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VIA EMAIL

June 8, 2012

BRITISH COLUMBIA UTILITIES COMMISSION
GENERIC COST OF CAPITAL PROCEEDING EXHIBIT A2-3

To: All Registered Parties
(*BCUC-GCOC*)

Re: British Columbia Utilities Commission
Project No. 3698659/G-20-12
Generic Cost of Capital Proceeding

Commission staff submits the following document for the record in this proceeding:

The Brattle Group (May 31, 2012) – Survey of Cost of Capital Practices in Canada
(Click here to download Appendix B of The Brattle Report)

Yours truly,

Erica Hamilton

EC/dg
Attachment

The Brattle Group

Survey of Cost of Capital Practices in Canada

Bente Villadsen
Michael J. Vilbert
Toby Brown

May 31, 2012

Prepared for

British Columbia Utilities Commission

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I. INTRODUCTION AND SUMMARY

This Survey of Cost of Capital Practices in Canada Report (Report) is prepared at the request of the British Columbia Utilities Commission (BCUC). The intention is to describe and summarize the cost of capital practices of Canadian regulatory jurisdictions. Chapter I and II of the Report describe cost of capital estimation methods, common approaches to implement the results, and the advantages and disadvantages of the various estimation methods. This section of the report is neither a comprehensive description of all such methods nor the authors' preferred methods, but rather it simply provides a description of the methods that are used in Canadian regulatory settings.

Chapter III to XV in the rest of the Report describes the methods relied upon by regulators in the following Canadian jurisdictions: British Columbia, Alberta, Ontario, Québec, Manitoba, Saskatchewan, New Brunswick, Nova Scotia, Prince Edward's Island, Newfoundland and Labrador, the National Energy Board, Northwest Territories, and Yukon Territory. Because no publicly available information was located regarding Nunavut, this jurisdiction is not included in the report. We note that not all jurisdictions are discussed using the same topic headings or the same amount of detail. There are two reasons for this. The available information differs across jurisdictions and the treatment of, for example, Crown corporations does lend itself to a standard cost of capital discussion in some jurisdictions.

Appendices A and B provide additional details of the regulatory websites that were reviewed as well as the decisions, orders, or letters relied upon in the preparation of the report. Appendix C includes a list of abbreviations and key terms used in the Report.

II. METHOD RELIED UPON TO ESTIMATE THE COST OF EQUITY CAPITAL

A. INTRODUCTION

To determine the cost of capital, a regulator must evaluate the cost of equity, the cost of debt (possibly both long-term and short-term), the cost of preferred equity and the capital structure of the company subject to regulation. Many regulators and most Canadian regulators determine the cost of the individual components of the capital structure but often deem a capital structure. To estimate the cost of common equity, it is common to select a sample of comparable companies.

The sections below describe the methodologies that Canadian regulators have used in recent proceedings.[1]

B. Models Typically Relied Upon For Cost of Capital Estimation

1. Context

The principle underlying the determination of the cost of capital for a regulated entity is the "fair return standard," which has been articulated in key decisions in Canada as well as in the U.S.[2] In *Northwestern Utilities Limited*, the Supreme Court of Canada described the fair return standard as follows:

> By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise, which will be net to the company, as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.

Based on this notion, as well as that of similar decisions by the U.S. Supreme Court,[3] cost of capital analysts typically select a group of companies that are considered to be of comparable business risk to the company being regulated and estimate the cost of capital that investors in comparable companies' expect to earn. However, the legal decisions, which provide the overarching principles, do not prescribe how to determine comparability, how to estimate the cost of capital for the comparable companies, or how to apply those estimates when setting allowable rates. The methods relied upon by various regulators and practitioners therefore differ substantially. For example, while some regulators set rates by determining the weighted-average cost of debt and equity that the regulated company should be allowed to earn on its invested capital (as a whole), others determine separately the cost of equity and possibly the percentage of equity that should be allowed in the regulated company's capital structure.

a. The cost of capital

The cost of capital is a key parameter in regulatory settings, because it contributes to determining the return to the company's investors. Defined as *the expected rate of return in capital markets*

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[1] The criterion for inclusion in this section of the report is that at least one regulator in Canada has considered the methodology, but the inclusion or exclusion of any methodology does not address the authors' views of the merits of any methodology.

[2] *Northwestern Utilities Limited v. City of Edmonton* (1929) (*Northwestern Utilities*) is the landmark Canadian decision.

[3] *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia et al.* (1923) and *Federal Power Commission v. Hope Natural Gas* (1944) are the key U.S. decisions.

on alternative investments of equivalent risk, it is the expected rate of return investors require based on the risk-return alternatives available in competitive capital markets. Stated differently, the cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk.[4, 5]

b. Regulation and the cost of capital

In Canada, utilities are regulated on a cost-of-service basis.[6] In cost-of-service regulation, rates are set to recover costs including the cost of capital.

It has become routine in rate regulation to accept the "cost of capital" as the right rate of return to target. Setting and achieving a fair return helps ensure that the regulated company has access to capital for maintaining and expanding utility infrastructure, as needed, yet does not charge customers more than is required. Thus, the regulated company is entitled to receive the return of its invested capital and to expect to earn a fair return on the invested capital.

c. What should we expect from models?

It is useful to recognize explicitly at the outset that models are imperfect. All are simplifications of reality, and this is especially true of financial models. Simplification, however, is also what makes them useful. By filtering out various complexities, a model can illuminate the underlying relationships and structures that are otherwise obscured. After all, while a perfect scale model representation of the city might be highly accurate, it would make a poor road map. Nevertheless, the gap between financial models and reality can sometimes be quite significant (as was painfully demonstrated by the recent financial crisis). There is no single, widely accepted, best pricing model to estimate the cost of capital – just as there is still no consensus on some fundamental issues, such as the Efficient Market Hypothesis.[7] Analysts have a dizzying array of potential models at their disposal, and it must be acknowledged that cost of capital

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[4] "Expected" is used in the statistical sense: the mean of the distribution of possible outcomes. The terms "expect" and "expected" in this Report, as in the definition of the cost of capital itself, refer to the probability-weighted average over all possible outcomes.

[5] The cost of capital is a characteristic of the investment itself, not the investor.

[6] Some jurisdictions also operate with versions of incentive based regulation.

[7] The Efficient Market Hypothesis (EMH) says that stocks prices very rapidly reflect available information. There are different versions of the EMH that relate to the specific definition of information considered. For example, weak form efficiency suggests that each security's price reflects the information contained in that security's price history. Semi-strong efficiency would suggest that all publicly available information is reflected in security prices. The market turmoil from the recent credit crisis generated considerable debate about whether the EMH has any validity.

estimation continues to be as much art as it is science. The generally recommended "best practice" is therefore to look at a totality of information from alternative methodologies.

While no model is perfect, there are certain features that make models more useful from a regulatory perspective. For example, it is desirable to have models and methods that i) are consistent with the goal being pursued, ii) are transparent, iii) minimize the use of judgmental factors, iv) produce consistent results, v) are robust to small deviations or sampling error, vi) are as simple as possible (while maintaining reliability), vii) can be replicated by others (*e.g.,* data is widely available), and viii) recognize the regulatory context and legislative requirements in which the regulatory body operates. Clearly different models will satisfy these criteria to differing degrees, and different models may be better suited to different regulatory jurisdictions.

The Capital Asset Pricing Model (CAPM), for example, has a transparent and well-explored economic theory underlying it. Its results can be replicated easily, since the data required are widely available from many public sources. Implementing the CAPM, however, requires a number of subjective decisions – decisions which can be hotly contested and can lead to significantly different results.

Conversely, the Discounted Cash Flow (DCF) model can be relatively objective to implement in its simplest form, although the required data on growth rates may be difficult to cross-check in publicly available datasets. Moreover, the DCF model is highly sensitive to the growth rate estimates, which can vary widely among analysts, and that variation may increase in times of greater economic uncertainty. As such, the reliability of DCF methods can be questionable in times of economic turmoil or when an industry is in transition. These reliability concerns are further exacerbated by the extent of simplification underlying the constant growth version of the DCF model. For example, assuming that cash flows will grow at a constant rate into the infinite future is a gross simplification and makes the model highly sensitive to the growth rate assumption. If five-year growth rate forecasts are used as the constant growth rate, as is often the case, then the reliability of the model can be significantly reduced in periods of abnormally high or low growth. Moreover, the results of applying the methodology can be unstable over time, leading to rapid shifts from high cost of capital estimates to low ones. Some of this sensitivity can be mitigated in the DCF framework by adjusting the growth path more realistically, but this then opens the DCF model to some of the same subjective parameter concerns raised in implementing the CAPM.

Like the CAPM and the DCF model, the difficulties in relying on the risk premium or comparable earnings models also lie in their implementation. For example, the risk premium model requires that the analyst decide the benchmark against which to measure the premium, and the comparable earnings model requires that the analyst select a comparable sample, determine a time horizon over which to implement the model, etc. These choices necessarily involve subjective judgments.

d. Model stability and robustness

For an estimation model, stability and robustness over time are desirable. Stability means that cost of capital estimates done in similar economic environments should be similar, not only period-to-period but also company-to-company within a comparable sample. Robustness is meant here as the ability of a model to estimate the cost of capital across different economic conditions.

In general, all of the models discussed here have characteristics that make them more or less suited to one economic environment versus another. As such, all individual models can be, and often are, subject to some instability over time. For example, beta estimates for utilities were very close to zero in the aftermath of the 2001 tech collapse, suggesting a near risk-free rate of return for these securities – less than their individual costs of debt in many cases! During the early 2000s, the DCF model was subject to substantial criticism due to allegations of analysts' optimism bias. Similarly, the risk premium model has produced very different results in times of high and low inflation that did not necessarily reflect the true cost of capital. Thus, estimates at any given point of time may seem too high or too low, and it is important to understand whether the estimated figures are driven by actual changes in the systemic risk of the regulated entities or something else (*e.g.,* data irregularities). It is for these reasons that analysts typically rely on the results from at least two estimation models.

2. Risk-Return Tradeoff

a. Asset pricing principles

At its most basic level, an asset (security) is a claim to a stream of future (risky) cash flows and sometimes with potential rights to exert some control over those flows.[8] Financial markets allow investors to exchange these claims, and therefore risks. Through trade, investors are able to

[8] Cost of capital estimation models are also called asset pricing models because the price of an asset reflects the discounted present value of its claim to future cash flows where the discount rate is the cost of capital.

create different packages of risks and returns than could be achieved by holding individual securities (or fixed packages of securities), and investors can change their risk exposure over time. Because investors are assumed to be risk averse, they evaluate the universe of risky investments on the basis of a risk-return trade-off. Investors can only be induced to hold a riskier investment if they expect to earn a higher rate of return on that investment.[9]

The presence of a market underlies the "opportunity cost" interpretation of cost of capital – by investing in a security A, an investor foregoes (some) investment in an alternative, "comparable risk," investment B obtainable through the market. The risk-return tradeoff leads to the questions of what makes two investments comparable in terms of risk, and once comparable risk investments have been identified, how does one measure their expected returns? These problems lie at the core of asset pricing theory. Without more structure, the potential relationships between prices, risks, expected returns, etc. can take an overwhelming number of configurations. The "no free lunch" assumption, however, provides for a simple and robust pricing framework.[10]

No free lunch

The most basic assumption typically made in asset pricing is that you "cannot get something for nothing – there is no free lunch." Although there can be (and probably will be) moments where this premise is violated, such occurrences are not likely to last very long, and they cannot represent a state of equilibrium. If investors prefer more to less, they will quickly invest in such opportunities, driving prices up in the process and eradicating the free-lunch. As such, most economists are comfortable starting with the assumption that markets admit no free lunches, or in more formal terms, no arbitrage opportunities. Arbitrage is defined as the ability to purchase one security and simultaneously to sell another to gain a risk-free profit.

Assuming no-arbitrage imparts a remarkable amount of structure on asset prices and returns. In particular, it ensures the existence of the market's minimum variance frontier and the security market line that underlie the CAPM. The insight here is that when security returns are positively correlated (i.e., have a tendency to move in the same direction, to some degree), trade in capital

[9] We assume throughout that markets are frictionless and participation is not constrained. A frictionless market is one without credit constraints (i.e., everyone can borrow as much as desired at the risk-free rate), where goods and services are bought and sold without outside interference from commissions, fees, taxes, and so forth. In a frictionless market, the only factors affecting a price are the supply and the demand of the good or service. It is impossible for a completely frictionless market to exist, but it serves as the standard benchmark in economic research.

[10] Robust in this context means that the model is not disrupted due to violations in the assumptions underlying the development of the model.

markets allows investors to reduce their total risk exposure by holding portfolios, which serve to diversify the risk of the individual securities.[11] Diversification permits investors to obtain lower variance for a given expected return or a higher expected return for a given level of variance, where variance of returns over time is a measure of risk. This essential tradeoff between the risk and the cost of capital is depicted in **Figure 1** below.

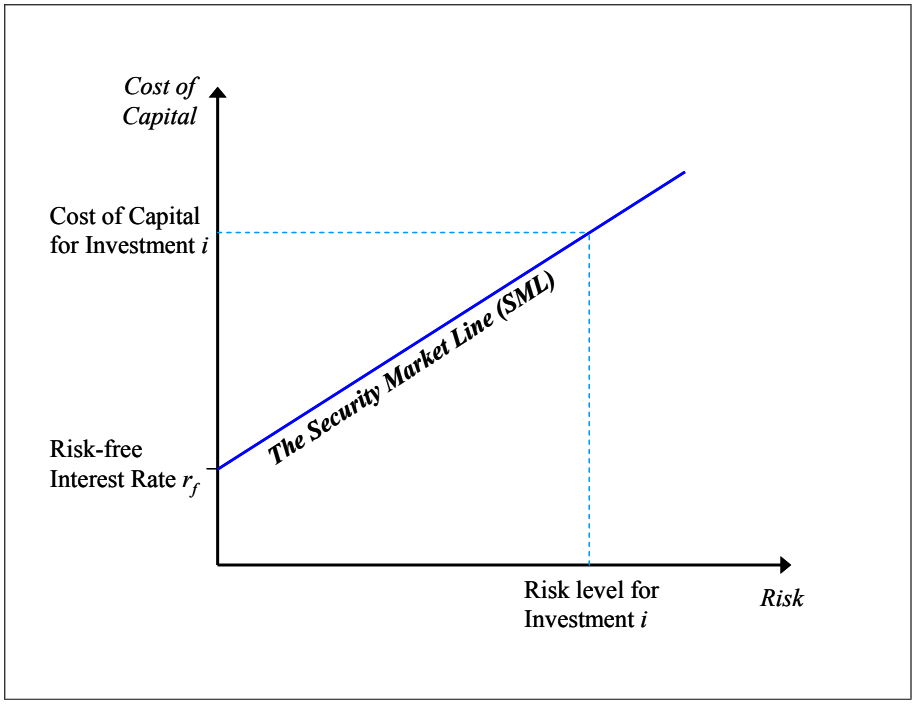

Figure 1: The Security Market Line

3. Pricing Models Traditionally Used by Regulators

This section discusses the theoretical basis of the pricing models traditionally used by regulators. The implementation issues are discussed in Section II.C.

a. CAPM

One of the most common pricing models used in business valuation and regulatory jurisdictions is the Capital Asset Pricing Model (CAPM), which in its simplest form is depicted in **Figure 2** below.

[11] Harry Markowitz received the 1990 Nobel prize in economics for his work investigating the efficient frontier.

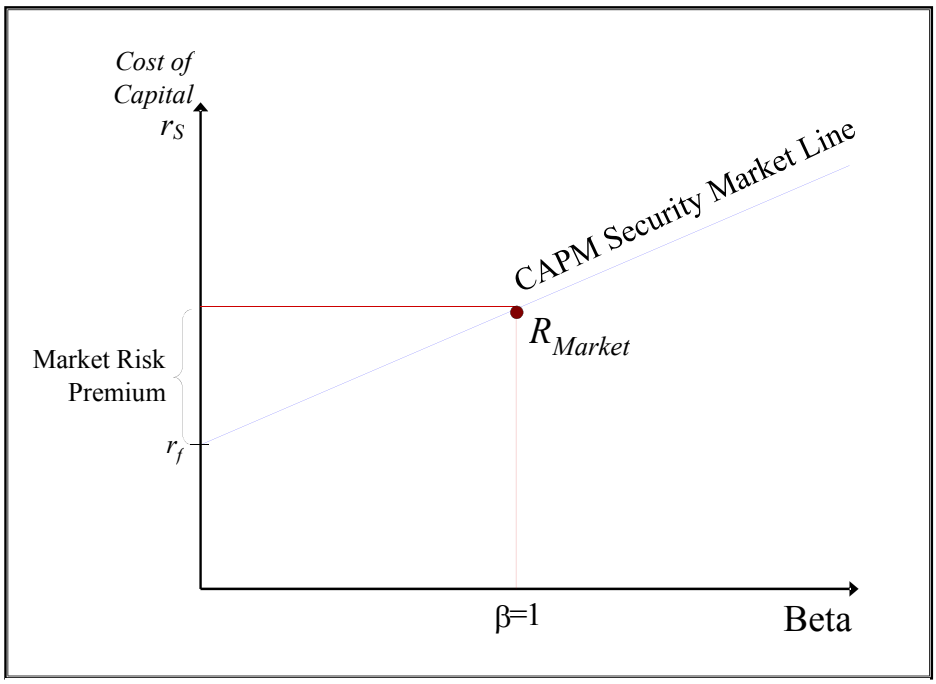

Figure 2: Capital Asset Pricing Model

Thus, in the world in which the CAPM holds, the expected cost of (equity) capital for an investment is a function of the risk-free rate, a measure of systematic risk (beta), and an expected market risk premium (MRP):[12]

$$E(r_S - r_f) = \beta_S \times E(r_M - r_f) \quad \textbf{(1)}$$

where r_s is the cost of capital for investment S; r_M is the return on the market portfolio, r_f is the risk-free rate, and β_S is the measure of systematic risk for the investment S. The $(r_M - r_f)$ term is known as the market risk premium (MRP) or the equity risk premium (ERP).[13] β_S measures the response of the stock S to systematic risk. Re-arranging this equation produces the CAPM's formula for the cost of (equity) capital of a traded asset:

$$r_S = r_f + \beta_S \times MRP \quad \textbf{(2)}$$

The CAPM has gained much of its popularity due to its insights, its theoretical underpinnings, and its simplicity to implement. Although the specific assumptions underlying the CAPM are never met exactly in practice, it is typically viewed as a reasonable model, especially for markets that are relatively "sophisticated." In other words, sophisticated markets are those that are large (many buyers and sellers) and have efficient trading and clearing mechanisms (*e.g.,* electronic),

[12] While the CAPM model frequently is applied to equity capital, it applies to all assets.

[13] Throughout this paper we use MRP and ERP interchangeably to refer to the same concept. To be consistent with the terminology used by the different regulators, we use MRP or ERP in various places.

where pricing is transparent and readily available, where short-selling mechanisms are in place, where capital flows are not overly restricted, and where regulations to support the market institution and protect property rights are in place and enforced. The Toronto Stock Exchange (TSX) certainly satisfies these traits to a degree that makes CAPM modeling applicable.

To implement the CAPM, it is necessary to determine the risk-free rate, r_f, and to estimate the MRP and beta, β_s. Principles guiding the determination of these values are provided in *Section II.C.*

b. DCF model

Although there are several versions of the DCF model, all versions determine today's stock price as a sum of discounted cash flows that are expected to accrue to shareholders. Assuming that dividends are the only type of cash payment to shareholders, the pricing formula becomes:

$$P_t = \frac{E_t(D_1)}{(1+r_s)} + \frac{E_t(D_2)}{(1+r_s)^2} + \frac{E_t(D_3)}{(1+r_s)^3} + \cdots \tag{3}$$

where "P_t" is the market price of the stock; "D_i" is the dividend cash flow at the end of period i; "r_s" is the cost of capital of asset/security s (as before); and the sum is into the infinite future.[14] The formula above says that the current stock price is equal to the sum of the expected future dividends, each discounted for the time and risk between now and the time the dividend is expected to be received – with the cost of capital r_s as the appropriate discount rate.

If the dividend growth is constant, then we obtain the standard Gordon growth model[15] or constant growth DCF:

$$P_t = \frac{D_0 \cdot (1+g)}{(1+r_s)} + \frac{D_0 \cdot (1+g)^2}{(1+r_s)^2} + \frac{D_0 \cdot (1+g)^3}{(1+r_s)^3} + \cdots \tag{4}$$

which reduces to:

$$P = \frac{D_0 \times (1+g)}{(r_s - g)} \tag{5}$$

Re-arranging then gives the standard, single-stage DCF formula for cost of capital:

[14] With the convention that if an asset has an expected finite life to time T, D_i is zero for periods i greater than T.

[15] Named after Myron J. Gordon, who published an early version of the model in "Dividends, Earnings and Stock Prices," *Review of Economics and Statistics*, Vol. 41, 1959.

$$r_s = \frac{D_O \times (1+g)}{P} + g \tag{6}$$

This equation says that the cost of capital equals the expected dividend yield (dividend divided by price) plus the (perpetual) expected future growth rate of dividends. As is readily seen from Equation (6) above, an implementation of the constant growth DCF requires a determination of the current stock price, current dividends, and the applicable growth rate.

If the assumption of constant growth is not considered reasonable for several years before settling down to a constant rate, variations of the general present value formula can be used instead. For example, if there is reason to believe that investors do *not* expect a steady growth rate forever, but rather have different growth rate forecasts in the near term (*e.g.,* over the next five or ten years) converging to a constant terminal growth, these forecasts can be used to specify the early dividends in Equation (3). Once the near-term dividends are specified, Equation (5) can be used to specify the share price value at the end of the near-term (*e.g.,* at the end of five or ten years), and the resulting cash flow stream can be solved for the cost of capital using Equation (6). A standard "multi-stage" DCF approach solves the following equation for r:

$$P = \frac{D_1}{(1+r_s)} + \frac{D_2}{(1+r_s)^2} + \ldots + \frac{D_T + P_{TERM}}{(1+r_s)^T} \tag{7}$$

The terminal price, P_{TERM} is just the discounted value of all of the future dividends after constant growth is reached:

$$P_{TERM} = \frac{D_T(1+g_{LR})}{(r_s - g_{LR})} \tag{8}$$

where T is the last of the periods in which a near term dividend forecast is made, and g_{LR} is the assumed long-run growth rate. The implementation of the multi-stage growth model requires in addition to a current price and current dividend, the selection of growth rates for each stage of the model and a determination of the length of each period.

c. Risk premium approaches

Some regulators use a simplified version of the CAPM, the so-called risk-premium approach, which is also called the equity risk premium model, to estimate the cost of equity for regulated entities. It is sometimes used as the primary tool or as one of several methods depending on the regulator. The risk premium method is related to the CAPM in that it determines the regulated

entity's cost of equity as the sum of the return on a benchmark debt instrument and a risk premium relative to that debt instrument. Like the CAPM it recognizes the risk-return tradeoff and determines the cost of equity capital as the sum of the cost of debt plus an equity risk premium. Thus, the risk premium approach calculates the cost of equity, r_S, as:

$$r_S = r_D + \text{ estimated risk premium} \tag{9}$$

where r_D is the return on a selected debt instrument. There are many versions of this model depending on the choice of the debt instrument, r_D, and the estimation of the risk premium. *Section II.C* discusses common approaches to selecting the debt instrument and for estimating the risk premium.

d. Comparable earnings

Among the traditional approaches to cost of capital estimation is the comparable earnings method. The comparable earnings methodology does not have a financial economics foundation. Neither the Canadian nor the U.S. Supreme Courts identified any specific methodology to determine a "fair return,"[16] but the legal decision, *Federal Power Commission v. Hope Natural Gas* (1944) is often cited in the use of comparable earnings. The decision stated that

> … the return to the equity owner should be commensurate with returns on investment in other enterprises having corresponding risks.[17]

The steps in the comparable earnings approach include (i) selecting a group of *unregulated* companies of comparable risk, (ii) calculating the average accounting return on book equity over an appropriate time period, and (iii) adjusting the result for any differences in risk between the regulated entity and the comparable companies. These steps require the analyst to make choices regarding each of the above three steps.

Common choices to implement the model are discussed in *Section II.C* below.

C. Estimation Implementation Issues

1. Evaluation Criteria

This section discusses implementation issues for the models relied upon among regulators and focuses on the pros and cons of the various methods. While the evaluation criteria for models

[16] The fair return standard focuses on the allowed rate of return being "fair" (*e.g.,* the outcome) and not the process used to arrive at the return.

[17] *Federal Power Commission v Hope Natural Gas Company*, 320 U.S. 391 (1944).

are not universally agreed upon, the following is a set of criteria that practitioners in the field have used in the past.

- Reasonable
  - Be consistent with the objective being pursued – namely to provide regulated utilities with a fair and reasonable return;
  - Be transparent by relying as much as possible on a formula/structured methodology and by minimizing the use of judgmental factors;
- Reliable
  - Be based upon auditable information;
  - Produce consistent results for like conditions;
  - Be robust, and reasonably sensitive, to a broad range of economic/financial conditions;
- Pragmatic
  - Be based upon readily available information or information that can be obtained with minimal costs; and
  - Be simple to implement for interested parties.

The remainder of this section is organized as follows: *Section II.C.2* discusses a few generic principles related to cost of capital estimation*, Sections II.C.3* through *II.C.6* focus on the four most commonly used cost of capital estimation methods, *Section II.C.7* discuss methods that Canadian regulators have used to look at differences in financial risk.

