uncertainty of both the recovery of the costs themselves and the timing of the recovery.

In the *Capital Tracker Decision*,[52] the AUC assessed the 2013 capital tracker proposals of each the distribution utilities based on the criteria that it had set out in the *PBR Decision*. For AltaGas and EPCOR Distribution, the Commission determined that the projects proposed for capital tracker treatment largely met the three specified criteria. For ATCO Gas, ATCO Electric and FortisAlberta, the AUC concluded that it was unable to determine whether the programs proposed for capital tracker treatment met the criteria, and consequently did not approve any of the projects for capital tracker treatment. Instead, the utilities were directed to retain in rates the interim placeholder of 60% of the applied-for 2013 K factor amounts adopted in the *PBR Decision*, and refile by May 2014, demonstrating that the projects proposed for 2013 capital tracker treatment meet the criteria. The absence of a final resolution to the capital tracker proposals of utilities which account for the preponderance of the electric and gas distribution

[52] AUC, *Distribution Performance-Based Regulation, 2013 Capital Tracker Applications, Decision 2013-435*, December 6, 2013; hereafter referred to as the *Capital Tracker Decision*.

assets in Alberta adds a further element of uncertainty to PBR regulation in the Province.

The conclusion that PBR exposes the Alberta distribution utilities to higher risk than cost of service regulation is shared by both DBRS and Standard & Poor's. In its May 2012 report, *Assessing Regulatory Risk in the Utilities Sector*, DBRS stated that it views cost of service as lower risk than incentive regulation.[53] In its October 15, 2012 *Commentary: Alberta Utilities Commission's Performance-Based Regulation and Its Implications for DBRS-Rated Issuers*, DBRS undertook a preliminary review of the Alberta PBR framework within the context of the ten regulatory risk criteria that it had set out in the May 2012 report. On the criterion of cost of service versus incentive rate mechanism, DBRS rated the Alberta PBR framework as "Very Good", two steps down from the "Outstanding" rating that it afforded cost of service regulation. In a more recent report, entitled *The Regulatory Framework for Utilities: Canada vs. the United States, A Rating Agency Perspective*, October 2013 (hereafter referred as "*Regulatory Framework Report*"), DBRS rated all the Canadian provinces and U.S. states on the ten regulatory risk criteria originally set out in the May 2012, report, but with somewhat different rating category designations.[54] Alberta was rated "Satisfactory" on the Cost of Service vs. Incentive Rate Mechanism criterion, one step below the "Very Good" assigned to British Columbia and Ontario, the other two provincial regulatory jurisdictions that have implemented forms of performance-based regulation.

With respect to S&P's view of the impact of PBR on the Alberta distribution utilities, "it believes that performance-based regulation (PBR) will heighten regulatory risk during its roll-out and over the initial five-year period and could make it more challenging for utilities to continue to earn the allowed generic return on equity (currently set at 8.75%)." Although S&P concluded that the increased regulatory risk may diminish as the AUC establishes precedents reducing

[53] In that report, DBRS set out ten regulatory risk criteria, for each of which one of five rating categories would apply: Outstanding, Excellent, Very Good, Good and Satisfactory.
[54] The five ratings categories are; Excellent, Very Good, Satisfactory, Below Average and Poor.

uncertainty, it also concluded that capital spending and the implementation of the capital tracker within the PBR formula will remain a key area of risk.[55]

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

One of the studies cited was an empirical study by Ian Alexander, Colin Mayer and Helen Weeds, *Regulatory Structure and Risk: An International Comparison*, prepared for PSD/PPI, World Bank, January 30, 1996. That study, a cross-country study of differences in costs of capital resulting from different types of regulatory regimes, concluded that the difference in asset (business risk) betas between energy utilities operating under cost of service or rate of return regulation (a "low powered" regulatory regime) and price cap or revenue cap regulation ("high powered" regulatory regimes) was close to 0.40, translating into a material difference in the cost of equity.

The PBR plan adopted by the Commission for the Alberta distribution utilities is not a pure price or revenue cap model, given the adoption of Y and Z factors and some level of incremental capital funding. Nevertheless, given that the PBR plan in Alberta has many of the features of pure price cap regulation, it is reasonable to conclude, based on the study, that the cost of equity for the Alberta distribution utilities (holding the equity ratio constant) is higher under PBR than it was under cost of service regulation.

[55] S&P, *Credit FAQ: How The Alberta Utilities Commission's Rate Regulation Initiative Will Affect Alberta Utilities' Credit Quality*, November 30, 2012.

E. TREND IN BUSINESS RISKS OF ATCO PIPELINES

The primary long-term business risks which ATCO Pipelines faces are market demand, competitive and supply risks. ATCO Pipelines engaged ICF International to analyze recent changes in the natural gas market environment in North America and Alberta and to assess the impact of those changes on the market demand, competitive and supply risk faced by ATCO Pipelines. I have considered the analysis and conclusions of ICF, in conjunction with my evaluation of trends in the other categories of business risk faced by ATCO Pipelines, to assess whether there has been a material change in overall risk.

The ICF report addresses the changes in ATCO Pipelines' market demand, competitive and supply risks since the Alberta System Integration Agreement ("Integration Agreement") was signed in 2009, as well as since the 2011 GCOC proceeding. In my view, the ICF report's evaluation of trends in business risk since the Integration Agreement was signed, not solely since the 2011 GCOC proceeding, is appropriate. That approach recognizes that natural gas market conditions and the natural gas environment in North America and Alberta have been evolving continuously and rapidly since the Integration Agreement was signed. The implications of the evolving market conditions and the Integration Agreement for ATCO Pipelines can only be fully evaluated when considered since integration.

ICF's analysis of the changes in North American and Alberta gas markets and its conclusions regarding the change in ATCO Pipelines' market demand, competition and supply risks (in the aggregate, market related risks) subsequent to integration can be summarized as follows:

ATCO Pipelines' market related risks and uncertainties have increased since integration, i.e., post-2009, as well as since the conclusion of the 2011 GCOC proceeding. The increase in market related risks reflects the following factors:

1. The shale gas boom in North America has contributed to a significant decline in natural gas prices in recent years. While there is the potential for growth in industrial demand in ATCO Pipelines' footprint, the continent-wide decline in

natural gas prices has reduced the competitive energy price advantage of much of Alberta's industrial sector, e.g., the petrochemical sector, potentially limiting growth in this part of the Alberta economy.

2. While there is potential for significant demand growth in the oil sands sector, which would benefit the Alberta System, including ATCO Pipelines, the uncertainty attached to that growth has risen, given public opposition to the pipeline expansion required to deliver oil sands production to markets. In addition, market expectations for mid- to long-term oil prices have fallen, which has the potential to slow the development of the oil sands and slow growth in Alberta.

3. The recent growth in shale gas production in eastern North America has reduced demand in those markets for natural gas from the Western Canada Sedimentary Basin (WCSB), increasing the downward pressure on throughput on the TransCanada Pipelines Mainline, and putting upward pressure on the Mainline's tolls. The relatively high Mainline tolls reduce the incentive for shippers to deliver gas into the Alberta System for delivery to east of Alberta markets. The proposed Mainline settlement under review by the NEB likely would accelerate this trend.

4. Following from (3) above, as throughput on the Mainline fell, and Mainline tolls rose, TransCanada has been more strongly incented to seek revenues from alternative sources. These include the proposed, but disallowed (in *Decision RH-003-2011*), Alberta System Extension, which would have increased NGTL tolls by allocating costs of the Mainline to the Alberta System, and the Coastal GasLink (for LNG Canada) and Prince Rupert Gas Transmission ("PRGT") (for the Pacific Northwest LNG facility) pipeline projects, which would transport northwestern Alberta/northeastern BC gas west for export as LNG. TransCanada's proposals to reallocate costs from the Mainline to the Alberta System, to include some of the costs of its Coastal GasLink pipeline in the

Alberta System cost of service based on TBO capacity to Vanderhoof, and to include in the Alberta cost of service costs of pipeline expansion to connect with the PRGT pipeline are examples of TransCanada's broader corporate focus than just the Alberta System, and which raise the risk of higher tolls on the Alberta System.

5. The development of proposed LNG projects (in addition to the above referenced Coastal GasLink and PRGT) that would divert new WCSB natural gas production west for export, away from the Alberta System, has accelerated over the past three years, increasing supply risk.

6. The uncertainty surrounding the ultimate volume of LNG exports creates additional market uncertainty for Alberta natural gas consumers, increasing market demand risk for ATCO Pipelines. ICF is projecting 2.7 Bcfd of natural gas demand for LNG exports from British Columbia by 2025; however, if all of the proposed LNG projects are completed, natural gas demand for LNG exports could reach 23.6 Bcfd.

7. Development and production of unconventional natural gas in the WCSB has shifted toward liquids-rich natural gas, which disadvantages the Alberta System versus Alliance Pipeline because of Alliance's rich gas tolling advantage. The competitive position of Alliance will benefit further from the reversal of Kinder Morgan's Cochin Pipeline, which removes one of the primary options for transporting NGLs from the WCSB, and increases the value of Alliance's ability to transport liquids.

8. Tolls on the Alberta System have risen by close to 20% in the past two years, increasing competitive pressures on the Alberta System and ATCO Pipelines. Potentially partially offsetting that increase has been the clarification of Alliance Pipelines' market strategy subsequent to the expiration of its long-term contracts in 2015. While Alliance has developed a new services framework which will

transform it from a single service/single toll pipeline to a multi-services pipeline offering both long-haul and short-haul transportation, at present, the new strategy does not appear to entail direct competition for delivery customers on the Alberta System. However, as of early December 2013, only a small proportion (8%) of the Alliance Pipeline capacity had been re-contracted (through 2016). In addition, new contracts are expected to be shorter term than the expiring contracts. Inasmuch as Alliance Pipeline can reasonably be expected to take steps to mitigate its own market risk, it continues to represent a source of uncertainty as a potential competitive alternative for much of the industrial load served by ATCO Pipelines.

9. With integration, ATCO Pipelines has little flexibility to respond to changes in market conditions, but instead must rely on Nova Gas Transmission Ltd. (NGTL) to respond, as NGTL has assumed responsibility for customer service, tolls and tariffs, and operational planning, system design and expansion on the Alberta System. As TransCanada's recent actions have demonstrated, its broader corporate focus may result in actions which seek to mitigate risks to other TransCanada assets and operations, raising the risks of the Alberta System and ATCO Pipelines. An example includes the NGTL TBO proposal on Coastal GasLink to reduce the cost to producers seeking west coast LNG markets, while potentially raising tolls in Alberta.

In summary, changes in market demand, competition and supply conditions affecting the Alberta System and ATCO Pipelines since integration and the 2011 GCOC proceeding have made the business of transporting natural gas in Alberta far more uncertain, and thus subject to increased business risk.

With respect to operating risks, there have been no material changes in the risks faced by the Alberta System or ATCO Pipelines since integration or since the 2011 GCOC proceeding. In other words, there have been no material changes in the configuration of the Alberta System that have altered operating risk.

There have been no material changes in energy policies, regulations or in the political environment in Canada or Alberta since integration unique to ATCO Pipelines. With respect to regulation, although the regulatory framework specific to ATCO Pipelines has not changed since integration, as indicated below, the regulatory environment generally in Alberta has exhibited less predictability and has become less supportive of the utilities, which increases the regulatory risk of all the Alberta Utilities. Similarly, ATCO Pipelines faces increased risk arising from the *UAD Decision*, particularly given the potential diversion of gas flows from the Alberta System with the westward focus of natural gas transportation for LNG export. Further, although the NEB's *Decision RH-003-2011* resolved some immediate uncertainties with respect to the Alberta System (e.g., the disallowance of the Alberta System Extension), there remains uncertainty as regards the potential impact on the Alberta System and ATCO Pipelines of decisions that might be made by the National Energy Board with respect to the ultimate resolution of the underutilization of the TransCanada Mainline and its tolls.

In addition to the risks outlined above, it should be recognized that ATCO Pipelines' forecast of capital expenditures remains significantly higher than historical levels, due largely to system replacements required for the Urban Pipeline Replacement program. As was noted during the 2011 GCOC, these capital expenditures are primarily due to safety and reliability requirements, rather than system growth, i.e., there are few new customers and incremental throughput over which to spread the additional cost. Although the capital expenditure requirements themselves have not changed materially since the 2011 GCOC proceeding, the costs are forecast to be incurred on a transmission system where, given the changes in the market environment, both producers and end users have become increasingly sensitive to toll increases. As was the case at the time of the 2011 GCOC proceeding, given the significant capital requirements, ATCO Pipelines continues to require ongoing access to the capital markets on reasonable terms and conditions.

Based on the above assessment, ATCO Pipelines' business risks are higher than when they were assessed at the time of the 2011 GCOC proceeding. As the Commission noted in *Decision 2011-474*, the combined ATCO Pipelines/NGTL system faces certain competition and supply risks that should be taken into account. That conclusion is also applicable to ATCO Pipelines on a stand-alone basis. The increased uncertainty in market, competitive and supply conditions as they apply to the Alberta System as a whole, and to ATCO Pipelines on a stand-alone basis, translates into greater uncertainty regarding future earnings and, in the long-run, recovery of the invested capital.

This conclusion is valid, in my opinion, despite the fact that NGTL is responsible for paying ATCO Pipelines' approved revenue requirement under the Integration Agreement. The degree of certainty that the approved revenue requirement will be recovered due to the existing regulatory framework or contractual arrangements is not synonymous with uncertainty of future earnings.[56] From an investor's perspective, the cost of capital is a function of expected earnings and the risk that those earnings will not materialize. The price that investors are willing to pay for assets (in which the cost of capital is implicitly embedded) reflects the expected growth in earnings in combination with how much risk they perceive that the expected growth will not be realized. As the natural gas markets in North America and Alberta have transformed, the uncertainty regarding ATCO Pipelines' future earnings (e.g., its ability to capture and maintain market share) has increased.

F. RELATIVE BUSINESS RISKS OF ALBERTA UTILITY SECTORS

Despite the changes in risk that have been identified and discussed above, the relative risk rankings of the electric transmission, electric distribution and gas distribution utility sectors in Alberta have not changed since the 2011 GCOC. The increase in regulatory risk arising from the *UAD Decision* impacts all of the Alberta Utilities. While many of the changes in regulatory risk are specific to the electric transmission utilities, the cumulative effect of the changes demonstrates a change in regulatory tone and a trend to less regulatory support and less predictability that pervades all of the utility sectors. With the move to performance-based regulation by the electric and gas distribution utility sectors, there is a larger risk differential

[56] Post-integration, ATCO Pipelines' approved revenue requirement is recovered from a single counter-party, itself exposed to increased market uncertainty. Pre-integration, ATCO Pipelines' approved revenue requirement was recovered from a broader base of creditworthy shippers, to which both a stringent investment policy and tight credit policy applied.

between these sectors and the electric transmission utility sector than was the case at the time of the 2011 GCOC. As discussed later in Section X, I recommend that compensation for the increased risk differential between the electric transmission and the electric and gas distribution utility sectors take the form of an additional equity risk premium to the generic or benchmark utility ROE for the latter.

VII. CAPITAL STRUCTURES FOR THE ALBERTA UTILITIES

A. BACKGROUND

In *Decision 2011-474*, in establishing the capital structures for each of the Alberta Utilities, the Commission noted that its previous GCOC decision (*Decision 2009-216*) adopted a two percentage point increase in equity thickness premised on several factors. The AUC declined to reverse the adjustment to the equity ratios that had been adopted in 2009 solely because the credit crisis concerns had somewhat abated, noting that the credit crisis was only one of several factors that had led to the two percentage point increase in *Decision 2009-216*.

The Commission confirmed the importance of targeting ratings in the A category and that minimum credit metrics associated with an A credit rating, as observed in *Decision 2009-216*, could be accepted as guidelines for purposes of the 2011 proceeding. The AUC updated its 2009 credit metrics analysis and found that the previously approved equity ratios for the Alberta Utilities met or exceeded the minimum equity ratios produced by the update. The AUC also concluded that the business risks of the Alberta Utilities had not changed materially since 2009, with the exception of ATCO Pipelines. The Commission then made company-specific adjustments resulting from the specific circumstances of the utilities. As was the case in *Decision 2009-216*, *Decision 2011-474* concluded that the equity ratios awarded would remain in place until changed by the Commission, but that either utilities or interveners could apply for changes to equity ratios on the basis of significantly changed circumstances.

Table 6 below summarizes the equity ratios adopted by the Commission for the Alberta Utilities in *Decision 2011-474*.

Table 6

Utility	**Awarded Equity Ratio**
AltaGas Utilities	43%
AltaLink	37%
ATCO Electric Distribution	39%
ATCO Electric Transmission	37%
ATCO Gas	39%
ATCO Pipelines	38%
ENMAX Distribution	41%
ENMAX Transmission	37%
EPCOR Distribution	41%
EPCOR Transmission	37%
FortisAlberta	41%

Source: *Decision 2011-474*, Table 10, page 53.

The following three sections of my testimony, Sections VII.B through VII.D, address whether there have been changes in circumstances since the 2011 GCOC that are germane to the Alberta Utilities generally which should lead to changes in the common equity ratios previously adopted.

B. CHANGES IN CAPITAL MARKET CONDITIONS

With respect to the Commission's reaffirmation in *Decision 2011-474* that it is important to target the debt ratings for the Alberta Utilities in the A category, nothing has fundamentally changed since the 2011 GCOC that would alter this conclusion. As the Commission noted in *Decision 2011-474* (referencing *Decision 2011-453*, paragraph 798),[57] "as a BBB category issuer, a utility may face more significant challenges in accessing debt markets, particularly at a time of adverse market conditions." That conclusion remains valid.

With respect to conditions in the credit and capital markets, since the 2011 GCOC proceeding, A-rated utilities have been the beneficiaries of Canada's safe haven status, and have been able to

[57] AUC, *AltaLink Management Ltd. 2011-2013 General Tariff Application*, *Decision 2011-453*, November 18, 2011.

issue long-term debt at relatively low absolute interest rate levels. Nevertheless, as noted in Section V, spreads for A-rated utilities have remained relatively high. At the end of December 2013, the spread between the yield on 30-year A-rated Canadian utility bonds as measured by the Bloomberg index and the 30-year Government of Canada bond, at 136 basis points, was slightly lower than the end of June 2011 spread of 144 basis points. In September 2013, AltaLink, CU Inc. and FortisAlberta all issued new long-term debt at virtually the same spreads as when they issued new long-term debt in the fourth quarter of 2011. Also, as discussed in Section V above, while the risks to the Canadian financial system have declined since the 2011 GCOC, they remain elevated, according to the most recent Bank of Canada assessment.[58] Although, overall, there has been incremental improvement since the 2011 GCOC, capital markets have not returned to pre-crisis conditions and the risk of a market disruption remains relatively high. The conclusion the AUC drew in *Decision 2009-216* when it adopted the two percentage point increase in common equity ratios remains valid, that is, the Commission:

> must also consider that the events that drove the original crisis will be factored into investors' perceptions. Companies will therefore protect their balance sheets and investors will adjust risk perceptions whether unexpected events present themselves again or not. In order to protect investors' and ratepayers' interests, the Commission must award equity ratios that recognize the need for the ongoing viability of the utility even in adverse conditions.[59]

That consideration alone supports, at a minimum, reaffirmation of the two percentage point increase in equity ratios first adopted by the Commission in *Decision 2009-216*.

[58] This assessment contrasts with the Bank of Canada's characterization of the risks to the Canadian and global financial systems pre-crisis. In its December 2006 *Financial System Review*, for example, the Bank described the risk assessment as "favourable", and continued to do so in the June 2007 *FSR*. By the time of the December 2007 *FSR*, the global financial system had experienced what the Bank referred to as a "sudden repricing of risk".

[59] *Decision 2009-216*, page 90.

C. BUSINESS RISK

With respect to business risk, Section VI above evaluates the trends in business risks of the Alberta Utilities. The evaluation of both the electric transmission and the electric and gas distribution sectors leads to the conclusion that the regulatory environment in Alberta has become less predictable and less supportive. To some extent, the higher regulatory risk directly arises from AUC undertakings and decisions (e.g., UAD Decision, adoption of PBR). It also arises from political intervention into the regulatory process, e.g., changes in the Transmission Regulation. As a further example, in addition to the government-led initiatives referenced above, in early 2012, the Minister of Energy requested that the AUC freeze electric transmission and delivery rates pending the results of a review of the retail electricity market. As a result of the province's request, the AUC agreed to defer release of decisions that would entail a rate increase. The freeze was lifted at the end of January 2013.

From an investor's perspective, less regulatory support, higher potential for political intervention in the regulatory process, and more regulatory uncertainty translate into higher regulatory risk. The higher regulatory risk, which extends to all the utility sectors, directionally, points to higher common equity ratios for all of the Alberta Utilities as support for maintenance of debt ratings in the A category.

D. CREDIT METRICS AND EQUITY RATIOS

In *Decision 2009-216*, the AUC examined three credit metrics, from which it identified what it viewed to be the minimum levels associated with a debt rating in the A category, and in turn, what the associated (minimum) equity ratio was that would, under specified assumptions, produce the minimum credit metric. The three credit metrics and the corresponding minimums specified by the Commission were as follows:

1. Earnings before Interest and Taxes (EBIT) Interest Coverage: 2.0X

2. Funds from Operations (FFO) to Debt: 11.1% to 14.3%

3. Funds from Operations (FFO) Interest Coverage: 3.0X

The minimum credit metrics identified were based on the published credit metrics of Alberta utilities with rated debt, as calculated by DBRS and Standard & Poor's. Use of published actual credit metrics to establish the minimums necessary for a debt rating is somewhat problematic for four reasons.