2. Context and Generic Issues

Regardless of the cost of equity estimation method that is used to estimate the cost of capital, there are some key elements of the cost of capital estimation process that must be addressed. This section discusses some of these issues although the treatment is far from complete.

First, most Canadian regulatory agencies rely on a "comparable sample" to determine the cost of equity for the regulated entity, so it becomes important to determine what is meant by comparable.[18] Although the selection of comparable companies is method and context specific,

[18] A comparable sample can be used to assess the cost of capital for the regulated entity by (i) estimating the individual companies' cost of capital and placing the regulated company's cost of capital in relation to the sample using the average, median, range, or other measure to assess the cost of capital or (ii) using a portfolio approach, where the cost of capital for the portfolio of companies (rather than individual companies) is estimated to assess the cost of capital for the regulated entity.

it is generally viewed as ideal to have sample companies with business risk similar to the regulated company. Similar business risk generally implies selecting companies in the same line of business. Most researchers and practitioners rely on additional criteria to exclude sample companies that have the potential to bias the cost of capital estimation methodologies. For screening, it is preferable to rely on objective information from publicly available data sources; however, the determination of exactly which criteria to use is subject to the constraint that the sample be "large enough." This, in turn, requires a determination of which criteria are the most important from the many possible criteria that could be considered. Among the criteria typically employed are combinations of the following:

- Include companies with similar business risks (*e.g.,* companies in the same or similar industries);
- Exclude companies that face financial distress;
- Exclude companies that are or have recently been involved in substantial merger and acquisition activity;
- Exclude companies with unique circumstances that may bias the cost of capital estimation (*e.g.,* restatements of financial statements); and
- Exclude companies with insufficient data.

There is, however, controversy about how to implement the criteria above. Each element of the sample selection criteria requires some judgment. For example, what size sample is "large enough"? Should the sample include both Canadian and foreign companies? How is financial distress measured? How is "substantial merger or acquisition" activity to be defined? The selection criteria are interrelated, because selection of the sample based upon one criterion may immediately reduce the potential sample to a small number of companies. The sample selection process is, therefore, a balancing act between selecting a sample that is "more comparable" and one that is "too small." The analyst must decide which criteria are most important and are likely to result in as accurate an estimate of the cost of capital as possible without leaving a sample that is small.

Second, regulators must decide how the components of the cost of capital will be determined. For example, regulators can estimate (1) the cost of debt, the cost of equity and the regulatory capital structure, each separately or (2) an overall cost of capital to be applied to the rate base or (3) a combination of these. Another component of the cost of capital is the allowance for income taxes. Because the dollar amount that accrues to the investors in the regulated entity ultimately

depends on not only the allowed cost of equity and the size of the rate base but also on the relative share of equity and debt in the capital structure, it is important to consider the overall impact of the decisions on the individual components. Specifically, it is important to note that cost of equity estimation models provide estimates that reflect both the underlying business risk of the assets but also the financial risk inherent in how those assets have been financed.

3. CAPM Implementation Issues

Fundamentally, an analyst using the CAPM must determine three parameters to implement the model: the risk-free rate (r_f), the Market Risk Premium (MRP), and the asset's beta (β_s) as shown in the CAPM equation below.

$$r_S = r_f + \beta_S \times MRP \tag{10}$$

Through the determination (or estimation) of the parameters on the right-hand side in Equation (10), the analyst obtains an estimate of the cost of equity, r_s. Despite its theoretical elegance, implementation presents a number of challenges primarily because the CAPM was developed as a two-period, partial equilibrium model not as a multi-period model. Thus, the theory provides little guidance as to how it should be implemented in a multi-period world.

a. Common practices in Canada

The Risk-free rate

It is common among Canadian regulators to rely on a forecasted yield on long-term Canadian Government bonds. The federal National Energy Board (NEB) and the provincial regulators often rely on forecasts from *Consensus Forecasts*,[19] when determining the risk-free rate. Commonly, the forecasted yield on 10-year government bonds is used with an amount added for the maturity premium needed to get to a 30-year bond. [20]

The Canadian Market Proxy

The S&P/TSX composite (total return) index is often used as the market proxy. If U.S. companies are included in the proxy group, a U.S. market proxy such as the S&P 500 is often used as the market proxy for those companies.

[19] *Consensus Forecasts* is provided by Consensus Economics, which surveys more than 250 economists monthly and based on their survey provides forecasts for the Canadian 3-month and 10-year government bond rate. *Consensus Forecasts* is published monthly.

[20] Reliance on the current spreads between 10-year and 30-year government bond yields implicitly assumes that the spread has been constant during the time over which the MRP was determined.

While broader indices seem more compatible with the theoretical CAPM on a technical level, lack of easy access to data or lack of regular trading activity may make such an index less desirable. For example, some stocks trade infrequently, raising questions as to whether or not the last recorded price data truly reflects the value at which a willing buyer and seller would exchange the security.[21]

The Canadian MRP

A standard for many years was to estimate the MRP from an arithmetic average of historical realized MRPs. In Canada, the frequently used data from the Canadian Institute of Actuaries estimated the MRP by looking at the year-over-year excess of the S&P/TSX total return over the corresponding treasury rate: 3-month Canadian Treasury bill (short-run CAPM), or long-term Canada bond total return (long-run CAPM). Standard practice in the academic literature and among valuation practitioners is to use the income return (i.e., bond coupon payment dividend by bond price) on long-term bonds as opposed to the total return, because the total return includes capital gains or losses which are not risk-free.[22] The historical average of realized MRP is an unconditional version of the MRP.[23] Using the longest period available, Credit Suisse reports an arithmetic MRP of 5.5% over government bills and 5.0% over government bonds.[24]

Evidence from a survey of Canadian economists has placed the Canadian MRP in a similar range. For example, Fernandez (2009) and Fernandez, Aguirreamalloa and Corres (2011) find that Canadian professors, responding to the survey, placed the MRP at 5.4 percent (on average) in 2008 and at 5.9 percent in 2011.[25]

Beta Estimation

Beta estimates are provided by many data services for Canadian, American and other traded companies. The most common methodology to estimate betas is to use the most recent five

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[21] No market proxy is perfect for the CAPM. The market in the theoretical version of the CAPM includes all assets (art, real estate, bonds, etc.); not just stocks. This is an important insight from Professor Richard Roll, now often called "Roll's Critique" (R. A. Roll, "A Critique of the Asset Pricing Theory's Tests," *Journal of Financial Economics*, 4, 1977, pp. 129-176.

[22] See, for example, Morningstar, "*Ibbotson SBBI 2010 Valuation Yearbook*," pp. 55-56.

[23] Unconditional MRP means that the MRP for the coming period is estimated without regard to current economic conditions or other current factors.

[24] Credit Suisse, "*Global Investment Returns Sourcebook 2012*," Tables 9 and 10.

[25] P. Fernandez, "Market Risk Premium Used By Professors In 2008: A Survey With 1,400 Answers," IESE Working Paper WP-796, University of Navarra, May 2009, and P. Fernandez, J. Aguirreamalloa and L. Corres, "US Market Risk Premium Used in 2011 by Professors, Analysts and Companies: A Survey with 5,731 Answers," SSRN April 2011.

years of weekly or monthly return data. These betas may then be adjusted towards one as an adjustment for sampling reversion that was first identified by Professor Marshal Blume (1971, 1975).[26]

Ignoring dividends and using weekly data, the raw beta is computed as follows. First, determine the weekly return from price data on both the stock in question and the market index:

$$r_{t+1} = (p_{t+1} - p_t)/\, p_t \tag{11}$$

where r_{t+1} is the return in period (t+1) and p_t denotes the stock price in period t. Second, taking the difference between each of the two returns series (security and market) and the risk-free rate provides the two realized excess return series that are needed for the CAPM regression. It is common to include a constant term in the regression, so that the regression equation is

$$(r_S - r_f) = \alpha_S \; + \beta_{S,raw} \times (r_M - r_f) + \varepsilon_S \tag{12}$$

where r_S, r_f, and r_M are the return on the stock in question, the risk-free rate and the return on the market, respectively; α_S is a constant, β_S is the beta coefficient and ε_S is an error term. In other words, the regression allows for a non-zero constant in the equation.[27] Third, estimate the raw beta, β_{raw} by ordinary least squares. Fourth, potentially adjust the raw beta estimate using Blume's adjustment procedure:

$$\beta_{adjusted} = \tfrac{2}{3} \cdot \beta_{raw} + \tfrac{1}{3} \cdot 1 \tag{13}$$

Although it is common to estimate betas from a regression using the most recent five years of return data, the justification for doing so is more practical than theoretical.

b. Implementation issues

Long-run versus Short-run CAPM

The CAPM is typically implemented using either a long-term risk-free interest rate or a short-term risk-free interest rate. Using short-term Treasury bills as the risk-free asset seems most in line with the traditional CAPM – the return on Treasury bills is the closest to a truly risk-free rate

[26] M.E. Blume, "On the Assessment of Risk," *Journal of Finance* 26, 1971, pp. 1-10 and M.E. Blume, "Betas and Their Regression Tendencies," *Journal of Finance* 30, 1975, pp. 785-795.

[27] There are multiple alternative specifications of the regression equation including versions where the constant term is forced to equal zero (as is the case in the theoretical version in Equation (1), versions where the excess return is measured using total returns (*e.g.,* including dividends) rather than price returns, etc.

of return, and the shorter horizon is closer to the 2-period nature of the CAPM. However, it has become common in regulatory settings to implement a long-term version of the model using a long-term government bond yield as the risk-free rate and an MRP relative to the long-term bond yields. There are several justifications given by analysts and regulators for using the long-term version of the model. One is that regulated rates are set periodically, which means that current cost of capital estimates will determine rates for a relatively long period (potentially years). Estimates must therefore be seen to be reasonable (on an expected basis) over the entire period. Short-term rates are a tool of monetary policy and are much more affected by efforts of a country's central bank to alter economic activity than long-term rates. As a result, short-term rates are more volatile. Cost of equity estimates based on short-rates could therefore change rapidly over the course of a few months.

MRP Estimation Issues

The magnitude of the MRP has been and continues to be the subject of debate, because the MRP is not observable, but it has a significant impact on estimates. Other parameters such current or forecasted bond yields are observable, so there is much less controversy regarding their estimates. Moreover, there is significant divergence of opinion on the MRP in both academic and practitioner circles. There is no consensus on either the magnitude of the MRP or even how it should be estimated.[28]

A number of methods for estimating the MRP exist, but the four general categories of estimates are those based on (1) averages from historical data, (2) conditional estimates, (3) survey data, and (4) a so-called "Supply Model" to derive the MRP implications of expected productivity in the real economy.

Historical Average MRP

In his presidential address to the American Finance Association in 2001, Professor Constantinides, of the University of Chicago, sought to estimate the unconditional equity premium based on average historical stock returns.[29] (Note that this address was based upon evidence just before the major fall in market value in that time period, the Tech Bubble period.)

[28] Some confusion over the MRP is due to lack of clarity as to which MRP is being discussed. It is important to specify whether the MRP is for use in the long-term or short-term version of the CAPM, whether the estimate is based upon an arithmetic or geometric average of realized returns, and whether the MRP is an unconditional estimate or a conditional estimate.

[29] G.M. Constantinides, "Rational Asset Prices," *Journal of Finance* 57, 2002, pp. 1567-1591.

Professor Constantinides adjusted the average historical stock market returns downward by a fraction of the increase in the price-earnings ratio. If there is no change in valuations in an unconditional state, this adjustment will capture the unconditional return on the stock market and the difference between the adjusted return and the risk-free rate measures the MRP. His estimates of the U.S. MRP for 1926 to 2000, and 1951 to 2000 were 8.0 percent and 6.0 percent, respectively, over the 3-month T-bill rate. In another published study in 2001, Professors Harris and Marston use the DCF method to estimate the market risk premium for the U.S. stocks.[30] Using analysts' forecasts to proxy for investors' expectation, they conclude that over the period 1982-1998 the U.S. MRP over the long-term risk-free rate is 7.14 percent. Another line of research was pursued by Steven N. Kaplan and Richard S. Ruback (1995),[31] who estimated the U.S. MRP by comparing published cash flow forecasts for management buyouts and leveraged recapitalizations over the 1983 to 1989 period against the actual market values that resulted from these transactions. One of their results is an estimate of the market risk premium over the long-term Treasury bond yield that is based on careful analysis of actual major investment decisions, not realized market returns. Their median estimate is 7.78 percent and their mean estimate is 7.97 percent.[32]

Estimation Window

The first decision is over what period to average excess returns.[33] Some argue that returns over more recent periods are likely to be a better measure of investor expectations going forward, because the economy and capital markets have evolved so much over time. Alternatively, some argue that using the historical arithmetic average of excess returns going back as far as possible provides data spanning many different economic environments and therefore provides the best measure on an unconditional basis (albeit not necessarily on a conditional basis).

Geometric vs. Arithmetic Mean

A debate sometimes arises in regulatory settings as to whether a geometric or arithmetic historical average should be used to estimate the unconditional MRP. Since the difference can

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[30] R. Harris and F. Marston, "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," *Journal of Applied Finance* 11, 2001, pp. 6-16.

[31] S. N. Kaplan and R.S. Ruback, "The Valuation of Cash Flow Forecasts: An Empirical Analysis," *Journal of Finance*, 50, September 1995, pp. 1059-1093.

[32] *Ibid*, p. 1082.

[33] "Excess returns" are the returns on the market index in excess of the measure of the risk-free interest rate.

cause a one to two percentage point difference in estimates, it is important to regulators, customers and investors.

The arithmetic average of historical market returns is calculated by the standard formula:

$$\text{Arithmetic mean } r_M = \frac{1}{T}\sum_{t=1}^{T} r_{M,t} \tag{14}$$

where $r_{M\,t}$ is the realized annual return on the market index, adjusted to match the return horizon of the risk-free rate being used, and T, is the number of periods used for the calculation. The geometric average is obtained as:

$$\text{Geometricmean } r_M = \left(\frac{P_{M,T}}{P_{M,0}}\right)^{\frac{1}{T}} - 1 \tag{15}$$

where $P_{M,T}$ is the value of the market index with reinvested dividends. It can be shown that the geometric mean is less than the arithmetic mean, and if returns have certain statistical properties, the relationship between the two is given as: [34]

$$\text{Arithmetic Mean} \approx \text{Geometric Mean} + \tfrac{1}{2} \times \text{std. deviation of returns.}$$

Generally speaking, the geometric mean is a backward looking measure of performance – that is, it provides a measure for comparing past performance across different securities or portfolios.[35] Many economists therefore find that from a forward-looking cost of capital perspective, the arithmetic mean is more appropriate, since it reflects the expected value of future returns.[36] Specifically, compounding the arithmetic return over a number of periods gives the expected compound return over those periods, but compounding the geometric mean does not.

Some financial economists, however, have suggested that this line of reasoning is flawed when returns are mean reverting; *i.e.*, exhibit negative correlation between consecutive periods. When such is the case, the expected return may differ from the historical returns and the arithmetic mean no longer provides an accurate measure of the expected return. The reason for this

[34] Technically, this holds if the returns follow a geometric Brownian motion, which is a stochastic process in which the logarithm of the randomly varying quantity follows a Brownian motion (or Wiener process). It is often used to model stock prices. See, for example, J.Y. Campbell, A.W. Lo, and A.C. MacKinley, "*The Econometrics of Financial Markets*," Princeton University Press, 1997, Chapter 9.

[35] See, for example, Morningstar, "*Ibbotson SBBI 2010 Valuation Yearbook*, p. 56; R.A. Brealey, S.C. Myers, and F. Allen, "*Principles of Corporate Finance*," 10th edition, 2008, p. 175-176; or J. Berg and P. DeMarzo, "*Corporate Finance: The Core*," 2009, p. 296.

[36] See, for example, Morningstar, "*Ibbotson 2010 Valuation Yearbook*," pp. 56-57.

conclusion is that negative correlation introduces a degree of path dependence – above average returns in one year are more likely to be followed by below average returns the following year – and vice-versa. In such situations, using a value between the geometric mean and the arithmetic mean is technically a more accurate estimate of the unconditional MRP.

Concerns with Historical Averaging

Estimating the MRP became particularly controversial as a result of the so-called Tech Bubble era the in late 1990s to 2001, because of the remarkable appreciation in the stock market, particularly the prices of technology-oriented stocks. Because the realized MRP increased substantially during this period, a line of research arose that questioned the use of a historical average to estimate the forward-looking MRP. At the height of the stock market bubble in the U.S. and Canada, many claimed that the only way to justify the high stock prices would be if the MRP had declined dramatically.[37] However, this argument has been heard less frequently in recent years now that the market has declined substantially and continues to struggle.

Conditional MRP Estimates

There are also a number of papers that argue that the MRP is variable and depends on a broad set of economic circumstances. For example, Mayfield (2004) estimates the MRP in a model that explicitly accounts for investment opportunities. He models the process that governs market volatility and finds that the MRP varies with investment opportunities which are linked to market volatility. Thus, the MRP varies with investment opportunities and about half of the measured MRP is related to the risk of future changes in investment opportunities. Based on this approach, Mayfield estimates the U.S. MRP to be 5.6 percent measured since 1940.[38] However, the problem with such an approach is determining when the MRP has changed and by how much. Another version of the conditional MRP is found in French, Schwert, and Stambaugh (1987),[39] for example, who find a positive relationship between the expected MRP and volatility of stock returns. Put differently, the conditional MRP varies with the volatility in the stock market.

Some practitioners forecast the expected MRP. To do so, a DCF model is commonly used to estimate the expected return on the market (*e.g.,* the S&P/TSX companies) and subtracting the

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[37] See Robert D. Arnott and Peter L. Bernstein, "What Risk Premium is 'Normal'?" *Financial Analysts Journal* 58, 2002, pp. 64-85, for an example.

[38] E. S. Mayfield, "Estimating the market risk premium," *Journal of Financial Economics* 73, 2004, pp. 465-496.

[39] K. French, W. Schwert and R. Stambaugh, "Expected Stock Returns and Volatility," *Journal of Financial Economics* 19, 1987.

forecast government bond (or bill) yield to obtain a forward looking estimate of the expected premium that stocks command over bonds. This forecasted MRP can then be used with a forecasted risk-free rate to estimate the forward-looking CAPM estimate of the cost of equity. This method is also a version of the Conditional MRP as the forecast depends on the economic circumstances at the time of the forecast.

Survey Based MRP Estimates

Survey evidence also provides insight into the conditional MRP. Initially, Professor Ivo Welch surveyed a large group of financial economists in 1998, 1999 and 2001 to assess the perception of the U.S. MRP. The average of the estimated MRP for the U.S. was 7.1, 6.7 and 5.5% for 1998, 1999 and 2001, respectively.[40] More recently, Professor Welch found that a sample of about 400 finance professors estimated the geometric MRP at about 5%[41] and an arithmetic MRP of about 7% (the arithmetic mean is approximated by the geometric mean plus one half of the variance of the returns).[42] One note of caution with regard to survey evidence is that Professor Welch's study shows that the survey participants' views on the MRP change quickly. In recent years, Professor Fernandez has surveyed finance and economics professors around the globe to assess their view on the MRP. He found that the average for Canada was 5.4% in 2008 and 5.9% in 2010[43] – again illustrating a relatively quick change in the view of the MRP.

MRP Estimates from Supply Models

The supply-side estimate of the MRP is based upon the observation that the "supply" of market returns is generated by the productivity of businesses in the real economy. Investors should not expect to have returns much higher or much lower than those produced by businesses in the real economy. A paper by Professors Ibbotson and Chen (2003) adopts a supply-side approach to estimate the forward looking long-term sustainable equity returns and equity risk premium based

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[40] I. Welch, "Views of Financial Economists on the Equity Premium and on Professional Controversies," *Journal of Business*, 73(4), 2000, pp. 501-537. The cited figures are in Table 2, p. 514. [40] I. Welch, "The Equity Premium Consensus Forecast Revisited," School of Management at Yale University working paper, 2001. The cited figure is in Table 2.

[41] I. Welch, "The Consensus Estimate For The Equity Premium by Academic Financial Economists in December 2007: An Update to Welch (2000)," Working paper, SSRN, 2008.

[42] See, Morningstar*, Ibbotson SBBI Valuation 2011 Yearbook*, p. 66. The historical standard deviation of the return on the U.S. market has been about 20%, so that the arithmetic market risk premium equals the geometric market risk premium of 5% plus approximately 2% for a premium of approximately 7%.

[43] P. Fernandez, "Market Risk Premium Used By Professors In 2008: A Survey With 1,400 Answers," IESE Working Paper WP-796, University of Navarra, May 2009, P. Fernandez, J. Aguirreamalloa and L. Corres, "US Market Risk Premium Used in 2011 by Professors, Analysts and Companies: A Survey with 5,731 Answers," SSRN April 2011.

upon economic fundamentals. The primary difference between the supply-side estimates and historical realized estimates of the MRP is that the supply-side model notes that the increase in the average price-earnings ratio for stocks cannot continue. Therefore, the growth in the average price earnings ratio is subtracted from the other factors that generate returns in the market. Ibbotson and Chen's supply-side estimate of the U.S. equity risk premium over the long-term risk-free rate is updated annually and reported in the Morningstar *Ibbotson SBBI 2011 Valuation Yearbook.* The estimate for the U.S. is currently 3.88% in geometric terms and 5.99% on an arithmetic basis.[44]

Beta Estimation Issues

There are generally four issues for beta estimation: what interval of return data to use; over how long a time period; whether to adjust the beta estimates for mean reversion; and whether to estimate the beta using the returns from a portfolio or the returns from individual securities. This section addresses these issues.

Choosing a Return Interval and Estimation Window

As noted earlier, the traditional CAPM does not address the issue of returns over time well, because theoretically it is a two period model. A common practice, however, in business applications and in regulatory proceedings is to use a long-term version of the CAPM.

The choices for the interval for the return data and the length of the beta estimation window involve a tradeoff between obtaining more observations through the choice of a longer window and/or more frequent return data and ensuring that no structural change in business risk for the company has occurred during the estimation window as well as that the return data are based on sufficient trading activity. For example, monthly data provides fewer observations unless a long enough estimation window is chosen (i.e., 5 years of monthly data gives only 60 data points – by contrast, a weekly horizon provides 260 observations over a 5 year period). Daily data is noisy with potentially few trades in any particular day.[45]

Structural changes means that the risk of the asset relative to the market could change over the estimation period, so that the resulting beta estimate would be a "blend" of the risk of the asset over the historical estimation period instead of representing the forwarding-looking risk of the

[44] Morningstar Ibbotson SBBI 2011 Valuation Yearbook, p. 66.

[45] We are not aware of any Canadian regulator, who has relied upon daily return data to estimate beta.

asset. The choice of a very long-run horizon (say, 10 years) introduces a potential problem for beta estimation, as many economic relationships shift in fundamental ways over a period of time. **Figure 3** below illustrates the beta for a portfolio of Canadian utilities over time using a one-year, five-year or ten-year horizon for the beta estimate.

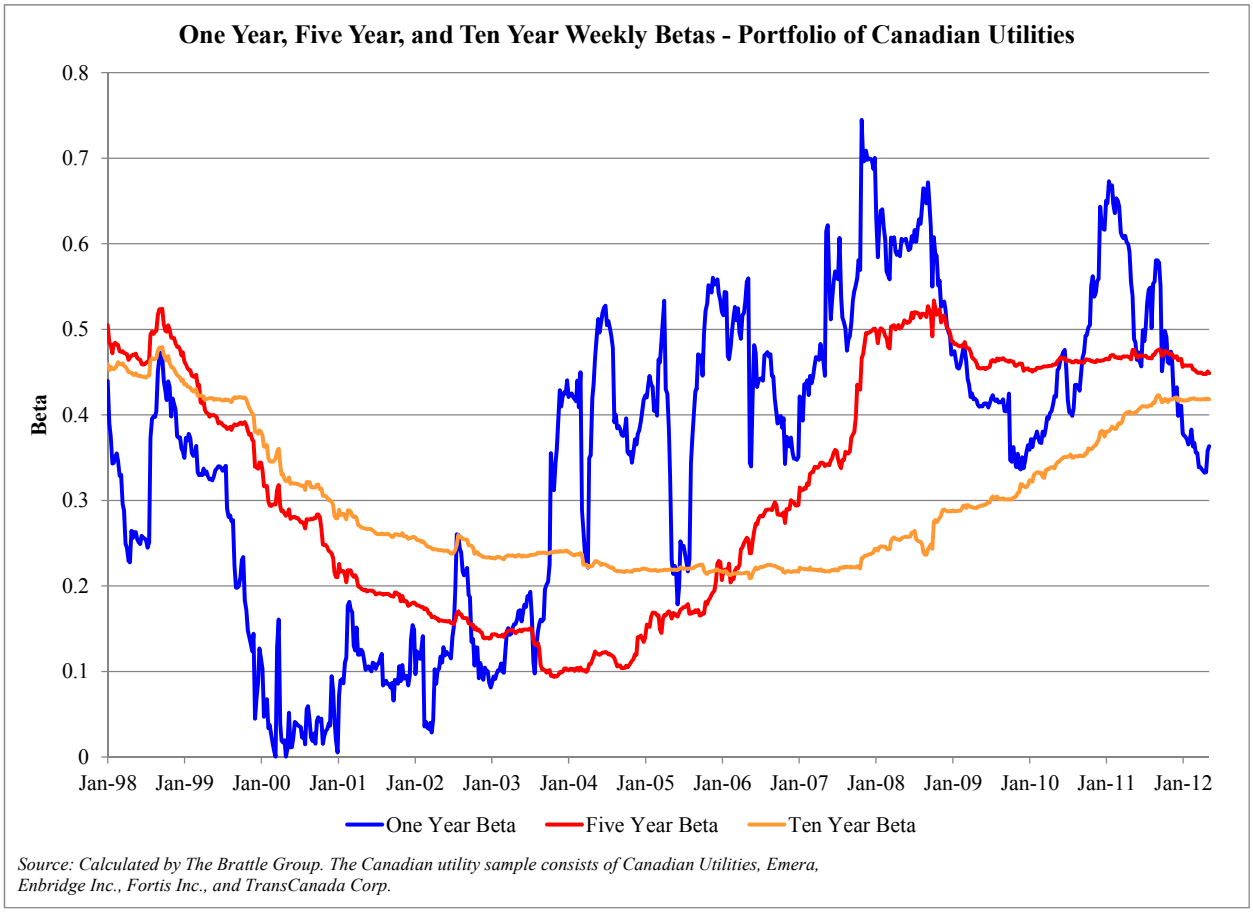


Figure 3

Figure 3 above illustrates the relative smoothing that is achieved by using a longer estimation window. Betas estimated over five years produce a smoother (more stable) estimate over time than do betas estimated over a one-year period. Betas estimated over a ten-year horizon produce an even more stable estimate over time. However, the longer the estimation horizon the more likely it becomes that fundamental economic relationships have changed.