1. The published ratios used by the Commission to establish the minimums were based on a small sample of companies over a limited period of time. The 11.1% FFO/Debt ratio identified as a minimum reflects AltaLink's S&P calculated ratio for a single year, 2007. The debt rating agencies do not develop their ratings on the basis of a single year's ratios. Instead, they look at multiple years' actual ratios, in conjunction with observed trends and forecasts.

2. The debt rating agencies take into account a utility's specific circumstances. For a utility that is experiencing high growth and undertaking significant capital expenditures, the debt rating agencies are more likely to accommodate some weakening in credit metrics during the build cycle without a negative impact on the rating. However, it would not be appropriate to consider the high growth utility's build cycle credit metrics to be the minimums applicable to a utility with a steady state rate of growth.

3. While it may be useful to identify "minimum credit metrics", the equity ratios for the Alberta Utilities should not be set so that only the minimum levels of credit metrics are expected to be achievable, i.e., there should be a downside cushion. The reported credit metrics of Canadian utilities generally and Alberta utilities specifically have been viewed as weak by the major global debt rating agencies (Standard & Poor's and Moody's). Standard & Poor's, for example, considers FortisAlberta Inc.'s "Weak, albeit stable, financial measures for the rating" to be

one of the utility's weaknesses.[60] However, as shown in the table below, the reported credit metrics[61] for investor-owned Canadian utilities with rated debt for the past three years (2010-2012), which have frequently been considered weak for the ratings (A-/A3 by S&P/Moody's) were, in most cases, on average, materially higher than the AUC minimums.

Table 7

	Debt Ratings		**EBIT Coverage**	**FFO Coverage**	**FFO to Debt**
	DBRS	**S&P/Moody's [1/]**			
AUC Minimum	A-	A-/A3	2.0 X	3.0X	11.1-14.3%
Utility Median	A	A-/A3	2.4X	3.5X	14%

[1/] As a number of Canadian utilities have either S&P or Moody's ratings, but not both, the median comprises both the Moody's and S&P ratings.

Source: Schedule 7.

Moody's reaction to the British Columbia Utilities Commission's May 2013 *GCOC Stage 1 Decision*[62] highlights the potential for debt rating downgrades into the BBB category should the AUC's decision in this proceeding reduce equity ratios and weaken credit metrics. In its *GCOC Stage 1 Decision*, the BCUC reduced FortisBC Energy's deemed common equity ratio from 40% to 38.5% and it's allowed ROE from 9.5% to 8.75%. As a result, Moody's changed each of the FortisBC utilities' Outlooks from Stable to Negative and cited "historically weak financial profiles that are expected to deteriorate further, given the Province's recent generic cost of capital decision." Moody's press release stated, "The level of BCUC regulatory support, though considered favorable, may not be sufficient to counterbalance the severely weak financial metrics at current ratings levels."[63] Moody's further commented that:

[60] S&P, *RatingsDirect, FortisAlberta Inc.*, November 30, 2012.

[61] As reported by Standard & Poor's if available. If not, the corresponding credit metrics reported by Moody's or DBRS were used.

[62] *In the Matter of British Columbia Utilities Commission Generic Cost of Capital Proceeding (Stage 1) Decision*, May 10, 2013.

[63] Moody's, *Rating Action: Moody's changes outlook for FortisBC entities to negative; ratings affirmed*, June 21, 2013. FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc., both gas distribution utilities, are currently rated A3 by Moody's. FortisBC Inc., a vertically integrated electric utility, is rated Baa1.

> The potential for sub-13% CFO pre-WC to debt that Moody's suspects that each FortisBC utility could produce over the intermediate-term, is paltry compared to US peer transmission and distribution electric companies and local gas distribution companies which produce well above 20% CFO pre-WC to debt, on average since 2010, in both the A3 and Baa1 rating categories. Although we consider the BC regulatory environment to be generally supportive and able to provide credit lift to offset weaker financial metrics, the regulatory provisions of the province do not support A3 and Baa1 credit ratings for utilities that exhibit financial profiles associated with the Ba rating category (i.e., 5% - 13% CFO pre-WC to debt, according to the Regulated Electric and Gas Utilities rating methodology).

4. The less supportive regulatory tone in Alberta and the corresponding higher regulatory risk should, in principle, be reflected in higher minimum credit metrics than those designated as such by the AUC. Although I am not proposing specific increases to the minimums, the increased regulatory risk faced by the Alberta Utilities provides further support for the Commission to target credit metrics well above the specified minimums in setting the allowed common equity ratios for the lowest risk Alberta utilities.

5. The Commission's credit metrics analysis is not as rigorous as that undertaken by the rating agencies and tends to understate the equity ratios necessary to actually produce the specified minimum credit metrics. The rating agencies adjust reported values from utilities' financial statements to produce a more economically meaningful assessment of the companies' financial position than accounting values might indicate. The adjustments tend to produce reported lower actual credit metrics than those produced by the basic credit metrics analysis undertaken in the 2009 and 2011 GCOC proceedings. Thus, the metrics produced by the Commission's approach tend to overstate the metrics that would actually be calculated by the debt rating agencies, in particular Standard & Poor's. Consequently, the equity ratios produced by the Commission's credit metrics analysis tend to understate what would be required in order to actually achieve the minimum credit metrics the debt rating agencies would require to maintain ratings in the A category.

> For the EBIT interest coverage ratios, the principal adjustments that S&P makes to reported values that are not reflected in the Commission's approach are for interest on operating leases and interest associated with pension expense. The inclusion of these additional amounts of interest in the EBIT interest coverage calculations will result in lower published EBIT interest coverage ratios than indicated by the Commission's estimation procedures. The implication is that the Commission's EBIT interest coverage analysis will tend to understate the actual equity ratio required to produce the actual published EBIT interest coverage ratios.
>
> S&P also adjusts reported debt values for operating leases, debt/equity hybrids, pension liabilities and asset retirement obligations. Consequently, there are material differences between the reported (adjusted) FFO/Debt ratios and the unadjusted ratios. For example, the difference between the adjusted FFO/Debt ratios reported and relied on by S&P and the unadjusted FFO/debt ratios (also available from S&P) for AltaLink, CU Inc., and FortisAlberta has been, on average, over the past five years, over two percentage points, i.e., the adjusted values averaged 13.7% versus an average 16.1% pre-adjusted FFO/Debt ratio.
>
> On average, based on data for a broad range of Canadian utilities, S&P's adjustments to reported debt values have increased the amount of debt included in the FFO/Debt ratio by close to 10%. In capital structure terms, a 10% increase in debt for a utility whose common equity ratio based on reported debt and equity is 40% translates to an equity ratio of less than 38% after S&P's analytical adjustments to reported debt have been made.

The following updates the inputs and revises the equity ratios required to achieve the specified minimum credit metrics. As the analytical adjustments made by the debt rating agencies to reported values are company-specific, they are difficult to translate into a generic credit metrics analysis. As a result, the only "analytical adjustment" I made was to increase the indicated debt levels to better approximate the actual FFO/Debt ratios that S&P would calculate and the corresponding common equity ratios required to achieve them.

The following updated inputs were used to revise the Commission's credit metrics analysis:

1. A reduction in the embedded cost of debt (from 6.4% to 5.7%), consistent with the decline experienced by the Alberta Utilities since the analysis was performed for the 2011 GCOC.

2. ROE of 8.75%, equivalent to the rate used in *Decision 2011-474*.

3. Corporate income tax rate of 25%, unchanged from *Decision 2011-474*.

4. Depreciation as percent of rate base of 5%, reduced from 6%, as reflected in the Alberta Utilities' Rule 005 filings.[64]

5. CWIP as percent of regulated assets of 8%, increased from 5%, as reflected in the Alberta Utilities' Rule 005 filings.

6. A 10% increase to the indicated debt levels, to recognize the impact of S&P's analytical adjustments.

As regards the EBIT interest coverage ratio, in *Decision 2011-474*, the Commission noted that 34% had previously been (*Decision 2009-216*) the minimum equity ratio needed to achieve a 2.0 times EBIT interest coverage ratio.[65] With the updated assumptions that the Commission relied on in *Decision 2011-474*, the indicated minimum equity ratio rose to 37%.[66] With the updates to the inputs listed above, the indicated minimum equity ratio is 36%,[67] slightly lower than in the

[64] Rule 005, Annual Reporting Requirement of Financial and Operational Results.
[65] In *Decision 2009-216*, the Commission had also noted that an equity ratio of 40% was indicated as the minimum equity ratio required for an EBIT interest coverage ratio of 2.3 times.
[66] The corresponding equity ratio at a 2.3 times interest coverage ratio was 43%.
[67] 42% at a minimum 2.3 times EBIT interest coverage ratio.

2011 GCOC proceeding, but higher than the 34% minimum equity ratio indicated in the 2009 GCOC proceeding.

As indicated above, the revised indicated equity ratio required to achieve a minimum 2.0 times EBIT interest coverage ratio should be viewed as conservative. Published EBIT coverage ratios for individual utilities (which are what the Commission initially relied on to establish its minimums) incorporate analytical adjustments, e.g., the imputation of additional interest for liabilities related to operating leases or pension expense. No allowance was made for these analytical adjustments in the Commission's metrics methodology or in the updated EBIT coverage ratios I calculated using the Commission's methodology.

With respect to the FFO interest coverage ratio, in *Decision 2011-474*, the AUC identified the minimum equity ratio associated with a 3.0 times FFO interest coverage ratio to be 35%. Based on the updated inputs listed above, the corresponding minimum equity ratio for a 3.0 times FFO interest coverage ratio is 37%, i.e., higher than the 35% minimum specified in *Decision 2011-474*. As with the EBIT interest coverage ratio, in calculating the FFO interest coverage ratio, S&P makes adjustments to interest expense that will tend to result in lower reported FFO interest coverage ratios than the basic metrics analysis relied on by the Commission. In other words, the Commission's FFO interest coverage ratio analysis will tend to understate the actual equity ratio required to produce the actual published FFO interest coverage ratios.

With respect to the FFO/Debt ratio, it is the main credit metric that the debt rating agencies look at. Moody's calls it the single most predictive financial measure. It is one of the three key quantitative metrics cited by S&P in its corporate criteria. A review of the S&P ratings reports for individual Canadian utilities supports the conclusion that FFO/Debt ratio is S&P's key factor.

In *Decision 2009-216*, based on published FFO/Debt ratios of Alberta utilities, the Commission identified an FFO/Debt range of 11.1% to 14.3% as the minimum required for a debt rating in the low A range. In *Decision 2011-474*, the Commission concluded that equity ratios of 30% to 38% were indicated to achieve FFO/Debt ratios in the range of 11.1% to 14.3%. In this proceeding, with the decrease in depreciation percentage and increase in CWIP percentage, the corresponding minimum equity ratio range is 34% to 43%, approximately four to five percentage points higher than indicated in *Decision 2011-474*.[68]

The 34% to 43% equity ratio range does not incorporate the effect of the analytical adjustments S&P makes to reported debt values. By incorporating the average 10% increase to the debt of Canadian utilities arising from S&P's analytical adjustments (and underpinning its reported FFO/Debt ratios), the range of indicated equity ratios required to achieve the Commission's minimum FFO/Debt ratio range increases from approximately 34% to 43% to 37% to 46%.

The table below compares the *Decision 2009-216* and *Decision 2011-474* minimum equity ratios identified by the Commission to those estimated for the 2013 GCOC based on the updated and revised inputs specified above:

Table 8

	EBIT Coverage (2.0X)	**FFO Coverage (3.0X)**	**FFO to Debt (11.1% to 14.3%)**
Decision 2009-216	34%	33%	30% to 36%
Decision 2011-474	37%	35%	30% to 38%
Revised 2013 GCOC	36%	37%	37% to 46%

Based on the updated and revised credit metrics analysis alone, an across-the-board increase in the deemed common equity ratios of no less than two percentage points is warranted.

[68] Updating the depreciation percentage only (no change to the CWIP percentage), the indicated range of minimum equity ratios is 33% to 42%, an increase of three percentage points from the minimum range specified in *Decision 2011-474*.

E. CONTRIBUTIONS IN AID OF CONSTRUCTION

In the 2011 GCOC, the Alberta Utilities applied to the Commission for a management fee as compensation for the risks and value of services associated with ownership, operation and maintenance of assets financed by Contributions in Aid of Construction (CIAC). CIAC relates to assets that are constructed, owned, managed and operated by the utilities, but for which no compensation in the form of return, margin or fee is provided, despite the fact that the utilities bear risks related to them and use them to provide valuable services.

A significant proportion of the assets of the Alberta Utilities continues to be funded by CIAC. On a company median basis, in 2012, 15% of the rate base of the Alberta Utilities was represented by CIAC. By comparison, the proportion of CIAC to total regulated assets for the typical ex-Alberta utility is approximately 4% on average. The proportion of CIAC to total regulated assets for the Alberta Utilities in the composite is materially higher than for the typical ex-Alberta utility. At present and for the foreseeable future, the Alberta utilities are, and will, be servicing a significant CIAC-financed asset base.

Although, in *Decision 2011-474*, the Commission declined to allow a management fee for risks and value of service associated with CIAC, it did conclude (para. 495):

> Nonetheless, even though the management fee proposed by the Utilities is not warranted, the Commission agrees with the Utilities that CIAC-funded assets contribute to business risk. In general, business risk would be expected to rise in proportion to assets. The Commission agrees with the Utilities that, without an increase in equity, CIAC-funded assets would cause an increase in financial risk and operating leverage risk.

As indicated above, the high levels of CIAC maintained by the Alberta Utilities distinguish them from the preponderance of Canadian utilities operating in other regulatory jurisdictions, and, all else equal, expose them to higher operating and financial leverage risk. The high levels of CIAC provide further support for an across-the-board increase in equity ratios from those adopted in *Decision 2011-474*.

F. CONCLUSIONS ON CAPITAL STRUCTURE

I recommend that the Commission adopt a two percentage point across-the-board increase in deemed common equity ratios for the Alberta Utilities. The updated credit metrics analysis summarized in Table 8 above supports an across-the-board increase in common equity ratios of no less than two percentage points from the levels adopted in *Decision 2011-474.* When current capital market conditions, the increased regulatory risk and the high levels of CIAC being financed by the Alberta Utilities are taken into consideration along with the credit metrics analysis, a two percentage point across-the-board increase in the common equity ratios is conservative.

The resulting recommended equity ratios for the Alberta Utilities are as follows:

Table 9

Utility	Recommended Equity Ratio
AltaGas Utilities	45%
AltaLink	39%
ATCO Electric Distribution	41%
ATCO Electric Transmission	39%
ATCO Gas	41%
ATCO Pipelines [1/]	N/A
ENMAX Distribution	43%
ENMAX Transmission	39%
EPCOR Distribution	43%
EPCOR Transmission	39%
FortisAlberta	43%

[1/] Recommendation for ATCO Pipelines is addressed below.

The recommendations in the table incorporate the two percentage point adjustment for tax-exempt status (ENMAX Distribution, ENMAX Transmission, EPCOR Distribution and EPCOR Transmission) and *de facto* non-taxability (FortisAlberta)[69] that the Commission confirmed as appropriate in *Decision 2011-474.* In that decision (para. 244), the Commission stated:

[69] FortisAlberta estimates that it will not be taxable until after 2018 at the earliest.

> As such, the Commission reaffirms its findings in Decision 2009-216 that, while income tax exempt status lowers a company's costs, it increases the volatility of earnings and decreases interest coverage ratios, and thereby adds to risk from the debt holder's perspective. Accordingly, the Commission will maintain the addition of the two percentage point increase to the equity ratios of income tax exempt utilities.

In *Decision 2009-216*, para. 383, the Commission stated:

> The Commission agrees that entities with tax exempt status have a higher volatility of earnings than otherwise equivalent taxable companies because of the absence of an income tax component in their forecast revenue requirements. There was no disagreement among participants in the proceeding that while income tax exempt status lowers a company's costs, it increases the volatility of earnings and decreases interest coverage ratios. Therefore, the Commission will continue to add two percentage points to the equity ratios of income tax exempt utilities.

The two rationales that the Commission relied upon for adopting the two percentage point higher equity ratio for tax-exempt and *de facto* non-taxable utilities, higher volatility of earnings and lower pre-tax interest coverage ratios, remain valid. There have been no changes since the 2011 GCOC proceeding that would alter the reasonableness of adopting higher common equity ratios for the tax-exempt and *de facto* non-taxable Alberta utilities.

The recommendations in Table 9 above also include the two one percentage point adjustments for AltaLink and ATCO Electric Transmission that the Commission awarded in *Decision 2009-216* and *Decision 2011-474* in recognition of the pressure on their credit metrics arising during their extended "big build" cycles, which are ongoing.

G. EQUITY RATIO FOR ATCO PIPELINES

1. Background

In April 2009, ATCO Pipelines and NGTL signed the Integration Agreement, under which the two companies would combine physical assets and offer a single suite of services to provide seamless, integrated gas transmission service to customers in Alberta.

At the time of the 2009 GCOC, the process of integration was still in relatively early stages, and the impact of integration on ATCO Pipelines' business risk profile could not be ascertained. In *Decision 2009-216*, the AUC agreed that until the agreement had been finalized and has received regulatory approvals, it was difficult to determine what changes to ATCO Pipelines' risks might occur. The AUC therefore decided not to make adjustments for changes in risk that might result from the agreement. In *Decision 2009-216*, the AUC adopted a deemed 45% common equity ratio for ATCO Pipelines. The allowed 45% common equity ratio reflected the 43% common equity ratio that had been previously adopted by the Alberta Energy and Utilities Board in *Decision 2004-052* plus the two percentage point across-the-board increase in common equity ratios awarded by the AUC.

By the time of the 2011 GCOC, significant steps had been taken toward completion of the integration of the two pipelines' services.[70] Pursuant to the provisions of ATCO Pipelines' negotiated settlement for 2010-2012 revenue requirements, approved by the Commission in *Decision 2010-228* (May 2010), the common equity ratios for 2011 and 2012 were to be:

a) For 2011, the common equity ratio would be as established by the AUC in the 2011 generic cost of capital proceeding, provided that the ratio did not take into account ATCO Pipelines' post-integration status.

b) For 2012, the common equity ratio would be as determined by the AUC in the 2011 GCOC proceeding, provided that it took into account ATCO Pipelines' post-integration status.

For both 2011 and 2012, the corresponding allowed return on equity would be the generic ROE awarded by the AUC for the Alberta utilities in the 2011 GCOC proceeding.

[70] Integration was effective October 1, 2011. In November 2012, the AUC approved AP's Asset Swap Application (Decision 2012-310).

In *Decision 2011-474* (December 2011), the AUC maintained ATCO Pipelines' common equity ratio at 45% for 2011, but reduced the 2012 common equity ratio by seven percentage points, from 45% to 38%. In so doing, the AUC concluded the following:

a) The only risk of ATCO Pipelines not recovering its revenue requirement is if NGTL was unable to make its payments. As such, the Commission found that that the business risks faced by ATCO Pipelines have been significantly reduced through its integration with NGTL. (para. 265)

b) The combined ATCO Pipelines/NGTL system faces certain competition and supply risks that should be taken into account. (para. 266)

c) ATCO Pipelines' business risk is higher than that of the electric transmission utilities but is somewhat lower than that of the electric and gas distribution utilities; the 2012 common equity ratio for ATCO Pipelines will be set at the average of these two sectors, i.e., average of 36% and 40%. (para. 267)

As discussed in Section VI.E above, ATCO Pipelines' business risks are higher than when they were assessed at the time of the 2011 GCOC proceeding, and should be reflected in a higher common equity ratio.

2. Approach

In developing an estimate of the appropriate equity ratio for ATCO Pipelines, I have proceeded on the premise that the AUC will continue to determine a benchmark or generic utility ROE, as it has since the 2004 GCOC proceeding. As noted in Section VIII.A below, the benchmark utility ROE is intended to represent the ROE that would be applicable in the absence of changes in business risk since the last GCOC. To the extent that such changes have occurred, they would be reflected in a change in capital structure, a risk premium to the benchmark ROE, or a combination of both. The equity ratio that I have estimated for ATCO Pipelines is intended to be the equity ratio at which the benchmark utility ROE plus any incremental equity risk premium common to all the Alberta Utilities is applicable, i.e., no incremental equity risk premium for business risk unique to ATCO Pipelines is required.

As noted above, in *Decision 2011-474*, the Commission concluded that, in terms of relative business risks, ATCO Pipelines fell between the electric transmission utilities and the electric and gas distribution utilities. In light of the changed natural gas market circumstances, in terms of fundamental risks (i.e., the performance-based regulatory framework of the distribution utilities aside),[71] that conclusion no longer holds.

In contrast to the Alberta System and ATCO Pipelines, the Alberta electric distributors continue to have a monopoly for delivery of power. Their distribution systems are unlikely to be duplicated, and the ability of customers to bypass the electric distribution system is very limited. Electricity is required by every household and business for some applications, has diverse end uses, and is delivered to a broad customer base. Although there is some competition between electric and natural gas distribution in Alberta, it remains limited, as natural gas is the energy source of choice for heating load. Supply risk in the context of electric distribution is relatively low and has not changed, as the Alberta electric distributors do not have the obligation to build, lease or contract for power to serve their customers. The major natural gas distributor, ATCO Gas, similar to the electric distributors, is unlikely to have its distribution system duplicated. Its customer base has not changed; it is predominantly comprised of residential and commercial customers. Competitive risk with other forms of energy remains relatively low in ATCO Gas' core business, space and water heating, in large part due to the price advantage of natural gas in Alberta. Supply risk for a gas distributor in Alberta has also remained relatively low, not only due to the proximity of resources, but also the importance of natural gas to the core market. In contrast, the fundamental market

[71] Compensation for the incremental risk inherent in the performance-based regulation plans for the Alberta Distribution utilities is being addressed through a risk premium to the benchmark utility ROE, as discussed in Section X below.

demand, competitive and supply risks to which the Alberta System and ATCO Pipelines are exposed have risen and, in my judgment, would be viewed by investors as higher than those of the Alberta electric distributors and ATCO Gas.

The implication of this judgment is that ATCO Pipelines' common equity ratio should be higher than those of electric and gas distribution utilities. For the taxable electric distribution utilities and ATCO Gas, I have recommended that the AUC adopt a common equity ratio of 41%, which for AltaGas, indicates a common equity ratio of 45%, reflecting its smaller size than ATCO Gas. Based on those conclusions, a reasonable equity ratio for ATCO Pipelines, given its higher business risk than the Alberta electric and gas distributors, even allowing for AltaGas Utilities' small size, is no less than 42%, with a reasonable range of 42% to 47%.

In assessing what is a reasonable equity ratio for ATCO Pipelines, I considered whether the 40% equity ratio allowed for NGTL is an appropriate benchmark. I concluded that NGTL's 40% common equity ratio cannot be used as a benchmark in isolation, i.e., without simultaneously taking account of the allowed ROE. In *Decision RH-1-2008,* the NEB adopted an overall cost of capital approach for Trans Québec & Maritimes Pipelines Inc. (TQM), in which it did not specify capital structure and allowed ROE separately. TQM did, however, request in its application, separate cost of capital components, including a common equity ratio of 40% (which is what the pipeline has since maintained). In its Decision, the NEB set out various combinations of ROE and common equity ratios that were equivalent to the overall return allowed to facilitate comparisons with traditional separate ROE and common equity determinations. At TQM's requested 40% equity ratio, the corresponding ROE was 9.7%. Subsequent to that decision, in October 2009, the NEB rescinded *Decision RH-2-94*, pursuant to which it had established a single ROE for Group 1 pipelines, using capital structure as the business risk "adjusting variable". With the rescission of *Decision RH-2-94*, the equity ratios of Group 1 NEB regulated pipelines can no longer be used in isolation as benchmarks. Instead, it is necessary to consider both capital structure and ROE in order to assess comparability.

As was the case with other major Group 1 gas pipelines (Foothills, Westcoast) which negotiated returns subsequent to the rescission of *Decision RH-2-94*, NGTL negotiated a common equity ratio of 40%, in conjunction with an ROE of 9.7%, approved by the NEB in September 2010.[72] By comparison, the AUC allowed an ROE of 9.0% for 2010, a difference of 0.70%. The 0.70% difference in ROE can be translated into a common equity ratio differential.

The translation of the 0.70% ROE into an equity ratio differential proceeds on the same premise that the NEB used in *Decision RH-1-2008*, i.e., that the after-tax weighted average cost of capital (ATWACC) is flat, or constant, across a range of capital structures.[73]

ATWACC is equal to:

[(% Debt) x (Cost of Debt) x (1-tax rate)] + [(% Equity) x (Cost of Equity)]

Where,

a) the cost of debt is a market (current), not embedded, cost of debt, and

b) the debt and equity components can be measured on either a book value or market value basis.[74]

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[72] NGTL has since negotiated an unopposed tolls settlement for 2013 and 2014, including an ROE of 10.1% on a common equity ratio of 40%, approved by the NEB November 1, 2013. Foothills also negotiated a settlement for 2013 and 2014 that included an ROE of 10.1% on a common equity ratio of 40%.

[73] This methodology is the same as what is referred to as Approach 1 in Appendix E.

[74] In its application of ATWACC, the NEB used market value capital structures. However, the equation can be applied to book value capital structures as well. In *1999/2000 Electric Tariff Applications, Decision U99099*, November 1999, the AUC's predecessor, the EUB, concluded that "Further, the Board considers that an ATWACC determined using book capitalization ratios appropriately measures the true ATWACC for a regulated firm." (page 303) The EUB also stated "The Board considers that the ATWACC $_{BV}$ should be consistent over a narrow range of book equity ratios." (page 307)

ATWACC at 40% common equity ratio and 9.7% ROE:

6.4% = (60% * 6% * (1-.29)) + (40% * 9.7%)

Common Equity Ratio at ATWACC of 6.4% and ROE of 9.0%, where X is the common equity ratio:

6.4% = ((1-X) * 6% * (1-.29)) + (X * 9.0%)

Using the ATWACC approach with an ROE of 9.7% and a common equity ratio of 40% as the points of departure, the corresponding common equity ratio at an ROE of 9.0% is approximately 46%.[75] This analysis supports the reasonableness of the previously identified range of 42% to 47%.

In its *Decision 2011-474* (page 49), in setting ATCO Pipelines' common equity ratio at 38%, the AUC commented that, if ATCO Pipelines remains concerned about its credit metrics, this matter can be addressed at the time of its next GTA. Although my recommendation for ATCO Pipelines' common equity ratio is not prompted by concerns with ATCO Pipelines' credit metrics, but with increased business risk, credit metrics have been a key element in establishing deemed common equity ratios in each of the three previous GCOC proceedings.

Table 10 below presents the indicated credit metrics at a 44.5% common equity ratio (mid-point of the recommended 42% to 47% range), using the same analysis and revised inputs as in Section VII.D above, along with the AUC's specified minimum ratios and the actual reported ratios (2010-2012) for investor-owned utilities with rated debt (Schedule 7).

Table 10

	Credit Metric Summary		
	Minimum	**Utility Median**	**44.5% Equity Ratio**
EBIT Coverage	2.0X	2.4X	2.4X
FFO/Debt	11.1%-14.3%	14%	14.7%
FFO Interest Coverage	3.0X	3.5X	3.5X

X = 46%

[75] At the 2009 combined Alberta/Federal corporate income tax rate of 29% referenced *in Decision 2009-216* (page 322) and a market cost of debt of 6.0%. The latter is equivalent to the long-term rate for an A- rated regulated firm that would have been consistent with the AUC's forecast of long-term Canada bond yields (approximately 4.3%) and the then prevailing spread between yields on long-term A rated utility bonds of 170-175 basis points cited in *Decision 2009-216* (pages 65 and 79).

Considering all three metrics, the indicated credit metrics for a 44.5% common equity ratio are in line with those that have been maintained by the universe of investor-owned Canadian utilities. As noted earlier, these utilities have debt ratings, on average, in the A rating category, which the AUC has determined to be an appropriate target stand-alone debt rating for the Alberta utilities. Given ATCO Pipelines' increased business risks, it is reasonable that the indicated credit metrics at the proposed equity ratio should be comparable to those maintained, by the typical, or average risk, investor-owned Canadian utility.

VIII. BENCHMARK UTILITY RETURN ON EQUITY

A. CONCEPT OF BENCHMARK UTILITY RETURN ON EQUITY

The cost of equity, as estimated using tests applied to proxy companies, reflects the composite of those proxy companies' business, regulatory and financial risks. The cost of equity estimated by reference to a sample of companies is applicable to a specific utility without adjustment only if the magnitude of the total risks (business plus financial) of the sample and the specific utility is comparable. In principle, given a sufficiently large universe of utilities, different samples of proxy companies can be selected, each designed to be a proxy for a specific utility.

Alternatively, one or more samples of companies can be selected as proxies to establish a benchmark utility ROE. For the resulting benchmark utility ROE to be applicable to a specific utility, the specific utility's total risk needs to be similar to that of the proxy companies. If it is not, the solutions include: (1) changing the specific utility's capital structure; (2) making an adjustment to the proxy companies' cost of equity to reflect the relative total risk of the specific utility; or (3) some combination of (1) and (2).

For the purpose of establishing the benchmark utility ROE in this proceeding, I have relied primarily on two samples of utilities, a sample of U.S. utilities and a sample of Canadian utilities. The sample of U.S. utilities was selected using similar criteria to those relied in the 2011 GCOC proceeding. The underlying premise of the selection process was to keep the overall (business plus financial) risk profile of the sample utilities the same as it was in the 2011 GCOC. Consequently, any change in the benchmark ROE between the 2011 GCOC proceeding and this proceeding represents changes in the utility cost of equity due to changes in capital market conditions generally, not changes in business and/or financial risk. To the extent that the business risk of the Alberta Utilities either as a sector or individually has changed relative to the benchmark utility sample since the 2011 GCOC, the changes will need to be reflected in changes to the Alberta Utilities' capital structure, ROE (e.g., equity risk premium relative to the benchmark utility ROE) or a combination of changes in capital structure and ROE.

B. IMPORTANCE OF MULTIPLE TESTS

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: (1) Equity Risk Premium tests, which include, but are not limited to, the Capital Asset Pricing Model; (2) Discounted Cash Flow models, and (3) the Comparable Earnings test.

Equity risk premium tests are market-based tests premised on the basic concept of finance that the higher the risk to which an investor is exposed, the higher is the return that the investor requires. Equity risk premium tests entail estimation of the additional premium or incremental return that an equity investor requires relative to a less risky security, e.g., government bonds or corporate bonds.

Discounted cash flow models are based on the proposition that the market price of a security or value of an investment is equal to the present value of all the future expected cash flows from the security or investment, discounted at a rate that reflects the riskiness of the cash flows. If the price of an equity share is known, and the expected cash flows can be estimated, the investor's expected rate of return can also be estimated.

The comparable earnings test is based on the proposition that capital should not be committed to a venture unless it can earn a return commensurate with that available prospectively in alternative ventures of comparable risk. The comparable earnings test estimates a fair return on equity by reference to returns achievable on the book value of companies subject to a similar level of investment risk to the regulated utility.

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 ensuring that all three requirements of the fair return standard are met; 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.[76] Changes to the inputs to individual tests may have different implications depending on the prevailing economic and capital market conditions.[77] These considerations emphasize the importance of reliance on multiple tests.

Each test has its own set of pros and cons. The theoretical Capital Asset Pricing Model, an equity risk premium test framed in an elegant, simple construct, has an intuitive appeal. With only three components, it appears, on the surface, easy to apply. Nevertheless, it faces numerous challenges, including a historical absence of meaningful relationships between the model's measure of risk, beta, and return.[78] Other risk premium tests, which are based on common sense relationships and rely on empirical results, are sometimes criticized for their lack of theoretical foundation. The discounted cash flow test directly measures expected utility returns by using utility-specific data only: prices, dividends and estimates of expected growth in the cash flows to

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[76] 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., Arlington, VA.: Public Utility Reports, Inc., March 1988, page 317).

[77] 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.

[78] Section VII.D below and Appendix A include a full discussion of the challenges of the CAPM. The focus on the challenges is not to suggest that other tests are necessarily superior, but because a number of Canadian regulators have, in recent years, tended to focus on CAPM in their estimation of the allowed ROEs, albeit, in some circumstances, with recognition of its shortcomings and adjustments to the model that may be required. The challenges associated with the CAPM are of a sufficient magnitude to warrant the conclusion that it is not inherently superior to other approaches to the estimation of a fair return, particularly in light of the adjustments to the theoretical CAPM necessary to apply it to the utility industry.

investors. It is subject to an ongoing debate around the accuracy of investment analysts' forecasts as the measure of investor expectations of growth. The comparable earnings test explicitly recognizes that the objective of regulation is to emulate competition and measures returns on the same original cost basis on which utilities are regulated. It is subject to concerns around selection criteria and whether the results are representative of economic returns.

All approaches to estimating a fair return require significant judgment in their application, the extent of which depends on the prevailing state of the capital markets. Any individual cost of equity model implicitly ascribes simplicity to a cost whose determination is inherently complex. No single model is powerful enough on its own to produce "the number" that will meet the fair return standard. Only by applying a range of tests along with informed judgment can adherence to the fair return standard be ensured.[79]

C. SELECTION OF PROXY UTILITIES

As indicated in Section VIII.A, the benchmark utility cost of equity is intended to represent the ROE that would be applicable to the Alberta Utilities based solely on changes in capital market conditions, i.e., absent changes to the Alberta Utilities' business or regulatory risks. It is based in large part on estimates of the cost of equity of publicly-traded U.S. utilities selected using criteria designed to identify companies of comparable risk to the Alberta Utilities prior to the *UAD Decision* and the adoption of PBR.

Reliance on comparable risk companies to estimate the equity return requirement recognizes that investors have alternatives for their investment capital. Rational investors will commit funds to

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[79] I am strongly of the view that the comparable earnings test is the only test which measures returns in a manner compatible with the base (original cost) to which they are applied. However, I also recognize that the comparable earnings test is the most controversial, not only in terms of its applicability to the estimation of a fair return, but in terms of its application (e.g., criteria for selection of comparables, period over which returns should be measured, need for adjustments for relative risk). In *Decision 2009-216*, the AUC declined to give weight to the comparable earnings test, as had its predecessor, the EUB, in *Decision 2004-052*. In order to limit the issues relevant to the estimation of a fair return, I did not apply the comparable earnings test in the 2011 GCOC, nor have I applied it in this proceeding, i.e., I have applied equity risk premium and discounted cash flow tests only. However, if the comparable earnings test is not to be used, the determination of the allowed ROE needs to expressly recognize that market-based costs of equity relate to market value capital structures, not the book value capital structure to which the cost of equity is applied. See Section VII.F for a full discussion.

the investments that promise the highest return for a given level of investment (business plus financial) risk. Unless the return that can be expected on an investment in an Alberta utility is equal to that available from comparable risk investments, investors will direct their funds elsewhere.

In Canada, there are only six publicly-traded Canadian companies whose operations are largely regulated.[80] These companies are relatively heterogeneous in terms of both operations[81] and size.[82] The relatively small and heterogeneous universe of publicly-traded Canadian utilities means that it is impossible to select a sample of companies that would be considered directly comparable in total risk to any specific Canadian utility.

U.S. regulated companies represent a reasonable point of departure for the selection of a sample of proxies from which to estimate the benchmark utility cost of equity. The operating (or business) environments in Canada and the U.S. are similar, the regulatory model in the U.S. is similar to the Canadian model, Canadian and U.S. capital markets are significantly integrated and the cost of capital environment is similar. In *Decision 2009-216* (para. 135), the Commission recognized that "Alberta regulated utilities must, on a risk-adjusted basis, compete for their capital requirements with alternative investments of comparable risk across North America. Therefore, U.S. information on U.S. utility returns is relevant to a determination of the fair return for Alberta regulated utilities. If Alberta utilities must compete for investment across North America, the returns available to investors must be competitive enough to attract capital in order to ensure their financial integrity as a going concern."[83]

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[80] Canadian Utilities Limited, Emera Inc., Enbridge Inc., Fortis Inc., TransCanada Corporation and Valener Inc.

[81] Their operations span all the major utility industries, including electric 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.

[82] Ranging from an equity market capitalization of approximately $600 million (Valener) to $35.5 billion (Enbridge).

[83] The OEB's *Report of the Board on the Cost of Capital*, pages 21-22, stated, "Second, there was a general presumption held by participants representing ratepayer groups in the consultation that Canadian and U.S. utilities are not comparators, due to differences in the "time value of money, the risk value of money and the tax value of money."[fn] In other words, because of these differences, Canadian and U.S. utilities cannot be comparators. The Board disagrees and is of the view that they are indeed comparable, and that only an analytical framework in which to apply judgment and a system of weighting are needed."

The BCUCs *In the Matter of British Columbia Utilities Commission Generic Cost of Capital Proceeding (Stage 1) Decision*, issued May 10, 2013, stated that "Canadian utilities need to be able to compete in a global marketplace

Equity markets are global; investors are increasingly committing equity funds beyond domestic borders. Canadian investors looking to commit funds to utility equity shares will compare returns available from Canadian utilities to returns available from utility shares globally, including returns from U.S. utilities (both market and allowed). A review of the major Canadian public sector defined benefit pension funds which list all their equity holdings individually shows that the funds have invested in a significant number of U.S. utilities.

While market data for the Canadian utilities provide some perspective on the fair return for Canadian utilities generally and Alberta utilities specifically, a more accurate assessment can be made by reliance on samples of U.S. utilities drawn from a much broader universe. From the universe of U.S. utilities, a sample was selected to serve as proxies to estimate the benchmark utility ROE, according to criteria designed to (1) identify companies which face a level of total risk relatively similar to that of the Alberta Utilities prior to taking account of the risk implications of the *UAD Decision* and PBR and (2) produce a large enough sample of companies to ensure reliable cost of equity test results. Selection criteria were specified to recognize that, just as not all U.S. utilities would be of similar risk to each other, not all U.S. utilities would be

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and be allowed a return for them to do so. In addition, the Panel accepts that there continues to be limited Canadian data upon which to rely and considers that there may be times when natural gas companies operating within the US may prove to be a useful proxy in determining the cost of capital. **Accordingly, we have determined that it is appropriate to continue to accept the use of historical and forecast data for US utilities and securities as outlined in the 2006 Decision and again in the 2009 Decision.**" (emphasis in original)

The BCUC did note: "In making this determination the Commission Panel would like to be clear that while we accept there are similarities between the two jurisdictions, we do not accept that US data should be considered to be the same or necessarily be given equal weight as the data for Canadian utilities."

In light of potential differences between U.S. and Canadian utility investments, the BCUC concluded:

> Therefore, in the view of the Commission Panel, the use of US data must be considered on a case by case basis and weighed with consideration to the sample being relied upon and any jurisdictional differences which may exist.

In the NEB's *Reasons for Decision: TransCanada PipeLines Limited, NOVA Gas Transmission Ltd., and Foothills: Pipe Lines Ltd. RH-003*-2011, March 2013, the Board stated "We note that TransCanada's evidence indicating that Canadians pursue investment opportunities in the U.S. and beyond was not disputed in this proceeding. In our view, capital markets are increasingly integrated, and as a result, the allowed return has to enable the Mainline to compete for capital in the global marketplace to comply with the Fair Return Standard. In this context, we find that evidence from comparable companies operating in the U.S. can be a useful proxy for investment opportunities in the global marketplace."

exposed to a level of total business, regulatory and financial risk that would make them reasonable proxies for estimating the benchmark utility ROE.

The selected U.S. utilities include only relatively pure-play utilities, i.e., a high proportion of regulated operations. They have strong debt ratings assigned by the major debt rating agencies. The selected utilities are rated no lower than BBB+/Baa1 by both Standard & Poor's and Moody's. For perspective relative to Canadian utilities, the median S&P debt rating of the U.S. utility sample is A-, identical to the A- rating accorded on average to the universe of Canadian utilities rated by S&P. All of the companies in the sample are assigned an "Excellent" business risk ranking, the same as the ranking assigned to the majority of Canadian utilities rated by S&P.[84] The median Moody's rating for the U.S. utility sample is Baa1[85] (Schedule 14, page 1 of 2), equal to the median of the ratings that Moody's has assigned to Canadian gas and electric utilities it has rated.[86] The average and median *Value Line* Safety ranks of the U.S. utility sample are 1.5 and 2 respectively (Schedule 14, page 1 of 2); the Safety ranks of the two Canadian regulated companies covered by *Value Line* (Enbridge Inc. and TransCanada Corp.) are 1 and 2 respectively.[87] As regards financial risk, the U.S. utility sample has higher common equity ratios than those proposed for the Alberta Utilities. The average common equity ratio of the sample of U.S. utilities is approximately 48% (Schedule 6).[88] Consequently, even if equity investors viewed the U.S. utility sample as of higher combined business and regulatory risk than "the benchmark" (e.g., an Alberta utility absent the *UAD Decision* and/or PBR risks), the higher business risk is offset by lower financial risk.

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[84] Standard & Poor's assigns a business risk ranking to each of the companies it rates. There are six business risk categories, ranging from "Excellent" to "Vulnerable".
[85] As discussed below, Moody's has placed the ratings of most U.S. regulated utilities and utility holding companies on review for upgrade, including nine of the 11 utilities in the selected sample.
[86] Including FortisBC Energy Inc. (A3), FortisBC Energy (Vancouver Island) Inc. (A3), FortisAlberta (Baa1), FortisBC Inc. (Baa1), Hydro One (Baa1 on a stand-alone basis), Newfoundland Power (Baa1), and Nova Scotia Power (Baa1).
[87] The Safety rank represents *Value Line's* assessment of the relative total risk of the stocks. The ranks range from "1" to "5", with stocks ranked "1" and "2" most suitable for conservative investors. The most important influences on the Safety rank are the company's financial strength, as measured by balance sheet and financial ratios, and the stability of its price over the past five years.
[88] Appendix B provides both details of the selection criteria and information on the selected U.S. utilities' operations and regulation, including for each a list of the regulatory mechanisms that have been adopted. Schedule 14, page 1 of 2 provides additional quantitative and qualitative data for the selected U.S. utilities. The most recently allowed ROEs and capital structures for the operating companies are found on Schedule 14, page 2 of 2.