There are also concerns that market microstructure effects can bias beta estimates.[46] **Figure 4** below suggests that weekly betas for Canadian utilities are more stable than monthly betas using a 5-year estimation window. Because monthly data include a number of very large returns (changes in prices from the prior month), the monthly observations result in less stable estimates

[46] Microstructure effects are recognition of the fact that daily prices reported can be affected by whether the price quoted is a bid price or an ask price based upon the last trade of the day.

over time. Statistically, the additional sampling error for monthly betas (since they are based on significantly fewer data points) seems to dominate other sources of variation, and produce a less stable estimate than at the weekly horizon.

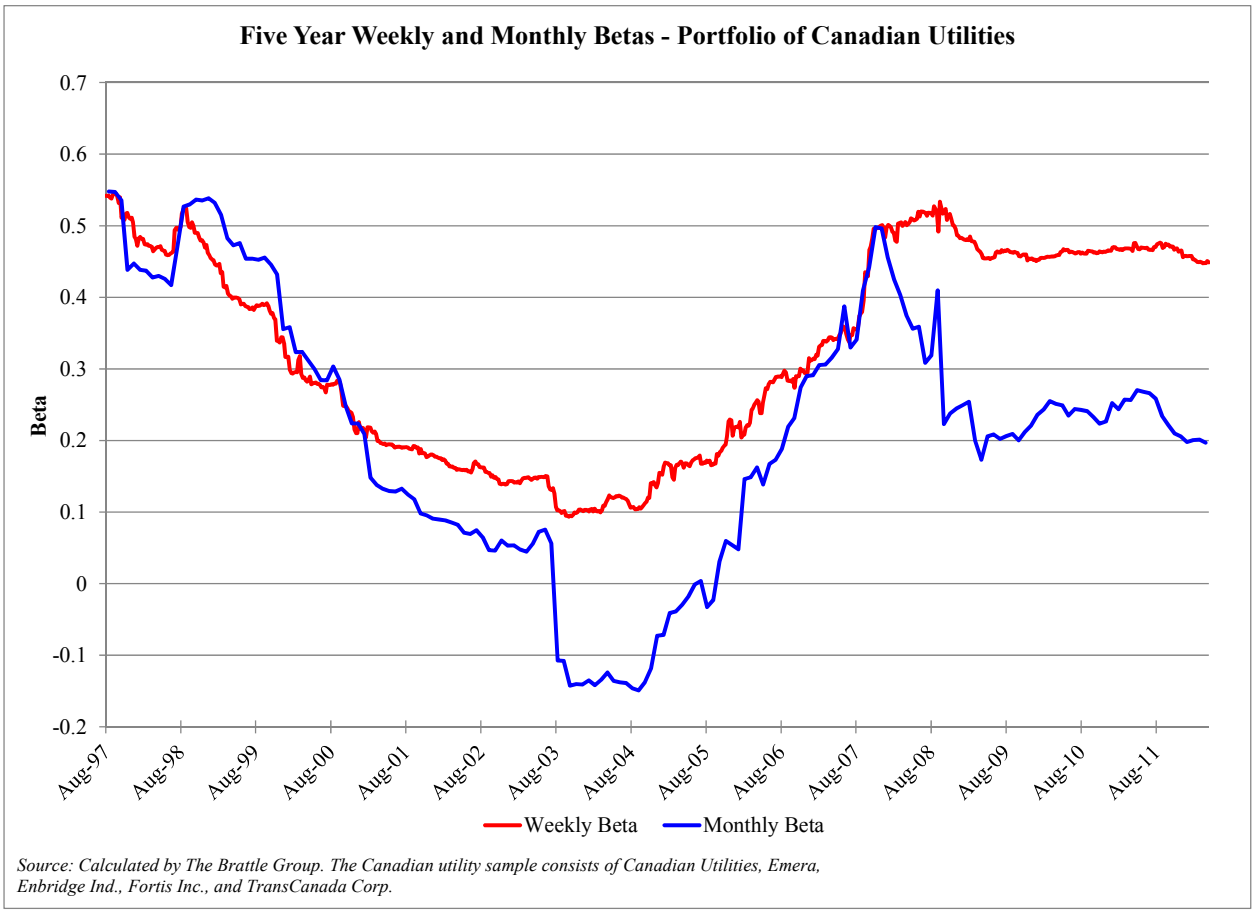


Figure 4[47]

Balancing these considerations, economists typically recommend beta be estimated using either weekly or monthly returns over the most recent 2 to 5 year period, with weekly betas becoming more common.

As noted above, some academics and practitioners adjust beta towards one using, for example, the Blume methodology discussed above (Equation (13)). Many financial data providers including Bloomberg report adjusted betas using Professor Blume's methodology as their default beta.

[47] The monthly betas have a much wider confidence band than do the weekly betas. For example, currently monthly betas are barely statistically significant while weekly betas are highly statistically significant.

c. Empirical challenges to the CAPM

Perhaps the most fundamental challenge to the CAPM has been the consistent empirical observation that the model does not explain stock performance well in a statistical sense. For example, low beta stocks tend to have higher average returns than predicted by the CAPM, and high beta stocks have lower average returns – that is, the empirical estimates seem to require a pivot of the SML around beta = 1.0 from the traditional version of the CAPM.[48]

d. CAPM evaluation: pros and cons

To summarize the strengths and weaknesses of the CAPM, it is important to note that many aspects of the CAPM depend on its implementation. The following refers to the best practices when applicable.

First, the CAPM will provide regulated entities with a reasonable return only if it is implemented accurately, and the analyst must take into account any unique circumstances that may bias the estimates. Second, assuming that the regulator specifies the relied upon model and data sources, the model is transparent and thus satisfies that requirement. Third, if the data sources are widely available and well-specified, the results can be audited by all interested parties. Fourth, the model may but is not guaranteed to produce similar results for similar conditions. The model's result will be more consistent if a portfolio approach or a sample of companies is used to estimate beta. Fifth, the model is very sensitive to the estimates of the risk-free rate, beta and MRP. Short-term risk-free rates tend to change more quickly than long-term rates, so use of the long-term risk-free rate generally results in more stability in the estimates. Beta estimates tend to be quite sensitive to market developments and therefore are sensitive to economic factors, but not necessarily in a manner that is easy to predict. The portfolio approach to estimating beta tends to provide more stable results than estimating betas on a company specific basis, but the estimates remain sensitive to market changes. Sixth, assuming that the regulator relies on standard data sources, the model is pragmatic in the sense that it is based on readily available information that is either free or relatively inexpensive to obtain. Seventh, the model is also pragmatic in that it is relatively easy to implement. Eighth, because the model was developed as a generic approach to determine the cost of capital for companies, it does not specifically take the regulatory context into account. Overall, the CAPM is a well-founded and commonly used

[48] We are not aware of any Canadian regulator that makes an explicit adjustment to the CAPM model for the empirical observation that the empirical SML may be flatter than the theoretical SML, so we do not discuss the details of any adjustment procedure.

model that relies primarily on readily available information. It may be less stable than ideal because changes in interest rates affect the risk-free rate and market volatility affects the beta estimates. Furthermore, determination of the MRP remains controversial.

4. Discounted Cash Flow Model

Like the CAPM, the Discounted Cash Flow (DCF) model, takes its point of departure from the Security Market Line depicted in **Figure 1**. However, it works directly with the individual asset's cash flows and price. As a tool for estimating cost of capital, it derives the opportunity cost of capital determined by the market, without having to model explicitly the market risk-return tradeoff that generated the market's opportunity set.

As noted in *Section II.B.3*, the DCF model is based upon the recognition that the current stock price is the discounted sum of all future expected dividends (see Equation (3)). If the growth rate in earnings and dividends is constant over time, then the cost of capital for investment S can be expressed as

$$r_s = \frac{D_O \times (1+g)}{P} + g \qquad \textbf{(16)}$$

This equation says that the cost of capital equals the expected dividend yield plus the (perpetual) expected future growth rate of dividends. Thus, for implementation purposes, it is necessary to determine the expected dividend, the growth rate and current stock price.

a. Multi-stage DCF models

A variation of the constant growth DCF model can be used if the assumption of constant growth is not considered reasonable for the short term, and variations of the general present value formula can instead be used to solve for r_s. For example, if there is reason to believe that investors do *not* expect a steady growth rate forever, but rather have different growth rate forecasts in the near term (*e.g.,* over the next five or ten years) converging to a constant terminal growth rate, these forecasts can be used to specify the early dividends in Equation (3). Once the near-term dividends are specified, Equation (5) can be used to specify the share price value at the end of the near-term (*e.g.,* at the end of five or ten years).[49] A standard "multi-stage" DCF approach solves the following equation for r:

[49] This can be done through a numerical procedure if the growth path becomes too complicated.

$$P = \frac{D_1}{(1+r_s)} + \frac{D_2}{(1+r_s)^2} + \ldots + \frac{D_T + P_{TERM}}{(1+r_s)^T} \tag{17}$$

The terminal price, P_{TERM} is just the discounted value of all of the future dividends after constant growth is reached:

$$P_{TERM} = \frac{D_T(1+g_{LR})}{(r_s - g_{LR})} \tag{18}$$

where T is the last of the periods in which a near term dividend forecast is made, and g_{LR} is the assumed long-run growth rate. Equation (17) defers adoption of the very strong perpetual constant growth assumption that underlies Equation (4) — and hence the simple DCF formula, Equation (16) — for as long as possible, and instead relies on near term knowledge to improve the estimate of r_s. The Alberta Utilities Commission (AUC), for example, has expressed an implicit preference for the multi-stage model.[50]

b. DCF implementation issues

Growth Rates

In most applications, the choice of growth rate is the most controversial part of the DCF implementation. While some analysts rely on historic growth rates, most economists agree that the growth rates currently expected by investment analysts are more representative of investor expectations than historical growth rates, if an adequate sample of such rates is available.

Stock prices are influenced by the information available to investors, and for companies in financial distress or companies involved in merger or acquisition activities, the information available to investors may be dominated by these events rather than any underlying trend in earnings or dividend growth. Therefore, the cost of capital estimation methods should not be applied to such companies. In addition, the stock prices for some companies reflect the market's perception of the value of real options available to the company. The forecast of the cash flows in the DCF approach does not include the value of the, as yet unexercised, real options, so for companies with material real option opportunities, the DCF model will underestimate the cost of equity.[51] Finally, the DCF approach requires that the stable-growth assumption must be

[50] Alberta Utilities Commission, Decision 2009-216, ¶271.

[51] The DCF model underestimates the cost of equity for companies with real options because the market price of the stock reflects the value of the options but the forecast cash flows do not.

reasonable and must be met *within the period for which forecasts are available*. That is, the expected growth rate must become and remain constant at some point.

Analyst Growth Forecasts

Some critics of the DCF model claim that analysts' forecasts of earnings growth rates are tainted by "optimism bias" which is related to an observed tendency for analysts to forecast earnings growth rates that are higher than are actually achieved. This tendency to over-estimate growth rates is perhaps related to incentives faced by analysts that provide rewards not strictly based upon the accuracy of the forecasts. To the extent optimism bias is present in the analysts' earnings forecasts, the cost of capital estimates from the DCF model would be too high.

From a regulatory perspective, however, the issue is not whether analysts' growth forecasts generally exhibit optimism bias but whether there is bias in forecast growth rates for utilities. In addition, presence and magnitude of the optimism bias (if any) for regulated companies is not clear. For example, a paper by Capstaff et al. (2001) finds that "analysts' forecasts for the health care and public utilities were the most accurate…. [P]art of the explanation may be the low earnings volatility…."[52] In another paper, Markov and Tamayo (2006) find that the autocorrelation in analysts' forecast errors for the utilities industry is close to zero and state that "[t]his is not surprising. The quarterly earnings process for a utility firm is more likely to be stationary and present better opportunities for learning than other firms."[53] Thus, analyst forecasts for utilities may have characteristics that differ from those of other industries.

There is also substantial academic evidence that analyst earnings estimates are superior to other forecasts. Specifically, Brown et al. (1987) find that analyst forecasts are better predictors of earnings numbers than time-series earnings forecasts (which look at historical earnings information as a gauge of future earnings). Further, fundamental analysis models rarely outperform analyst forecasts:

> The ratio-based earnings prediction literature focuses on the forecasting power of financial ratios with respect to future earnings. Empirical evidence is generally consistent with the ratios' ability to predict earnings growth. These models,

[52] Capstaff, J., Paudyal, K., Rees, W., 2001, "A Comparative Analysis of Earnings Forecasts in Europe." *Journal of Business Finance & Accounting* 28, p. 548.

[53] Markov, S., Tamayo, A., (2006), "Predictability in Financial Analyst Forecast Errors: Learning or Irrationality?" *Journal of Accounting Research* 44, p. 750.

> however, rarely outperform analysts' forecasts of earnings, especially forecasts over long horizons.[54]

Analyst forecasts for the utility industry are likely to be more accurate than forecasts for other industries because firms with less variability in their earnings tend to have more accurate forecasts. This suggests analyst forecasts for the utility industry are likely to be more accurate and less prone to potential bias when compared to forecasts for other industries.

Dividends Versus Cash in the Formula

The DCF model is based on the notion that the stock price equals the sum of the discounted cash flows that accrue to shareholders. This is usually implemented assuming that the cash flow that investors receive equals dividends. While this is true over the lifespan of the firm and in many instances also true over a shorter horizon, there may be instances where cash flow and dividends diverge for a period of time. This is the case, for example, when a company engages in share buybacks. In addition, some data providers and analysts believe that cash flows provide a better measure of the yield investors expect. This could occur, if dividends are unusually low (or high) as would be the case if, for example, companies retain cash to make capital investments (or if companies pay out dividends in excess of earnings). As a result, some data providers and analysts rely on the cash flow yield rather than the dividend yield in the DCF model.

In summary, the reliability of the DCF model hinges on the appropriateness of its assumptions — whether the basic present value formula works for stocks; whether option pricing effects are important for the company; whether the right variant of the basic formula has been found; and whether the true growth rate expectations have been identified.

c. DCF evaluation: pros and cons

Most of the data necessary for DCF implementation is widely available at low cost. The exception is that there is no source of data on the long-term (i.e., longer than five years) growth rate of dividends. The calculations are relatively simple, and the logic of the model is intuitive in that the expected return on an investment is equal to the expected amount of current income (i.e., the dividend payment) and the expected amount of capital gain (i.e., the growth in the price or dividend payments).

[54] Kothari, S.P., "Capital Markets Research in Accounting," *Journal of Accounting and Economics* 31, 2001, p. 186.

The major source of debate for the DCF model is determining the dividend growth rate, particularly for the long-term. There is generally no publicly available data on forecast growth rates for periods longer than 5 years. Unfortunately, the forecast growth rate has a major effect on the cost of equity estimated by the DCF method.

The DCF approach is conceptually sound if its assumptions are met, but can run into difficulty in practice because those assumptions are so strong, and hence unlikely to correspond to reality. Two conditions are well-known to be necessary for the DCF approach to yield a reliable estimate of the cost of capital: (i) the variant of the present value formula (Equation (17)) that is used must actually match the variations in investor expectations for the dividend growth path; and (ii) the growth rate(s) used in that formula must match current investor expectations. In practice, the stability of the DCF estimates of the cost of capital across similar companies or over a relatively short time span can be a problem. The more stable the company and industry is, the less of a problem the issues discussed above are.

The degree to which estimates from the DCF models are consistent with the objective being pursued depends largely on (i) the reliability of the estimates as discussed below and (ii) company and economy-wide factors. Because DCF models quickly incorporate new information regarding the company's stock price, dividends, and growth rates, the ROE estimates reflect this information, which may or may not be consistent with the regulatory objective.

A strength of both the constant growth and a well-defined multi-stage DCF model is that the models rely on auditable information. A weakness of the DCF models is that they do not necessarily produce consistent results for like conditions because stock prices and growth rates can change quickly. However, the multi-stage DCF model tends to dampen the effect of changes in the basic model parameters compared to the constant growth DCF model. Finally, the cost of capital estimates from the multi-stage DCF model are more stable than the estimates from the constant growth DCF model, but neither model is truly robust because both versions of the DCF model are sensitive to economic/financial conditions.

As with other models, if the models relied upon are well-defined, the information needed for their implementation is readily available from public sources, and the models are simple to implement. The DCF model is transparent and can easily be audited by interested parties. To determine whether a constant growth or a multi-stage DCF is appropriate for the regulatory context, it is important to recognize that the constant growth DCF model responds quickly (and

sometimes dramatically) to company-specific changes, while the presence of growth rates other than those of the company in the multi-stage model dampens the model's response to company-specific changes. Therefore, the choice of model or models will necessarily involve a tradeoff between the stability of the estimates and the goal of rapidly reflecting current company-related conditions.

5. Risk Premium Approaches

a. Equity risk premium implementation

The risk premium model, sometimes called the equity risk premium model, in *Section II.B.3* Equation (9) is frequently implemented using either a historical estimate of the risk premium or a forward-looking or expected risk premium. The historical risk premium is commonly determined as the historical spread between equity and debt returns, so the primary choices for the analyst become which equity returns and debt instrument to use as well as the period over which the spread (i.e., the risk premium) is to be measured. It is not uncommon to see this model implemented using long-term government bonds or utility/corporate bonds to measure the cost of debt, while the equity investments used are typically either (a) realized accounting returns of regulated entities in the same industry, (b) realized stock returns of companies in the same industry, or (c) allowed returns on equity for the industry. In choosing a debt instrument to determine r_D, it is important that it be consistent with the debt instrument used to determine the risk premium. In other words, if a 10-year government bond is used to determine the historical risk premium, then r_D must also be measured using a 10-year government bond. The realized risk premium is highly dependent on the time period over which it is estimated, so that choice is also important. The historical risk premium approach assumes that a historically realized risk premium is an appropriate measure for expected returns. However, over any given period, and especially over a short period of time, realized returns can differ substantially from expected returns. Therefore, the accuracy of the estimated risk premium will typically increase if estimated using a longer time period.[55]

The forward looking model requires that the analyst determine a proper measure the cost of debt and how to *estimate* the expected risk premium. Because the yield to maturity of an investment grade bond serves as a proxy for the expected return, yield to maturity measures are natural

[55] The more tosses we undertake with a fair coin, the more likely it becomes that we realize heads close to 50% of the time and tails 50% of the time.

candidates for the expected bond cost.[56] Determining the expected equity return is more difficult and requires the reliance on an estimation technique. It is common to rely on DCF models to determine the risk premium in the forward looking version of the model. For example, the analyst may choose companies in the same industry as the regulated entity and use the DCF method to calculate the expected return on equity for the industry monthly (or quarterly) for a number of years. The analyst then determines the risk premium as the average spread between the estimated return on equity for the industry and the yield to maturity on the selected debt instrument. Again, consistency requires use of the same debt instrument to measure the cost of debt (r_D) as is used to estimate the expected risk premium. One result originating from these analyses of historical or forward-looking risk-premium approaches is that empirically there is a negative relationship between the risk premium and the yield-to-maturity. Historically, a 1% increase in the yield-to-maturity of government bonds results in less than a 1% increase in the estimated (or realized) return on common equity.[57] The relationship between the return on equity and (government or utility) bond yields is depicted in **Figure 5** below. The figure is for illustrative purposes only and does not reflect an actual analysis of the relationship.

[56] As noted above, the cost of capital is the expected rate of return on an investment. Strictly speaking, the yield-to-maturity of debt includes a premium for default risk, so if there is no default on the bonds, the investors will earn slightly more than the cost of capital. For investment grade bonds, the default premium is likely to be small.

[57] For example, Roger A. Morin, "*New Regulatory Finance*," Public Utilities Reports, Inc., 2004 pp. 128-129 summarizes several studies and found that the realized ROE changes approximately 50 basis points when government bond rates change 100 basis points. Regulatory agencies such as the Ontario Energy Board relied on this empirical finding as well as data submitted by experts in its recent hearing to update its annual change in the estimated cost of equity for Ontario utilities by less than the change in government bond rates.

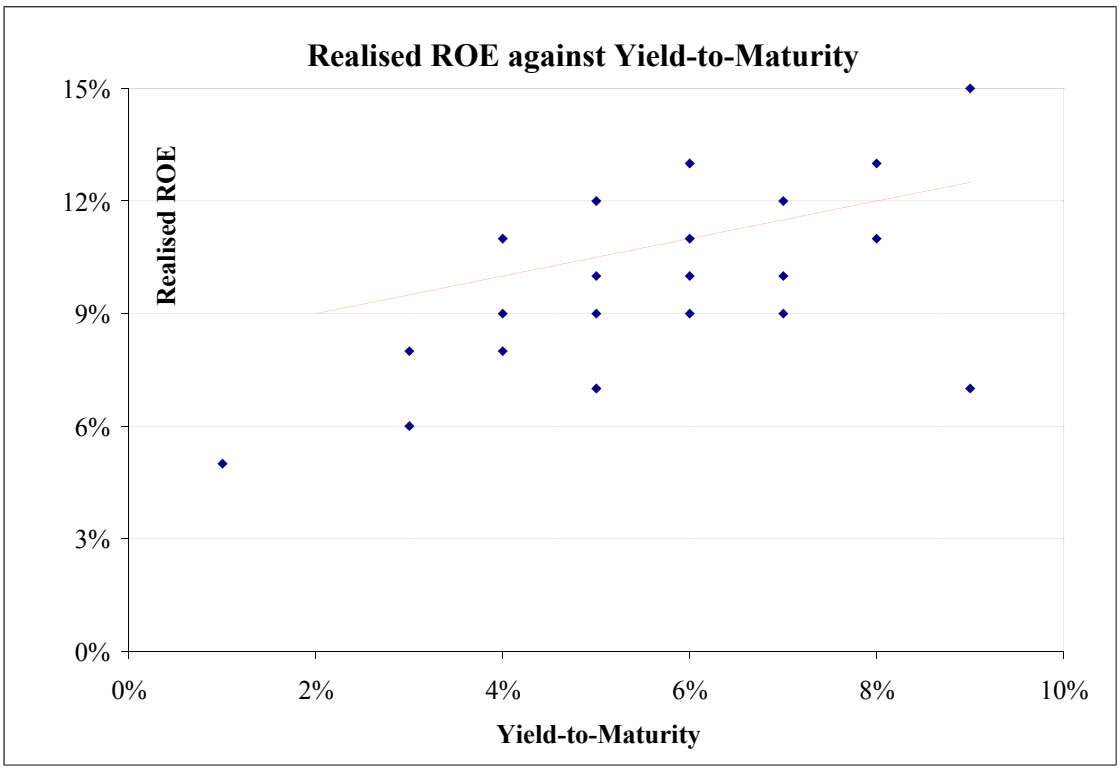


Figure 5

This is a reason why, for example, the Ontario Energy Board (OEB) took evidence from the risk premium approach into consideration when determining its baseline cost of equity.

b. Risk premium model evaluation: pros and cons

The risk premium model is a derivative of the CAPM so the comments that apply to the CAPM also apply to the Risk Premium Model; however, the Risk Premium Model does not have the same level of theoretical support. The tie between theory and implementation is weakened because the interest rate in the Risk Premium Model is not necessarily equal to the risk-free rate and the risk premium is not explicitly based upon the product of the investment's beta and the MRP. However, the calculations are simple and the model is based upon the risk-return trade-off underlying the CAPM. The model is forward looking because the benchmark interest rate is a current rate, and the data necessary for the model is generally widely and cheaply available, depending upon how the risk premium is estimated.

The difficulty with the model is determining the appropriate risk premium and whether it has changed since it was last estimated. There is also an issue of whether the relationship of the risk premium to changes in the benchmark interest rate remains constant. If the interest rate increases

by 1%, does the risk premium stay constant or change? Because there is no underlying theory, there is no definitive answer to the question.

There are only two parameters in the Risk Premium Model so implementation only requires estimating the two parameters. The benchmark interest rate is observable so the primary controversy centers on determining the risk premium. Because there is no theory for how the risk premium should be estimated, there will always be controversy about it. However, from a regulatory consistency practice, it is important to specify whether the benchmark bond rate is the government or corporate bond rate. An argument can be made for using the corporate bond rate because regulated entities necessarily raise capital as a corporation rather than as a government entity. While the reliance on allowed rates of return provide a benchmark for whether the allowed returns are comparable to those allowed in other jurisdictions, a reliance on the allowed return of a small set of regulators or the regulator itself should be avoided to ensure there is no circularity in determining the allowed return on equity.