In a number of Canadian cost of capital proceedings over the past several years, including the 2011 GCOC, intervenor evidence has taken issue with the conclusion that U.S. utilities are comparables for Canadian utilities, relying on the Moody's *Rating Methodology, Regulated Electric and Gas Utilities,* August 2009 to conclude that Moody's considers U.S. utilities to face higher regulatory risk than Canadian utilities.[89] Since the 2009 report cited above, Moody's view of the supportiveness of the U.S. regulatory framework has evolved. In its September 2013 *Request for Comment*, Moody's stated as follows:

> Our updated view considers improving regulatory trends that include the increased prevalence of automatic cost recovery provisions, reduced regulatory lag, and generally fair and open relationships between utilities and regulators. While US state regulatory environments have been characterized by a process that is more openly adversarial than some other global jurisdictions, there have been very few instances where eventual regulatory outcomes deviated enough from the established regulatory framework to severely undercut utility creditworthiness. In the few instances where inconsistent regulatory decisions have led to serious credit stress, courts have proved to be a reliable secondary support for utility credit worthiness through rulings that mandate that regulatory decisions must follow the established regulatory framework.
>
> Our revised view that the regulatory environment and timely recovery of costs is in most cases more reliable than we previously believed is expected to lead to a one notch upgrade of most regulated utilities in the US, with some exceptions**.**

Further:

> While we had previously viewed individual state regulatory risks for US utilities as generally being higher than utilities in most other developed countries (where regulation usually occurs at the national level), we have observed an overall decrease in regulatory risk in the US. While state regulatory jurisdictions seem to be more prone to highly visible disputes and parochial political intervention than national regulatory frameworks, which has sometimes raised concerns about regulatory consistency, we now believe that the more openly adversarial process in the US does not lead to materially less reliable regulatory outcomes for credit quality.[90]

In its recent credit opinions for three FortisBC utilities, Moody's expressly likened the regulatory framework in British Columbia, historically considered to be one of the more supportive

[89] For example, Exhibit 145, *Fair Return for an Alberta Utility, Update & Rebuttal Evidence of Laurence D. Booth*, May 31, 2011.

[90] Moody's, *Request for Comment, Proposed Refinements to the Regulated Utilities Rating Methodology and our Evolving View of US Utility Regulation*, September 23, 2013.

regulatory environments in Canada, to a strong U.S. jurisdiction, due to similar procedural and legal processes and supportive cost recovery features, including a forward looking test year, deferral accounting for certain costs and timely decisions from the commission.[91]

On November 8, 2013, Moody's placed the ratings of most U.S. regulated utilities and utility holding companies on review for upgrade, representing approximately $400 billion of debt. In its announcement, Moody's stated that its placement of the issuers on review considers improving regulatory trends in the US, including better cost recovery provisions, reduced regulatory lag, and generally fair and open relationships between utilities and regulators. Moody's believes that many US regulatory jurisdictions have become more credit supportive of utilities over time and that its assessment of the regulatory environment that has been incorporated into ratings may now be overly conservative.[92]

In addition, in October 2013 (prior to the *UAD Decision*), DBRS issued its *Regulatory Framework Report*, which, as noted in Section VI.D above, ranked the ten Canadian provinces and 50 states and the District of Columbia in the U.S. on what it determined were the ten key regulatory risk considerations. They include:

1. Deemed Equity
2. Allowed Return on Equity
3. Energy Cost Recovery
4. Cost of Service vs. Incentive Regulation Mechanism
5. Capital Cost Recovery
6. Political Interference
7. Retail Rate
8. Stranded Cost Recovery
9. Rate Freeze
10. Market Structure (Deregulation)

[91] Moody's, *Credit Opinion: FortisBC Inc.*, *Credit Opinion: FortisBC Energy Inc.*, *Credit Opinion: FortisBC Energy (Vancouver Island) Inc.* and *Credit Opinion: FortisBC Holdings Inc.*, all dated June 26, 2013.
[92] Moody's, *Rating Action: Moody's places ratings of most US regulated utilities on review for upgrade*, November 8, 2013. Moody's has since issued a revised rating methodology for regulated electric and gas utilities globally, replacing the methodology published August 2009 (Moody's, *Rating Methodology: Regulated Electric and Gas Utilities*, December 23, 2013).

DBRS assigned each province and state on each of the ten regulatory risk criteria one of the following rankings: Excellent, Very Good, Satisfactory, Below Average or Poor. I compiled DBRS' ratings for each of the Canadian and U.S. jurisdictions, and calculated medians and a GDP-weighted composite for each country by assigning numerical values (1 to 5) to each of the rankings. The following table summarizes the regulatory risk expressed on a numerical basis. The overall risk scores give equal weight to each criterion.

Table 11

	Canada			United States	
	Alberta	All Provinces		All Jurisdictions	
		Median	Weighted by GDP	Median	Weighted by GDP
Deemed Equity	3	4.0	3.5	1.0	1.5
Allowed ROE	3	4.0	3.1	1.0	1.3
Energy Cost Recovery	1	1.0	1.2	2.0	1.8
COS versus IRM	3	1.0	1.8	1.0	1.3
Capital Cost Recovery	3.5	3.0	3.0	2.0	2.0
Political Interference	4	4.0	4.0	3.0	2.7
Retail Rates	2	2.0	2.0	2.0	2.4
Stranded Cost Recovery	2	2.0	1.8	3.0	3.1
Rate Freeze	3	1.0	2.2	1.0	1.8
Market Structure (Deregulation)	5	1.0	2.8	1.0	2.7
Overall Average	**3.0**	**2.3**	**2.6**	**1.7**	**2.1**
Overall Average (Ex. Deemed Equity & ROE)	**2.9**	**1.9**	**2.4**	**1.9**	**2.2**
1-Excellent; 2-Very Good; 3-Satisfactory; 4-Below Average; 5-Poor					

Source: DBRS, *Industry Study: The Regulatory Framework for the Utilities: Canada vs. the United States, A Rating Agency Perspective*, October 2013.

In summary, based on all ten criteria, Alberta is riskier than Canada as a whole, and Canada is of higher risk than the U.S. on both a median and GDP-weighted basis. If the equity ratio and ROE criteria are removed from the analysis, and the remaining eight criteria weighted equally, Alberta is higher risk than Canada as a whole and higher risk than the U.S. on both a median and GDP-weighted basis. Canada is the same risk as the U.S. on a median basis but slightly higher risk than the U.S. on a GDP-weighted basis.

Although Moody's and DBRS are not the sole arbiters of relative risk, their recent reports and comments provide support for the conclusions that (1) the universe of U.S. utilities does not face a materially higher level of regulatory risk than the universe of Canadian utilities; and (2) there should be no question that it is possible to select a reasonably sized sample of U.S. utilities whose business and regulatory risks are comparable to those of a typical Canadian utility.

D. EQUITY RISK PREMIUM TESTS

1. Conceptual Underpinnings

Equity risk premium tests are premised on the basic concept of finance that the higher the risk to which an investor is exposed, the higher is the return that the investor requires. 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 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. An equity risk premium can be estimated relative to a risk-free rate, for which a government bond yield is typically the proxy, as well as relative to utility bond yields, depending on the type of equity risk premium test being conducted.

Three equity risk premium tests were used to estimate the benchmark utility cost of equity:

1) Risk-Adjusted Equity Market Risk Premium Test

2) DCF-Based Equity Risk Premium Test

3) Historic Utility Equity Risk Premium Test

2. Risk-Free Rate

The application of equity risk premium tests in relation to a risk-free rate requires a forecast of the risk-free rate to which the equity risk premium is applied. A forecast long-term (30-year) Government of Canada bond yield is most widely used as the risk-free rate, although long-term Government of Canada bond yields are not risk-free. They are considered to be free of default risk, but are subject to interest rate risk.[93] Use of the long-term government bond yield recognizes (1) the administered nature (determined by monetary policy) of short-term rates; and (2) the long-term nature of the assets to which the utility equity return is applicable.

For purposes of applying the equity risk premium tests, I have recognized that the current level and near-term forecasts of the long-term (30-year) Government of Canada bond yield are at abnormally low levels, but that they are expected to gradually return to more normal levels. My reliance on a forecast of 30-year Government of Canada bond yields in the application of the equity risk premium tests is intended to recognize the expectation that long-term Canada bond yields will return to more normal levels. Based on the October 2013 Consensus Economics, *Consensus Forecasts*, the forecast 2014-2016 long-term Government of Canada bond yield is approximately 4.0%.[94]

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[93] If interest rates rise, the value of the bond will decline.

[94] Based on the October 2013 Consensus Economics, *Consensus Forecasts*, the forecast 2014 30-year Canada bond yield is 3.45%, equal to the average of the three-month (2.7%) and 12-month (3.1%) forward consensus forecasts of 10-year Government of Canada bond yields (2.9%) plus the October 2013 actual spread between 30-year and 10-year Government of Canada bond yields (0.55%). The forecasts for 2015 and 2016 are, respectively, 4.1% and 4.6%. They reflect the October 2013 *Consensus Forecasts*' anticipated 10-year Canada bond yields of 3.6% and

Although the 4.0% forecast 30-year Government of Canada bond yield for 2014-2016 represents a material increase from the abnormally low levels observed during the past two years, it is still well below levels expected to prevail over the longer-term. Consensus Economics' survey of economists anticipates that the 10-year Canada bond yield will rise from 3.1% in 2014 to an average of 4.6% from 2019-2023,[95] which corresponds to a 30-year Canada bond yield of approximately 5.0%.[96] The estimation of the market and utility equity risk premiums to be used needs to expressly recognize the relatively low level of the 2014-2016 30-year Canada bond yield forecast relative to its longer-term expected level.[97]

3. Risk-Adjusted Equity Market Risk Premium Test

3.a. Conceptual and Empirical Considerations

The risk-adjusted equity market risk premium approach to estimating the required equity market risk premium for a utility 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 market risk premium. The cost of equity is thus estimated as:

Risk-Free Rate	+	{	Relative Risk Adjustment	x	Market Risk Premium	}

4.1% for 2015 and 2016 plus a spread between the 30-year and 10-year Canada bond yields of 45 basis points. The 45 basis point spread, in turn, represents the average of the recent (December 2013) spread (55 basis points) and the historic average spread (35 basis points).

[95] Consensus Economics, *Consensus Forecasts*, October 2013.

[96] Based on the historical long-term average 35 basis point spread between 30-year and 10-year Canada bond yields.

[97] In AUC, *Decision 2011-474*, the Commission concluded "it does not appear that the market equity risk premium is constant or independent of the level of interest rates, which is what is implied when an historic equity risk premium is applied to today's low interest rates. This calls into question the use of long-term historic market equity risk premiums without regard to the current level of interest rates." (paragraph 56) Further, it considered that "it would not be correct to assume that the currently expected market equity risk premium is necessarily equal to its long-term average value" (paragraph 57) concluding "that the expected market equity risk premium today may be higher than its' (sic) historic average, due to today's low interest rates." (paragraph 58)

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 or what returns are actually available to investments of comparable risk). 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 the S&P/TSX Composite, and the returns on individual stocks or portfolios of stocks.

3.b. Equity Market Risk Premium

3.b.(i) Overview

The size of the market risk premium cannot be directly observed and is subject to a wide divergence of opinion. The market risk premium is not a fixed quantity; it changes with investor experience and expectations. It would be higher, for example, when investors perceive that the risk of the equity market has increased relative to that of the government bond market and vice versa. However, neither the CAPM nor variants thereof readily allows estimation of changes in the size of the market risk premium as economic or capital market conditions (e.g., interest rates) change. In other words, the model itself does not offer any insight into how the equity market risk premium changes when interest rates change. Nevertheless, as the application of the CAPM typically relies on relatively near-term forecasts of the risk-free rate, not historical long-term averages or the expected long-term average, it is critical that such changes be estimated, particularly when the current and forecast long-term Canada bond yields are at historically low levels. Estimates of such changes require analysis of the available data, to which expert judgment must be applied.

Historic risk premiums provide a perspective on the size of the expected forward-looking market risk premium. They need to be used with caution, however, as historic returns and risk premiums are sensitive to the country from which the data are drawn and the time period over which they are measured.

My estimation of the market risk premium starts with historic returns and risk premiums drawn from Canadian capital markets. 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, the analysis of historic returns and risk premiums starts with both the post-World War II period (1947-2012)[98] and on longer periods. My analysis of historic returns and risk premiums was based on the Canadian experience as well as on the U.S. experience as a relevant benchmark for estimating the equity risk premium from the perspective of Canadian investors. The U.S. experience is relevant given the close relationship between the two economies, the fact that the U.S. has historically been the single largest alternative destination for Canadian portfolio investment (See Appendix A, page A-16) and the similarity between historical Canadian and U.S. equity market returns and equity return volatility.

[98] 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; and
4. Technological change, particularly in the areas of telecommunications and computerization, which have facilitated both market globalization and rising productivity.

3.b.(ii) Historic Returns and Risk Premiums

Table 12 below summarizes the achieved equity and government bond returns and the corresponding experienced risk premiums for Canada and the U.S.[99]

Table 12

Period	Stock Return	Bond Total Returns	Bond Income Returns	Risk Premium Over Bond Total Returns	Risk Premium Over Bond Income Returns
Canada					
1924-2012	11.4%	6.6%	6.0%	4.8%	5.4%
1947-2012	11.7%	7.0%	6.7%	4.7%	5.0%
U.S.					
1926-2012	11.8%	6.1%	5.1%	5.7%	6.7%
1947-2012	12.4%	6.6%	5.8%	5.8%	6.5%

Source: Schedule 9.

The more relevant representation of the historical risk premium for the purpose of a CAPM cost of equity estimate is the risk premium measured as total equity returns less bond income returns. This is because the CAPM or variants thereof are seeking to estimate the equity return above a risk-free rate. The bond total return includes annual capital gains or losses and reinvestment of the bond coupons, i.e., it incorporates the interest rate risk that is inherent in a government bond. The bond income return reflects only the coupon payment portion of the total bond return. As such, the income return represents the riskless component of the total government bond return. The bond income return is similar to the bond yield. In principle, using the bond income return in the calculation of historical risk premiums more accurately measures the historical equity risk premium above a true risk-free rate.[100]

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[99] The equity and bond market returns in Table 12 represent arithmetic averages of historical returns. Appendix A explains the rationale for using arithmetic, rather than compound (geometric), averages for the purpose of estimating the expected return from historic returns.

[100] In *Decision 2011-474*, para. 51, the AUC concluded that it was inconsistent to compare the return on bonds which excludes capital gains caused by lower interest rates to a return on equities that may include capital gains directly caused by lower interest rates. The Commission stated that it was not convinced that it should base the market equity risk premium on bond income-only returns, rather than bond total returns, "which is the traditional approach." As the objective is to measure the equity market premium over a risk-free rate, there is no inconsistency, inasmuch as the equity returns should reflect the equity market risks, including those arising from changes in interest

The raw data in Table 12 show that, on average, equity returns in Canada have averaged approximately 11.5% to 11.75%, compared to average bond income returns of approximately 6.0% to 6.5%, resulting in average achieved risk premiums relative to bond income returns in the range of approximately 5.0% to 5.5%.[101] The slightly lower achieved equity risk premium relative to bond income returns achieved during the post-World War II period reflects a slightly higher average equity return relative to the longer period, which was more than offset by higher bond income returns.

The corresponding raw data for the U.S. indicate average equity market returns of approximately 11.75% to 12.25%, corresponding to average bond income returns of approximately 5.0% to 5.75%, resulting in an average achieved equity risk premium of approximately 6.5% to 6.75% relative to bond income returns.

3.b.(iii) Canadian Equity and Government Bond Returns

To assess whether there has been a trend in the underlying returns which generate the achieved risk premiums, the returns and risk premiums for each non-overlapping ten year period from 1933 to 2012 were examined and are presented in Table 13 below.

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rates. Government bonds represent the best proxy for the risk-free rate, but "interest rate risk" needs to be removed from the bond returns so that what remains is a measure of the risk-free rate.

With respect to the Commission's reference to the traditional approach, according to the textbook, *Principles of Utility Corporate Finance*, by Drs. Leonardo Giacchino and Jonathan Lesser, Public Utilities Reports, 2011, page 234, states: "The most common historic risk-free rate used to estimate the historic market risk premium, i.e., E(Rm)-rf, is the income return on U.S. Treasury bonds." They state that of the three components of the of the bond return, the income return, or coupon payment, reinvestment return and capital appreciation return, only the historic income return is the only truly "risk-free" component.

[101] The medians of the annual risk premiums over the periods 1924-2012 and 1947-2012 were somewhat higher, 6.1% and 5.2%, respectively, relative to bond income returns.

Table 13

10-YEAR AVERAGE CANADIAN MARKET RETURNS					
	Canadian Stock Returns	**Canadian Bond Total Returns**	**Canadian Risk Premium Over Bond Total Returns**	**Canadian Bond Income Returns**	**Canadian Risk Premium Over Bond Income Returns**
1933-1942	11.8%	5.7%	6.2%	3.4%	8.4%
1943-1952	17.5%	2.3%	15.2%	3.0%	14.5%
1953-1962	12.5%	2.5%	10.0%	4.2%	8.3%
1963-1972	11.2%	4.3%	6.9%	6.3%	4.9%
1973-1982	11.4%	6.9%	4.6%	10.5%	1.0%
1983-1992	10.1%	13.6%	-3.4%	10.5%	-0.4%
1993-2002	10.3%	10.5%	-0.2%	6.7%	3.5%
2003-2012	11.1%	8.2%	2.8%	4.1%	7.0%

Source: www.bankofcanada.ca, Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2012.*

Table 13 indicates a clear pattern in bond returns, reflecting:

1. rising bond yields in the 1950s through the early 1980s, which produced capital losses on bonds and low bond total returns;

2. high total bond returns and yields in the 1980s, reflecting the high rates of inflation; and,

3. high bond total returns in the 1990s and the 2000s, relative to bond income returns, reflecting the secular decline in long-term government bond yields, which resulted in capital gains and total bond returns, well in excess of the concurrent bond yields.[102]

In contrast to the pattern in bond returns, Table 13 does not indicate a discernible pattern in equity market returns.[103]

[102] The long-term Government of Canada bond yield is equivalent to an estimate of the expected return on the bond.
[103] Slope coefficients of trend lines fitted to the annual equity return data for the periods 1924-2012 and 1947-2012 are estimated at 0.00 for both periods.

Further analysis of the historical data for Canada indicates, as shown in Table 14 below, that, on a cumulative average basis, lower bond income returns have been associated with higher achieved risk premiums.

Table 14

	Averages for the Period: 1924-2012			Averages for the Period: 1947-2012		
All Bond Income Returns:	**Equity Returns**	**Bond Income Returns**	**Risk Premium**	**Equity Returns**	**Bond Income Returns**	**Risk Premium**
Below 4%	13.6%	3.1%	10.5%	17.2%	3.2%	14.0%
Below 5%	12.5%	3.6%	8.8%	13.5%	3.5%	10.0%
Below 6%	11.1%	4.1%	7.0%	11.6%	4.3%	7.3%
Below 7%	11.3%	4.2%	7.1%	11.9%	4.5%	7.4%
Below 8%	11.4%	4.5%	7.0%	12.0%	4.8%	7.2%
Below 9%	10.8%	4.9%	5.9%	11.0%	5.4%	5.6%
All Observations	11.4%	6.0%	5.4%	11.7%	6.7%	5.0%

Source: www.bankofcanada.ca, Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2012*.

Table 14 above indicates that, for all observations where the bond income return has been below 8% (average bond income return in the range of 4.5% to 5.0%), the corresponding equity risk premium averaged approximately 7.0% to 7.2%. Only when the highest historical levels of bond income returns are included does the average achieved equity risk premium drop to approximately 5.5% to 6.0% ("Below 9%") and then to approximately 5.0% to 5.5% ("All Observations"). In other words, the historical data are consistent with the conclusion that the market equity risk premium is higher at lower levels of bond yields and vice versa.

The theoretical basis for higher equity market risk premiums at lower bond income returns or yields is as follows: When investors invest in long-term bonds, they are effectively locked into the cash flows that are established at the time the bond is issued (coupon payments and principal repayment). If inflation turns out to be higher than anticipated when the bond investment is undertaken, the bond investor will experience an unanticipated loss in purchasing power if the bond is held to maturity. When the rate of inflation is high and uncertain, bond investors will demand a premium not only for expected inflation, but an additional premium to compensate for the risk that actual inflation will turn out to be higher than the forecast rate. In contrast, equity shareholders have an opportunity to be better protected than bondholders against unanticipated inflation, because firms have an ability to raise prices during inflationary periods. All other things equal, the increased risk of investing in bonds during periods of high and/or uncertain inflation translates into a higher required yield and, because equities are a better inflation hedge than bonds, a lower equity market risk premium.[104]

The forecast 2014-2016 4.0% 30-year Government of Canada bond yield is 2.0 percentage points lower than the long-term average bond income return (6.0%) and 2.7 percentage points lower than the post-World War II average bond income return (6.7%). Based on historical average achieved risk premiums at relatively low Government of Canada bond yields, the indicated market equity risk premium is approximately 7.0% to 7.5%.

[104] This phenomenon, as it applies to both industrial stocks and to utilities, was discussed in Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, "The Risk Premium Approach to Measuring a Utility's Cost of Equity", *Financial Management*, Spring 1985.

An earlier article, Myron Gordon and Paul Halpern, "Bond Share Yield Spreads Under Uncertain Inflation", *American Economic Review*, September 1976, demonstrated that an increase in variable and uncertain inflation will theoretically decrease the spread between bond and share yields.

Robert S. Harris and Felicia C. Marston, in "The Market Risk Premium; Expectational Estimates Using Analysts' Forecasts", *Journal of Applied Finance*, Vol. 11, No. 1, 2001, found an inverse relationship between the equity market risk premium and long-term Treasury bond yields in both the 1980s and 1990s, and that the market equity risk premium declines by 70 basis points for every one percentage point increase in bond yields. The same study also identified a positive relationship between the market equity risk premium and corporate bond yield spreads.

3.b.(iv) Impact of Inflation on Equity Market Returns[105]

Theoretically, the expected return on equity should be equal to the sum of the real risk-free cost of capital, the expected rate of inflation and an equity risk premium. Thus, the question arises whether the forward-looking nominal (inclusive of inflation expectations) equity market return should differ from historic nominal equity returns due to differences in the historic versus expected rates of inflation. On average, historically, the actual rate of consumer price (CPI) inflation in Canada was higher than the rate of inflation currently forecast to prevail over the longer term. The arithmetic average CPI rate of inflation from 1924-2012 in Canada was 3.0%; the most recent consensus long-term (2014-2023) forecast of CPI inflation is 2.0%.[106] The lower forecast rate of inflation compared to the historical average rate of inflation might suggest that expected nominal equity returns would be lower than they have been historically. However, an analysis of nominal equity returns, rates of inflation and real returns on equity shows that real equity returns have generally been higher when inflation was lower.[107] Table 15 below summarizes the nominal and real rates of equity market returns historically at different levels of CPI inflation (December over December).[108]

[105] 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 analyzed the trends in P/E ratios and equity market returns and determined that there is no indication that rising P/E ratios during the bull market of the 1990s resulted in average equity market returns that are unsustainable going forward. The analysis is summarized in Appendix A.

[106] Consensus Economics, *Consensus Forecasts*, October 2013.

[107] The observation that real rates of return have been higher at lower rates of inflation is consistent with the documented negative effect on real economic activity and corporate profitability of high rates of inflation. Eugene F. Fama, "Stock Returns, Real Activity, Inflation, and Money", *The American Economic Review*, September, vol. 71(4), 1981, documents the negative relationship between high rates of inflation and future real economic growth rates. Steven A Sharpe, "Stock Prices, Expected Returns, and Inflation", *Finance and Economics Discussion Series 1999-02*, 1999, argued that expectations of real earnings growth are negatively related to expected inflation due to declines in productivity which, in turn, impact corporate profitability.

[108] A study on U.S. markets that historically, inflation has not been good for real equity returns. The study found that, over a 200 year period, equities performed best during periods of deflation, returned an average real return of 8% when inflation was in the range of 0-5% over the entire period and 10% since 1971, and that while equities have more than kept pace with inflation over the long-term, "the asset class generally does not do well in high inflation years." (John J. Mullin and Leila Heckman, "Outlook for U.S. Inflation: Lessons from Two Centuries of Financial History", *Mesirow Financial International Equity*, September 2009.)

Table 15

Inflation Range	Nominal Equity Return	Average Rate of Inflation	Real Equity Return
Less than 1%	11.1%	-1.7%	12.8%
1-3%	13.6%	1.9%	11.7%
3-5%	6.8%	4.0%	2.7%
Over 5%	12.1%	8.6%	3.4%
Avg. 1924-2012	11.4%	3.0%	8.4%

Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2012*.

While the average real equity return in Canada over the longer period was 8.4%, it is materially affected by the inclusion in the average of a relatively small number of high inflation years. When years in which inflation exceeded 10% are excluded (five of 89 observations), the average real equity return is a full percentage point higher, i.e., 9.4%.[109] At a real equity return of 9.4%, combined with the forecast longer-term inflation rate of 2.0%, the indicated nominal equity return would be approximately 11.4%, similar to historic average nominal equity market returns. The corresponding indicated market equity risk premium at the 4.0% forecast long-term Canada bond yield is just under 7.5% (11.4% - 4.0%).

3.b.(v) Comparison of Canadian and U.S. Returns and Risk Premiums

A comparison of the returns in Canada and the U.S. over the longer-term and the post-World War II period shows that the equity market returns in the two countries have been similar, approximately 11.5% to 11.75% in Canada and 11.75% to 12.25% in the U.S. (see Table 12 above).

Despite relatively similar equity market returns, the achieved risk premium (equity market returns less bond income returns) in Canada has been 1.3% to 1.5% lower than in the U.S. The difference in the equity market returns accounts for just over 50 basis points

[109] The average real equity return is approximately 9.8% when the years in which inflation exceeded 10% and the same number of abnormally low inflation (deflation) years (average of -4.1%) are removed.

of the difference in the observed risk premiums, with the largest part of the difference attributable to higher bond yields historically in Canada. Over the period 1926-1997, the difference between long-term government bond yields in Canada and the U.S. averaged close to 100 basis points.

With the vastly improved economic fundamentals in Canada (e.g., lower inflation, balanced budgets), the risk of investing in Canadian government bonds (relative to equities) declined and the differential between Canadian and U.S. government bond yields that existed historically fell. Between 1998 and 2012, the average yield on 10-year Government of Canada bonds was only slightly higher (+7 basis points) than the corresponding average yield on 10-year U.S. Treasury bonds. The corresponding differential between the yields on the long-term (30-year) government bonds was -18 basis points.

With respect to the relative risk of the two equity markets, the historic annual volatility in the two markets over the longer-term has been quite similar. The table below compares the average arithmetic equity market returns and the corresponding standard deviations, as well as the compound (geometric) average returns from 1926-2012 and post-World War II (1947-2012) for the two countries.

Table 16

	Canada			**United States**		
	Arithmetic Average	**Standard Deviation**	**Compound Average**	**Arithmetic Average**	**Standard Deviation**	**Compound Average**
1926-2012	11.2%	18.8%	9.5%	11.8%	20.2%	9.8%
1947-2012	11.7%	16.9%	10.4%	12.4%	17.3%	11.0%

Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2012*, Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2013 Yearbook*.

To put the differences in the relative risk of the two markets in perspective over these two time periods, it is useful to compare the differences between the arithmetic and compound average returns in the two markets. The difference between the arithmetic and compound average returns is approximately equal to one-half of the variance in the annual returns. The variance in the arithmetic average returns in turn is equal to the standard deviation squared. The larger the difference between the arithmetic and compound averages, the more volatility there has been in the annual returns.

For the longer period, 1926-2012, the difference in the arithmetic and compound average returns in Canada was 1.7%; the corresponding difference in the U.S. was 2.0%, a difference between the two of approximately 0.3%. During the post-World War II period, the differences in Canada and the U.S. were approximately 1.3% and 1.4% respectively, i.e., virtually the same. The differentials between the Canadian and U.S. arithmetic and compound average returns of 0.3% and 0.1% can be interpreted as the difference in equity return required for the difference in volatility between the two markets. As such, the data indicate that the required equity market return would be only 0.30% and 0.10% higher in the U.S. than in Canada based on the longer period and the post-World War II period respectively, i.e., the differences are minor.[110]

With similar government bond yields in the two countries for more than a decade, U.S. historical equity market risk premiums are a relevant benchmark for the estimation of the forward-looking equity market risk premium for Canadian investors. As shown in Table 12 above, the average achieved equity risk premium relative to bond income returns in the U.S. has been approximately 6.5% to 6.75%. Similar to Canada, however, as demonstrated in Table 17 below, higher risk premiums in the U.S. have been associated with lower bond income returns.

[110] Since the onset of the financial crisis (August 2007) to the end of December 2013, the two markets have exhibited similar volatility; the standard deviations of weekly price changes in the S&P/TSX Composite (Canada) and the S&P 500 (United States) have been virtually identical.

Table 17

Bond Income Returns:	Averages for the Period: 1926-2012			Averages for the Period: 1947-2012		
	Equity Returns	Bond Income Returns	Risk Premium	Equity Returns	Bond Income Returns	Risk Premium
Below 4%	14.0%	2.9%	11.1%	18.9%	2.9%	16.0%
Below 5%	12.0%	3.3%	8.7%	13.3%	3.6%	9.8%
Below 6%	11.5%	3.5%	8.0%	12.3%	3.9%	8.4%
Below 7%	10.8%	3.9%	6.9%	11.1%	4.4%	6.7%
Below 8%	10.4%	4.3%	6.1%	10.5%	4.9%	5.7%
Below 9%	11.2%	4.5%	6.6%	11.6%	5.2%	6.4%
All Observations	11.8%	5.1%	6.7%	12.4%	5.8%	6.5%

Source: Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2013 Yearbook*.

As Table 17 shows, the 6.7% long-term (1926-2012) average historical equity risk premium corresponds to an average bond income return of 5.1%, approximately 1.0 percentage point higher than the forecast 4.0% 30-year Canada bond yield. The experienced equity risk premium at levels of bond income returns similar to the forecast 4.0% 30-year Canada bond yield was approximately 7% based on the 1926-2012 period and close to 8.5% based on the post-World War II period.

3.b.(vi) Equity Market Risk Premium

Given the absence of any material upward or downward trend in the nominal historic equity market returns over the longer-term, the P/E ratio analysis, the higher achieved risk premiums at lower levels of government bond yields and the observed generally negative relationship between real equity returns and inflation, a reasonable estimate of the expected value of the equity market risk premium is a range of 7.0% to 7.5% (mid-point of 7.25%) at the forecast 4.0% 30-year Government of Canada bond yield. The indicated risk premium based on an analysis of the U.S. data supports an equity risk premium of approximately 7.0% to 8.5%. With preponderant weight given to the Canadian data, the indicated equity market risk premium at the forecast 4.0%

Government of Canada bond yield is a range of 7.0% to 7.5% (mid-point of 7.25%). The corresponding indicated equity market return is 11.25%.

3.c. Relative Risk Adjustment

3.c.(i) Overview

The equity market risk premium result needs to be adjusted to recognize the relative risk of a benchmark utility. The theoretical CAPM holds that equity investors only require compensation for risk that they cannot diversify by holding a portfolio of investments. In the simple, single risk variable CAPM, the non-diversifiable risk relative to the market as a whole is measured by beta.

Impediments to reliance on the equity beta as the sole relative risk measure include:

1. The assumption that all risk for which investors require compensation can be captured and expressed in a single risk variable. The determination of the return on equity that investors require for bearing the risk of a particular investment is more complex than the single risk variable, beta, implies.

2. The only risk for which investors expect compensation is non-diversifiable equity market risk; no other risk is considered (and priced) by investors. This premise erroneously implies that investors are only concerned with the price volatility of their equity investments, not the underlying fundamental risks that may lead to loss of earning power and ultimately a failure to recover their invested capital.

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) are a good measure of the

relative return requirement. Empirical tests of the CAPM and experienced returns undermine the validity of that assumption. Empirical tests of the model have shown in some cases that the model underestimates the returns for low beta stocks and overestimates them for high beta stocks and in other cases that there is no relationship between beta and return. The objective of any cost of equity test is to determine the return that investors require or expect. When the empirical relationships between actual returns and the risk measures are unreliable, or indeed, opposite to expected relationships, it becomes difficult to place a high degree of confidence in the results

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 move counter to the rest of the equity market could be expected to have betas that are negative. In that case, the CAPM would posit that the cost of equity capital 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 proposition that a firm's cost of equity could be lower, not only than its own cost of debt, but then the risk-free rate is dubious at best.

5. Utilities are not investing in a portfolio of securities. They are committing capital to long-term assets. Once the capital is committed, it cannot be withdrawn and redeployed elsewhere. In this context, investors are not concerned about the relative fluctuations in the utilities' equity share prices; they are concerned about the potential loss of earnings power of the underlying enterprise. The CAPM does not capture that reality.

Thus, a risk measurement that reflects those considerations is relevant for estimating the benchmark utility equity risk premium.

3.c.(ii) Total Market Risk

These considerations support focusing on total market risk, as well as on beta, to estimate the relative risk adjustment for a utility. The absence of an observable relationship between "raw"[111] betas and the achieved market returns on equity in the Canadian market[112] provides further support for reliance on total market risk to estimate the relative risk adjustment.

The standard deviation of market returns is the principal measurement of total market risk. To estimate the relative total benchmark utility risk, the S&P/TSX Utilities Index was used as a proxy. The standard deviations of monthly total market returns for each of the 10 major Sectors of the S&P/TSX Index, including the Utilities Index, were calculated over five-year periods ending 1997 through 2012 (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 <u>relative</u> 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 to the mean and median standard deviations of the 10 major Sector Indices suggests a relative risk adjustment for an average risk Canadian utility in the range of 0.55-0.85, with a central tendency of approximately 0.65-0.70.

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[111] The term "raw" means that the beta is solely a statistical calculation of the historical relationship between the price movements of a stock and the corresponding price movements of the market portfolio.

[112] See Appendix A, pages A-21 to A-26.

3.c.(iii) Historical "Raw" Betas of Canadian Utilities

Schedule 13, pages 1 to 3 summarizes "raw" betas calculated using monthly and weekly price changes[113] for the five major publicly-traded Canadian utilities, the TSE Gas/Electric Index, and the S&P/TSX Utilities Sector.[114]

As Schedule 13, page 1 indicates, there was a significant decline in the calculated "raw" monthly five-year betas of the individual Canadian regulated utilities between 1994-1998 and 1999-2005 (from approximately 0.50 to 0.0 and slightly negative). Following an increase in 2007 to slightly above 0.50, the "raw" monthly betas for the individual Canadian regulated utilities again declined in 2008 to approximately 0.20 and have remained at a similar level through the end of 2012.

The observed levels and pattern of the calculated "raw" utility betas in 1999-2012 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 greater sensitivity of utility stock prices than 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); and (4) the more extreme price changes of the market as a whole during the financial crisis and the subsequent market recovery.[115]

[113] The use of price betas for utilities has been criticized on the grounds that the exclusion of dividends from the calculated betas overestimates the betas. A comparison of price and total return (including dividends) betas for Canadian utilities showed that there was no material difference between the two.

[114] 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.

[115] Schedule 11 shows that utilities were not the only companies whose betas were negatively impacted by the technology sector bubble and subsequent market decline. To illustrate, the five-year monthly beta ending 1997 of the Consumer Staples Sector was 0.62; the corresponding betas ending 2003 and 2004 were -0.08 and -0.07 respectively. In contrast, over the same periods, the beta of the Information Technology Sector rose from 1.57 to 2.87. Schedule 11 also demonstrates how variable betas are generally. For example, between 2002 and 2012, the five-year monthly betas for the energy sector ranged from 0.17 to 1.44.

There can be significant differences in measured "raw" betas depending on the interval over which the change in share price is calculated. Betas calculated using monthly changes in price can differ systematically from betas calculated using weekly changes in prices.[116] Table 18 below shows that, for the five large Canadian utilities whose shares are regularly traded, the mean and median five-year "raw" betas ending December 2008 to December 2012 calculated using weekly price changes were twice as high as the corresponding mean and median betas calculated using monthly price changes. These large differences due solely to the choice of interval cast significant doubt on how meaningful calculated betas are as a measure of relative risk.

Table 18

	Weekly Data		Monthly Data	
	Mean	**Median**	**Mean**	**Median**
2008	0.46	0.45	0.25	0.21
2009	0.43	0.44	0.22	0.2
2010	0.44	0.44	0.23	0.21
2011	0.45	0.44	0.21	0.21
2012	0.44	0.43	0.17	0.20

Source: Schedule 13.

3.c.(iv) Canadian Regulated Company Returns and "Raw" Betas

The equity betas of traded Canadian utility company shares and of the S&P/TSX Utilities Index explain a relatively small percentage of the actual achieved market returns over time. The following analysis 1) estimates how much of the historical utility market returns can be explained by the equity market, long-term Government of Canada bonds

[116] There is no theoretically correct time interval for calculations of betas. Betas are frequently, but not exclusively, measured over five years using monthly price change intervals (60 observations). For example, Bloomberg calculates betas over three-year periods using weekly price change intervals (156 observations) whereas *Value Line*, which also utilizes weekly prices, estimates the beta over a period of 2.5 to 5 years (over 250 observations). The measurement of betas over a five-year period is simply a convention. In *Modern Portfolio Theory, The Capital Asset Pricing Model & Arbitrage Pricing Theory: A User's Guide,* 2nd Ed., Englewood Cliffs, New Jersey: Prentice-Hall, 1987, page 114, the author, Dr. Diana Harrington, noted that the CAPM itself provides no guidance with respect to the choice of a measurement horizon; the five-year estimation period (i.e., 60 monthly observations) became widely used because of the availability of monthly data in computer-readable form, and the need for a reasonably sized sample.

and other factors and 2) uses these relationships to assist in the determination of an appropriate estimate of the required relative risk adjustment.

In the context of the CAPM, the utility return should equal:

Risk-Free Rate + Beta X (Equity Market Return – Risk-Free Rate)

A regression of the monthly returns on the TSX Utilities Index against the market risk premium measured as the return on the TSX Composite less the risk-free rate as proxied by 90-day Treasury bill returns over the period 1970-2012[117] shows the following:

Table 19

$$\text{Monthly TSX Utilities Index Return} = 0.008 + 0.464 \left\{ \text{Monthly TSX Composite Excess Return} \right\}$$

t-statistics	=	5.4	13.9
R^2	=	27%	

The relationship quantified in the above equation suggests a long-term utility beta of 0.46. However, the R^2, which measures how much of the variability in utility returns is explained by variability in the returns of the equity market as a whole, is only 27%. That means 73% of the monthly volatility in utility returns remains unexplained.[118] The intercept in the equation should, in principle, represent the risk-free rate. Over the entire 1970-2012 period, the average annual return on Treasury bills was 6.8%; the corresponding intercept in the equation above is 10.0%, when expressed on an annualized

[117] The Monthly TSX Utilities Index Returns are comprised of the monthly returns on the TSE Gas & Electric Index for the period January 1970 to April 2003 and the monthly returns on the S&P/TSX Utilities Index for the period May 2003 to December 2012.

[118] As shown in Schedule 13, page 2 of 6, the R^2s of the monthly betas for individual Canadian utilities calculated over five-year periods ending 2004 to 2012 have been extremely low, averaging less than 10%. The low R^2s indicate that very little of the volatility in the utility share prices is explained by the volatility in the equity market composite. It bears noting that, while the five-year "raw" monthly and weekly betas ending December 2012 of Canadian Utilities Limited, at -0.04 and 0.36 respectively, are the lowest of the individual Canadian utilities, its absolute price volatility, measured by the standard deviation of both monthly and weekly price changes, was the highest of the group.

basis.[119] The difference between the calculated intercept and the average 90-day Treasury bill return of approximately 3.2% represents the component of the utility return incremental to what the CAPM would predict.

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 excess long-term Canada bond returns to the analysis indicates the following:

Table 20

$$\begin{array}{c} \text{Monthly TSX} \\ \text{Utilities} \\ \text{Index Return} \end{array} = 0.0074 + .40 \left\{ \begin{array}{c} \text{Monthly TSE} \\ \text{Composite} \\ \text{Excess Return} \\ \text{over T-bills} \end{array} \right\} + .45 \left\{ \begin{array}{c} \text{Monthly Excess} \\ \text{Long Canada} \\ \text{Bond Return} \\ \text{over T-bills} \end{array} \right\}$$

t-statistics =	5.0	12.6	8.6
R^2 =	36%		

When government bond returns are added as a further explanatory variable, somewhat more of the observed volatility in utility stock prices is explained (36% versus 27%). The second regression equation suggests that utility returns have had approximately 40% of the volatility of equity market returns and approximately 45% of the volatility of government bond market returns, the latter consistent with utility common stocks' interest sensitivity. Nevertheless, the equation still leaves more than half of the utility return volatility unexplained.

In this equation, the market equity risk premium is equal to the return on the equity market composite less the Treasury bill return and the long-term Canada bond risk premium, or maturity premium, is equal to the return on the long-term Canada bond less the Treasury bill return. The intercept in the equation in Table 20, as was the case in Table 19, is the sum of the risk-free rate, as proxied by the 90-day Treasury bill return, and the component of the return which is unexplained by, differs from or is incremental to, what the two variable model would have predicted. As in Table 19, the equation

[119] The regression was performed using monthly data, so the intercept of 0.008 is equal to the monthly return on 90-day Treasury bills. The annualized return is equal to $(1+.008)^{\wedge 12}-1.0 = 0.1003 = 10.0\%$.

intercept is a monthly number. When annualized, the intercept equals approximately 9.2%.[120] Since the average annualized Treasury bill return over the 1970-2012 period of analysis was 6.8%, the actual utility return was 2.4% higher than predicted by the two variable model.

To assess whether this unexplained component of the utility returns arises from a downward trend in utility risk over the period 1970-2012, I analyzed the trend in the relative total volatility of the S&P/TSX Utilities Index, measured by the ratio of five-year monthly standard deviations of the total market returns of the Utilities Index to those of Composite. The results of the analysis indicated that, although the relative volatility was not constant throughout the period, there has not been a statistically significant trend up or down in the relative total risk of the Utilities Index compared to the Composite over the period 1970-2012.

The objective of the relative risk adjustment is to predict the investors' required or expected return. To do so, the persistent large component of the achieved utility return, as reflected in the equations' intercepts, which is above what the CAPM or the two variable model would have predicted, should be explicitly taken into account. The use of the calculated "raw" Canadian betas alone as an estimate of the relative risk adjustment, without consideration of the extent to which the two models have underestimated the utility return, will result in the underestimation of expected utility returns.[121]

The equations in Tables 19 and 20 above can be solved in order to estimate a reasonable utility relative risk adjustment. To do so, values for the three independent variables (TSX equity market return, long-term Canada bond return and Treasury bill return) must be specified. For the TSX, the estimated equity market return of 11.25% developed above was used. For the long-term Canada bond return, the 4.0% yield forecast for 2014-2016 was used as a proxy. As regards the Treasury bill return, a normalized yield of 2.65%

[120] $(1.0 + 0.0074)^{12} - 1.0 = .0923 = 9.23\%$.

[121] The explicit recognition of the unexplained component of the return is consistent with the empirical observation that low beta stocks, including, but not limited to, utilities have historically earned returns higher than the CAPM predicts, with the converse observed for high beta stocks.

was used, reflecting the historical average yield spread between 30-year Government of Canada bonds and 90-day Treasury bills of approximately 1.35% (4.0% - 1.35% = 2.65%). In addition, estimates of the incremental utility return (i.e., the component of the return not captured by the models) are required. These estimates were based on two alternative assumptions: (1) the incremental expected utility return is the same in absolute terms as it was historically; and (2) the incremental expected utility return is in the same proportion to the total utility return as was the case historically.