To assess the strengths and weaknesses of the risk premium model, we note the following: As with other models, the degree to which the risk premium model is consistent with the objective being pursued depends to a degree on its implementation. A strength of the model is that it explicitly considers current bond yields for the regulated entity and hence the regulated entity's cost of debt, provided the implementation relies on industry as opposed to government bond yields. Regulated companies cannot borrow at the same rates as the government. Also, if the methodology is well-defined, it is transparent and relies on a structured formula. Among the weaknesses of the risk premium approach is that it may be influenced by monetary policy - especially if the implementation relies on government bond yields.

A strength of the model is that the information on which it relies is auditable, while the weakness is that it may or may not produce consistent results for like conditions. Because inflation and other factors that are not directly related to the cost of equity capital may affect bond yields, the model will not necessarily produce like results for like conditions. The implementation of the model largely determines its ability to capture the systematic risk of companies. For example, unless a forecasted return for relevant companies is used, it will be unable to estimate reliably the cost of capital across different economic conditions. Inflation can be a problem for the risk premium model, because the historical data underlying the risk premium may not be consistent with the current level of inflation in the economy.

As noted above, so long as the model is well-specified and uses well-defined inputs, easy access to the underlying information and easy implementation are strengths of the model. However, the estimates from the model may or may not recognize the regulatory context in which the cost of capital is being applied at any given time.

6. Comparable Earnings

a. Comparable earnings implementation issues

As noted in *Section II.B.3*, the comparable earnings method requires the analyst to go through four steps. First, a group of *unregulated* companies is required because the realized accounting rate of return of a regulated company depends on its allowed return. Using regulated companies to estimate the comparable earnings cost of capital would be circular, i.e., the allowed rate of return is used to determine the allowed rate of return. However, the use of unregulated companies requires careful consideration of the risk characteristics of the companies and the comparability to those of the target utility.

Second, a time period over which to estimate the return on equity must be selected. Because a company's achieved earnings fluctuate from year to year and depend substantially on both company-specific and economy-wide factors, it is necessary to include companies from several industries, averaged over several periods.

Third, because the comparable companies are unregulated entities, it is necessary to adjust for any risk differences between the sample companies and the target company. There are many ways to adjust for risk differences, so the following is a simplified description of some common approaches rather than an exhaustive review. Analysts often collect information on the comparable companies' and the target company's bond ratings, asset betas, DCF estimates of the cost of equity, and other measurable risk factors. In many instances, this information is also collected for a sample of regulated companies in the same industry as the target company. If the sample companies are found to be consistently more (less) risky than the target company and its industry peers, then an adjustment is made to the required return on equity. This can sometimes be done formally. For example, if the sample companies' DCF estimates of cost of equity are consistently 25 basis points higher (lower) than the DCF estimates for the target company (or industry peers), then a downward (upward) adjustment of 25 basis points is made. For other measures, it is more difficult to determine the exact adjustment, so it is usually made based on the analyst's experience. For example, does a two notch difference in bond rating require a

specific upward or downward adjustment? Thus, while the differences are relatively easy to measure, the adjustment for such differences requires subjective judgment.

A major issue is whether realized book returns are a good proxy for the return that investors expect going forward. From a statistical perspective, the realized accounting return on book equity for any given period is the realization of a single outcome of a distribution, whereas the expected return represents the probability-weighted average of all possible outcomes of the distribution. These two figures can differ substantially. In addition, there are practical problems with the implementation because financial reporting occurs with a lag, which during times of change can mean that the results are out of date. Moreover, the procedure is inherently "backward looking" in that it considers realized returns over historical periods instead of estimating the cost of capital going forward.

The advantage of the method, if implemented correctly, is that (i) it looks directly at the return that accrues to investors in "comparable companies," (ii) it is relatively simple to implement, and (iii) data are publicly available and easily accessible. The disadvantages to the methods are that it (i) lacks an economic foundation because accounting returns and investors' expected returns are two different concepts, (ii) is backward looking, (iii) can be difficult to find a time period that accurately reflects the expected horizon of the regulated entity, and (iv) can be difficult to select a comparable sample and to adjust for risk differences between the comparable sample and the regulated sample.

b. Comparable earnings model evaluation: pros and cons

The primary appeal of the comparable earnings model is that it seems to be consistent with the language of the legal requirement established by the Supreme Court in both Canada and the U.S., although both courts focused on the established rate of return and not on the process by which is was established. Specifically, the decisions require that the regulated company be given a fair opportunity to earn a rate of return equal to that of comparable risk investments. The appeal is further strengthened by the fact that a comparable earnings estimate provides a rate of return on the book value of equity of a company. The allowed ROE for most regulated companies is based upon the book value of investment in the company, not the market value of the invested assets. Once a comparable sample has been selected, the data necessary for the calculations are generally readily available.

However, the comparable earnings method does not have strong theoretical basis for the estimate of the cost of capital. The cost of capital is defined as the expected rate of return of comparable risk investments. The comparable earning method fails to provide an expected rate of return, because it is a backward looking cost of equity measure. The method considers the realized rates of accounting return for the sample companies with no consideration of current market conditions. For example, if two otherwise similar companies choose different accounting conventions then the realized accounting return may differ.

The comparable earnings methodology can be implemented in many different manners, but if the best practices described above are used, the strengths and weaknesses of the method can be summarized as follows:

The comparable earnings methodology may or may not be consistent with the regulatory objective being pursued. Specifically, the method's strength is that it can accommodate information from non-regulated entities and hence be used to assess the required cost of capital more broadly than other methods. This is also a weakness of the model in that other industries are not necessarily comparable to the entities being regulated, so that the information may or may not be relevant. As with other models, transparency is a strength if the relied upon methodology is well-specified.

Also, if the relied upon methodology is well-specified, it is clearly based on auditable information from companies' annual filings, such as from SEDAR, for example.[58] Because the methodology relies on accounting information, a weakness is that it does not necessarily produce consistent results for like conditions. For example, accounting changes could produce changes in estimates without any change in the underlying cost of capital. The model is not necessarily sensitive to economic or financial conditions, because it relies on backward-looking accounting information that may not reflect current economic conditions.

Because the model uses accounting information that is available free of charge from SEDAR or alternatively from commercial data providers, it clearly fulfills the requirement of using readily available information. Also, it is easy to implement if a well-specified version is used.

[58] www.sedar.com is the official site that provides access to most public securities documents and information filed by public companies and investment funds with the Canadian Securities Administrators (CSA) in the SEDAR filing system. The statutory objective in making public this filed information is to enhance investor awareness of the business and affairs of public companies and investment funds and to promote confidence in the transparent operation of capital markets in Canada. Achieving this objective relies heavily on the provision of accurate information on market participants.

However, the estimates from the model do not come from regulated companies or activities, so it cannot be said to recognize the regulatory context in which the cost of capital is being applied.

7. Capital Structure and the Cost of Equity

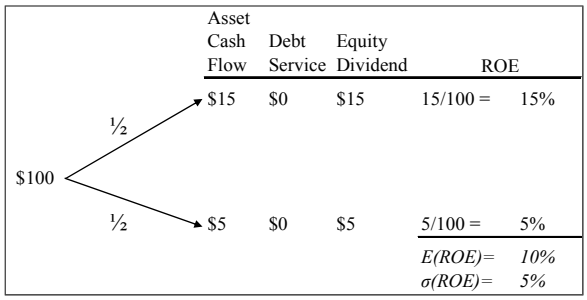
A common issue in regulatory proceedings is how to apply data from a benchmark set of comparable securities when estimating a fair return on equity for the target/regulated company.[59] On the one hand, it is tempting to simply estimate the cost of equity capital for each of the sample companies (using one of the above approaches) and average them. After-all, the companies were chosen as comparable risk, so why would an investor necessarily prefer equity in one to the other (on average)? The problem with this argument is that it ignores the fact that underlying asset risk in each company is typically divided between debt and equity holders – making them derivatives of the underlying asset return. Even though the risk of the underlying assets may be comparable, a different capital structure splits that risk differently between debt and equity holders, making the equity in one firm potentially more risky than equity in another.[60] Stated differently, increased leverage adds financial risk to a company's equity.[61]

Figures 6 and **7** below demonstrate this phenomenon by comparing equity's risk when a company uses no debt to finance its assets, and when it uses a 50-50 capital structure (i.e., it finances 50 percent of its assets with equity, 50 percent with debt). For illustrative purposes, the figures assume that the cash flows will be either $5 or $15 and that these two possibilities have the same chance of occurring (*e.g.,* the chance that either occurs is ½).

[59] This is also a common valuation problem in general business contexts.

[60] The difference in risk due to how the assets are financed is called financial risk. The impact of leverage on risk is conceptually no different than that faced by a homeowner who takes out a mortgage. The equity of a homeowner who finances his home with 90% debt is much riskier than the equity of one who only finances with 50% debt.

[61] It is referred to as *financial* risk because the additional risk on equity holders stems from how the company chooses to finance its assets.



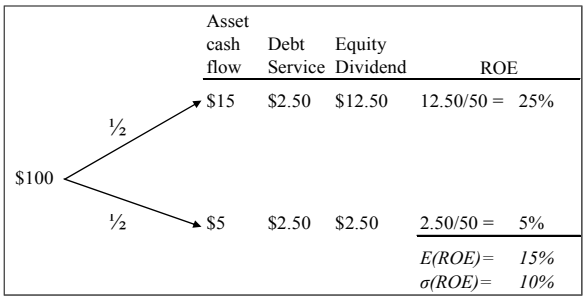


Figure 6. Firm with all equity capital structure **Figure 7. Firm with 50/50 capital structure**

Canadian regulators have historically deemed a capital structure that may or may not be similar to the actual capital structure of the company being regulated. While methodology relied upon to determine the capital structure differed among jurisdiction, a common theme was to look to the business risk (broadly defined) of the regulated entity. However, the National Energy Board (NEB) in RH-1-2008 chose instead to determine an after-tax, weighted-average cost of capital (ATWACC). Following the notion that if the companies in a sample are truly comparable in terms of the systematic risks of the underlying assets, then the weighted-average cost of capital of each company should be about the same across companies (except for sampling error), so long as they do not use extreme leverage or no leverage. The intuition here is as follows. A firm's asset value (and return) is allocated between equity and debt holders.[62] The expected return to the underlying asset is therefore equal to the value weighted average of the expected returns to equity and debt holders – which is the WACC.[63]

$$WACC = r_D(1-T_C)\cdot D/V + r_E \cdot E/V \qquad \textbf{(19)}$$

where r_D = market cost of debt, r_E = market cost of equity, T_C = corporate income tax rate, D = market value of debt, E = market value of equity, and V is the market value of the firm (i.e., $V=D+E$). Since the WACC is the cost of capital for the underlying asset risk, and this is comparable across companies, it is reasonable to believe that the WACC of the underlying companies should also be comparable, so long as capital structures do not involve unusual leverage ratios compared to other companies in the industry.[64] There are other mechanisms that

[62] Other claimants, such as preferred equity, can be added to the WACC, if they exist.

[63] As this is all on an after-tax basis, the cost of debt reflects the tax value of interest deductibility. Also, a number of underlying regularity assumptions is being made when the equivalence of the WACC and the asset cost of capital is asserted. For example, there is a need to assume additivity, no-arbitrage, and market efficiency, among other assumptions.

[64] Empirically, companies within the same industry tend to have similar capital structures, so whether a leverage ratio is unusual depends upon the company's line of business.

academics, practitioners and regulators outside Canada use to adjust for leverage differences between the comparable companies and the target company.[65]

D. Summary of Advantages and Disadvantages of the Four Cost of Equity Estimation Methods

The four estimation techniques discussed above are the most commonly relied upon methods to estimate the cost of equity capital in Canada. Each method has some advantages and disadvantages.

The CAPM model has the advantage of being based on an economic model and readily available market data. However, beta estimates are backward looking, and the question arise as to how representative these estimates are for the future period during which rates are in effect. In addition, the model is sensitive to the risk-free rate used in the model and the market risk premium relied upon as well as estimated betas. The reliability of each of these estimates are questioned in many regulatory proceedings with the risk-free currently being the subject of substantial controversy, because of it historically low level and because it may have been influenced by monetary policy.[66]

The DCF method has the advantage of being a forward looking methodology that relies on a forecasted growth rate and current stock prices.[67] However, the reliance on a forecasted growth rate that necessarily needs to be forecasted to the indefinite future (see Equation (3) above) is also a disadvantage, as it is inherently difficult to forecast more than a short period forward, and therefore the relied upon growth rates become a subject of debate.

An advantage of the risk premium model is that it is easy to understand and implement; it simply determines the premium equity investors' demand over and above the cost of debt. However, in its simple form, it captures only a difference in equity and debt return over a period of time and not expected changes in the economy, industry, or for the company in question.

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[65] See, for example, R.S. Hamada, "Portfolio Analysis, Market Equilibrium, and Corporate Finance," *Journal of Finance* 24, 1969.

[66] Jurisdictions such as the Alberta Utilities Commission, the British Columbia Utilities Commission, the Ontario Energy Board, Manitoba Public Utilities Board, the Régie de l'énerie du Québec, and Saskatchewan Rate Review Panel rely on forecasted risk-free rates.

[67] Regardless of whether the growth rates were obtained from analysts' forecasts, historical data, or in some other manner, they are used as if they are forecasted growth rates in the DCF model, i.e., the comments are independent of the source of the relied upon growth rates.

Finally, the comparable earnings methodology provides an estimate of the rate of return on the book value of equity for companies, which is consistent with regulatory regimes that rely on historical cost regulation. However, the comparable earnings methodology is a backward looking methodology, subject to being influenced by the choice of accounting methodology, and, if applied to regulated companies, subject to circularity. That is, the regulator sets the allowed rate of return and the realized rate of return is then used to set next year's allowed rate of return.

E. OTHER CONSIDERATIONS IN COST OF EQUITY ESTIMATION

The principle underlying the determination of the cost of capital for a regulated entity is the "fair return standard." In *Northwestern Utilities Limited*, the Supreme Court of Canada described the fair return standard as follows:

> By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise, which will be net to the company, as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.[68]

Based on this cost of capital analysts typically select a group of companies that are comparable to the company being regulated and estimate the cost of capital that investors in those companies expect. The specifics of the selection are subject to debate and often centers on

- What exactly constitute a comparable company?
- How large does the set of comparable companies need to be to be reliable?
- Does the sample capture the risk characteristics of the target company?
- Are there companies that bias the cost of equity estimate?

III. BRITISH COLUMBIA UTILITIES COMMISSION

A. INTRODUCTION

The British Columbia Utilities Commission (BCUC) is an independent regulatory agency that regulates British Columbia's natural gas and electric utilities. The Commission is responsible for ensuring that customers receive safe, reliable and non-discriminatory energy services at fair rates from the utilities it regulates, and that shareholders of these utilities are afforded a reasonable opportunity to earn a fair return on their invested capital. As such, one of the BCUC's

[68] *Northwestern Utilities Limited v. City of Edmonton* (1929) (Northwestern Utilities) is the landmark Canadian decision.

responsibilities is to determine the cost of capital for those utilities for which the BCUC determines rates.

Among the natural gas and electric utilities that the BCUC regulates are FortisBC Energy Inc. (formerly Terasen Gas Inc.), FortisBC Energy (Vancouver Island) Inc. (formerly Terasen Gas (Vancouver Island) Inc.), FortisBC Energy (Whistler) Inc. (formerly Terasen Gas (Whistler) Inc.), FortisBC Inc., Pacific Northern Gas, Ltd. and British Columbia Hydro and Power Authority (BC Hydro). In addition, the BCUC regulates some smaller utilities: Corix Multi-Utility Services Inc. (Corix) and River District Limited Partnership (River District), among others. Of the FortisBC companies, which are subsidiaries of Fortis Inc., the FortisBC Energy companies are gas local distribution utilities (LDC) and FortisBC Inc. is a vertically integrated electric utility. Corix is an investor-owned multi-utility, Pacific Northern Gas is an investor-owned natural gas distribution company,[69] and BC Hydro is an integrated electric utility (with generation, transmission, and distribution) and also a Crown corporation.

B. HISTORY

In June 1994, the BCUC issued a decision (BCUC 1994 Decision) in the first generic cost of capital proceeding in Canada, and that decision set its future policy on ROE in several ways.[70] First, the BCUC 1994 Decision established a benchmark ROE that pertains to "low risk, high grade benchmark utilities."[71] Second, the decision established a formulaic approach to updating annually the allowed ROE on a benchmark utility.[72] Third, the decision established base parameters to be used in the annual update. To establish the base parameters for the formula, the BCUC indicated that the primary reliance should be placed on risk premium tests, with comparable earnings and the DCF model as checks.[73]

In its reliance on a benchmark utility, the BCUC recognized that the ROE premium over and above that of a low risk, high grade utility and an individual utility's capital structure "are less likely to change for several years."[74]

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[69] PNG operates a Western system (PNG West) and a Northeastern system (PNG NE).

[70] BCUC Decision in the Matter of Return on Common Equity BC Gas Utility Ltd., Pacific Northern Gas Ltd., West Kootenay Power Ltd., June 10, 1994 (BCUC 1994 Decision).

[71] BCUC 1994 Decision, p. 2.

[72] BCUC 1994 Decision, pp. 39-40.

[73] BCUC 1994 Decision, p. 17.

[74] BCUC 1994 Decision, p. 47.

The formulaic approach from the 1994 decision enables an annual automatic update of the ROE using the forecasted change in the 30-year long-term Government of Canada bond yield. Specifically, the initial formula was

$$\text{ROE} = \text{BaseROE} + 1.0 \times (\text{LCBF} - \text{BaseLCBF}). \quad \textbf{(20)}$$

The formula in (20) was to be in effect as long as the change in the long-Canada forecast (i.e., LCBF – BaseLCBF) was less than 50 basis points, and the absolute forecast for the long Government of Canada (LCBF) forecast was below 13%.[75] The BaseROE for 1994 was set at 10.75%, and the Base Long Canada Bond Forecast (LCBF) was set at 7.75%.[76] The annual Long Canada Bond Forecast for future years would be obtained from the November issue of *Consensus Forecasts* and adjusted for the difference in the spread between the Long Canada Bond Forecast in *Consensus Forecasts* and a 30-year government bond. The reasoning behind the initial ROE determination is discussed further below.

The formula in (20) was modified in 2006 to include less than 100% of the forecasted change in the long Government of Canada yield in the ROE formula. Specifically, the BCUC adopted an adjustment factor of 75% instead of 100%,[77] so that the annual updating formula became:

$$\text{ROE} = \text{BaseROE} + 75\% \times (\text{LCBF} - \text{BaseLCBF}). \quad \textbf{(21)}$$

There was no change in the determination of the bond forecasts.[78]

The formula in (21) was reviewed in 2006, when an application from Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. was heard. In addition to modifying the formula so that 75% rather than 100% of the change in long-term government bond forecast was incorporated in the determination of the allowed ROE, the BCUC 2006 Decision confirmed Terasen Gas Inc. (TGI) as the benchmark, low risk utility. The 2006 decision determined that an appropriate risk premium for a benchmark utility over long-term government bonds was 3.9%, and that TGI's deemed capital structure would include 35% equity. The automatic adjustment mechanism remained in effect until 2009, when the BCUC eliminated the automatic adjustment formula stating that

[75] BCUC 1994 Decision, pp. 39-40.

[76] BCUC 1994 Decision, pp. 5 and 18.

[77] BCUC, In the Matter of Terasen Gas Inc., et. al. Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism, March 2, 2006 (BCUC 2006 Decision), p. 1.

[78] BCUC 2006 Decision, p. 15.

> in its present configuration, the AAM [Automatic Adjustment Mechanism] will not provide an ROE for TGI for 2010 that meets the fair return standard.[79]

Where TGI was once referred to as the low-risk benchmark utility, the 2009 Decision refers to TGI as the "benchmark utility" and stated that Terasen

> can continue to serve as the Benchmark ROE for FortisBC and any other utility in British Columbia that uses a Benchmark ROE to set rates.[80]

The BCUC established an ROE of 9.5% at the time for the benchmark utility, TGI. The BCUC subsequently, by Order G-20-12, initiated a generic cost of capital proceeding that will determine the Benchmark ROE for the regulated utilities going forward.

C. ESTABLISHING THE ROE

The BCUC's views on how to determine the appropriate cost of equity capital have evolved over time. In the BCUC 1994 Decision, the BCUC "placed primary reliance on the various risk premium tests presented" whereas the "comparable earnings and DCF test results have been used primarily as a checks upon reasonableness."[81] However, in the BCUC 2006 Decision, the BCUC assigned weight to the DCF model and found the comparable earnings methodology useful.[82] The BCUC 2006 Decision did not state how much weight it assigned to each model it considered. In the BCUC 2009 Decision, the BCUC decided that

> in determining a suitable ROE for TGI, it will give most weight to the DCF approach, some lesser weight to the ERP and CAPM approaches and a very small amount of weight to the CE approach.[83]

In 1994 the greatest weight was assigned to the equity risk premium results, so a determination of the appropriate risk-free rate, market risk premium and relative risk (beta) was important. The three components of the methodology, the risk-free rate, the market risk premium, and the relative risk, were determined as follows.

First, to assess the risk-free rate, the BCUC looked to the *Consensus Forecasts* and found that the forecasted yield on 10-year Government of Canada bonds adjusted for the spread in yield

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[79] BCUC In the Matter of Terasen Gas Inc. et al. Return on Equity and Capital Structure Decision, December 18, 2009 (BCUC 2009 Decision), pp. 72-73.

[80] Order 158-09, p. 3.

[81] BCUC 1994 Decision, p. 17.

[82] BCUC 2009 Decision, pp. 44-45.

[83] BCUC 2009 Decision, p. 45.

between 10 and 30-year Government of Canada bonds was reasonable. Second, to determine the market risk premium, the BCUC noted that

> Although historical studies can be used to establish a starting point for the estimate of the market risk premium, these studies show a wide dispersion of results depending on the time period and measurement techniques used.
>
> In addition, the measured market risk premium estimates must be adjusted to reflect concerns about the applicability of past time periods to future time periods. On balance, the Commission finds that these concerns suggest that the measured market risk premium over-estimates the market risk premium which investors currently anticipate. The Commission finds that the market risk premium is approximately 4.5 to 5.0 percent.[84]

Third, to determine relative risk, the BCUC commented that no single statistical measure would

> adequately capture investors' perceptions of the risk of utilities relative to the market, the Commission finds that the combination of the various statistical measures indicate that utilities are approximately one-half as risky as the market as a whole.[85]

Looking to the fair return standard, the BCUC 2009 Decision examined the short-term and long-term risks of the benchmark utility (TGI), the applicability of U.S. data and proxies, the methodologies to be used to determine the return on equity and the impact of deferral accounts. In assessing the use of Canadian and U.S. data, the BCUC considered recent decisions by the Alberta Utilities Board (AUC), the National Energy Board (NEB) as well as several studies on the allowed return on equity and stated that

> the Commission Panel agrees with the NEB and AUC that utilities in Canada need to compete for capital in the global market place, and regulatory agencies in Canada have to ensure that utilities subject to their jurisdiction are allowed a return that enables them to do so.[86]

As a result, the BCUC concluded that

> Given the paucity of relevant Canadian data, the Commission Panel considers that natural gas distribution companies operating in the US have the potential to act as a useful proxy in determining TGI's capital structure, ROE, and credit metrics.[87]

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[84] BCUC 1994 Decision, p. 18.

[85] BCUC 1994 Decision, p. 17.

[86] BCUC 2009 Decision, p. 15.

[87] BCUC 2009 Decision, p. 16.

In 2009, the BCUC considered results from the CAPM, ERP, DCF, and Comparable Earnings models to determine the ROE. The BCUC found that the DCF approach had more appeal than the ERP method because

> it is based on a sound theoretical basis, it is forward looking and can be utility specific.[88]

In evaluating the DCF results, the BCUC considered both single-stage and multi-stage models and determined that Canadian data suitable for DCF analysis are lacking but viewed the results from a DCF analysis of U.S. companies and U.S. gas distribution companies to be meaningful. The BCUC especially looked to *Value Line* growth forecasts and ignored large, diverse entities.[89] The BCUC considered but did not agree with arguments that analysts' growth forecasts were upward biased. It found no allegations against utility analysts and also viewed *Value Line* estimates as being free of any bias.[90] The BCUC found the DCF results to be consistent with an ROE of 10 to 10.5%.

When considering the risk premium results, the BCUC gave weight to Canadian data but not to U.S. data. Specifically, the BCUC considered the risk premium results calculated as the historical premium Canadian utilities have earned over long-term Canadian government bonds using the period 1956 through 2008.

Looking at the CAPM results, the BCUC noted that the underlying model is based on a theory that cannot be proven or disproven, relies on a market risk premium that looks back over nine decades and depends on a relative risk factor or beta. The BCUC noted that the relative risk factor or beta for Pacific Northern Gas (PNG) was only 0.26 in 2008 and required adjustment. Therefore, the

> relative risk factor should be adjusted in a manner consistent with the practice generally followed by analysts so that it yields a result that accords with common sense and is not patently absurd.[91]

As a result, the BCUC in its 2009 Decision relied on beta estimates in the range of 0.60 to 0.66, where the upper bound is consistent with *Value Line*'s beta estimates.[92] Based on the evidence,

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[88] BCUC 2009 Decision, p. 45.