Under the first assumption, the single and two variable models and the resulting indicated relative risk adjustments are as follows:

Table 21

Equity Market Return (EMR):	11.25%
Risk Free Rate (RF = T-Bill Yield):	2.65%
Equity Market Risk Premium (MRP = 11.25% - 2.65%):	8.60%

Model	**Utility Equity Beta**	**Utility Bond Beta**	**Incremental Utility Return**	**Utility Return**	**Utility Risk Premium**	**Relative Risk Adjustment**
	(1)	(2)	(3)	(4)	(5)= (4)-RF	(6) = (5)/MRP
Single Variable	0.46	N/A	3.20%	9.9%[1/]	7.2%	0.84
Two Variable	0.40	0.45	2.40%	9.1%[2/]	6.5%	0.75

[1/] 9.9% = 3.2% + 2.65% + 0.46*MRP

[2/] 9.1% = 2.4% + 2.65% +0.40*MRP + 0.45*(1.35%), where 1.35% is the maturity risk premium.

In the alternative, as noted above, the prospective incremental component of the utility return can be estimated to be in the same proportion to the total utility return as was the case historically. These proportions are approximately 25%[122] in the case of the single variable model and 20%[123] in the case of the two variable model. In these two cases, the expected utility returns are 8.9% (single variable) and 8.3% (two variable) respectively.[124] The indicated utility risk premiums above the Treasury bill yield are

[122] 3.2%/12.5% ≈ 25%.

[123] 2.4%/12.5% ≈ 20%.

[124] 8.9% = (2.65% + 0.46*8.6%)/(1-25%); 8.3% = (2.65% + (0.40*8.6%) + (0.45*1.35%))/(1-20%).

6.3% and 5.7%, corresponding to relative risk adjustments of 0.73 and 0.66, or a mid-point of 0.70.[125]

Based on all four approaches, the indicated utility relative risk adjustment is in the range of 0.66 to 0.84 (average of approximately 0.75).

3.c.(v) Use of Adjusted Betas

From the calculated "raw" betas, the inference can readily be made that regulated companies 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, stocks with betas higher than the equity market beta of 1.0 have achieved lower returns than the model predicts.[126]

The use of betas that are adjusted toward the equity market beta of 1.0, rather than the calculated "raw" betas, is a partial recognition of the observed tendency of low (high) beta stocks to achieve higher (lower) returns than predicted by the simple CAPM. Adjusted historical betas are a standard means of estimating expected 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. While the rationale for the specific adjustment formula reflects the

[125] $\frac{8.9\% - 2.65\%}{11.25\% - 2.65\%} = 0.73; \ \frac{8.4\% - 2.65\%}{11.25\% - 2.65\%} = 0.66.$

[126] See Appendix A, page A-23.

tendency for betas in general to drift toward the market mean beta of 1.0, the adjustment is also justified on the grounds that the adjusted betas are better predictors of returns than "raw" betas.[127]

The following table presents recent reported Bloomberg adjusted betas for the five major Canadian utilities. Based solely on the recent Bloomberg betas, the relative risk adjustment would be approximately 0.70. The application of the same adjustment formula used by Bloomberg to the long-term calculated "raw" beta of 0.46 for the TSX Utilities Index shown in Table 19 above results in a relative risk adjustment of close to 0.65.[128]

Table 22

Company	**Bloomberg Beta**
Canadian Utilities Ltd.	0.67
Emera Inc.	0.75
Enbridge Inc.	0.70
Fortis Inc.	0.71
TransCanada Corp.	0.60
Average	**0.69**
Median	**0.70**

Source: Bloomberg.

The widely disseminated *Value Line* adjusted betas (based on weekly price change intervals) for the comparable U.S. utility sample provide a further indicator of the relevant risk adjustment for the benchmark utility ROE. As summarized on Schedule 13, page 6 of 6, the reported *Value Line* betas for the sample of U.S. utilities have been approximately 0.675 on average for the five-year periods ending 1996-2012, close to the recent level (median of 0.65).

[127] Pablo Fernandez and Vicente Bermejo, in an article entitled *$\beta = 1$ Does a Better Job than Calculated Betas,* May 19, 2009, find that adjusted betas (0.67 X calculated beta + 0.33 X Market Beta of 1.0) do a better job of predicting returns than the calculated beta. They also find that assuming a beta of 1.0 (i.e., the market beta) does a better job than the adjusted beta.

[128] Adjusted beta = 0.67 x "Raw" Beta + 0.33 x Market Beta of 1.0.

3.c.(vi) Relative Risk Adjustment

A summary of the results of the preceding analysis is set out in the table below:

Table 23

Relative Risk Indicator	**Relative Risk Factor**
Total Market Risk (Standard Deviations)	0.675
Relative Historic Returns and Betas: Canadian Utilities	0.75
Recent Bloomberg Adjusted Beta: Canadian Utilities	0.70
Long-term Adjusted Beta: Canadian Utilities Index	0.65
Value Line Betas: U.S. Utility Sample	0.675

These results support a relative risk adjustment for the benchmark utility ROE in the approximate range of 0.65-0.70.

3.d. Risk-Adjusted Equity Market Risk Premium Test Results

The equity market risk premium was previously estimated to be 7.0% to 7.5% (mid-point of 7.25%) at the forecast 4.0% 30-year Government of Canada bond yield. At an equity market risk premium of 7.25% and a relative risk adjustment of 0.65-0.70, the indicated equity risk premium for the benchmark utility ROE is in the range of approximately 4.7% to 5.1%. Based on the risk-adjusted equity market risk premium test, the corresponding cost of equity is in the range of approximately 8.7% to 9.1% (mid-point of 8.9%).

4. DCF-Based Equity Risk Premium Test

4.a. Overview

The Discounted Cash Flow-Based (DCF-Based) Equity Risk Premium Test estimates the utility equity risk premium as the difference between the DCF cost of equity and yields on long-term government bonds.

The DCF-based equity risk premium test estimates the equity risk premium directly for regulated companies by explicitly analyzing regulated company equity return data. In contrast, the risk-adjusted equity market risk premium test discussed above estimates the required utility equity risk premium indirectly, that is, it focuses on the risk-free rate and returns at the overall market level. Of the components of that test, only the relative risk adjustment is derived directly from utility-specific data.

The DCF-based equity risk premium test was applied to a sample of U.S. utilities.[129] The DCF-based equity risk premium test was applied only to the sample of U.S. utilities, because its application requires a history of consensus long-term earnings growth rate forecasts, which is not available for Canadian utilities.[130]

A key advantage of the DCF-based equity risk premium test relative to the other equity risk premium tests is that it can be used to test the relationship between the cost of equity (or risk premiums) and interest rates (and/or other variables).[131] In the application of this test, the relationships between utility risk premiums, long-term government bond yields, the spread between the yields on long-term utility and government bond yields and utility bond yields were estimated.

4.b. Constant Growth 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 U.S. utilities in the sample from 1998-2013Q3.[132] The

[129] The selection criteria for the sample of U.S. utilities to which the DCF-Based Equity Risk Premium Test was applied are found in Appendix B.

[130] Analysts' forecasts of long-term earnings growth for Canadian utilities are currently accessible, which permits the application of the DCF test to Canadian utilities. However, there is no readily accessible history of those forecasts which would permit the application of the DCF-based equity risk premium test to a sample of Canadian utilities.

[131] Of the three equity risk premium tests conducted, the DCF-based equity risk premium test is the only one that lends itself to explicitly estimating the relationship between utility equity risk premiums (or the utility cost of equity) and interest rates.

[132] The choice of period 1998-2013Q3 reflects the years during which long-term Canada and U. S. Treasury bond yields have been broadly similar. It is also intended to balance the exclusion of periods in which rates of inflation and long-term interest rates were well outside the range of levels expected to prevail in the future with the inclusion of a sufficient number of observations to provide reliable estimates of the relationships.

construction of the monthly constant growth DCF costs of equity and the corresponding equity risk premiums is described in Appendix D.

For the sample of U.S. utilities, the constant growth DCF-based equity risk premium test indicates that the average 1998-2013Q3 utility risk premium was 5.1%, corresponding to an average long-term government bond yield of 4.7%. The data also show that the risk premium averaged 4.4% when long-term government bond yields were 6.0% or higher and 6.4% when long-term government bond yields were below 4.0%.

The table below sets out the observed utility equity risk premium at various levels of long-term government bond yields based on the results of the 1998-2013Q3 constant growth analysis.

Table 24

Government Bond Yield	Below 4.0%	4.0%-5.0%	5.0%-6.0%	Above 6.0%
Utility Equity Risk Premium	6.4%	5.1%	4.4%	4.4%

Source: Schedule 15, page 1 of 4.

The data indicate that the utility equity risk premium is higher at lower levels of interest rates than it is at higher levels of interest rates, i.e., there is an inverse relationship between long-term government bond yields and the utility equity risk premium.

4.c. Three-Stage DCF-Based Equity Risk Premium Test

The DCF-based risk premium test was also applied using a three-stage DCF model. The construction of the monthly three-stage DCF cost of equity estimates is described in Appendix D. The use of the three-stage model, which assumes that, in the long run, earnings growth for the utility sample will converge to the long-term rate of growth in the economy, effectively lessens the volatility of the monthly growth rates utilized in the constant growth analysis.[133] Based on the three stage growth model, the average utility equity risk premium during the period of analysis was 5.2% at an average 30-year government bond yield of 4.7%. The table below sets out the observed utility equity risk premium at various levels of long-term government bond yields based on the results of the 1998-2013Q3 three-stage growth analysis.

Table 25

Government Bond Yield	**Below 4.0%**	**4.0%-5.0%**	**5.0%-6.0%**	**Above 6.0%**
Utility Equity Risk Premium	6.2%	5.3%	4.8%	4.4%

Source: Schedule 15, page 3 of 4.

4.d. Relationships between Equity Risk Premiums and Interest Rates

Using the constant growth and three-stage growth DCF models, the relationship between 30-year government bond yields (independent variable) and the corresponding utility equity risk premiums (dependent variable) was estimated. The analysis indicated that, based on the constant growth model, over the 1998-2013Q3 period, on average, for each 100 basis point change in the long-term government bond yield, the utility equity risk premium moved in the opposite direction by approximately 82 basis points. The results using the three-stage model showed a 59 basis point increase (decrease) in the utility equity risk premium for every 100 basis point decrease (increase) in the long-term government bond yield.[134]

The table below sets out the utility equity risk premium at various levels of long-term government bond yields based on the regressions using long-term government bond yields as the sole independent variable.

[133] The standard deviation of the monthly sample analysts' forecast growth rates is approximately 0.5; the standard deviation of the monthly implied growth rates utilized in the three-stage DCF-based risk premium analysis is approximately 0.3.

[134] Expressed in terms of cost of equity, on average, over the period of analysis, the cost of equity, as measured by the constant growth and three-stage DCF-based equity risk premium tests, increased (decreased) by approximately 18 to 41 basis points for every one percentage point increase (decrease) in the long-term government bond yield.

Table 26

Government Bond Yield	3.0%	4.0%	5.0%	6.0%	7.0%
Utility Equity Risk Premium:					
Constant Growth	6.5%	5.7%	4.9%	4.0%	3.2%
Three-stage Growth	6.3%	5.7%	5.1%	4.5%	3.9%

Source: Schedule 15, pages 2 and 4 of 4.

The analysis demonstrates that the utility equity risk premium is higher at lower levels of interest rates than it is at higher levels of interest rates, i.e., there is an inverse relationship between long-term government bond yields and the utility equity risk premium.

However, this specific analysis indicates that utility equity risk premiums have been, on average, much more sensitive to, and the corresponding utility costs of equity much less sensitive to, long-term government bond yields than was assumed by the automatic ROE adjustment formula previously used by the AUC. That formula assumes that the utility equity risk premium increases/decreases by 25 basis points for every one percentage decrease/increase in the long-term Government of Canada bond yield.

The single independent variable analysis reflects only the relationship between the equity risk premium and government bond yields to the exclusion of other factors which impact the cost of equity. To capture the impact of other factors, corporate bond yield spreads were incorporated into the analysis. The magnitude of the spread between corporate bond yields and government bond yields is frequently used as a proxy for changes in investors' risk perception or willingness to take risk. Various empirical studies have shown that there is a positive correlation between corporate yield spreads and the equity risk premium.[135] In the two independent variable regression analysis, government bond yields and the spread between long-term A-rated utility and government bond yields were both used as independent variables and the utility equity risk premium was the dependent variable. The two independent variable analysis indicates that, while the utility risk

[135] Examples include: N.F. Chen, R. Roll, and S. A. Ross, "Economic Forces and the Stock Market", *Journal of Business*, Vol. 59, No. 3, July 1986, pages 383-403 and R.S. Harris and F.C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts, *Financial Management*, Summer 1992, pages 63-70.

premium was negatively related to the level of government bond yields, it was positively related to the spread between utility bond yields and government bond yields.

Specifically, over the 1998-2013Q3 period, the constant growth analysis showed that the utility equity risk premium increased or decreased by approximately 96 basis points when the government bond yield decreased or increased by 100 basis points and increased or decreased by approximately ten basis points for every ten basis point increase or decrease in the utility/government bond yield spread (Schedule 15, page 2 of 4). The three-stage growth DCF model indicates that the utility equity risk premium increased or decreased by approximately 69 basis points when the government bond yield decreased or increased by 100 basis points and increased or decreased by more than six basis points for every ten basis point increase or decrease in the utility/government bond yield spread (Schedule 15, page 4 of 4).

The two independent variables (long-term government bond yields and the long-term A-rated utility bond/government bond yield spread) can be collapsed into a single independent variable, the long-term A-rated utility bond yield. That analysis shows the utility equity risk premium rising and falling by approximately 60% to 70% of the change in the A-rated utility bond yield using the constant growth and three-stage growth models (Schedule 15, pages 2 and 4 of 4).

To further test the sensitivity of the utility cost of equity to changes in long-term government bond yields and utility/government bond yield spreads, quarterly ROEs allowed for U.S. utilities[136] were used as a proxy for the utility cost of equity. The average allowed ROEs can be viewed as a measure of the utility cost of equity as they represent the outcomes of multiple rate proceedings across multiple jurisdictions, which in turn reflect the application of various cost of equity tests by parties representing both the utility and ratepayers.

[136] The analysis was not performed for Canadian utilities due to the widespread use of formulas over an extended period that specified the relationship between government bond yields and allowed ROEs. Thus, the analysis would provide no independent estimate of the relationship.

Initially, the risk premiums indicated by the quarterly allowed ROEs from 1998 to 2013Q3 were regressed against long-term Treasury bond yields lagged by six months.[137] The result indicated that the utility equity risk premium increased or decreased by approximately 50 basis points for every one percentage point decrease or increase in long-term government bond yields.

When long-term A-rated utility/government bond yield spreads were added as a second independent variable, the analysis indicated that (1) the utility equity risk premium increased (decreased) by approximately 55 basis points for every one percentage point decrease or increase in long-term government bond yields; and (2) the utility risk premiums increased or decreased by approximately 25 basis points for every one percentage point increase or decrease in the long-term A-rated utility/government bond yield spread.

Collapsing the two independent variables into a single variable, long-term A-rated bond yields, and regressing those yields against the corresponding utility risk premiums (measured as the allowed ROE minus the Moody's long-term A-rated utility bond yield lagged six months), the analysis indicated that the utility risk premiums have decreased (increased) approximately 60 basis points for every one percentage point increase (decrease) in the A-rated utility bond yield.[138]

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[137] The government bond yields and the spread variables were lagged by six months behind the quarter of the ROE decisions to take account of the fact that the dates of the decisions will lag the period covered by the market data on which the ROE decisions would have been based.

[138] Details of all the regressions are found in Schedules 15 and 16. The greater sensitivity of the ROEs to interest rates indicated by the regressions using allowed ROEs as a proxy for the utility cost of equity compared to those using DCF costs of equity most likely reflects other models, in addition to the DCF, used by regulators in arriving at the allowed ROE. These models include risk premium models such as the CAPM, ECAPM, *ex ante* and *ex post* risk premium models, which are explicitly tied to interest rates. While the DCF cost of equity is sensitive to bond yields, it is also a function of factors unique to the equity market.

4.e. DCF-Based Equity Risk Premium Test Results

The regressions were solved using the forecast 4.0% 30-year Canada bond yield. For the 30-year A-rated utility/Government of Canada bond yield spread, a spread of 135 basis points was used.[139]

The table below summarizes the estimated relationships among equity risk premiums, long-term government bond yields and utility/government bond yield spreads from the application of the various models to the U.S. utility sample over the 1998-2013Q3 period and the resulting equity risk premiums and costs of equity at a forecast 4.0% long-term Canada bond yield and a long-term A-rated utility/government bond yield spread of 135 basis points.

Table 27

	Coefficients		**Equity Risk Premium**	**Cost of Equity**
	Government Bond	**Bond Yield Spread**		
Constant Growth				
Single Variable	-0.82	n/a	5.7%	9.7%
Two Variable	-0.96	0.95	5.6%	9.6%
Three-Stage Growth				
Single Variable	-0.59	n/a	5.7%	9.7%
Two Variable	-0.69	0.65	5.6%	9.6%
Allowed ROEs				
Single Variable	-0.51	n/a	6.2%	10.2%
Two Variable	-0.54	0.25	6.2%	10.2%

Note: "Single Variable" refers to the regression analysis applied only to the long-term government bond yield and "Two Variable" refers to the addition of the spread variable to the regression analysis.

Sources: Schedules 15 and 16.

While the indicated sensitivities of the models to changes in long-term government bond yields vary, they support the conclusion that the utility cost of equity has not varied with (or tracked) long-term government bond yields to the extent that has been implicit in a number of automatic ROE adjustment formulas.

[139] Assumes utility spreads will contract slightly as long-term Government bond yields return to more normal levels.

Table 28 below summarizes the regression results using an A-rated bond yield of 5.35% (equal to the forecast 4.0% 30-year Canada bond yield plus a spread of 135 basis points):

Table 28

Model	Coefficient	Risk Premium over A-Rated Bond Yield	Cost of Equity
Constant Growth DCF	-0.68	4.2%	9.5%
Three-Stage DCF	-0.58	4.2%	9.6%
Allowed ROEs	-0.60	4.9%	10.2%

I have not given any weight to the results of the allowed ROE analysis in deriving an estimate of the utility cost of equity from the DCF-based risk premium test, as the allowed ROEs do not represent my own estimates of the cost of equity. Nevertheless, the relationships among utility equity risks premiums and bond yields established by that analysis provide further support for the conclusion that the utility cost of equity does not track government bond yields nearly to the extent that has been embedded in most of the automatic ROE adjustment formulas that have been used in Canada.

Based on the DCF-based regression analyses, at the forecast 30-year Canada and A-rated utility bond yields, the indicated utility cost of equity is in the range of approximately 9.5% to 9.7%, and approximately 9.6% based on all the DCF-based risk premium models.

5. Historic Utility Equity Risk Premium Test

5.a. Overview

The historic experienced market returns for utilities provide an additional perspective on a reasonable expectation for the forward-looking utility equity risk premium and returns. Similar to the DCF-based equity risk premium test, this test estimates the cost of equity for regulated companies directly by reference to market return data for regulated companies. Reliance on achieved returns and 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. Moreover, this test and the underlying data provide a direct measure of comparable investment returns.

5.b. Historic Returns and Risk Premiums

As shown in Table 29 below, over the longest term available (1956-2012),[140] the average achieved utility (gas and electric combined) equity risk premium in Canada was 4.7% in relation to the corresponding average long-term Government of Canada bond income return.[141] For U.S. electric utilities, the average historic utility equity risk premium in relation to long-term U.S. Treasury bond income returns over the entire post-World War II period (1947-2012) was 5.6%. For U.S. gas utilities, the corresponding average historic utility equity risk premium in relation to long-term U.S. Treasury bond income returns was 6.3%.

[140] The longest period for which Canadian utility index data are available from the Toronto Stock Exchange.
[141] Based on the Gas/Electric Index of the TSE 300 from 1956 to 1987 and on the S&P/TSX Utilities Index from 1988-2012.

Table 29

	Utility Equity Returns	Bond Income Returns	Utility Equity Risk Premium
Canadian Utilities	12.0%	7.2%	4.7%
U.S. Electric Utilities	11.4%	5.8%	5.6%
U.S. Gas Utilities	12.1%	5.8%	6.3%

Source: Schedule 17.

5.c. Trends in Utility Equity Returns and Government Bond Income Returns

Similar to the risk premiums for the market composite, the magnitude of achieved utility equity risk premiums is a function of both the equity returns and the bond returns. An analysis of the underlying data indicates there is little evidence of a secular change (higher or lower) in the utility equity returns. Trend lines fitted to the historic utility equity returns for each of the three utility indices are flat (Canadian Utilities and U.S. Gas Utilities) to slightly rising (U.S. Electric Utilities) (Schedule 17, pages 2 and 3 of 3). The historical average utility returns in both Canada and the U.S. have clustered in the range of 11.5-12.0%. However, the achieved average government bond income return in Canada over the period of analysis, at 7.2%, was materially higher than the 4.0% forecast yield on 30-year Government of Canada bonds for 2014-2016.

A reasonable approach to interpreting the historical utility equity market return data is the recognition of the inverse relationship between utility equity risk premiums and government bond yields. Table 30 derives estimates of the utility equity risk premium from the historical average risk premiums by applying a 50% sensitivity factor to the difference between the historical average bond income returns and the forecast Government of Canada bond yield forecast. A 50% sensitivity factor comports with the lower end of the range of the sensitivities of utility equity risk premiums to government bond yield changes estimated in Section VIII.D.3.c above.