[89] BCUC 2009 Decision, p. 51. For example, the BCUC did not use Equitable and Questar.

[90] BCUC 2009 Decision, p. 45.

[91] BCUC 2009 Decision, p. 45.

the BCUC concluded that a CAPM estimate using the estimate from *Consensus Forecasts* for the long-term risk-free rate, a beta of 0.60 to 0.66, and an MRP consistent with Canadian professors' forecast of 5 to 6% was reasonable. As a result the BCUC viewed the CAPM results to be in the range of 7.3 to 8.3%.[93]

Finally, the BCUC reviewed the results from the Comparable Earnings model and found that the companies in the selected sample were conservative stocks with conservative ratings with an average ROE of about 11.5%. The BCUC viewed a range of 10.5 to 11.5 as indicative of the ROE for a low business risk unregulated company.

The BCUC agreed with one of the expert witnesses that "under normal circumstances flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity, require a 25 basis point addition to the ROE estimate."[94] The BCUC further agreed with the practice of the AUC and added 50 basis points to the CAPM (for a total allowance of 75 basis points). The resulting ranges are indicated in **Table 1** below.

BCUC's 2009 ROE Decision			
	Range	Allowance	Total
DCF	9.0 - 10.0	0.25	9.25 - 10.25
ERP	9.25 - 10.0	0.25	9.5 - 10.25
CAPM	7.3 - 8.3	0.75	8.05 - 9.05
CE	10.5 - 11.5	0	10.5 - 11.5
Allowed ROE			**9.5**

Table 1

D. DETERMINING THE CAPITAL STRUCTURE

When setting the equity ratio for regulated utilities, the BCUC considers the utility's business risk.[95] In the BCUC 2006 Decision, when the BCUC considered the business risk of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc., the Commission noted that the business risks had not declined since 1994, so the benchmark utility would reasonably have a 35-38% equity

[92] *Value Line* reports betas that have been adjusted using a modification of the Blume adjustment method. Specifically, *Value Line* uses a formula of 0.35 plus 2/3rd times the estimated beta rounded to the nearest 0.05.

[93] BCUC 2009 Decision, pp. 59-60.

[94] BCUC 2009 Decision, p. 64.

[95] BCUC 1994 Decision, pp. 34-35, and BCUC 2009 Decision, pp. 76-77.

ratio. Due to the mitigating effects of deferral accounts, especially for commodities, the deemed equity for the benchmark utility was set at 35%, while the Terasen Gas (Vancouver Island) Inc.'s deemed equity ratio was set to 40% due to its higher risks.[96] In 2009, the BCUC also considered business risks to determine capital structures. For TGI, the BCUC distinguished between short-term and long-term risks with short-term risks but not long-term risks being mitigated by deferral accounts.[97]

Further, the BCUC considered PNG's risk from exposure to a mix of customers highly concentrated in industrial customers in determining PNG's deemed capital structure. In addition, the BCUC also reviewed the credit impact of capital structure decisions.[98] In raising the benchmark utility's equity ratio to 40% from 35% in 2009, the BCUC noted

> a 40 percent equity level would move TGI from a Ba to Baa under Moody's factor mapping and that this metric alone is worth 15 percent of a Moody's rating. Similarly the combination of a 40 percent equity level and a ROE of 9.5 percent will result in an increase in EBIT/Interest from between 1-2 to between 2-3 and would move TGI from Ba to Baa, under Moody's factor mapping and that this metric is worth another 15 percent of a Moody's rating.[99]

E. ALLOWED COST OF CAPITAL AND CAPITAL STRUCTURE

Table 2 below shows the allowed ROE and capital structure for the benchmark utility in British Columbia:

[96] BCUC 2006 Decision, pp. 36 and 38.

[97] BCUC 2009 Decision, p. 19.

[98] BCUC 1994 Decision, p. 23, BCUC 2006 Decision, pp. 31-38, BCUC 2009 Decision, pp. 36-37.

[99] BCUC 2009 Decision, p. 68.

BC Benchmark ROE and Capital Structure		
	ROE Benchmark utility	**Capital Structure**
2011	9.50%	40.0%
2010	9.50%	40.0%
July 2009	9.50%	40.0%
2009	8.47%	35.0%
2008	8.62%	35.0%
2007	8.37%	35.0%
2006	8.29%	35.0%
2005	9.03%	33.0%
2004	9.15%	33.0%
2003	9.42%	33.0%
1994	10.75%	33.0%

Table 2[100]

In addition to the benchmark utility, the BCUC sets the allowed ROE and capital structure for several other utilities. In the BCUC 1994 decision, PNG was considered to be the riskiest utility, because of its exposure to a few large industrial customers and its interruptible service. As a result, the BCUC in 1994 set its allowed ROE 75 basis points above that of the benchmark utility and its equity percentage at 43%. Also, the BCUC 2006 Decision allowed Terasen Gas Vancouver Island an ROE adder of 70 basis points over the benchmark utility. Other utilities were placed between the benchmark utility and PNG. **Table 3, Panel A** below shows the company equity risk premium over the benchmark utility that BC utilities were allowed to earn over the past five years.

[100] Sources: BCUC 1994 Decision, BCUC 2006 Decision, BCUC 2009 Decision, Fortis 2011 10-K, Order G-158-09, Letter No L-55-08, Letter No. L-93-07, Letter No. L-75-06, Letter No. L-104-05, Letter No. L-55-04, Letter No. L-57-03, Letter No. L-46-02, Order G-35-95.

Allowed Company Equity Risk Premiums

Company	2011	2010	July 2009	2009*	2008	2007
FortisBC Energy Inc.	0	0	0	0	0	0
FortisBC Energy (Vancouver Island) Inc.	50	50	50	70	70	70
FortisBC Energy (Whistler) Inc.	50	50	50	50	60	60
FortisBC Inc.	40	40	-	40	40	40
PNG - West Division	65	65	-	65	65	65
PNG - Fort St. John / Dawson Creek Division	40	40	-	40	40	40
PNG - Tumbler Ridge Division	65	65	-	65	65	65

*2009 benchmark as per Letter L-55-08.
All values are in basis points.

Table 3, Panel A[101]

The common equity thickness that BC utilities have been deemed over the past five years is shown in **Table 3, Panel B** below.

Allowed Common Equity Thickness

Company	2011	2010	July 2009	2009*	2008	2007
FortisBC Energy Inc.	40%	40%	35%	35%	35%	35%
FortisBC Energy (Vancouver Island) Inc.	40%	40%	40%	40%	40%	40%
FortisBC Energy (Whistler) Inc.	40%	40%	40%	40%	40%	40%
FortisBC Inc.	40%	40%	-	40%	40%	40%
PNG - West Division	45%	45%	-	40%	40%	40%
PNG - Fort St. John / Dawson Creek Division	40%	40%	-	36%	36%	36%
PNG - Tumbler Ridge Division	40%	40%	-	36%	36%	36%

*2009 benchmark as per Letter L-55-08.

Table 3, Panel B[102]

F. DEFERRAL ACCOUNTS

In assessing the impact of deferral accounts on the cost of capital and capital structure, the BCUC in its 2006 Decision observed that the majority of gas companies in North America have commodity deferral accounts. In addition, many other of TGI's deferral accounts were associated with its performance based rates and therefore were simply intended to avoid penalizing the company for over or underestimating costs it does not control.[103] Other accounts such as weather normalization act symmetrically and hence should not affect the cost of equity. The BCUC 2006 Decision concluded that

[101] Provided by BCUC Staff.
[102] Provided by BCUC Staff.
[103] BCUC 2006 Decision, p. 25.

> the appropriate capital structure range for consideration of TGI is in the range of 35 percent to 38 percent and that given the effect of deferral accounts in reducing the risk of TGI, the appropriate equity component for TGI is 35 percent.[104]

In its 2009 decision, the BCUC considered the effects of deferral accounts on reducing short-term risk and not the long-term business risk. As a result, the effect was taken into account through the ROE rather than through the capital structure. The BCUC concluded that significant risk adjustments to U.S. data are required to take into account the effect of deferral accounts. A partial reason for the reduction of the premium ROE to Terasen Gas (Vancouver Island) Inc. to 50 basis points from 70 basis points was that the utility was judged to have greater certainty of recovery of its Revenue Deficiency Deferral Account.[105]

IV. ALBERTA UTILITIES COMMISSION

A. INTRODUCTION

In 2008, the former Alberta Energy and Utilities Board (AEUB) was split into two parts with the Alberta Utilities Commission (AUC) becoming the regulator of electric, gas, and water utilities plus some municipal electric utilities. Therefore, the following pertains to the current AUC and until the split, the former AEUB. The AUC currently determines a "generic" cost of capital for all the entities it regulates. The most recent decision was in December 2011, which set the rate of return on equity and the capital structures of the regulated firms for 2011 and 2012. Similarly, a generic proceeding in 2009 determined the cost of capital and capital structure for the utilities for 2009 and 2010. Until 2009, the AUC (and its predecessor the AEUB) relied on a formulaic approach to update the cost of equity annually using a formula whose parameters had been determined in 2004. Capital structure is deemed and based on the business risk of the individual utilities and updated less frequently than the cost of capital. The ROE is referred to as "generic" because the approved ROE applies uniformly to all affected utilities, which currently consist of AltaGas Utilities Inc. (gas distribution), AltaLink L.P. (electric transmission), ATCO Electric Ltd. (electric distribution and transmission), ATCO Gas (gas distribution), ATCO Pipelines (gas transmission), ENMAX Power(electric distribution and transmission), EPCOR Distribution & Transmission Inc. (electric distribution and transmission), and FortisAlberta Inc. (electric distribution).[106] AUC's generic cost of capital and capital structure decisions apply to electric

[104] BCUC 2006 Decision, p. 36.

[105] BCUC 2009 Decision, p. 76. Another reason was a resolution of a contracting issue.

[106] Decision 2011-474, p. 1.

transmission, electric distribution, gas distribution, and pipelines as listed above.[107] In addition, prior decisions on the allowed ROE have also been applied to smaller municipal utilities such as Lethbridge TFO and Red Deer TFO.[108] The main electric distribution companies are ATCO Electric Disco,[109] ENMAX Disco, EPCOR Disco, and FortisAlberta. Gas distribution companies are ATCO Gas and AltaGas, which serves a smaller number of customers and in more rural areas. Finally, ATCO Pipeline, which is a natural gas pipeline, is included in AUC's generic proceedings.[110] All of the above ATCO entities are subsidiaries of ATCO Holdings, which is an investor-owned public utility operating in electric and gas distribution and transmission. FortisAlberta is an electric distribution company that is a subsidiary of Fortis Inc., which in addition to FortisAlberta operates electric distribution, integrated, and power utilities in British Columbia, Ontario, Newfoundland, Prince Edward Island, and overseas. AltaLink is an investor-owned transmission only entity. EPCOR and ENMAX are owned by the City of Edmonton and the City of Calgary, respectively, and both operate in generation, transmission, and distribution of not only electricity but also gas and water. Finally, the cities of Lethbridge and Red Deer provide electric and gas services to the communities in which they are located and are subject to AUC regulation under a cost-of-service model.

B. HISTORY

In 2002, the AEUB (now AUC) called a generic cost of capital proceeding that included a consideration of whether the AUC should rely on a generic cost of capital going forward and if so, at what level should the parameters be set.[111] The process also involved a determination of whether a formulaic approach to updating the cost of equity was warranted, and if so, what that formula should be. In Decision 2004-052, the AEUB (the predecessor to the AUC) implemented a generic cost of capital for the utilities it regulated and adopted a formula, updated annually, that used 75% of the change in the forecasted long-term government bond yield to adjust the return

[107] The rate is also commonly applied to water utilities regulated by the AUC.

[108] The AUC uses the term Transmission Facilities Owner (TFO) to designate electric transmission.

[109] The AUC uses the term Disco to designate an electric distribution entity.

[110] NGTL (a subsidiary of TransCanada) was under AUC jurisdiction until 2009, when it moved to National Energy Board jurisdiction.

[111] In the proceeding that led to Decision 2004-052 (issued July 2, 2004), some utilities (ATCO and NGTL) objected to the formulaic approach while others (AltaGas) were in favour. Consumer groups and industrial users were all in favor of a generic cost of capital updated annually using a formulaic approach.

on equity. Specifically, the formula the AEUB adopted as a result of its 2004 generic ROE proceeding[112] was

$$\text{ROE} = \text{BaseROE} + 0.75 \times (\text{LCBF} - \text{BaseLCBF}) \quad \textbf{(22)}$$

The BaseROE for 2004 was set at 9.60%, and the Base Long Canada Bond Forecast (LCBF) was set at 5.68%.[113] In Decision 2004-052, the AEUB arrived at its cost of equity estimate looking to the CAPM, which resulted in an estimate of 9.2% and adjusted for the results of other tests. The AEUB found that looking at market-to-book ratios and acquisition premia or income trusts would indicate an ROE below that obtained from the CAPM. However, the AEUB also found that results from equity risk premium models other than the CAPM, allowed ROEs for other Canadian utilities and U.S. utilities as well as pension fund return expectations indicated an ROE higher than the CAPM. The AEUB also found because the formula in Equation (22) adjusts the ROE by only 75% of the change in government bond yields, rather than the 100% indicated by the CAPM, an upward adjustment of 40 basis points to the cost of equity obtained from the CAPM was warranted. The annual Long Canada Bond Forecast was obtained from the November issue of *Consensus Forecasts*.

The formula had two sunset provisions. Decision 2004-052 called for a (i) review in five years or (ii) a review if the calculated ROE increased or decreased by more than 2% over the base level of 9.60%.[114]

The formulaic approach was maintained through 2008, when the AUC called for a review of the base ROE, the formulaic update and the capital structures of the individual utilities which led to Decision 2009-216.[115] The formula was discontinued in Decision 2009-216, but the AUC maintained a generic cost of equity. For 2009-10 the generic ROE was set at 9.0%, which Decision 2011-474 updated to 8.75%. The AUC explained its reasons for discontinuing the formula as follows:

> As the Commission explained in Decision 2009-216, the 2004 formula was developed based on the expectation that the required rate of return for utilities

[112] The AEUB called a generic hearing to consider cost of capital matters for electric, gas and pipeline utilities under its jurisdiction in 2002, which lead to submissions and expert evidence from interested parties, a hearing and ultimately Decision 2004-052.

[113] The 5.68% was the estimate from *Consensus Forecasts* in November 2003 for the 2004 long-term government bond yield.

[114] Decision 2004-052, pp. 56-59.

[115] Decision 2009-216 was issued November 12, 2009.

> moves in the same direction as the return on 30-year Government of Canada bonds. The Commission found that, during a time of adverse market conditions, this expected relationship between interest rates and the required return on equities does not necessarily hold.[116]

The AUC will use the 8.75% ROE as an interim rate for 2013, but expects to initiate a proceeding to establish the final ROE for 2013 as well as to revisit the formula approach.

C. ESTABLISHING THE ROE

In its 2009 decision, the AUC reviewed the ROE methodologies submitted by the participating parties. The AUC considered the Capital Asset Pricing Model (CAPM) and the Discounted Cash Flow (DCF) Model to determine the ROE but did not specify the weight assigned to each method.[117]

1. Capital Asset Pricing Model

The AUC considered evidence on the CAPM model specified in Equation (2) in *Section II.B.3*, i.e.,

$$r_S = r_f + \beta_S \times MRP$$

Where, as before, r_S is the return on stock S, r_f is the risk-free rate, β_S is the beta measure and MRP is the market risk premium.

In its 2009 order, the AUC focused on the composition of the sample of comparable companies, the risk-free rate, the measure of beta and the market risk premium.

Comparable Companies

An issue in the AUC proceeding was the comparability of Canadian and U.S. utilities. The AUC looked to the comparability of business risk and of the regulatory environment and found that the business risk was comparable, stating that

> The Commission agrees that the business risks, other than regulatory risks, of the utility business are similar between Alberta utilities and counterparts in the U.S. With a few exceptions, utilities on both sides of the border utilize similar capital intensive fixed cost infrastructure and employ the same technologies in delivering their services, have similar operating and reliability standards and face similar commodity supply and demand dynamics. The Commission would also agree

[116] Decision 2011-474 issued December 8, 2011, ¶163.

[117] Decision 2009-216, ¶323.

> that while there may be some short-term differences in investor expectations between the two countries arising from macroeconomic factors given the relative impact of the current financial crisis on the U.S. and Canadian economies, in the longer run microeconomic factors should not result in an appreciable difference in investor expectations.[118]

However, regarding the regulatory risk, the AUC distinguished between allowed and expected returns for U.S. utilities and determined that allowed U.S. returns were not suitable as a benchmark for Alberta utilities. The AUC found that risk-adjusted market return were useful in determining the cost of capital for Alberta utilities.

> Accordingly, expected market determined returns for U.S. utilities may be used on a market risk-adjusted basis in assessing a fair return for Alberta utilities, provided there is sufficient evidence to derive those expected market determined returns.[119]

Risk-free Rate

The AUC has traditionally used the *Consensus Forecasts* for the risk-free rate and did so in 2009, when the forecast was 4.13 to 4.50% depending on the exact forecast period.[120] In 2011, the AUC also looked to the *Consensus Forecasts* to determine the risk-free rate and added 50 basis points for the spread between the 10-year and the 30-year bonds. This resulted in a risk-free rate of 3.8 to 4.3%.[121]

Beta[122]

In determining which beta to use, the AUC reviewed the evidence submitted and made the following determinations:

- Accepted a recommended beta estimate of 0.50 as the lower bound.[123]
- Accepted a recommended beta of 0.63 for Canadian utilities based on an adjustment toward one because "unadjusted results were not adequately

[118] Decision 2009-216, ¶144.

[119] Decision 2009-216, ¶200.

[120] Decision 2009-216, ¶233.

[121] Decision 2011-474, ¶41.

[122] Some jurisdictions consider or rely on adjusted betas. Although the methodology may vary, the adjustment moves the estimated betas towards one. For example, the Blume adjustment moves the beta estimate 1/3 towards one.

[123] Decision 2009-216, ¶254 and Decision 2011-474, ¶67.

representative of forward looking expectations" in 2009. For 2011, the upper bound was set at 0.65 as it had not changed materially from 2009.[124]

- Rejected the use of "adjusted betas for Canadian utilities if the purpose of the adjustment is to adjust the beta towards one..."[125]
- Rejected a beta of 0.93 "as unreasonably high, noting that it is based strictly on U.S. data."[126]

Market Risk Premium

For the 2009 proceeding, the participating experts submitted evidence on a market risk premium ranging from 5.0% to 6.25%. The AUC rejected the highest figure, 6.25%, as "unreasonably high,"[127] but accepted that "the market equity risk premium may currently be higher than in the past, a market equity risk premium of 5.75 may be warranted." As a result, the AUC found the market risk premium to be in the range of 5.0% to 5.75% for 2009-2010. However, in the 2011 proceeding, the AUC decided that

> the expected market equity risk premium today may be higher than its" historic average, due to today's low interest rates. The Commission accepts that the market equity risk premium today may reasonably be as high as the 7.25 per cent.[128]

The higher MRP was obtained as a result of regression analyses demonstrating that the market return on equity changes by less than the amount of the change in the risk-free rate.[129] As in the 2009 decision, the lower bound on the MRP was set at 5.0%.

Results from the CAPM

Based on the parameters discussed above, the AUC calculated the following CAPM-based ROE figures:

[124] Decision 2009-216, ¶254 and Decision 2011-474, ¶67.

[125] Decision 2009-216, ¶251.

[126] Decision 2009-216, ¶252.

[127] Decision 2009-216, ¶239.

[128] Decision 2011-474, ¶58.

[129] Decision 2011-474, ¶50-58.

AUC's CAPM-Based ROE			
	Before Flotation Costs	Flotation Costs	**Resulting ROE**
2009	6.63% - 8.12%	0.50%	7.13% - 8.52%
2011	5.9% - 8.5%	0.50%	6.4% - 9.0%

Table 4

Flotation costs are the costs a company incurs when it issues new securities. The AUC has historically added flotation costs to the allowed ROE and in the proceeding that led to Decision 2009-216, all parties recommended 50 basis points. The AUC agreed "that a flotation allowance of 0.50% is warranted."[130]

2. Discounted Cash Flow Model

In both the 2009 and 2011 proceedings, the AUC evaluated the CAPM and the Discounted Cash Flow or DCF model. Although there are many versions of the DCF model, they all determine today's stock price as a sum of discounted cash flows that are expected to accrue to shareholders. The model specification was provided in *Section II.C.4* above.

In its 2009 decision, the AUC expressed concern that many of the comparable companies were holding companies with un-regulated activities. The AUC therefore decided to rely primarily on a version of the multi-stage model, where the growth rate converges from the utility-specific growth forecast to the GDP growth rate.[131] This resulted in a lower estimate than would have been derived from the single-stage model in Equation (16). In 2011, the AUC expressed concern about analysts' optimism bias for the single stage model and again relied on a multi-stage version of the DCF model.[132]

As for the CAPM, the AUC includes a 50 basis point flotation allowance and consequently obtained the following ranges for its DCF estimates in 2009 and 2011.

- 2009: 8.8% to 9.3% (including flotation costs)
- 2011: 8.8% to 9.5% (including flotation costs)

[130] Decision 2009-216, ¶255.
[131] Decision 2009-216, ¶271.
[132] Decision 2011-474, ¶87-90.

D. PREFERRED SHARES

In Decision 2004-052, the AEUB noted that ATCO Electric Transmission, ATCO Pipelines, ATCO Gas, and ATCO Electric Distribution had preferred shares in the companies' capital structure,[133] but the AEUB concluded that

> Although the preferred shares provide additional support to the capital structure, in this analysis, the Board has evaluated the appropriate common equity ratio as if the company had no support from its preferred shares.[134]

Because no preferred equity was present in the deemed capital structure, no cost of preferred was determined. More recent decisions have followed the same practice and no cost of preferred equity is mentioned in the more recent AUC decision.

E. SETTING THE CAPITAL STRUCTURE

The AUC considers the utility's business risk to determine its capital structure and performs an analysis of the equity ratio that is needed to target an A-rating. In the 2009 Decision, the AUC, in response to the financial crisis, increased all utilities equity ratio by 2% and then made adjustments based on the individual utility's risk profile. Further, the AUC added an additional 1% equity to the electric transmission entities in recognition of their large upcoming capital expenditures. In 2011, the AUC found that

> There is no need to reverse the adjustment to the Alberta utilities' capital structure that was provided in Decision 2009-216 to account for the financial crisis, because the effects of the financial crisis have not completely abated.[135]

The credit metric analysis of relatively pure-play Canadian utilities indicated that for the utilities to target an A-rating, the minimum equity ratio would be:[136]

- Based on EBIT coverage: 37%
- Based on FFO Interest Coverage: 30 – 38%
- Based on FFO to Total Debt: 35%

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[133] Decision 2004-052, pp. 44, 47, 52 and 55.

[134] Decision 2004-052, p. 44.

[135] Decision 2011-450, ¶288.

[136] EBIT is Earnings Before Interest and Taxes, FFO is Funds from Operations and the coverage ratio is obtained by dividing EBIT or FFO by interest.

Based on these figures and a review of the business risk, the AUC determined the 2009 (and 2011) equity percentages as follows:[137]

- Distribution (except AltaGas): 39 – 41%
- AltaGas 43%
- Electric Transmission: 36 – 37%
- Pipelines: 45%.

The AEUB in Decision 2004-052 determined that electric transmission entities had the lowest risk, because they were less exposed to demand risk than other entities and because the Alberta Electric System Operator, who is the sole customer, has low credit risk. Further, the AEUB noted that the pipelines face more competition risk than other utilities and therefore had the highest business risk.[138] Finally, AltaGas was awarded a higher equity percentage because of its more disperse service territory. The AUC in 2009 modified the equity percentages of the utilities, but did not change its ranking. In its 2011 Decision, the AUC concluded that there had been no major changes in business risk between 2009 and 2011 with the possible exception of ATCO Pipelines following its integration with NGTL. As a result the equity ratios were not changed in the 2011 decision.

F. ALLOWED COST OF EQUITY AND DEBT

Based on the methodology described above, the AUC (AEUB) has allowed a generic cost of equity for the majority of its utilities as indicated in **Table 5** below. The ROEs displayed in bold are those from the periodic review of the AUC's methodology.[139]

[137] Decision 2009-216, ¶412.

[138] Decision 2004-052, pp. 46-54.

[139] A few smaller utilities have had their cost of equity or capital structure modified.

AUC / AEUB Cost of Equity	
	ROE
2012	8.75%
2011	***8.75%***
2010	9.00%
2009	***9.00%***
2008	8.75%
2007	8.51%
2006	8.93%
2005	9.50%
2004	***9.60%***

Table 5[140]

The AUC (and AEUB) has consistently allowed utilities it regulates to recover their embedded cost of debt and the decisions do not address debt costs.[141]

G. CAPITAL STRUCTURE

The AUC determines a deemed (allowed) capital structure. In recent years electric transmission entities have been allowed 36-37% equity, electric and gas distribution entities have been allowed 39-41% equity, except AltaGas which has been allowed 43% equity and ATCO Pipelines which has been allowed 45% equity. In allowing AltaGas and ATCO Pipelines a higher equity percentage than that of other utilities, the AUC stated

> The Board considers that AltaGas has greater business risk than the typical gas distribution company.[142]

The AEUB noted that the larger business risk was due to the nature of AltaGas's service territory and rejected attributing the additional business risk to the company's smaller size.[143]

In **Table 6** below, the bolded years and figures indicate years, where the capital structure was changed.