Table 30

		Canadian Utilities	U.S. Electric Utilities	U.S Gas Utilities
Equity Returns	(1)	12.0%	11.4%	12.1%
Bond Income Returns	(2)	7.2%	5.8%	5.8%
Utility Risk Premium (RP)	(3) = (1) – (2)	4.7%	5.6%	6.3%
Forecast 30-Year Canada Bond Yield	(4)	4.0%	4.0%	4.0%
Change in Bond Yield/Return	(5) = (4) – (2)	-3.2%	-1.8%	-1.8%
Change in Utility Equity RP	(6) = – (5) X 50%	+1.6%	+0.9%	+0.9%
Utility Equity Risk Premium at 4.0% Long Canada Bond Yield	(7) = (3) + (6)	6.4%	6.5%	7.2%

Source: Schedule 17, page 1 of 3.

At the forecast 4.0% 30-year Government of Canada bond yield and a 50% sensitivity factor between utility equity risk premiums and long-term government bond yields, the indicated utility equity risk premium derived from historical averages is in the approximate range of 6.5% to 7.0%.

5.d. Historic Utility Equity Returns, Size and Relative Risk

In comparison to the historic achieved returns for the equity market portfolios in Canada and the U.S. (the TSX Composite and the S&P 500), the corresponding utility market returns have been somewhat higher. The fact that the level of the observed utility returns may not appear, superficially, to comport with their risk relative to the equity composites has called into question their reliability as a measure of the returns utility investors required and expected.[142] However, when the relative size of utilities is taken into account, their returns relative to "the market" are not out of line with their relative risk.

The returns reported for "the market" in Canada and the U.S. respectively are the returns achieved by the largest capitalization stocks. In Canada, the largest 25 stocks (just over

[142] In the 2011 GCOC, the UCA argued that part of the reason for higher historic returns may be that allowed returns have been above the actual ROE that investors expected and required for investments of comparable risk. There is no evidence, and seems unlikely, that North American regulators as a group would have over a long period of time systematically overestimated the returns utility investors expected and required.

10% of the number of stocks in the Composite) account for 55% of the market capitalization of the S&P/TSX Composite. Thus the returns of a relatively small number of large stocks have a significant impact on the achieved returns of the composite.

Smaller stocks, historically, have tended to achieve higher returns than the largest capitalization stocks. As stated in Ibbotson, *SBBI 2013 Valuation Yearbook: Market Results for Stocks, Bonds, Bills and Inflation 1926-2012*, 2013:

> One of the most remarkable discoveries of modern finance is that of a relationship between firm size and return. The relationship cuts across the entire size spectrum but is most evident among smaller companies, which have higher returns on average than larger ones.[143]

The size effect was studied in Canada at approximately the same time (late 1980s) as the initial Ibbotson size analyses. Drs. James Hatch and Robert White stated that:

> recent capital market research suggests that the returns obtained from the equities of small firms are larger than those from the equities of large firms [footnote]. Moreover, it appears that the extra return provided by small firms more than compensates the investor for the extra risk taken. To shed additional light on this controversy, a detailed analysis was conducted of the return of a sample of small and large firms in the data base.

The analysis, conducted on Canadian equity returns from 1950-1987, by dividing the equities into small and large portfolios and measuring the market returns of each, led to the conclusion that:

> It is apparent from the data that the small firms as a group earned a higher average return and had a higher degree of month-to-month variability of return than was exhibited by the large-firm portfolio."[144]

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[143] Ibbotson Associates included their first analysis of firm size and return in their 1989 yearbook, citing the seminal study of the small firm size effect in the U.S. equity market, Rolf W. Banz, "The Relationship Between Return and Market Value of Common Stocks", *Journal of Financial Economics*, Vol. 9 (1981), pages 3-18. That study found that smaller firms have had higher risk adjusted returns, on average, than larger firms, that this size effect had been in existence for at least forty years, and concluded this constituted evidence that the capital asset pricing model is mis-specified.

[144] James E. Hatch and Robert W. White, *Canadian Stocks, Bonds, Bills and Inflation: 1950-1987*, The Research Foundation of the Institute of Financial Analysts, 1988. A more recent study found that, based on data covering 1950 to 2009, the small stock effect had not lessened over the decades in Canada (Stephen R. Foerster, Lionel

The table below is a summary from the most recent Ibbotson analysis of U.S. equity market returns by firm size. The study covers stocks that are traded on the NYSE, AMEX and NASDAQ. The stocks are divided into deciles, from largest to smallest. The table shows that, over the past 87 years, on average, the arithmetic average return for the largest two deciles (large cap stocks) was 2.5 percentage points lower than the returns of stocks in deciles 3-5 (mid-cap stocks).[145]

Table 31

Decile	**Market Cap Largest Company ($ thous)**	**Average Return 1926-2012 (%)**
1	626.6	10.9
2	17.5	12.8
3	7.7	13.4
4	4.2	13.8
5	2.8	14.6
6	1.9	14.8
7	1.8	15.2
8	0.8	16.3
9	0.4	16.8
10	0.3	20.6
Large cap (1-2)		**11.2**
Mid cap (3-5)		**13.7**
Low Cap (6-8)		**15.2**

Source: Morningstar, *Ibbotson SBBI, 2013 Valuation Yearbook, Market Results for Stocks, Bonds, Bills, and Inflation 1926-2012*

As shown on Schedule 25, page 1 of 2, the median U.S. utility equity market capitalization in 2012 was approximately $4.5 billion. Based on the table above, at a $4.5 billion equity market capitalization, the typical utility stock is a mid-cap stock. The average equity market return for mid-cap stocks for the post-World War II period was 14.0%,[146] compared to the U.S electric and gas utility returns for the same period of

Fogler, Stephen G. Sapp, "Northern Exposure: How Canadian Small Stock Investments Can Benefit Investors", November 5, 2011).

[145] To my knowledge, there are no corresponding data for Canada from which a similar analysis could be done.

[146] Morningstar, *Ibbotson SBBI, 2013 Classic Yearbook, Market Results for Stocks, Bonds, Bills, and Inflation 1926-2012*, Tables 7-2 and 7-4., page 102

11.4% and 12.1%, respectively shown in Table 29 above. The mid-cap stock risk premium over the bond income return was 8.2% (14.0% - 5.8%), compared to 5.6% and 6.3% for the electric and gas stocks. In other words, the achieved risk premiums for utility stocks were approximately 68% to 77% of the returns of the entire mid-cap market within which the typical utility stock falls. As such, when size is accounted for, the utility returns have been within a range consistent with their relative risk.

5.e. Historic Utility Equity Risk Premium Test Results

Recognizing the inverse relationship between utility equity risk premiums and long-term government bond yields, and giving primary weight to the Canadian data, the historic utility equity risk premium approach indicates a benchmark utility equity risk premium of approximately 6.5% to 6.75% at the forecast 4.0% 30-year Government of Canada bond yield. The corresponding utility cost of equity is approximately 10.5% to 10.75% (mid-point of 10.625%).

6. Cost of Equity Based on Equity Risk Premium Tests

The estimated benchmark utility costs of equity based on the three equity risk premium methodologies are summarized below:

Table 32

Risk Premium Test	Cost of Equity
Risk-Adjusted Equity Market	8.7% to 9.1%
DCF-Based	9.5% to 9.7%
Historic Utility	10.5% to 10.75%

E. DISCOUNTED CASH FLOW TEST[147]

1. Conceptual Underpinnings

The discounted cash flow approach proceeds from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate that reflects the risk of those cash flows. This proposition is based, in turn, on the efficient markets hypothesis, which states that the price of a stock today is determined by all of the available information about the stock. While the Dividend Discount Model, as it is now formally called, was not so named until the latter half of the twentieth century,[148] the concept of the discounted cash flow approach was first expressed in the early 20th century by Irving Fisher and later expanded on by J.B. Williams in his classic book, *The Theory of Investment Value* (Cambridge, Mass.: Harvard University Press, 1938) in which he stated:

> A stock is worth the present value of all the dividends ever to be paid upon it, no more, no less ... Present earnings, outlook, financial condition, and capitalization should bear upon the price of a stock only as they assist buyers and sellers in estimating future dividends.

The DCF test allows the analyst to directly estimate the utility cost of equity, in contrast to the Capital Asset Pricing Model (CAPM), which estimates the cost of equity indirectly. The DCF model is widely used to estimate the utility cost of equity for the purpose of establishing the allowed ROE.[149]

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[147] See Appendix C for a more detailed discussion.

[148] Myron Gordon, *The Investment, Financing and Valuation of the Corporation*, Homewood, Illinois: Irwin, 1962.

[149] The Commission noted in the *2009 ROE Decision*, page 45, "As for the two most commonly used approaches, the Commission Panel finds that the DCF approach has the more appeal in that it is based on a sound theoretical base, it is forward looking and can be utility specific."

In simplest terms, the DCF cost of equity 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[150]
$\mathbf{P_o}$	=	current price
g	=	expected growth in dividends

There are multiple versions of the discounted cash flow model available to estimate the investor’s required return on equity, including the constant growth model and multiple period models 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.

2. Application of the DCF Test

2.a. DCF Models

To estimate the DCF cost of equity, both the constant growth model and a multiple stage (three-stage) model were used. In both cases, the discounted cash flow test was applied to the sample of U.S. gas and electric utilities selected to serve as proxies for the estimation of the benchmark utility cost of equity (the same sample used in the DCF-based equity risk premium test), as well as to a sample of Canadian utilities.

2.b. Growth Estimates

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

[150] Alternatively expressed as D_o (1 + g), where D_o is the most recently paid dividend.

is, in some measure, attempting to project what returns the regulator will allow, and the extent to which the utilities will exceed or fall short of those returns. To mitigate that circularity, it is important to rely on a sample of proxies, rather than the subject company. When the subject company does not have traded shares, a sample of proxies is required.[151]

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. The constant growth model was applied to the U.S. sample using two estimates of long-term growth. The first estimate reflects the consensus of investment analysts' long-term earnings growth forecasts drawn from four sources: Bloomberg, Reuters, *Value Line* and Zacks. The second is an estimate of sustainable growth. The sustainable growth rate represents the growth in earnings that a utility can expect to achieve as a result of the ROE it is expected to earn and the proportion of the ROE it reinvests plus incremental earnings growth achievable as a result of external equity financing. The development of the sustainable growth rates is explained in detail in Appendix C.

In the application of the DCF test, the reliability of the analysts' earnings growth forecasts as a measure of investor expectations has been questioned by some Canadian regulators, as some studies have concluded that analysts' earnings growth forecasts are optimistic. That proposition can be tested indirectly. Three such tests are described in Appendix C. These tests indicate that the consensus of analysts' long-term earnings growth forecasts is not an upwardly biased estimate of investor expectations.

[151] In addition, any cost of equity estimate that relies on data for only a single company is subject to measurement error.

3. Results of the DCF Models

3.a. Results for the Sample of U.S. Utilities

The constant growth model applied to the U.S. utility sample using the consensus of analysts' long-term earnings growth forecasts indicates a cost of equity of approximately 9.0% (Schedule 18). The utility cost of equity based on the sustainable growth model is approximately 8.5% (Schedule 19).

The three-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 to migrate to the expected long-run rate of nominal growth in the economy. The three-stage DCF model is fully described in Appendix C. The three-stage model applied to the sample of U.S. utilities indicates a cost of equity of approximately 8.8% (Schedule 20).

3.b. Results for the Sample of Canadian Utilities

The constant growth and three-stage DCF models were also applied to the five major publicly-traded Canadian utilities.[152,153] The application of the constant growth model to the Canadian utilities indicated a cost of equity of approximately 10.8%,[154] see Schedule 21. The cost of equity developed using the three-stage model indicates a cost of equity of approximately 9.5%; see Schedule 22.

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[152] For the five major publicly-traded Canadian utilities, the consensus long-term earnings growth forecasts were obtained from Reuters, as it provided the highest number of analysts' forecasts for each company. There are no widely available estimates of long-term expected returns on equity and earnings retention rates from which to make forecasts of sustainable growth.

[153] In *Decision 2011-474*, para. 87, the Commission expressed concern about applying the DCF test to companies with significant unregulated activities, e.g., Enbridge Inc. However, while Canadian Utilities, Enbridge and TransCanada do have a larger proportion of unregulated activities than, for example, Fortis or Emera, from a relative risk perspective, they do not appear to be viewed as riskier either from a beta or debt rating perspective.

[154] Based on sample median, as the high forecast earnings growth rates for Enbridge Inc. and TransCanada skew the average.

3.c. DCF Cost of Equity

The table below summarizes the results of the DCF models applied to both the U.S. and Canadian utility samples.

Table 33

	Constant Growth		
	Analysts' EPS Forecasts	**Sustainable Growth**	**Three-Stage Model**
U.S. Utilities	9.0%	8.5%	8.8%
Canadian Utilities	10.8%	N/A	9.5%

Source: Schedules 18-22.

The constant growth and three-stage DCF models applied to the U.S. sample indicate a utility cost of equity of approximately 8.75%. For the Canadian utilities, the higher long-term earnings growth forecasts in conjunction with lower dividend yields lead to a wider range of DCF test results than for the U.S. utilities. Based on the mid-point of the range of the constant growth and three-stage models, the cost of equity for the Canadian utility sample is approximately 10.2%. The application of both constant growth and three-stage models to the two samples supports a benchmark utility DCF cost of equity of approximately 8.75% to 10.2% (mid-point of approximately 9.5%).

F. ALLOWANCE FOR FINANCING FLEXIBILITY AND FINANCIAL RISK ADJUSTMENT

1. Allowance for Financing Flexibility[155]

The equity risk premium tests (Section VIII.D) and discounted cash flow tests (Section VIII.E) both indicate a benchmark utility "bare-bones" cost of equity of approximately 9.6%. 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) recognition of the "fairness" principle. It has been the normal practice of Canadian regulators, including the AUC, to add an adjustment for financing flexibility to the estimated market-based utility cost of equity.

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 averaged 2.1 times from 1993-2012; the corresponding average market/book ratio of the S&P 500 was 3.0 times.[156]

At a minimum, the financing flexibility allowance should be adequate to allow a regulated company to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10 times. 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

[155] See Appendix E for a more complete discussion.

[156] The market to book ratio of the S&P 500 includes Utilities. The market to book ratio of the S&P Industrials alone has been higher.

allowance adequate to maintain a market/book in the range of 1.05-1.10 times is approximately 50 basis points.[157]

2. Financial Risk Adjustment

The cost of capital, as determined in the capital markets, is derived from market value data, and reflects a level of financial risk represented by market value capital structures. The cost of equity for the benchmark utility has been estimated using samples of proxy companies with a lower level of financial risk, as reflected in their market value capital structures, than the financial risk inherent in the book value capital structures of the utilities to which the cost of equity is to be applied. Regulatory convention applies the allowed ROE to a book value capital structure. The application of the market-derived cost of equity to the book value of equity without taking account of the higher level of financial risk than the level inherent in the proxy utilities' cost of equity will underestimate the cost of equity and the fair return.

Utilities are entitled to the opportunity to earn a return that meets the fair return standard, namely one that provides the utility an opportunity to earn a return on investment commensurate with that of comparable risk enterprises, to maintain its financial integrity and to attract capital on reasonable terms. What must be fair is the overall return on capital. The recognition in the allowed return on equity of the impact of financial risk differences between the market value capital structures of the proxy companies and the ratemaking capital structure is required to ensure the opportunity to earn a return commensurate with that of comparable risk enterprises. A full recognition of the disparity between the levels of financial risk in the market value capital structures and utility book value capital structures warrants an adjustment to the "bare bones" cost of equity of approximately 140 basis points, based on the application of three capital structure theory models (See Appendix E).

[157] Based on the DCF model as shown in Appendix E, footnote 2.

3. Adjustment to "Bare Bones" Cost of Equity

A reasonable adjustment to the "bare bones" cost of equity estimated by reference to the market-based tests is the mid-point of a range from 50 to 140 basis points, or approximately 1.0 percent. The bottom end of the range represents the addition of an allowance for financing flexibility of 50 basis points to the "bare-bones" cost of equity derived from the equity risk premium and DCF tests. The top end of the range represents the application of the financial risk adjustment as estimated based on three theories of capital structure.

This approach is similar to that taken by the National Energy Board in setting the allowed ROE for TransCanada Pipelines in *Decision RH-003-2011* when it gave weight to both direct estimates of the cost of equity and After-tax Weighted Average Cost of Capital (ATWACC) implied costs of equity. In giving weight to the latter, the NEB concluded that it is consistent with the process that would be used by private industry to set a minimum hurdle rate. Further, in setting an allowed return, particularly when considering the capital attraction and comparable investment requirements of the fair return standard, the regulator is conducting a very similar process.[158]

The benchmark utility ROE resulting from this approach is approximately 10.5%, as summarized below.

[158] In *Decision RH-003-2011*, the NEB set the ROE taking into consideration both the direct, or "bare bones" costs of equity and the costs of equity that had been adjusted for financial risk differences (ATWACC-implied). In arriving at its decision to set the allowed ROE for TransCanada at 11.5%, the NEB agreed that financial risk, while reflected in market values, is also, to some extent, controlled and adjusted by the regulator in traditional rate making by setting the regulated utility's deemed capital structure and that several factors, including financial risk, influence the market value of a firm's debt and equity. The NEB concluded that the expected ROE observable in the equity markets did not need to be increased to the extent that had been estimated by TransCanada's cost of capital experts (equivalent to Approach 1 in my Appendix E). As a result, they gave weight to both the direct estimates of the cost of equity and those that were adjusted for market value financial risk. The approach I have taken is analogous to the NEB's, although I have relied on additional capital structure theory models, as the NEB's decision suggested should be considered. As a result of relying on more than one capital structure theory model, the financial risk adjustment I estimated is smaller than indicated by the approach taken by TransCanada.

G. BENCHMARK UTILITY ROE

Based on the risk premium and discounted cash flow tests, the benchmark utility ROE is approximately 10.5%, reflecting the following:

Table 34

Summary of Benchmark Utility ROE	
Risk Premium Tests:	
Risk-Adjusted Equity Market	8.9%
Discounted Cash Flow-Based	9.6%
Historic Utility	10.625%
Discounted Cash Flow Tests:	
Constant Growth: U.S. Utilities	8.75%
Constant Growth: Canadian Utilities	10.8%
Three Stage: U.S. Utilities	8.8%
Three Stage: Canadian Utilities	9.5%
"Bare Bones" Cost of Equity	9.5%
Financial Flexibility/Financial Risk Adjustment	1.0%
Benchmark Utility ROE	10.5%

The 10.5% benchmark utility ROE is applicable to both 2013 and 2014.

IX. COMPENSATION FOR STRANDED ASSET RISK

As indicated in Section VI.B above, mainstream regulatory policy supports a utility's right to the opportunity to recover its prudently incurred costs. In the *UAD Decision* the AUC states that under-recovery or over-recovery of capital investments on extraordinary retirements is to the account of the shareholder. That decision confirms that the Alberta Utilities have been exposed to a stranded asset risk since 2011 in respect of which their relatively low allowed returns in the past did not include compensation.

The awarded returns historically have contemplated that the regulator cannot guarantee that, despite the best efforts of regulation, the utility will be able to fully recover the invested capital. Competitive conditions, including the absence of customers, may preclude setting prices at levels that will permit full recovery. This risk has frequently been termed the “death spiral”. The allowed return is intended to compensate shareholders for this risk.

In this context, the example of the TransCanada Mainline is instructive. Historically, TransCanada’s allowed returns (which were in a similar range to those allowed the Alberta Utilities) have been premised on a regulatory model that provided the Mainline a reasonable opportunity to recover its prudently incurred costs.[159] A fundamental shift in North American gas supply dynamics, resulting in material reductions in long haul throughput on the Mainline, created significant challenges for TransCanada. Had TransCanada continued to increase its tolls to recover its prudently incurred costs under the *status quo* model, a “death spiral” might have been triggered. In *Decision RH-003-2011* addressing TransCanada’s restructuring proposal, the NEB determined that, rather than disallow recovery of costs, there were alternative tools that would assist the Mainline in adapting to its new business environment, provide it with a reasonable opportunity to recover its prudently incurred costs over a reasonable period of time and to be competitive. The NEB emphasized, “In our view, we are not implementing an at-risk approach.” (page 234) Nevertheless, the NEB recognized that the Mainline’s business risk had increased materially and allowed a much higher ROE.

Accordingly, the NEB refrained from any cost disallowances for a five-year period, in order to permit the new tools to be employed. The NEB also awarded TCPL an ROE of 11.5% to compensate for increased business risk, including the risk that competitive market conditions might ultimately prevent full recovery of the capital investment in the Mainline. To put this higher ROE in context, the 11.5% awarded ROE was 180 basis points higher than the effective ROE of 9.7% at the same equity ratio (40%) awarded TQM in *Decision RH-1-2008*.

In contrast to the TransCanada decision, the AUC has assigned responsibility to shareholders for the costs of assets no longer required for the provision of utility service without additional tools to manage the increased risk. In other words, unlike TransCanada, the Alberta Utilities have been put at-risk for stranded assets. In that context, it is notable that the NEB contrasted the circumstances of the Mainline with utilities subject to the obligation to serve (e.g., the Alberta

[159] NEB, *RH-2-2004 Phase II*, page 43.

Utilities), suggesting that TransCanada had the discretion to avoid capital expenditures if the cost recovery risk was deemed unacceptable. The Alberta Utilities cannot avoid capital expenditures related to the obligation to serve and consequently, their stranded asset risk appears higher. In addition, the Commission imposed the stranded asset risk effective 2011 with no risk adjustment to the ROE, whereas TransCanada was awarded elevated returns for approximately five years prior to the issue of actual disallowances arising.