[140] Decision 2009-216 and Decision 2011-474.

[141] Decision 2004-052, p. 41. Neither Decision 2009-216 nor Decision 2011-474 address explicitly the cost of debt but calculations are done using an assumed "embedded cost of debt".

[142] Decision 2004-052, p. 53.

[143] Decision 2004-052, p. 54.

Deemed Equity Percentage				
	Electric Transmission[1]	Electric and Gas Distribution[2]	AltaGas	ATCO Pipelines
2012	36-37%	39-41%	43%	45%
2011	36-37%	39-41%	43%	45%
2010	36-37%	39-41%	43%	45%
2009	**36-37%**	**39-41%**	**43%**	**45%**
2008	33-35%	37-39%	41%	43%
2007	33-35%	37-39%	41%	43%
2006	33-35%	37-39%	41%	43%
2005	33-35%	37-39%	41%	43%
2004	***33-35%***	***37-39%***	***41%***	***43%***
2003	32-35%	35-37%	41%	43.5%

Sources and Notes:
1, 2009 36%: ATCO Electric TFO, AltaLink, TransAlta
37%: ENMAX TFO, EPCOR TFO, Lethbridge TFO, Red Deer TFO,
2, 2009 39%: ATCO Electric DISCO, ATCO Gas,
41%: ENMAX Disco, EPCOR Disco, FortisAlberta
1, 2004 33%: ATCO Electric TFO
35%: AltaLink, EPCOR TFO
2, 2004 37%: ATCO Electric DISCO, FortisAlberta, NGTL (at the time under AEUC jurisdiction)
38%: ATCO Gas
39%: ENMAX Disco, EPCOR Disco

Table 6 [146]

H. DEFERRAL ACCOUNTS

Several utilities under AUC jurisdiction have deferral accounts, and the AUC found in its 2009 generic cost of capital decision that the presence of such accounts affects business risk. For example, the AUC found that the presence of deferral accounts reduced the business risk of Alberta utilities relative to U.S. utilities.[145] Further, the AUC specifically evaluated the impact of weather normalization deferral accounts and found that they reduced business risk. For example, while all utilities were awarded a 2% increase in the equity thickness in 2009 prior to any adjustments for business risk, the AUC reduced the increase for ATCO Gas to 1%.

> This is based on the 2 percentage point base increase and a deduction of 1 percentage point to recognize that it now has a weather deferral account.[146]

[144] Decision U99099, Volume I, Decision 2009-216, and Decision 2011-474.

[145] Decision 2009-216, ¶166.

[146] Decision 2009-216, ¶212.

Because the AUC has in past decisions determined that some deferral accounts reduce business risk, the AUC reduced the equity ratio of ATCO gas.

V. ONTARIO ENERGY BOARD

A. INTRODUCTION

The Ontario Energy Board (OEB) regulates Ontario's electric and gas markets and utilities including large electric distribution and transmission utilities such as Hydro One, Enbridge Gas, Union Gas as well as other utilities.[147] The OEB introduced a formulaic approach to setting cost of equity in 1997 and reviewed the formula and its base parameters in 2004 and 2009. The same cost of equity is awarded to electric and gas distribution and transmission entities (including Crown corporations).[148]

While the OEB generally uses the utility's embedded cost of debt for rate making purposes, a formulaic approach is used to determine the deemed cost of long-term and short-term debt. This cost of debt is used to set the cost of debt for entities that have no debt outstanding and as a cap on inter-company borrowing costs.

During its periodical review of the cost of capital methodology and the formula used annually to update the cost of equity and debt, the OEB reviews and sets the deemed capital structure for the utilities it regulates. The OEB finds that "capital structure should be reviewed only when there is a significant change in financial, business, or corporate fundamentals."[149] In its most recent review in 2009, the OEB found that 40% equity and 60% debt (56% long-term and 4% short-term) was appropriate for all electric distributors whereas the deemed capital structure for electric transmission and gas distribution and transmission would be reviewed on a case-by-case basis.

The largest electric distribution and transmission utility regulated by the OEB is Hydro One Networks, which is a subsidiary of Hydro One. Hydro One Networks provides approximately 95% of the electric transmission needs in Ontario and handles the distribution service for 1.3 million customers in Ontario. The two largest gas distribution companies, Union Gas and Enbridge Gas, are both subsidiaries of larger entities, Spectra Energy and Enbridge Inc.,

[147] The OEB does not regulate competitive electric or gas supply, but it oversees wholesale markets.

[148] The OEB bases rates on a forecast test year and the forecasted cost of service.

[149] Ontario Energy Board, "EB-2009-0084: Report of the Board on the Cost of Capital for Ontario's Regulated Utilities," issued December 11, 2009 (EB-2009-0084), p. 49.

respectively. Although the holding companies are involved in a wide range of energy and utility-related businesses, both Union Gas and Enbridge Gas focus on natural gas distribution, storage and transmission. Union Gas provides distribution services to approximately 1.4 million customers in Ontario, while Enbridge Gas has approximately 2 million customers in Ontario and upstate New York.

B. HISTORY

In each of 1997,[150] 2004, and 2009, the OEB determined the allowed return on equity for that year as well as a Base ROE. The ROE is then modified each year based on the change in interest rates. The decision following each review determined that a formula-based approach was appropriate using a version of the Equity Risk Premium (ERP) method, where the initial or Base ROE is determined as the return on long-term government of Canada bonds plus a premium. Exactly how the premium was determined is not clear, but the OEB's consultant considered the risk premium model and the CAPM to assess the premium and included a flotation allowance. Further, the OEB's 2006 Report on Cost of Capital and 2nd Generation Incentive Regulation indicates that since 1999 the OEB has relied on its consultant's report.[151] The 1997 review primarily reviewed evidence from other jurisdictions (British Columbia, Manitoba, and the National Energy Board). The 2004 review was requested by Enbridge Gas and Union Gas. The 2009 review was a Board initiated consultative process involving all stakeholders.[152] In each decision, the OEB maintained its formulaic approach relying on the equity risk premium methodology. The 2004 review maintained the parameters from prior years, but the 2009 proceeding updated the Base ROE and also changed the formula taking the financial crisis and interest rate developments into account.

1. Annual Update

From 1998 through 2009, the OEB determined the annual allowed cost of equity in a manner similar to the AUC using the formula:

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[150] The 1997 process applied to gas utilities only. The approach was extended to included electric utilities in 1999 when the OEB's oversight was expanded to include electric utilities. See EB-2009-0084, p. 5.

[151] See RP-1999-0034 pp. 22-24, William T. Cannon, "*The Appropriate Return on Equity for the Transco and Disco Business Operations of the Ontario Hydro Services Company*," prepared for the Ontario Energy Board, January 22, 1999, pp. 28-44, and *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, issued December 20, 2006, p. 5.

[152] OEB, "Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities," March 1997 (1997 Draft Guidelines), RP-2002-0158, and EB-2009-0084.

$$ROE = BaseROE + 0.75 \times (LCBF - BaseLCBF) \quad \textbf{(23)}$$

Where ROE is the allowed return on equity; BaseROE is return on equity that was allowed in the initial year; LCBF is the Long Canada Bond Forecast for the year; and BaseLCBF is the Long Canada Bond Forecast for the initial year. The 0.75 adjustment factor was determined following a generic cost of capital proceeding.[153]

Following the 2009 review, the OEB decided to update the BaseROE and BaseLCBF as well as to modify the formula to

$$\begin{aligned} ROE = BaseROE_{2009} &+ 0.50 \times (LCBF - BaseLCBF_{2009}) \\ &+ 0.50 \times (UtilBondSpread - BaseUtilBondSpread_{2009}) \end{aligned} \quad \textbf{(24)}$$

Where ROE is the allowed return on equity; $BaseROE_{2009}$ is return on equity that was allowed in 2009 (the new base year); LCBF is the Long Canada Bond Forecast for the year; and $BaseLCBF_{2009}$ is the Long Canada Bond Forecast for 2009. As a result of the review process in 2009, the adjustment factor on long Canada bonds was reduced to 0.50, because the OEB agreed that the new empirical evidence indicated that the adjustment factor was closer to 0.50 than to 0.75. In addition, the OEB added a second adjustment factor to its formula. The second factor is based on the change in the spread between utility bond yields and long Canada bond yields, i.e., it accounts for changes in utility bond yields, but does so in a manner that only considers the change in the spread relative to long-term government bond yields. The inclusion of this second factor was also based on acceptance of evidence presented by experts in the 2009 review of the OEB's formula.

C. ESTABLISHING THE ROE

In the OEB's view, the BaseROE needed to "be reset to address the difference between the allowed return on equity arising from the application of the formula and the return on equity for a low-risk proxy group that cannot be reconciled based on differences in risk alone."[154] Consequently, the OEB updated the BaseROE using the evidence from its 2009 generic proceeding. Specifically, the OEB reviewed the recommendations in the submissions, determined each submission's Low, Medium, and High ERP, and then selected an ERP of 5.50%

[153] The 0.75 adjustment factor originated in the Ontario Energy Board's, "Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities," March 1997, p. 31. The long-term government bond forecast is obtained from the publication Consensus Forecasts, which is a UK based subscription service, and from Bank of Canada.

[154] EB-2009-0084, p. ii.

based on the average of the low end of the submitted ERP recommendations.[155] In determining the initial ERP, the OEB found that "**the use of multiple tests to directly and indirectly estimate the ERP is a superior approach to informing its judgment than reliance on a single methodology**."[156] As a result, the OEB included all submissions, which included ERP estimates based on the CAPM, DCF, econometric ERP analyses, realized ERP analyses, the difference between awarded ROEs and realized government bond yields, and various forecasts. The OEB summarized the experts' calculations of the risk premium over the long-term government bond and found that the low-end of the recommended ERPs averaged 5.51%, the medium averaged 5.67%, and the high-end averaged 5.85%.[157] Based on this evidence, the OEB decided to use an ERP of 5.50% and added a forecasted long-term Canadian Government bond yield of 4.25% to arrive at an initial ROE of 9.75% for 2009.

In determining the initial risk premium, the OEB reviewed the evidence submitted by five experts and concluded that "North American gas and electric utilities provide a relevant and objective source of data for comparison."[158] As a result, the OEB included analyses of U.S. electric and gas utilities as part of the evidence used to determine the baseline risk premium, which is added to the long-term Government bond yield to estimate the baseline ROE (for 2009).

To arrive at the formula in Equation (24) and the initial ERP, the OEB determined that the forecasted long-term government bond is an important forward looking component of the formula and that using the same government bond as is used to determine the initial ROE ($BaseROE_{2009}$) is logical.[159] The OEB determined that the adjustment factor on the change in the long-term government bond rate is an empirical question and relied upon statistical analyses provided by experts to assess its magnitude.[160] The OEB included an additional factor in the formula, in Equation (24), because as the OEB concluded that "**there is a statistically significant relationship between corporate bond yields and the cost of equity, and that a corporate bond yield variable should be incorporated in the ROE formula**."[161] Three experts in the OEB proceeding provided statistical analyses of the relationship between the allowed ROE and utility bond yields or between realized returns on equity and corporate bond yields. They found that an

[155] EB-2009-0084, p. 38.
[156] EB-2009-0084, p. 36 (emphasis in the original).
[157] See Table 1 p. 37 of EB-2009-0084.
[158] EB-2009-0084, p. 23.
[159] EB-2009-0084, p. 45.
[160] EB-2009-0084, p. 46.
[161] EB-2009-0084, p. 48 (emphasis in the original).

increase (decrease) in bond yield results in an increase (decrease) in allowed ROE / realized equity return of 0.45 to 0.55.

D. COST OF DEBT

If the regulated utility issues its own debt, the OEB relies on the embedded cost of debt as the cost of debt for utilities it regulates unless the utility issues no debt.[162] The allowed embedded cost of debt includes interest and amortizations of any issuing discounts or premia. If the utility expects to issue new debt during the test year, the utility is expected to provide a forecast of the associated costs.

For those utilities that have no issued debt and those that expect to issue new debt but have no third-party estimate on the cost, the OEB relies on a deemed cost of long-term and short-term debt. The deemed cost of debt can also be used as a cap on the interest that can be paid to affiliated companies and recovered in rates.[163] The deemed long-term cost of debt is determined as the Long Canada Bond Forecast used in the ROE formula (24) plus the average spread of a long-term A-rated utility bond yield over the long Canada bond yield. Specifically,[164]

$$LTDR_t = LCBF_t + Average_{3\ months}\ (UtiliBonds_t - CB_t) \qquad \textbf{(25)}$$

Where LTDR is the Long-term Deemed Debt Rate, LCBF is LCBF is the Long Canada Bond Forecast for the year, UtiliBonds is the realized yield on 30-year A-rated utility bonds, CB is the realized yield on 30-year Canada Bonds and the average is taken over three months prior to the date the rates are implemented.[165]

Similarly, the OEB determined a deemed short-term debt rate (STDR), which is the average 3-month banker's acceptance rate plus a forecasted average spread of short-term debt issuances over the 3-month banker's acceptance rate using R1-low Canadian utilities.[166] Specifically,[167]

$$STDR_t = Average\ (BA_t) + AnnualSpread_t \qquad \textbf{(26)}$$

[162] Utilities must submit embedded cost of debt estimates to the OEB annually.

[163] EB-2009-084, p. 59.

[164] EB-2009-0084, Appendix C.

[165] OEB obtains the UtiliBond yield from Bloomberg (Series C29530Y) and the yield on long Canada Bonds (CB) from Cansim (Series V39056).

[166] R1-low is a rating designation used by Dominion Bond Rating Services.

[167] EB-2009-0084, Appendix D.

Where STDR is the Short-Term Deemed Debt Rate, BA is the 3-month Banker's Acceptance rate, which is averaged over a month, and AnnualSpread is the average annual spread between debt issuances of an R1-low utility and 3-month Banker's Acceptance rate. The AnnualSpread is obtained by OEB staff by contacting major banks whereas the 3-month Banker's Acceptance rate is available from Cansim (Series V39071).

E. ALLOWED COST OF EQUITY AND DEBT

Based on the methodology described above, the OEB has determined a generic cost of equity for the electric and gas distribution and transmission entities it regulates. The ROE that has resulted from the OEB's formula and reviews along with the deemed long-term and short-term cost of debt appear in **Table 7** below.

OEB Generic Cost of Capital Rates			
	ROE	**Deemed LT Debt Rate**	**Deemed ST Debt Rate**
1/1/2012	9.42%	5.01%	2.08%
5/1/2011	9.58%	5.32%	2.46%
5/1/2010	9.85%	5.87%	2.07%
1/1/2009	9.75%	7.62%	1.33%
1/1/2008	8.53%	n/a	n/a
1/1/2007	8.35%	n/a	n/a
1/1/2006	9.00%	n/a	n/a
1/1/2005	9.00%	n/a	n/a
1/1/2004	9.71%	n/a	n/a

Table 7[168]

F. CAPITAL STRUCTURE

The OEB determines a deemed (allowed) capital structure. In recent years all electric distribution utilities have been allowed the same capital structure consisting of 40% equity, 56% long-term debt, and 4% short-term debt. Since the OEB issued its 1997 Draft Guidelines on cost of capital, the OEB has been of the view that

> capital structures should be reviewed only when there is a significant change in financial, business or corporate fundamentals.[169]

[168] EB-2009-0084 "Cost of Capital Parameters Updates for 2010 Cost of Service Applications," 2/24/2010; "Cost of Capital Parameters for 2011 Cost of Service Applications for Rates Effective May 1, 2011," 3/3/2011; "Cost of Capital Parameters Updates for 2012 Cost of Service Applications," 11/10/2011; and "Cost of Capital Parameters Updates for 2012 Cost of Service Applications for Rates Effective May 1, 2012," 3/2/2012.

Until 2006, the OEB considered the relative size of electric distribution utilities rate base to determine their deemed capital structures. Specifically, the OEB historically used a deemed equity percentage of 35% for entities with a rate base in excess of $1 billion, an equity percentage of 40% for entities with a rate base between $250 million and $1 billion, 45% equity for entities with a rate base between $100 million and $250 million, and an equity percentage of 50% for those with a rate base smaller than $100 million. In 2006, the OEB changed its prior policy of deeming an equity percentage for electric distribution utilities based on the size of their rate base because "utility size no longer represent an accurate proxy for risk."[170] Instead, the OEB looked to factors such as load concentration and noted that larger distributions utilities support the use of a 60% debt - 40% equity capital structure. Further, the OEB noted that merger and acquisitions had reduced the number of distribution utilities, that the OEB did not want to create barriers to consolidation and that "one of those barriers is the differing capital structure of distributors." The OEB was not convinced that concerns regarding credit ratings warranted different capital structure across electricity distributors.[171] As a result, the OEB moved to a 40% equity ratio as the target equity percentage for electric distributors and created a phase-in period. For example, it was not until 2008 that Hydro One got a deemed equity percentage of 40%. In 2009, the policy of allowing all electric distribution entities the same capital structure was formalized in EB-2009-0084, which also confirmed the OEB's policy of deeming the capital structure for electric transmission utilities as well as gas utilities on a case-by-case basis[172] taking the utility's business risk into account.[173]

The OEB reviewed Enbridge Gas' and Union Gas' cost of capital in 2002 but did not focus on capital structure.[174] Union Gas' equity percentage was changed from 35% to 36% in a settlement agreement in 2006, to be effective in 2007.[175] Enbridge Gas' equity percentage increased from 35% to 36% in 2007,[176] and the OEB acknowledged that the prior 35% equity was a lower bound on equity and that the deemed equity percentages of Canadian utilities had increased in recent

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[169] 1997 Draft Guidelines, p. 4 and EB-2009-0084, p. 49.

[170] OEB, "Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors," December 20, 2006 (OEB 2006 Report), p. 7.

[171] OEB 2006 Report, pp. 6-7.

[172] EB-2009-0084, p. 50.

[173] There appears to be no deviations from the capital structures below with Union Gas' increased equity percentage being part of a negotiated settlement (EB-2005-0520, issued May 15, 2006, p. 22).

[174] RP-2002-058, Issued January 16, 2004.

[175] EB-2005-0520, issued May 15, 2006, p. 22.

[176] EB-2006-0034, issued July 5, 2007, pp. 62-66.

years. However, the OEB found that bypass risk could be mitigated in part, that weather risk and interest rate changes had negatively impacted the company in recent years and that customer growth had been a positive. As a result of these factors, the OEB increased Enbridge Gas' equity percentage by one percent.

The OEB's 2009 review of cost of capital did not focus on capital structure and did not discuss the business risk differences between electric and gas utilities.[177] To the best of our knowledge, there has been no recent review of the capital structure for the two largest gas distributors in Ontario. **Table 8** below summarizes the deemed capital structure of major Ontario utilities. In the table bold figures represent years in which the capital structure was changed.

Deemed Equity Percentage			
	Enbridge Gas	Union Gas	Hydro One / Electric Distribution after 2006
2012	36%	36%	40%
2011	36%	36%	40%
2011	36%	36%	40%
2010	36%	36%	40%
2009	36%	36%	40%
2008	36%	36%	**40%**
2007	***36%***	***36%***	36%
2006	35%	35%	36%
2005	35%	35%	36%
2004	35%	35%	36%

Table 8 [178]

G. USE OF DEFERRAL ACCOUNTS

The Ontario Energy Board generally uses deferral accounts for fuel, tax rate changes, pension cost, export revenues, maintenance, construction, land-use true-up, transmission costs, short-term and long-term storage services for gas and other items.

The interaction of deferral accounts and cost of capital was not mentioned in the OEB's decisions on cost of capital, although some participants in the generic proceedings argued that

[177] EB-2009-0084, p. 50.

[178] EB-2008-0272; EB-2009-0084; EB-2010-0002; EB-2011-0268.

the existence of these deferral accounts made Ontario utilities less risky than, for example, U.S. based utilities.

VI. QUÉBEC RÉGIE DE L'ÉNERGIE

A. INTRODUCTION

The Régie de l'Énergie du Québec (Régie) regulates gas and electricity distribution and transmission in Québec. We have reviewed the Régie's approach to setting the cost of capital for Gaz Metropolitain (Gaz Métro), the largest distributor of natural gas in the province, as well as Hydro Québec, which transmits (Hydro Québec TransÉnergie, HQT) and distributes (Hydro Québec Distribution, HQD) electricity across the province.[179]

Hydro Québec TransÉnergie (HQT) was established in 1997 and its parent, Hydro Québec (an integrated electric utility), was restructured into four divisions in 2001: Hydro Québec TransÉnergie (transmission), Hydro Québec Distribution (HQD, distribution), Hydro Québec Production (generation), and Hydro Québec Engineering, Procurement and Construction. The restructuring enabled Hydro Québec to sell power into the U.S. wholesale market.[180] Since the restructuring, the Régie has determined the ROE for HQT and HQD separately.

Gaz Métro is owned by private investors, whereas HQT and HQD are part of Hydro Québec, a Crown Corporation.

Since 1999, the Régie has consistently used a formula approach to set the cost of capital for Gaz Métro, although it has recently revised the formula and made adjustments to reflect the impact of the financial crisis. In practice, a full review has been carried out every other year since 2007.

For Hydro Québec's two subsidiaries, HQD and HQT, the Régie has not explicitly determined a formula approach. However, for many years the return on equity for HQD and HQT has been determined using the same risk premium relative to the Canadian long bond.

[179] Hydro Québec also generates electricity, but generation is not regulated by the Régie.

[180] National Energy Board, "*Canadian Electricity: Exports and Imports*," January 2003.

B. HISTORY

For Gaz Métro, a formula-based mechanism has been in place since 1999,[181] when the return on equity was set equal to a baseline amount of 9.6%. In subsequent years, the return on equity would be adjusted by 75% of the change in the *Consensus Forecasts* of the Canadian long bond.

The formula was "re-set" in 2007/8.[182] For 2009/10 the Régie also carried out a full review, and recognized the impact of the global financial crisis (while also noting that the financial crisis had not prevented Gaz Métro from earning its authorized return in 2008/9).[183]

In 2011/12, the Régie again carried out a full review, the result of which was to implement a new formula (as well as resetting the "baseline").[184]

For HQT and HQD, the Régie conducted its first review of tariffs in 2002 and 2003, respectively, *ex post* Hydro Québec's restructuring. While the Régie does not rely on a formulaic approach to determine the ROE for HQT and HQD, the Régie has consistently looked to its decisions on Gaz Métro for guidance on how to determine the ROE for the electric distribution and transmission utilities.

C. DETERMINING THE ROE

Because the Régie has relied on a formula approach to determine Gaz Métro's ROE, but did not formally adopt a formula for Hydro Québec TransÉnergie or Hydro Québec Distribution, the regulatory treatment of these entities will be discussed in turn.

1. Formula for Gaz Métro

From 1999 until 2011, the Régie has applied the following basic formula in determining the ROE for Gaz Métro, with annual updating of the long bond forecast and periodic updating of the base ROE:

$$\text{ROE} = \text{BaseROE} + 0.75 \times (\text{LCBF} - \text{BaseLCBF}) \quad \textbf{(27)}$$

[181] D-99-11 (in French).

[182] D-2007-116.

[183] D-2009-156.

[184] D-2011-182.

Where ROE is the allowed return on equity; BaseROE is return on equity that was allowed in the initial year; LCBF is the Long Canada Bond Forecast for the year; and BaseLCBF is the Long Canada Bond Forecast for the initial year, and the 0.75 is an adjustment factor.

The initial ROE for 1999 was determined using the CAPM. The risk-free rate was set at 5.759% (from *Consensus Forecasts*). The MRP was set at 6.44%, which was determined as the arithmetic average of the historically realized risk premium. The Régie obtained the historical average from five studies presented by Gaz Métro and placed 80% weight on Canadian data and 20% weight on U.S. data. The beta was set at 0.55 (unadjusted), being the highest estimated beta presented by the expert for the interveners. The Régie allowed flotation costs of 0.30% based on the opinion of the experts in the proceeding. The resulting risk premium was 3.84% for an ROE of 9.6% (determined as 5.759% + 3.84%).[185]

In its 2011 decision, the Régie implemented a new formula:[186]

$$\begin{aligned} \text{ROE} = \text{BaseROE} &+ 0.75 \times (\text{LCBF} - \text{BaseLCBF}) \\ &+ 0.50 \times (\text{UtilBondSpread} - \text{BaseUtilBondSpread}) \end{aligned} \tag{28}$$

In arriving at the new formula, the Régie looked at what the results would have been if the formula had been in operation over the period 1999 to the day of the decision. The Régie found that this formula produced results that were different in some years, but "averaged out" over the course of the economic cycle. The Régie also saw an advantage in having a formula that took into account changes in the yields on utility bonds, and which took, at least partly, the effect of the financial crisis into account.[187]

2. Approach for HQT

The Régie conducted its first review of transmission tariffs for HQT following Hydro Québec's restructuring in 2002.[188] It was therefore the first time that the Régie had considered cost of capital issues for the electricity transmission business. The Régie concluded that the CAPM was the best approach to estimating the required ROE, and that there was also some merit in considering the use of the Empirical CAPM, which is determined as

[185] D-99-11, pp. 42-46.
[186] D-2011-182, Appendix 2.
[187] D-2010-147.
[188] D-2002-95.

$$r_S = r_f + \alpha + \beta_S \times (MRP - \alpha) \quad \textbf{(29)}$$

where α is the "alpha" adjustment of the risk-return line (see Figure 1), a constant, and r_f, β_S, and MRP are respectively the risk-free rate, the beta coefficient, and the Market Risk Premium as earlier. The alpha adjustment has the effect of increasing the intercept but reducing the slope of the security market line.[189]

The Régie used the Empirical CAPM (ECPAM) to correct for a downwards bias in the ROE that would otherwise be estimated for companies, such as regulated networks, with a beta less than one. However, the Régie also said that more weight should be placed on the traditional CAPM than the Empirical CAPM, because the traditional CAPM is better established and tested.