In exposing the Alberta Utilities to stranded asset risk, the AUC increased the asymmetry in the risk to which Alberta utility shareholders are exposed. In principle, a utility's ability to earn a fair return should be symmetric, i.e., there should be an approximately equal probability that it will earn above or below its opportunity cost of capital. Under rate base/rate of return regulation, rates are generally set to ensure that utilities neither materially over-earn (i.e., the upside opportunities are limited) nor under-earn (downside risk is limited) their allowed returns. With the imposition of stranded asset risk on shareholders, the likelihood that the utility will not be able to earn a compensatory return on or fully recover the invested capital increases, without any offsetting upside potential afforded.

The following example is intended to illustrate how significant asymmetric risk can be. In this example, the underlying premise is that the utility must be afforded a reasonable opportunity to earn its cost of capital, where a reasonable opportunity is synonymous with an equal probability of the return being above or below the cost of capital. For simplicity, assume that the utility cost of equity is 10%. There is a 15% probability that the utility will not recover 10% of its equity investment in rate base (of 10%). For the utility to have a reasonable opportunity to earn a 10% ROE on its equity investment in rate base, the allowed return must be equal to 11.7% (premium of 1.7 %), estimated as follows:

$$\text{Allowed Return} = \{(1+ \text{Cost of Equity})/ [1 + (\text{Probability of Loss X Loss})]\} -1$$

$$11.7\% \quad = \{(1+ 10\%)/[1+ (.15\% \text{ X } -10\%)]\}-1$$

Depending on the probabilities and the proportion of the equity investment in rate base that is at risk of being stranded and not recoverable, the indicated premium that required to allow a fair opportunity to earn the cost of equity can be very large.[160] In fact, for an individual utility, the application of the approach articulated in the *UAD Decision* could result in a major cost disallowance for which no level of allowed return could compensate. At this point in time, for the Alberta Utilities, the magnitude of the potential dollars of assets that are at risk of being stranded is of serious concern. From the equity investors' perspective, the change in the "rules of the game" raises the perceived risk to which they are exposed. The regulatory framework in Alberta has historically been viewed as supportive and regulatory risk as relatively low. The decision to expose the Alberta Utilities to a stranded asset risk represents a change in the regulatory model, corresponding to an increase in regulatory risk and an increase in the cost of equity.

However, until the potential magnitude of the risk is better defined, it is difficult to accurately estimate the **additional** risk premium that investors would require as compensation for the actual consequences of the stranded asset risk. Further, because mainstream regulatory policy is grounded in a reasonable opportunity to recover prudently incurred costs, the potential impact on the Alberta Utilities' cost of equity resulting from exposure to a stranded asset risk cannot be directly estimated by reference to publicly traded utilities that face this risk. Nor can unregulated companies be used, for two reasons: (1) unlike regulated utilities, which have the obligation to build, unregulated companies can choose not to make investments; and (2) while unregulated companies face stranded asset risk, they have upside return potential that utilities do not.

Nevertheless, the *UAD Decision* has introduced a level of uncertainty for which equity investors will require additional compensation. An indirect way of estimating a reasonable premium to the benchmark utility ROE for the increased uncertainty arising from the UAD decision is to recognize that (1) regulatory risk generally is the most important risk to investors, both debt and equity; (2) all other things equal, higher regulatory risk is likely to be reflected in lower debt ratings (or higher debt costs even if current debt ratings are maintained); and (3) the uncertainty introduced by exposing the Alberta Utilities to a stranded asset risk raises the risk of debt downgrades into BBB rating territory due to perceived weaker business profiles. BBB-rated

[160] For perspective, if there is a 25% probability that 25% of the equity investment in rate base will be stranded and to the account of shareholders, the premium to the 10% cost of equity required to provide a reasonable opportunity to earn the 10% cost of equity is 7.3% (ROE of 17.3%).

utilities thus represent reasonable proxies for estimating the premium to benchmark utility return that would take account of the regulatory uncertainty created by the *UAD Decision*. The difference between the cost of equity of BBB-rated utilities and the benchmark utility cost of equity thus represents one estimate of the premium warranted for the increased regulatory uncertainty.

With only six publicly-traded utilities in Canada in total, this estimation cannot be done using Canadian utilities as proxies. However, the utility sector in the U.S. includes a sufficient number of publicly-traded companies so as to be able to gauge the magnitude of the likely difference between the cost of equity of BBB-rated utilities and the benchmark utility cost of equity. With respect to the latter, the sample of U.S. utilities relied on to estimate the benchmark utility return is the appropriate proxy.

The BBB-rated utility group includes the 30 utilities from the universe of 55 U.S. gas distribution and electric utilities covered by *Value Line* that have debt ratings in the BBB/Baa[161] category by both Standard & Poor's and Moody's.

As the CAPM is the cost of equity model that, in theory, explicitly accounts for differences in risk, using beta as the measure of relative risk, it was used to gauge the magnitude of the ROE premium that would reasonably compensate for the increased uncertainty resulting from the *UAD Decision*.

To estimate the incremental equity risk premium, differences in betas between the BBB-rated utilities and the U.S. benchmark utility sample were examined and those differences applied to the estimated equity market risk premium. The incremental equity risk premium based on this approach is equal to:

$$\mathbf{(Beta_{BBB/Baa\ rated} - Beta_{Benchmark})\ X\ Market\ Risk\ Premium}$$

[161] BBB+/BBB/BBB- on the S&P rating scale and Baa1/Baa2/Baa3 on the Moody's scale.

The following table summarizes the betas for the benchmark U.S. utility sample and the BBB rated sample. Betas can vary significantly, not only for individual companies, but also for specific industries, depending on the period over which the beta was calculated. As a result, betas were measured over multiple five-year periods. The betas shown in the table reflect the average of five five-year monthly betas ending in each year 2008-2012. The table below shows both “raw” (unadjusted) betas and betas adjusted to the market mean beta of 1.0.[162]

Table 35

	2008-2012 Average Common Equity Ratio	Betas	
		Unadjusted	Adjusted
Means			
All Companies	45.6%	0.55	0.70
Benchmark U.S. Utility Sample	47.5%	0.40	0.60
Both Ratings in BBB/Baa Category	45.1%	0.63	0.75
Medians			
All Companies	46.0%	0.57	0.71
Benchmark U.S. Utility Sample	46.1%	0.36	0.58
Both Ratings in BBB/Baa Category	45.4%	0.60	0.74

Source: Schedule 25, page 1 of 2.

The table shows a relatively broad range of differences among the groups, largely related to whether or not the betas were adjusted. By construction, the differences between the adjusted betas for the groups are smaller than the unadjusted beta differences because the adjustment equation moves all the calculated betas toward a common (market) mean.

The average of the differences in the betas of the BBB/Baa-rated utility sample and of the benchmark U.S. utility sample was 0.20. At the 7.25% market risk premium that I estimated in Section VIII.D above, the difference in the cost of equity between the BBB-rated companies and the benchmark utility sample is close to 150 basis points.

[162] Using the standard adjustment equation: 2/3 “raw” beta + 1/3 market mean beta of 1.0.

In principle, the equity (or investment risk) betas which are presented in Table 35 above measure both business and financial risk, as does the debt rating. When there are differences in financial risk among the groups, as reflected in differences in common equity ratios, the differences in beta may not be attributable solely to differences in business risk. To ensure that the beta differences are only due to differences in business risk, the equity betas of the proxy samples should be restated at a common capital structure, thus isolating differences in equity return requirement due solely to differences in business risk. Although the differences in the samples' equity ratios were small, as indicated in Table 35 above, the observed equity betas were all restated (relevered) at the utility universe average equity ratio of 45.6%.[163]

Table 36

	Relevered Betas	
	Unadjusted	**Adjusted**
Means		
Benchmark U.S. Utility Sample	0.41	0.62
Both Ratings in BBB/Baa Category	0.62	0.74
Difference	0.21	0.12
Medians		
Benchmark U.S. Utility Sample	0.35	0.55
Both Ratings in BBB/Baa Category	0.61	0.73
Difference	0.26	0.18

Source: Schedule 25, page 2 of 2.

The average of the differences in the betas of the BBB/Baa-rated utility sample and of the benchmark U.S. utility sample, as relevered to a common equity ratio of 45.6%, is 0.19. At a 7.25% market risk premium, the associated difference in the cost of equity between the two samples is close to 140 basis points.

Based on the above estimates, and recognizing that the beta estimates are only approximations, this analysis supports an equity return for the sample of BBB/Baa-rated utilities in the range of

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[163] Each utility's 2008-2012 five-year unadjusted and adjusted equity betas were unlevered from their five-year average equity ratio to derive asset or business risk betas using the following equation, commonly called the Hamada Equation:

Asset Beta = Equity Beta / (1 + (1 - Tax Rate) * (Debt Ratio / Common Equity Ratio)

and then relevered to the universe average and median common equity ratio using the following equation:

Relevered Equity Betas = Asset Beta * (1 + (1 - Tax Rate) * (Debt Ratio / Common Equity Ratio) approximately 1.25 to 1.5 percentage points higher than the benchmark utility ROE. Consequently, I recommend that the Commission adopt an incremental equity risk premium for each of the Alberta Utilities in the range of 1.25 to 1.5 percentage points above the recommended benchmark utility ROE. This premium is intended only to represent compensation for the uncertainty that the *UAD Decision* has created. It is not intended to represent the adjustment to the ROE that would provide adequate compensation if major stranded asset related cost disallowances were to occur.

The recommended risk premium above the benchmark utility ROE is applicable to all of 2013 as well as prospectively, as the Commission had already enunciated its position on responsibility for stranded assets in *Decision 2011-474*. Even though the stranded asset risk did not crystallize during 2011 and 2012, the years covered by *Decision 2011-474*, in principle, the Alberta Utilities were exposed to, but were not compensated for, the risk. Consequently, the recommended risk premium would apply equally to 2011 and 2012.

X. EQUITY RISK PREMIUM FOR PERFORMANCE-BASED REGULATION

As discussed above in Section VI.D, the adoption of performance-based regulation for the Alberta electric and gas distribution utilities exposes them to higher business risk than cost of service regulation. The increase in business risk specifically attributable to PBR has not been accounted for in the benchmark utility ROE, nor has it been reflected in the recommended common equity ratios, and thus, requires compensation in a risk premium to the benchmark utility ROE.

The magnitude of the risk premium required for the higher risks of PBR is subject to the exercise of expert judgment, as it is not possible to precisely isolate from estimates of the cost of equity the differential attributable to differences in the regulatory paradigm.[164] Although there are

[164] Although the Alexander *et al*. study, *Regulatory Structure and Risk: An International Comparison* referenced in Section VI.D did so by reference to beta differences for companies subject to different regulatory models, it did so across countries. Hence the beta differences are potentially capturing country factors in addition to differences in regulatory models.

utilities in Canada that are or have been subject to forms of incentive regulation, none of them are stand-alone publicly-traded companies. In the U.S., the cost of service model is the primary regulatory model; there are few U.S. utilities which are subject to price or revenue caps.

As was noted earlier, it is the overall return (combination of ROE and capital structure) that must meet the fair return standard. To establish the benchmark utility ROE, a sample of relatively low risk U.S. utilities was used as proxies. In determining the benchmark utility ROE, I concluded that, to the extent the U.S. utilities had been viewed as having higher business and regulatory risk, the higher business risk was offset by lower financial risk. In other words, in estimating the benchmark utility ROE, I made no adjustment to the U.S. utilities' estimated ROE to recognize that the U.S. utilities' average common equity ratio is 48%, compared to the 41% base line common equity ratio recommended for the taxable Alberta electric and gas distribution utilities.

With the adoption of performance-based regulation, the combined business and regulatory risk of the Alberta electric and gas distribution utilities is no less than that faced by the U.S. utility sample.[165] As the financial risk of the Alberta electric and gas distribution utilities is higher than that of the U.S. utility sample, their total risk (combined business, regulatory and financial) is also higher than that of the U.S. utility sample. A reasonable risk premium to compensate for the Alberta electric and gas distribution utilities' higher total risk due to PBR can be estimated as the ROE premium that accounts for the difference between the U.S. utility sample's common equity ratio of 48% and the recommended base line 41% equity ratio for the Alberta distribution utilities. In other words, it is the premium above the U.S. utilities' cost of equity that will make the overall return of the Alberta electric and gas distribution utilities equivalent to the overall return of the U.S. utilities.

To estimate the ROE premium attributable to the adoption of PBR, the same three capital structure theory methodologies were applied as in Section VIII.F, described in Appendix E, and for which the formulas were provided in Schedule 24.

[165] Absent the incremental risk resulting from the *UAD Decision*.

Table 37 below shows the adjustments to the cost of equity required under each of the three approaches to recognize the difference in financial risk between the recommended base line common equity ratio of 41% for the taxable Alberta electric and gas distribution utilities and the U.S. utility sample's 48% common equity ratio.[166]

Table 37

Equity Ratio		**Basis Point Adjustment to ROE for Change in Common Equity Ratio Based on Approach:**		
U.S. Utility Sample Equity Ratio	Recommended Base Line Equity Ratio	1: 25% tax rate	2: 25% tax rate	3: 0% tax rate
48%	41%	95	60	70

Source: Schedule 24.

Since all the approaches have merit, it is reasonable to give weight to all three. Based on all three approaches, the indicated difference in ROE at the recommended base line 41% common equity ratio for the taxable Alberta electric and gas distribution utilities versus the U.S. utility sample's 48% equity ratio is 75 basis points.[167]

XI. AUTOMATIC ADJUSTMENT MECHANISM

As I noted in Section V above, in light of the persistently unsettled capital markets and the unstable relationships between the utility cost of equity and Government bond yields, it is, in my view, difficult to construct an automatic adjustment mechanism for return on equity at this time that would successfully capture prospective changes in the utility cost of equity. In particular, an automatic adjustment formula tied to changes in government bond yields has the potential to unfairly suppress the allowed ROE. If, however, the Commission determines, in this proceeding, that a formula is required for 2015 (and beyond), the formula that was adopted in *Decision 2004-052* needs to be revised.

[166] Based on a 9.5% "bare bones" cost of equity, a market cost of debt of 5.35% and a corporate income tax rate of 25%, equal to the combined Alberta/federal rate of 25%.

[167] Although 2014 will be a rebasing year for ENMAX Distribution, the risk associated with PBR is still present. Consequently, the premium is equally applicable to ENMAX Distribution.

The *Decision 2004-052* formula, which changes the allowed ROE by 75% of the change in forecast long-term Government of Canada bond yields, does not accurately capture the relationship that has been observed between government bond yields and the utility cost of equity. Not only did the *Decision 2004-052* formula assume that the utility cost of equity is more sensitive to changes in government bond yields than has been the case, it did not take into account any other factors that determine the utility cost of equity. Consequently, the application of the formula resulted in allowed ROEs that did not correlate properly with the utility cost of equity.

A revised formula can retain the long-term government bond yield as an adjusting variable, as long as (1) the government bond yield is supplemented with a variable which more directly captures movements in the cost of equity; (2) the sliding scale factor is a more reasonable representation of the relationship between long-government bond yields and the utility cost of equity; (3) inasmuch as the risk premium tests are premised on more normal levels of long-term Canada bond yields, it does not operate until a specified level of long-term Government of Canada bond yields is reached; and (4) the formula adopted is internally consistent with the level of the initial allowed ROE.

An obvious potential complementary explanatory variable for long-term Government of Canada bond yields in an ROE formula is the spread between long-term government and corporate or utility bond yields.[168] Since both debt and equity holders have financial claims on the same cash flows of a corporation, all other things equal, it makes logical sense that changes in a firm's cost of equity will directionally track changes in its cost of debt. As noted in Section VIII.D.4 above, corporate bond yield spreads are a widely used variable for explaining and estimating equity returns.

[168] Changes in dividend yields are another alternative. The major drawbacks of using dividend yields in a formula are: (1) there is no "preset" index of comparable companies whose dividend yields could be tracked. Stakeholders would need to agree on a sample of companies which would serve as proxies to estimate the utility cost of equity and (2) a change in dividend yield may signal a change in investor growth expectations rather than a change in the cost of equity.

As the regression analysis in Section VIII.D.4 suggests, the utility data do not permit a precise estimation of the relationships between government bond yields, utility bond yields/spreads and the utility cost of equity. Nevertheless, while the data do support the conclusion that utility ROEs are generally related to interest rates, none of the estimated relationships support a sliding scale factor for long-term government bond yields at higher than 50%. With respect to the sensitivity of the utility ROE to changes in the utility bond yield spread, the regression analyses support the conclusion that the relationship is positive, is no less than 25%, but, based on all of the data, more likely to be higher.

Given the constraints of the data, should the Commission conclude that an automatic adjustment formula is required, I recommend that it be specified as follows:

$$\begin{aligned}\mathbf{ROE_{New}} \;=\;& \textbf{Initial ROE + 50\% X (Change in Forecast 30-Year GOC Bond Yield)}\\ & \textbf{+ 50\% X (Change in Utility Bond Yield Spread)}\end{aligned}$$

This is the formula that the OEB adopted in EB-2009-0084[169] and the BCUC adopted in its *GCOC Stage 1 Decision.*[170] The key difference between the OEB's formulation and the BCUC's formulation is that, in the latter case, the formula does not operate until the yield on long-term Government of Canada bonds exceeds 3.8%. The rationale for the BCUC's trigger is that its allowed benchmark utility ROE was premised on a normalized forecast long-term Government of Canada bond yield of 3.8%, rather than the abnormally low actual yields prevailing during the proceeding. The other key difference between the two formulas is the initial utility bond yield spread from which the change is calculated. The OEB chose to use the spread that was prevailing at the time it adopted the formula. The BCUC considered that spreads were likely to contract as long-term Canada bond yields rose to more normal levels. The BCUC thus specified a spread consistent with the 3.8% long-term Canada bond yield that would trigger the operation of the formula, determined to be 1.34%.

[169] OEB, *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084*, December 11, 2009.

[170] BCUC, *In the Matter of British Columbia Utilities Commission Generic Cost of Capital Proceeding (Stage 1) Decision*, issued May 10, 2013; hereafter referred to as "GCOC Stage 1 Decision".

Under the revised formula, the forecast 30-year Government of Canada bond yield would be estimated in a similar way as it was under the EUB's original automatic adjustment formula. The forecast 30-year Canada bond yield would be estimated using the November Consensus Economics, *Consensus Forecasts* of 10-year Government of Canada bond yields plus the October actual average daily spread between 30-year and 10-year Government of Canada bond yields. The relevant corporate bond yield spreads would be calculated using the average daily spread for the month of October between the yield on the Bloomberg 30-year A-rated Utility Bond Index and the yield on the 30-year long-term Canada bond prevailing at the time of the *Consensus Forecasts*.

I recommend that the formula not begin to operate until the actual yield on the long-term Canada bond equals or exceeds the 4% on which my equity risk premium tests are based. For the initial spread from which subsequent years' changes would be calculated, I would, as the BCUC did, specify a spread that is compatible with the 4% long-term Canada bond yield. A spread of 1.35% is a reasonable spread for that purpose.

It is critical to recognize that the formula adopted has to be internally consistent with assumptions made setting the initial allowed ROE. It is perhaps obvious that it would not be reasonable to implement the proposed revised formula without resetting the allowed ROE at a level that recognizes that the ROEs that have been allowed by the AUC and its predecessors prior to and under the automatic adjustment formula adopted in the *Decision 2004-052* reflected a much greater sensitivity to changes in long-term Canada bond yields than the empirical evidence supports. Specifically, it is critical to recognize that the implementation of a 50% elasticity factor on long-term Canada bond yields is only appropriate if the allowed ROE is initially set at a level that meets the fair return standard.

From the mid-1990s until the issuance of *Decision 2009-216*, the allowed ROEs for Alberta utilities had declined by more than 75% of the decline in long-term Canada bond yields.[171] The

[171] In 1996 *Electric Tariff Applications*, *Decision U97065* (October 1997), the EUB set the allowed ROEs for the Alberta electric utilities at 11.25% at a long-term Canada bond yield of 7.75%. Pursuant to the automatic adjustment formula adopted in *Decision 2004-052*, the 2008 allowed ROE was established at 8.75% at a long-term

implementation of a formula still tied to long-term Canada bond yields and a 50% sliding scale factor would be unfair and unreasonable without recognition in the level of ROE adopted in this proceeding that the "old" formula was not operating correctly and that the allowed ROEs before and during the operation of the formula adopted in *Decision 2004-052* overstated the decline in the cost of equity.

Given the unpredictability of capital markets, there is sufficient potential for any automatic adjustment mechanism based on relatively simplistic relationships among variables to produce ROEs that deviate from a fair return. Consequently, if the AUC determines that a formula is warranted, simultaneously establishing a process for a review on a regular basis to ensure that the fair return standard continues to be met would be prudent. For example, there is no explicit measure of the comparability of the fair return built into the formula. Since the comparability of the end result lies at the heart of the fair return standard, the formula's performance would need to be monitored carefully. Establishing a process for review of the ROE and formula on a regular basis (every three to five years) would balance the objective of achieving regulatory efficiency with the obligation to establish a fair return.

While a specified schedule for review provides a safeguard to ensure that the fair return standard continues to be met, stakeholders should retain the right to seek earlier review should changes in economic and capital market conditions so warrant or should it become apparent that the automatic adjustment formula is not producing ROEs that meet <u>all</u> elements of the fair return standard (comparability of returns, ability to attract capital on reasonable terms and conditions and maintenance of financial integrity).

Canada bond yield of 4.55%. The implied elasticity factor between long-term Canada bond yields and the allowed ROE over the entire period was 78%.