The risk free rate was estimated at 6% in 2001. The Régie did not investigate this in detail because all the experts were in agreement.

In setting the ROE for Gaz Métro, the Régie had already determined that unadjusted betas should be used.[190] Evidence was presented in the HQT proceeding that the average beta for telecoms companies was around 0.58.[191] The Régie set beta for HQT at 0.53 because it felt that, even with the increased financial risk associated with the deemed capital structure, HQT's risk would still be below the average of the utility sector (excluding telecoms).

The Régie determined that an appropriate MRP was 6.44%, based on arithmetic averages and a 60:40 weighting of Canadian and U.S. data.

Putting these parameters together, the Régie determined a risk premium of 3.66% and an ROE of 9.66%. Subsequently, the Régie has assigned an ROE to HQT that is consistent with a risk premium of 3.66% over the risk-free rate, which is updated using *Consensus Forecasts*.

3. Approach for HQD

For HQD, the Régie took a similar approach in 2003.[192] However, no weight was placed on the Empirical CAPM, because the Régie found the bias the ECAPM is correcting only is present

[189] See the discussion in *Section II.B.3.c*.

[190] D-99-11.

[191] D-2002-95, p. 165.

[192] D-2003-93.

when a short-term risk-free rate is used. As all experts recommended a risk-free rate based on long-term bonds, the Régie did not find the ECAPM justified.[193]

The risk free rate was determined to be 6%. The experts in the case were in agreement, and all based their evidence on *Consensus Forecasts* of the yield on the 30 year bond.

Based on evidence presented by the experts in the proceedings, the Régie determined that the risk of HQD is higher than the risk of HQT, so the Régie set beta at 0.55 (relative to 0.53 for HQT in the prior proceeding). The Régie did not specify how it arrived at 0.55, but this beta estimate is in the range of what was proposed by the experts and is above the 0.53 used for HQT.

The MRP was set at 6.19%, based on a method similar to that used for HQT.

Putting these parameters together, the Régie determined a risk premium of 3.4% and an ROE of 9.4%. Subsequently, the ROE for HQD has been updated using the risk premium of 3.4% and updating the risk-free rate using *Consensus Forecasts*.

D. COST OF DEBT

For Gaz Métro, actual embedded debt costs have been allowed. Neither HQT nor HQD issue their own debt and both are subsidiaries of Hydro Québec, which is an integrated electric utility and also a Crown Corporation. Because the parent of HQT and HQD, Hydro Québec, engages in non-regulated activities (*e.g.,* sale of power into wholesale markets), the Régie considered whether the higher-risk activities of Hydro Québec, including generation, could mean that it would be inappropriate to base the cost of debt for HQT on the overall embedded cost of debt for its parent, Hydro Québec. The Régie found that, in practice, the existence of the government guarantee of Hydro Québec's debt had the effect of immunising the regulated activities from any impact of the unregulated activities on the cost of debt for HQT. The Régie also found that, if HQT were to issue its own debt, the cost would be at least 50 basis points above the actual cost of Hydro Québec debt. The Régie therefore also allowed the cost of the government guarantee to be taken into account in setting the allowed cost of debt equal to the actual cost. The cost of embedded debt for 2001 was set at 9.75%. In subsequent years, the cost of debt has been set at the embedded cost of debt for the parent, Hydro Québec.

[193] D-2003-93, pp. 70-72.

A similar approach for HQD resulted in a cost of debt of 9.24% for 2002-03.[194] As for HQT, the cost of debt in subsequent years has been set at the cost of debt for the parent, Hydro Québec.

E. Cost of Preferred

Gaz Métro has approximately 7.5% preferred in its capital structure and has been allowed to recover its actual (embedded) costs of preferred equity.[195]

F. Capital Structure

For Gaz Métro, the 1999 decision allowed Gaz Métro to retain its actual capital structure (38.5% equity, 7.5% preferred, 54% debt), and the Régie has maintained this capital structure for Gas Métro ever since.

For HQT, the Régie adopted a notional capital structure of 30% equity in 2002.[196] The Régie's decision took into account the fact that much of the transmission revenue requirement comes from distribution customers, presumed to be low risk, and only a small fraction comes from services associated with the export of power to the U.S. As a result, the Régie viewed HQT as having lower business risk than other regulated entities in Québec.

In 2003 the Régie determined[197] that HQD has lower risk than otherwise comparable gas and electricity distributors, because of its access to low cost "heritage pool" power and because it had a deferral account to pass through changes in transmission costs. However, it was deemed riskier than HQT. Accordingly, the Régie determined that the proportion of equity in the capital structure should be 35%. In subsequent years, the Régie has maintained this capital structure for HQD.

G. Allowed Cost of Equity and Debt

Looking back over the most recent five years, the allowed return on equity and the capital structure for the Québec utilities have been as indicated in **Table 9** below. An empty entry in **Table 9** indicates that no decision on ROE or Equity % was located.

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[194] D-2003-93, p. 51.
[195] D-2011-185, p. 13.
[196] D-2002-95.
[197] D-2003-93.

Régie Allowed ROE and Deemed Equity %						
	HQD		HQT		Gaz Metro	
Year	ROE	Equity%	ROE	Equity%	ROE	Equity%
2012					8.90%	38.5%
2011	7.32%	35%	7.14%	30%	9.20%	38.5%
2010	7.85%	35%	7.59%	30%		
2008	6.99%	35%			9.05%	38.5%
2007	7.74%	35%	7.50%	30%		

Table 9

VII. MANITOBA PUBLIC UTILITIES BOARD

A. INTRODUCTION

The Manitoba Public Utilities Board (Manitoba PUB) regulates the rates charged by Manitoba Hydro, Centra Gas, Swan Valley Gas Corp. and all water and sewer utilities outside Winnipeg. Manitoba Hydro is an electric utility that owns generation, transmission and distribution and is a Crown corporation. Manitoba Hydro serves more than 500,000 electric customers in Manitoba. Centra Gas is a gas distribution company (LDC) and is a subsidiary of Manitoba Hydro. It serves more than 250,000 gas customers. Swan Valley Gas Corp. (SVGC) is a small LDC that is a wholly owned subsidiary of SaskEnergy, which is a Saskatchewan based Crown corporation. It serves about 1,500 residential and 200 industrial customers in the west-central part of Manitoba near the Saskatchewan border. Thus, the largest electric and gas utilities are part of a Crown corporation, and Manitoba PUB does not regulate traditional investor-owned utilities. As a result, the approach to determining rates differs in some aspects to that of, for example, the BCUC, AUC, OEB, and Régie. Specifically, the information about how ROE or capital structure is determined is limited. This Report summarizes the approach to setting rates and the information about recently used ROE, cost of debt and capital structure rather than the relied upon methodology.

B. APPROACH TO SETTING THE RATES

As Crown corporations, Manitoba Hydro and its subsidiary, Centra Gas, have the rates they charge approved by the Manitoba PUB, and the entities engage in general rate cases, which are focused on the level of rate increases. The most recent rate case was in 2011, but the last case

that reviewed the allowed ROE and capital structure was in 2009.[198] However, the Manitoba PUB decisions on rates do not contain detailed information about the determination of the allowed cost of equity, debt or deemed capital structure. Instead, the Crown corporation and its subsidiary forecast a return on equity and have a target equity ratio. The Manitoba PUB approves electric or gas rates, but does not usually specify an allowed ROE. That is, there is no determination of whether one methodology to determine ROE is preferable over another.

Manitoba Hydro's debt is guaranteed by the Province, and Manitoba Hydro pays an annual fee of 1% in debt guarantee fee.[199] For a number of years, Manitoba Hydro has operated with a target capital structure of 25% equity and 75% debt. The orders pertaining to Manitoba Hydro do not contain an explicit calculation of the cost of capital or a statement about the allowed ROE.

In Order 99/07, the Manitoba PUB deemed that 30% equity and 70% debt was sufficient for Centra Gas given its status as a subsidiary of Manitoba Hydro and to the Province's guarantee of the parent's debt. Order 128/09 revisited the issue and concluded:

> Centra's specific debt to equity ratio is not a material issue as long as Centra's financial position does not represent a risk to [Manitoba Hydro]'s overall capital position and borrowing ability. The 'excess' net income results of the last two fiscal periods due to weather have improved Centra's financial position, and with a debt to equity ratio of 69:31, Centra does not pose a drag on either MH's capital position or borrowing opportunities.[200]

Note that the Manitoba PUB did not deem a capital structure for Centra Gas, but instead concluded that Centra's actual capital structure with 31% equity was not an issue for Manitoba Hydro. Consequently Manitoba PUB did not request any changes.

Based on a survey of bank-provided interest rate forecasts, the Manitoba PUB decided to set the short-term debt rate for Centra Gas at 0.5% for 2009-10 and at 1.0% for 2010-11. Further, also based on a bank survey, the Manitoba PUB set the cost of long-term debt at 4%, which was consistent with the forecasted rate for the period over which Centra Gas expected to issue new capital.[201]

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[198] Order 128/09.

[199] Order 99/11, p. 16.

[200] Order 128/09, p. 90.

[201] Order 128/09, pp. 123-126.

In its most recent rate case, the gas distribution utility, Swan Valley Gas Corp. (SVGC) was deemed to have a capital structure consisting of 65% debt and 35% equity. Because SVGC issues no debt, the cost of debt was an issue for the company. For the purpose of determining customers' gas rates for 2009, the Manitoba PUB set the cost of debt at 4.22% and "allowable shareholder equity returns" of -21.66%, which was consistent with the forecasted return on equity.[202] SVGC was allowed an equity return that was expected to lead to a negative income in 2009. For 2010, the Manitoba PUB allowed a cost of debt of 4.49% and a return on equity of 11.0%.[203] The Manitoba PUB order does not explain how it arrived at the above return figures and provides no reason for the negative 2009 return on equity. However, the figures are consistent with the forecasted results provided by SVGC.[204]

C. ALLOWED ROE, COST OF DEBT AND CAPITAL STRUCTURE

Limited information is available regarding the allowed cost of capital and capital structure, or the characterization of an expected return or target capital structure. As a result, a table that compares the historical allowed ROE and capital structure in a manner similar to the tables prepared for other jurisdictions is not meaningful. Instead, the information is summarized by company below. In the comparison, we note the characterization in the orders, which often reference a "target" or "forecast" figure rather than an allowed figure. In interpreting the information below, the allowed ROE, allowed cost of debt, or deemed capital structure is determined by the Manitoba PUB and used to calculate the rates customers will pay for service. This applies only to SVGC. In comparison, the expected ROE is a regulated entity's forecast on which ROE will materialise. It is not directly used to determine rates, but a result of the allowed electricity and gas rates. The target capital structure is the capital structure that the regulated entity is aiming for over time.

Manitoba Hydro:[205]

Target Capital Structure:	25% Equity, 75% Debt	(2008-13)
Expected ROE:[206]	12.2% for 2008	
	11.2% for 2009	

[202] Order 148/09, p. 8.
[203] Order 148/09, p. 8.
[204] Order 148/09, p. 6.
[205] Order 5/12, Order 32/09, Order 116/08, and Order 99/11.
[206] The expected ROE is different from an allowed ROE.

Centra Gas:[207]

Deemed Capital Structure:	30% Equity, 70% Debt	(2007-11)
Long-term Cost of Debt:	4%	(2009-10)

Swan Valley Gas Corp.:[208]

Deemed Capital Structure:	35% Equity, 65% Debt	(2009-10)
Allowed ROE:	11% for 2010	
	(21.66%) for 2009	
Allowed Cost of Debt:	4.49% for 2010	
	4.22% for 2009	

Because of Manitoba Hydro and Centra Gas' status as Crown corporations and how these entities are regulated, the figures above are not directly comparable to those provided for other jurisdictions.

VIII. SASKATCHEWAN RATE REVIEW PANEL

A. INTRODUCTION

The Saskatchewan Rate Review Panel (SRRP) advises the Government of Saskatchewan on rate applications proposed by SaskEnergy, SaskPower and an insurance company. SaskEnergy is a natural gas distribution utility and a Crown corporation, while SaskPower (also a Crown corporation) owns generation, transmission and distribution assets and acts as the supplier of electricity to most of Saskatchewan. SaskPower also engages in non-regulated activities including energy marketing and trading operations as well as operating an environmental education facility.

The SRRP reviews each rate application and provides the government with an opinion about the fairness and reasonableness of the proposed rate change, while balancing the interests of the customer, the Crown Corporation and the public. Specifically, the Panel provides the Minister Responsible for the Crown Investment Corporation with a report regarding the Crown Corporation's rate application. This report is publicly available and forms the basis for this

[207] Order 148/09, pp. 8, 123-126 and Order 99/07.

[208] Order 148/09.

document. The Government of Saskatchewan makes the final decision on rate changes. Thus, the Panel's approach to determining rates is similar to that of the Manitoba PUB but differs from that of most other reviewed jurisdictions in that it usually reviews the rate application and recommends future rates without an explicit statement about the cost of equity, cost of debt, or capital structure. The resulting electric and gas rates are listed on the Crown Corporation's home page, but the site does not provide any details the process for their determination.

B. TARGET ROE AND CAPITAL STRUCTURE

As for Manitoba, limited information is available about the allowed ROE and capital structure. However, for some years a target ROE was provided. The target ROE is the ROE that is expected to materialize given the rates that are put in place.[209] The target ROE for SaskPower and SaskEnergy is provided in **Table 10** below for the years in which this information was available. A blank space in **Table 10** indicates that no information was located for the listed entity for the specific year.

	Saskatchewan Target ROE	
	SaskPower	SaskEnergy
2012		8.8%
2011		
2010	7.4%	
2009	8.5%	8.8%
2008		9.0%
2007	9.0%	9.0%
2006	10.0%	
2005	10.0%	
2004		
2003		
2002		
2001	10.0%	

Table 10[210]

The target debt percentage was 63%, 64% and 69% for SaskPower in 2009, 2010 and 2011, respectively. The target debt percentage was 65%, 68%, and 57% for SaskEnergy in 2009, 2010

[209] Unlike an allowed ROE, the target ROE is not used to determine customers' rates but is a consequence of the allowed rates.

[210] 2012 SaskEnergy: Natural Gas Delivery Service Application; Saskatchewan Rate Review Panel, "Report to the Minister of the Crown Investments Corporation of Saskatchewan," Dec. 29, 2009; Saskatchewan Rate Review Panel, "Report to the Minister of Crown Investments Corporation of Saskatchewan," December 2001.

and 2011, respectively.[211] Similar to the Crown Corporations of Manitoba, the figures for Saskatchewan's Crown Corporations are not comparable to other rate regulated utilities because both the ROE and capital structure are targets based on the financial performance of the entity rather than allowed returns / deemed capital structures.

IX. NEW BRUNSWICK ENERGY AND UTILITIES BOARD

A. INTRODUCTION

The New Brunswick Energy and Utilities Board (NBEUB) regulates gas and electricity rates in the province. However, the structure of the industries gives rise to several unusual features. On the gas side, the unusual feature is that the gas network is relatively new, having been built out by Enbridge Gas New Brunswick (EGNB) since 2000, with significant amounts of the costs associated with a sub-scale network being deferred into future rate periods. The NBEUB has reviewed EGNB's cost of capital and capital structure only twice, in 2000 and 2010, and the NBEUB does not update the cost of equity annually.

On the electric side, there are two unusual features: first, the industry is government-owned and 100% debt financed; second, the NBEUB only has jurisdiction over the distribution business even though New Brunswick Power operates as a vertically-integrated utility.[212] The NBEUB regulates the rates of the New Brunswick Power Distribution and Customer Service Corporation, known as "Disco". The NBEUB does not have jurisdiction over the generating companies of New Brunswick Power (NB Power), but has held that NB Power operates as a vertically-integrated utility.[213]

The NBEUB also has responsibilities in the pipeline, petroleum products and motor carrier industries.

Because of the unusual structure and financing of NB Power, we briefly describe the NBEUB's treatment of cost of capital issues on the electric side before reviewing gas separately.

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[211] Crown Investment Corporation of Saskatchewan Annual Reports.

[212] The discussion in this section is based on a July 12, 2010 report "IN THE MATTER OF an Investigation into the necessity for the 3% increase in the New Brunswick Power Distribution and Customer Service Corporation's charges, rates and tolls which came into effect on June 1, 2010".

[213] See discussion in NBEUB report, July 12, 2010.

B. COST OF CAPITAL ISSUES FOR NB POWER

Disco's distribution rates are regulated by the NBEUB. However, Disco is permitted to increase its rates without seeking approval from the NBEUB unless the rate increase is greater than 3%. As a result, the last rate case was in 2008, although in 2010 the NBEUB reviewed a rate increase of 3% implemented in 2010.[214]

Disco's rates incorporate the cost of power purchased by Disco from the generating companies in the NB Power group.

Disco is essentially 100% debt financed, because no equity has ever been introduced into its capital structure, and because it has accumulated a nominal amount of retained earnings. Nevertheless, the NBEUB has held that Disco should have equity in its capital structure, and that Disco rates should permit and reflect both the accumulation of retained earnings and a return on such retained earnings once accumulated.

While the NBEUB continues to be in favour of Disco having net earnings that can be retained in order to build up equity in the Disco capital structure, the NBEUB has also held that it does not have sufficient information to determine how much net earnings Disco requires. This is because NB Power operates as a vertically-integrated utility, yet the NBEUB does not have jurisdiction over the generating companies under the umbrella of New Brunswick Power. The NBEUB has stated that its regulatory activities would be more effective and more relevant to customers if the generating parts of NB Power were regulated in the same manner as Disco, but the NBEUB does not currently have authority to do this.

With Disco 100% debt financed, the NBEUB has historically relied on an interest coverage ratio to determine the amount of net earnings to allow in rates. Previously Disco had requested an amount based on an interest coverage ratio of between 1.25 and 1.75, with the upper end of this range being the amount that Disco felt would allow retained earnings to be accumulated, and the lower end of the range being a compromise designed to avoid rate shock. In the 2007 rate case, the NBEUB allowed a coverage ratio of 1.1, citing the adverse impacts on customers of rate

[214] The Energy Minister requested that the NBEUB undertake this review to determine whether the 3% rate increase was necessary.

increases.[215] Like the Crown corporations of Manitoba and Saskatchewan, there is no traditional determination of the allowed ROE for Disco.

Disco's debt is financed with a provincial guarantee. Disco pays interest at a rate between 4.25% and 7.50% (the weighted average embedded cost of debt is 6.73%). In addition, Disco pays a so-called "portfolio management fee" of 0.65%, representing the value of the Province's credit rating. The portfolio management fee is set by the Provincial Government.

C. ROE FOR ENBRIDGE GAS NEW BRUNSWICK

EGNB began operations in 2000. The initial approach to regulating EGNB's rates was that the company would make significant investments in building out the network during a "development period", and that these investments would be recovered from customers once the development period had ended. The ROE for EGNB was set at 13% as proposed by EGNB in 2000, because no alternative ROE was presented to the NBEUB and no participating party objected to an ROE of 13%.[216] The ROE was not reviewed until 2010.

It was originally anticipated that EGNB would defer some of the costs of building the system during the development period, and that these deferrals, to be recovered in future rates, would amount to some $13 million. However, by 2009 the deferral account balance was $155 million, not including the deferral of O&M costs. Total deferrals are expected to peak at $276 million in 2013.[217]

When it reviewed EGNB's cost of equity in the 2010 decision, the NBEUB included a premium of 2.75% over and above the ROE of a "benchmark utility"[218] because of deferral account risk. The NBEUB does not identify characteristics of a "benchmark utility" but uses the term "ROE of a benchmark utility" to refer to the ROE the NBEUB deems appropriate before considering EGNB's company specific risks; i.e., the average for the relied upon sample. In determining the impact of EGNB's specific risks on the allowed ROE, the NBEUB stated:

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[215] February 22, 2008 *Decision IN THE MATTER OF an application by New Brunswick Power Distribution and Customer Service Corporation for approval of changes in its Charges, Rates and Tolls*

[216] Decision IN THE MATTER of an Application by Enbridge Gas New Brunswick Inc. for Approval of Its Rates and Tariffs, issued June 23, 2000 (EGNB 2000 Decision), p. 25

[217] Decision IN THE MATTER of a review of the Cost of Capital for Enbridge Gas New Brunswick L.P. (EGNB), NBEUB, November 30, 2010, (EGNB 2010 Decision), p. 11.

[218] The NBEUB uses the term ROE for a benchmark utility to refer to the results deemed appropriate before considering EGNB specific risks.

> The Board finds that the risk that not all of the Deferral Account will be recovered is a real and significant risk facing EGNB's investors. Not only is the size of the debt to be paid large but EGNB's ability to recover it is dependent on market forces which are out of EGNB's control.
>
> The EGNB risk premium must give the investor a return in exchange for the risk relative to other investment options. Too much of a premium, in the case of this utility, imposes undue costs on future customers; too little risk may starve the utility of needed capital. In this respect the most important risk to consider is the added risk that the deferral account may not be fully recovered. Considering all of the evidence and risk factors and particularly the magnitude of the Deferral Account the Board finds that the EGNB risk premium is 2.75%.[219]

Taking a CAPM approach, the other elements of the NBEUB's cost of equity determination for EGNB are similar to decisions for mature gas utilities in other sectors. The NBEUB seeks to determine the ROE appropriate for an average utility, before considering the need for any change in the ROE to reflect the specific circumstances of EGNB. Specifically, the NBEUB determines EGNB's allowed ROE as:

$$ROE_{EGNB} = \text{Risk-Free Rate} + \text{Beta} \times \text{MRP} + \text{Flotation Costs} + \text{EGNB premium.} \quad \textbf{(30)}$$

Put differently, the NBEUB adjusts the CAPM estimate by adding flotation costs and an EGNB specific risk premium to determine EGNB's allowed ROE. The non-EGNB specific results (the CAPM plus flotation costs) is referenced as the benchmark utility ROE and are consistent with the ROE for an average utility. For the purpose of determining the ROE prior to any EGNB risk premium, the NBEUB looked to comparable companies consisting of Canadian holding companies in S&P/TSX's sub-index of utilities, i.e., no specific characteristics of the sample companies were identified in the decision. The parameters were obtained by reviewing the experts' evidence.

1. Risk free rate

The NBEUB determined that the appropriate risk-free rate would be a one-year forecast of the yield on the 30-year Government of Canada bond. Since there are no such forecasts available, the NBEUB used the *Consensus Forecasts* for the yield on a 10-year Government of Canada bond, plus the current yield spread between the 10-year and 30-year bond. This resulted in a risk

[219] *Ibid*., p. 11.

free rate of 4.6% being used to determine the 2011 cost of equity.[220] The NBEUB rejected both a longer-term forecast approach and an approach relying on historical yields.

2. The market risk premium

The Board set the market risk premium at 5.5% for rates that will be effective January 1, 2011, based on a combination of evidence from surveys of views of financial analysts and finance professors, and the difference between historical equity and bond returns in Canada. The NBEUB rejected an alternative approach based on the difference between forecast equity and bond returns (which yielded a market risk premium of 6.75%).

3. Equity beta

Expert evidence was presented on the equity betas of utility companies in Canada and a partial review of other jurisdictions, as well as judgment relating to the impact of the financial crisis.[221] The NBEUB concluded that an appropriate equity beta is 0.55 based on evidence on Canadian utility holding companies and information from other jurisdictions, resulting in a risk premium of 3.03% for a generic (or benchmark) utility.

4. Flotation costs

The NBEUB set flotation costs (also called issuance costs) of 0.5%, on the basis of expert recommendation. The NBEUB stated that very little evidence had been presented, and the matter was not discussed in detail at the hearing. One expert recommended 0.75%, and the other 0.5%. The NBEUB accepted the lower of the two recommendations.

5. Overall cost of equity

Combining the elements above, the NBEUB set the cost of equity for a "benchmark" utility at 8.13% based on the CAPM. The NBEUB considered a range of risk factors specific to EGNB (market risk, competitive risk, supply risk, regulatory risk, and deferral account risk). The NBEUB's view seems to have been that none of these risks were particularly significant or had

[220] The rates determined in the 2010 NBEUB Decision was effective January 1, 2011.

[221] One expert presented evidence on the S&P/TSX sub-index for utilities resulting in a beta of 0.65 to 0.70, while another expert presented evidence from selected Canadian utility holding companies and from other jurisdictions resulting in a beta of 0.45 to 0.55.

materially changed since 2000, apart from the deferral account risk. The deferral account risk led the NBEUB to increase the ROE by 2.75% to 10.9%.[222]

D. Cost of Debt

The cost of debt had originally been set (in 2000) at 1% above the borrowing rate of EGNB's parent, Enbridge Inc. The NBEUB heard evidence that EGNB would not be able to obtain debt financing at a rate lower than 1% above that paid by its parent, so determined that the cost of debt would continue to be set on this basis. This evidence was obtained by asking two investment banks to give a professional opinion on the likely funding costs.

E. Capital Structure

The NBEUB determined in 2000 that it was reasonable for EGNB to have a higher proportion of equity in its capital structure than a mature utility and deemed a capital structure including 50% equity in 2000. In 2010, the NBEUB again found that EGNB should have a higher proportion of equity than a mature utility, but also found that the equity proportion should also be lower than that originally approved in 2000. The reduction in the equity thickness was deemed reasonable because EGNB had developed its business significantly since then. The maximum approved equity proportion for other natural gas utilities in Canada was 45%, and the NBEUB set the maximum proportion for EGNB at this level.

F. Allowed ROE and Capital Structure

Based on the 2000 and the 2010 decision on EGNB, the allowed ROE and capital structure for the company has been as listed in **Table 11** below.

[222] 8.13% plus 2.75%, rounded to 10.9%.

EGNB Allowed ROE and Capital Structure		
	ROE	**Equity %**
2012	10.9%	45%
2011	10.9%	45%
2010	13.0%	50%
2009	13.0%	50%
2008	13.0%	50%
2007	13.0%	50%
2006	13.0%	50%
2005	13.0%	50%
2004	13.0%	50%
2003	13.0%	50%
2002	13.0%	50%
2001	13.0%	50%
2000	13.0%	50%

Table 11[223]

G. DEFERRAL ACCOUNTS

In reviewing the changes in EGNB's risks since 2000, the NBEUB focused on the deferral account associated with the build out in New Brunswick. The NBEUB concluded:

> The most important risk to consider is the added risk that the deferral account may not be fully recovered. Considering all of the evidence and risk factors and particularly the magnitude of the Deferral Account, the Board finds that the EGNB risk premium is 2.75%.[224]

The risk premium that the NBEUB is referencing is a premium over that of an average utility, so the NBEUB increased EGNB's ROE by 275 basis points because it viewed the recovery of EGNB's deferral account as uncertain.[225]

[223] EGNB 2000 Decision and EGNB 2010 Decision.

[224] EGNB 2010 Decision, p. 11.

[225] Recently, the issuance of final rates and tariff regulation by the Province of New Brunswick legislature in April 2012 capped the gas rates in New Brunswick and EGNB for financial reporting and GAAP accounting purposes wrote off part of its deferral account. See Enbridge Gas New Brunswick Press Release, "Enbridge Gas Confirms $262 million EGNB Write Down," May 3, 2012.

X. NOVA SCOTIA UTILITY AND REVIEW BOARD

A. INTRODUCTION

The Nova Scotia Utility and Review Board (NSUARB) is an independent, quasi-judicial body established in 1992. Among other things, the NSUARB exercises general supervision over all electric utilities, granted franchises, pipelines, gas plants and underground hydrocarbon storage facilities operating within the Province.

In awarding a franchise, the NSUARB may provide the franchise holder with performance-based rates, tolls or charges as determined by the NSUARB. Performance indicators on which the rates, tolls or charges are based shall be measured against criteria specified by the NSUARB in the terms and conditions of the franchise. The NSUARB shall create a single, franchise-wide rate, toll or charge for gas transportation services to each customer class of a franchise holder.

Currently, Heritage Gas Limited has the franchise to distribute natural gas, while Nova Scotia Power Inc. (NSPI) is the largest public utility regulated by the NSUARB.

B. ELECTRIC UTILITY REGULATION

Nova Scotia Power Inc. (NSPI) is the largest public utility regulated by the NSUARB and is a subsidiary of Emera, Inc. NSPI is an investor-owned, regulated public utility that provides over 95% of the electricity generation, transmission and distribution service in the province. The NSUARB regulates NSPI on a cost-of-service basis.

One of the NSUARB directives is to hold a separate generic hearing, relating to rate design and the methodology used by NSPI to calculate rates for electric service.

In its Decision dated March 31, 2005, the NSUARB explained its ratemaking guidelines as

> In utility regulation, there are generally accepted principles which govern the rate-making exercise. The object of rate-making under a cost-of-service-based model is that, to the extent reasonably possible, rates should reflect the cost to the utility of providing electric service to each distinct customer class. In regulating NSPI, the Board is guided by these generally accepted principles as well as by case law.[226]

[226] Decision 2005 NSUARB 27, p. 14.

C. DETERMINING THE ROE AND CAPITAL STRUCTURE

In its 2005 Decision, the NSUARB considered all submitted evidence including evidence on the CAPM, DCF, and Risk Premium models. The NSUARB rejected a recommended ROE of 11.2% as being too high and an ROE of 9.3% as being on the low side. Consequently, the Board decided on an ROE of 9.55% for 2005 and on a capital structure including 37.5% equity, which was an increase over the prior level.[227] The NSUARB did not explain how it weighted the evidence but stated that it emphasized the evidence of two witnesses, who relied on the CAPM and DCF models to determine the ROE.

For 2008, 2010 and 2011, the Board approved settlements that did not affect the capital structure and approved ROE of 9.35%, 9.35% and 9.20%, respectively.[228] The ROE and capital structure in a settlement remains in place until a new settlement or decision is in place. However, there are no specifics regarding the methodology used to determine the ROE or criteria relied upon to determine the capital structure.

D. ALLOWED ROE AND CAPITAL STRUCTURE

Table 12 below summarizes the allowed ROE and capital structure for NSPI since 2004, but it is important to keep in mind that since 2008, these parameters have been determined in settlements agreements rather than regulatory proceedings. The 2004, 2005-07, and 2011 allowed ROE were established in NSUARB decisions.[229]

[227] Decision 2005 NSUARB 27, p. 79.

[228] Decision 2008 NSUARB 140, Decision 2010 NSUARB 6, and Decision 2011 NSUARB 184.

[229] Decision 2002 NSUARB 1, Decision 2005 NSUARB 27, and Decision 2011 NSUARB 184.

NS Allowed ROE and Capital Structure		
	NSPI	
	Allowed ROE	Equity Percent
2011	9.20%	37.50%
2010	9.35%	37.50%
2009	9.35%	37.50%
2008	9.35%	37.50%
2007	9.55%	37.50%
2006	9.55%	37.50%
2005	9.55%	37.50%
2004	9.90%	35.00%

Table 12

In its November 29, 2011 Decision, the NSUARB agreed that there is merit to review the current Cost of Service Study for NSPI, but postponed the plans for a hearing until 2013.

E. DEFERRAL ACCOUNTS

In its 2008 Decision the NSUARB noted that a fuel adjustment clause would reduce the return on equity by 0.2% for NSPI. [230]

XI. PRINCE EDWARD ISLAND REGULATORY & APPEALS COMMISSION

A. INTRODUCTION

The Prince Edward Island Regulatory & Appeals Commission (IRAC) is an independent quasi-judicial tribunal operating under the authority of the Island Regulatory and Appeals Commission Act. The IRAC administers a number of provincial statutes dealing with economic regulation and hears appeals under provincial planning, tax and residential rental property legislation.

The IRAC's regulatory powers are derived from the *Electric Power Act*. The IRAC regulates the electric operations of Maritime Electric Company (Maritime Electric). On November 25, 2010, the Electric Power (Electricity-Rate Reduction) Amendment Act was enacted in the Legislative Assembly. This Act reduces electricity prices by 14% for customers of Maritime Electric and freezes these reduced rates until March 1, 2013. During this time, the IRAC will have limited

[230] Decision 2008 NSUARB 140, ¶134.

jurisdiction over electricity matters in the province. The IRAC expects that after March 1, 2013, it will resume regulatory responsibility, as existed prior to this amendment Act.[231]

According to the *Electric Power Act*:

- Maritime Electric shall, at all times, maintain not less than 40% of the capital it has invested in the power system, determined in accordance with generally accepted accounting principles, in the form of common equity.[232]
- Every public utility shall be entitled to earn annually such return as the [PEI] Commission considers just and reasonable, computed by using the rate base as fixed and determined by the [PEI] Commission for each type of service furnished, rendered or supplied by such public utility, and the return shall be in addition to the expenses as the [PEI] Commission may allow.[233]
- In the event Maritime Electric's return on average rate base for a year exceeds 8%, Maritime Electric shall return to its customers in the immediately following calendar year, on a monthly basis and in twelve equal installments, that portion of its earnings for the year which exceed a return on average rate base of 8%.[234]

Thus, by legislation, Maritime Electric has 40% equity and operates under an earnings sharing arrangement. The earnings sharing arrangement is based on the return on average rate base.

B. DETERMINING THE ROE AND CAPITAL STRUCTURE

The IRAC in some orders was specific about the methodology relied upon to determine the ROE whereas other orders either accepted the application or did not specify the reasons for choosing one methodology over another. In 1993, the IRAC found that

> The Commission has concluded in recent years that the various approaches to determining a fair and reasonable rate of return are all useful and should be considered.[235]

The IRAC agreed with the company witness that all three approaches (DCF, Risk Premium, and Comparable Earnings) "are useful in providing estimates of a fair return on common equity and

[231] IRAC's website at http://www.irac.pe.ca/electric/. See also, The Electric Power (Electricity-Rate Reduction) Amendment Act (Bill No. 25), which was passed on December 9, 2010 and remains in effect until March 2013.

[232] Electric Power Act, c. 12.1

[233] Electric Power Act, c. 24, s. 1

[234] Electric Power Act, c. 48, s. 13

[235] Order UE92-17, issued March 25, 1993, Section 2.2.

also" provide "some validation of the results of the other approaches."[236] In 1993, the maximum ROE was set at 13% in March[237] using the midpoint of the methodologies above. In the general rate case in June 1993, the IRAC set the allowed ROE at 12.75% and also allowed a capital structure including 43.8% equity, 12.5% preferred equity, and 43.7% long-term debt.[238] However, a July 1993 order reduced the ROE stating that

> A just and reasonable rate of return on average rate base is established at a range of 10.68% to 10.90% for 1993.[239]

The next order at the IRAC's website that discusses the determination of ROE comes in 2006, when Maritime Electric proposed an ROE of 10 to 10.5%. The IRAC allowed the midpoint of 10.25% for the period starting July 1, 2006.[240] No specifics regarding the methodology used to arrive at the ROE was provided in the order. The company had proposed increasing its equity percentage from 42.3% to 45%, but the order contains no determination on this issue.[241] For 2008 and 2009, the IRAC accepted the company's proposed 10% and 9.75% ROE, respectively. In 2008, the IRAC noted that it took into consideration the allowed ROE of other Atlantic electric utilities and company-specific risks, whereas in the 2009 decision, the IRAC noted

> The Commission is aware that current economic conditions are volatile and rates of return throughout the investment marketplace is in significant decline as can be seen in the dramatic declines in stock exchange values. However, the Commission must decide this case based on the evidence placed before it during this application and hearing process. No party has presented evidence of rate of return that takes into account the current financial market conditions and how it affects the fair return standard which regulators have followed for many years.[242]

Consequently, the IRAC awarded the 9.75% ROE applied for by the company. This ROE has been in effect since with the IRAC in 2010 noting the results from the CAPM, allowed ROE for other Atlantic electric utilities and the BCUC allowed ROE for FortisBC (electric).[243]

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[236] Order UE92-17, Section 2.2.

[237] Order UE92-17.

[238] Order UE93-11, issued June 24, 1993, Section 2.4.

[239] Order UE93-13, issued July 8, 1993.

[240] Order UE06-03, issued June 27, 2006, Section 3.4.

[241] Order UE06-03, Section 3.4.

[242] Order UE09-02, ¶62.

[243] Order UE10-03, issued July 12, 2010, ¶101-105.

The IRAC orders do not provide a deemed capital structure, but as noted in Section XI.A above, legislation requires Maritime Electric to have at least 40% equity.[244]

C. ALLOWED ROE

The approach discussed above has resulted in the allowed ROE being as listed in **Table 13** below.

Prince Edward Island (Maritime Electric) Allowed ROE and Capital Structure	
	Allowed ROE
2011	*9.75%*
2010	*9.75%*
2009	9.75%
2008	10.00%
2007	n/a
2006	10.25%

Table 13[245]

In **Table 13** above, the 2010-2011 ROE is what the IRAC allowed, but the ROE allowed does not take into account that the legislature reduced electricity rates by 14%.

XII. BOARD OF COMMISIONERS OF PUBLIC UTILITIES, NEWFOUNDLAND AND LABRADOR

A. INTRODUCTION

The Board of Commissioners of Public Utilities, Newfoundland and Labrador (NLPUB) is an independent, quasi-judicial regulatory body appointed by the Lieutenant Governor in Council, and operates primarily under the authority of the Public Utilities Act, R.S.N. 1990. The NLPUB was established in 1949.

The NLPUB is responsible for the regulation of the electric utilities in the province to ensure that the rates charged are just and reasonable, and that the service provided is safe and reliable.

[244] See also Order UE-10-03, ¶45.

[245] Order UE-10-03, Order UE-09-02, Order EU-08-01 and Order UE-06-03. The PEI Commission website does not provide ROE orders for 2007 or 2003-05.

The NLPUB has oversight over the electric and oil activities in the province of Newfoundland and Labrador and is the rate regulator for Newfoundland Power Inc. (NP) and for Newfoundland and Labrador Hydro Corporation (NLH).[246] An exception to this regulatory oversight is that some industrial customers have long-term contracts with NP. Newfoundland Power Inc. is an investor-owned utility that operates an integrated generation, transmission and distribution system throughout the island portion of Newfoundland and Labrador and is a subsidiary of Fortis Inc. Newfoundland and Labrador Hydro is primarily a generation and transmission utility with a relatively small amount of distribution. NLH is also a Crown corporation.[247]

The NLPUB used a formulaic approach to update the annual allowed ROE for Newfoundland Power whereas NLH's status as a Crown corporation has resulted in its allowed ROE and its capital structure being determined differently. The determination of ROE and capital structure for the two utilities is discussed separately.

B. NEWFOUNDLAND POWER

1. Formulaic Approach 1998-2002

In 1998, NP entered into a rate review which was preceded by a full cost of capital hearing which investigated the cost of capital, capital structure and merits of a formulaic approach. Specifically, the NLPUB reviewed:[248]

i. The appropriate capital structure of NP;
ii. The appropriate rate of return on common equity and rate base for NP;
iii. The appropriate frequency of a full cost of capital review and whether certain financial market benchmark parameters should be put in place to trigger a hearing on the matter; and
iv. Whether an automatic annual adjustment mechanism for resetting the rate of return in years subsequent to a test year would be appropriate in order to reflect changes in financial market benchmarks.

The resulting NLPUB Order used a maximum common equity ratio of 45% and return on equity of 9.25%. The Newfoundland and Labrador Board of Commissioners of Public Utilities' website does not provide information about the methodology used to determine the allowed ROE

[246] Board of Commissioners of Public Utilities, Newfoundland and Labrador website at http://www.pub.nf.ca/organ.htm.

[247] Order No. P.U. 7, dated June 7, 2002, p. 17.

[248] Newfoundland and Labrador Board of Commissioners of Public Utilities website. See Order No. P.U. 16 (1998-99) at www.pub.nf.ca/orders/pu99.htm

or capital structure. Additionally, the 1998-99 order considered whether to use an Automatic Adjustment Formula to determine the allowed return in the following years, but the decision on such a mechanism was postponed to a general rate application at a later date.[249]

A formulaic approach was put in place in 1998, and the formula was designed to adjust NP's return on equity annually based on changes in long-term Canada bond yields. The Order also confirmed a maximum common equity ratio of 45% and determined the return on rate base to be 9.81% based on an ROE of 9.25%.[250]

The Automatic Adjustment Formula uses three variables to adjust the rate of return on rate base: rate base, invested capital and the estimated cost of common equity. The first two variables are established as part of the annual approval of NP's capital budget, while the cost of equity is adjusted based on average daily closing yields of the long-term (30 year) Government of Canada bonds over the last five trading days in October and the first five trading days of November.[251] The formula differed from that of other jurisdictions along several dimensions. First it determined the total return on rate base rather than the return on equity:

$$\text{Return on rate base} = (\text{Invested Capital in Rate Base}) \times \text{WACC} + Z / (\text{Rate Base})$$

Where WACC is the weighted-average cost of capital, and Z represents amounts which are recognized in the calculation of either weighted average cost of capital or rate of return on rate base, but not both. These amounts include: (A) Amortization of Capital Stock Issue Expenses; (B) Interest on Customer Deposits; and (C) Interest Charges to Construction.[252] The WACC was determined as a weighted average of the allowed ROE and embedded cost of debt with the ROE being determined as a risk-free rate plus a risk premium. The risk-free rate was obtained as the actual yield on two Government of Canada bond series using the last five trading days in October and the first five trading days in November of each year.[253] The risk premium in the 1998 formula was set at 3.50% including an allowance of 0.50% for flotation costs.[254] This risk premium was based on a market risk premium of 5.00% and a beta of 0.60 (3.00% = 0.60 × 5.00%). Put differently, the NLPUB relied primarily on the CAPM to determine the initial ROE.

[249] Order P.U. 19 (2003), p. 8.

[250] Order P.U. 19 (2003), p. 8.

[251] Order P.U. 30 (2000-2001).

[252] Order P.U. 19 (2003), p. 62.

[253] Order P.U. 19 (2003), p. 65. The two series were the Government of Canada's 8% issue maturing June 1, 2027 and the Government of Canada's 5.75% issue maturing June 1, 2029.

[254] Order P.U. 19 (2003), p. 67.

This mechanism remained in effect until 2002, when the NLPUB ordered a review of the performance of the mechanism.[255]

2. 2003 Review of the Formula

In June of 2003, the NLPUB issued a decision that decided to continue the use of the formula, but the NLPUB made some adjustments to the determination of the allowed ROE. Specifically, the NLPUB continued to rely on a risk-free rate plus a risk premium, but the NLPUB changed the calculation of the risk-free rate and also adjusted the risk premium.[256]

For the risk-free rate, the NLPUB continued to establish the rate with reference to the yield on long-term 30-year Government of Canada bonds. However, the NLPUB switched from using two specific series to using the three most recent series issued by the Government of Canada. As before, the rate was calculated as the actual yield over a 10-day period in late October through early November of the year prior the year rates would be in effect.[257]

The risk premium had been set at 3.00% plus 0.50% for flotation cost allowance in 1998. However, in 2003, the NLPUB considered NP's application for rate increases and in its decision increased the risk premium to 4.15% but did not explain its specific reason for the increase.[258]

The formula established in the 2003 proceeding remained in effect through 2007, but was modified for the 2008 test year.

3. 2008 Agreement

In 2007 the NLPUB approved an agreement for 2008 that included some modifications to the formula. Specifically, the NLPUB approved the use of *Consensus Forecasts* rather than actual government bond yields being used to determine the risk-free rate. Further, to maintain consistency to the allowed ROE, the risk premium was increased to 4.35% (from 4.15%).[259] This settlement also maintained a capital structure with 45% equity. The formula and its 2008 parameters remained in place through 2009.

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[255] Order P.U. 28 (2001-2002).

[256] Order P.U. 19 (2003).

[257] Order P.U. 19 (2003), pp. 49-50.

[258] The company had applied for an increase to 4.75%.

[259] Order P.U. 32 (2007), p. 14.

4. 2009-11 Determination of NP's Allowed ROE

In 2009, the NLPUB reviewed the formula and ordered the continued use of the formula for 2011 and 2012.[260] Following an application from NP to change the methodology used to determine the risk-free rate, the NLPUB in December 2010 approved two changes to the calculation of the risk-free rate used in the formula. Specifically, the NLPUB changed the calculation to the following:[261]

i. The forecasted risk-free rate is calculated as the average of the 3-month and 12-month forecast of 10-year Government of Canada Bonds as published by *Consensus Forecasts* in the preceding November, and
ii. The average observed spread between 10-year and 30-year Government of Canada Bonds for all trading days in the preceding October is added to the forecasted risk-free rate.

In the following year, NP submitted an application proposing that the NLPUB suspend the operation of the formula to establish a rate of return on rate base for 2012 and approve, on an interim basis, the continued use of the current rate of return on rate base and allowed ROE of 8.38% for 2012. Because no party objected to the proposal, the NLPUB accepted the request in December 2012, and the 2012 allowed ROE remained the same as the previous year, 8.38%.[262]

C. NEWFOUNDLAND AND LABRADOR HYDRO[263]

As a Crown corporation, NLH has several unique features. The debt of NLH is guaranteed by the province of Newfoundland and Labrador, and NLH's only source of equity is retained earnings. As a result, NLH has a more leveraged capital structure than most utilities, but maintains its ability to raise debt.

Two main orders pertain to the cost of capital and capital structure for NLH. First, in 2002, the NLPUB reviewed NLH's capital structure and return on rate base. The NLPUB accepted NLH's proposed 2002 capital structure consisting of 17% equity and 83% debt and also accepted the short-term target of reaching 20% equity. The NLPUB did not support NLH request to move to a capital structure with 40% equity and 60% debt, because the NLPUB did not find support in

[260] Order P.U. 43 (2009).
[261] Order P.U. 12 (2010), p. 2.
[262] Order P.U. 25 (2011), p. 3.
[263] Order P.U. 7, dated June 7, 2002, p. 30.

the submitted evidence.[264] Further, the NLPUB accepted the proposed 3% return on equity for 2002, but acknowledged that a 3% ROE is below a normal market return.[265]

Second, in 2007 in a general rate case for NLH, the NLPUB reviewed NLH's allowed ROE and capital structure. The NLPUB used the forecasted ROE of 4.47% for 2006 as a baseline and accepted the proposed ROE of 5.20% for 2007. In addition, the NLPUB accepted NLH's forecasted equity percentage of 14% for 2007.[266] The 2007 decision also rejected at this time NLH's proposal to implement an automatic adjustment formula similar to that used for NP.[267] The NLPUB website does not provide a more recent decision for NLH on.

D. ALLOWED ROE AND CAPITAL STRUCTURE

The formulaic approach to determining the cost of equity for NP has resulted in allowed ROEs as indicated in **Table 14** below. The table also indicates the deemed capital structure for years in which it is available from orders.

Newfoundland and Labrador Allowed ROE and Capital Structure

	NP		NLH	
For Year	Allowed ROE	Equity %	Allowed ROE	Equity %
2012	8.38%	45.0%		
2011	8.38%	45.0%	n/a	n/a
2010	9.00%	45.0%	n/a	n/a
2009	8.69%	45.0%	n/a	n/a
2008	8.95%	45.0%	5.20%	14.0%
2007	8.60%	n/a	4.47%	n/a
2006	8.77%	n/a	3.00%	n/a
2005	9.24%	n/a	n/a	n/a
2004	9.75%	44.6%	n/a	n/a
2003	9.75%	n/a	n/a	n/a
2002	10.06%	n/a	8.76%	20.0%

Table 14[268]

[264] Order P.U. 7, p. 43.

[265] Order P.U. 7, p. 45.

[266] Order P.U. 8 (2007), p. 36.

[267] Order P.U. 8 (2007), p. 51.

[268] Order P.U. 7 (2002-2003); Order P.U. 8 (2007); Order P.U. 19 (2003); Order P.U. 50 (2004); Order P.U. 32 2007), Order P.U. 35 (2008), Order P.U. 43 (2009); Order P.U. 12 (2010).

As is evidenced from **Table 14** above, NP and NLH have quite different allowed ROEs and capital structures.

XIII. NATIONAL ENERGY BOARD

A. INTRODUCTION

The National Energy Board (NEB) is an independent federal agency in Canada that regulates international and interprovincial aspects of the oil, gas and electric utility industries. The NEB determines rates, including the cost of capital and capital structure, for interprovincial and international pipelines. It also has oversight over energy development projects and energy markets in Canada. However, cost of capital and capital structure regulation at the NEB is focused on pipelines.

B. HISTORY

In 1994, the NEB held its only multi-pipeline cost of capital hearing and determined appropriate debt-equity ratios for six pipeline companies based on their business risk. The NEB then approved a uniform rate of return on common equity for the six pipelines. At the time the allowed return on common equity was set at 12.25% and updated annually based on the changes in forecasted long-term Government of Canada bond rates. Specifically, the formula includes 75% of the change in long Canada bond yield forecasts in the ROE. Thus, that the formulaic approach to cost of equity was determined by:

$$ROE_t = ROE_{t-1} + 75\% \times (\text{LT Gov Bond Forecast}_t - \text{LT Gov Bond Forecast}_{t-1}). \quad \textbf{(31)}$$

LT Gov Bond Forecast came from *Consensus Forecasts*, which provide forecasts for 10-year government bonds, adjusted for the spread between 10-year and 30-year Government of Canada bonds.[269]

The formula was challenged on several occasions but remained in effect for pipelines, whose ROE was determined by the NEB's formulaic approach until early 2009,[270] when the NEB heard an application from Trans Québec & Maritimes Pipelines (TQM) to review the RH-2-94 ROE formula. The RH-1-2008 accepted a rate of return determination different from the formula. Rather than allowing TQM an ROE and a deemed capital structure, the NEB allowed TQM an

[269] RH-2-94 issued March 1995 and RH-1-2008, Issued March 2009.

[270] Some pipelines operated under settlements and hence were not subject to the formulaic approach.

After-Tax Weighted-Average Cost of Capital (ATWACC) to determine the appropriate rate of return on rate base. The ATWACC measures the after-tax return on rate base assigning market-value weights to debt and equity. Specifically,

$$ATWACC = r_D \times (1-\tau) \times (D/V) + r_E \times (E/V) \quad \textbf{(32)}$$

Where r_D is the cost of debt, τ is the tax rate, D is the market value of debt, E is the market value of equity (# of shares outstanding multiplied with the stock price), V is the sum of D and E, and r_E is the cost of equity capital.

Following the RH-1-2008 decision, the NEB notified the public in October 2009 that it would no longer rely on the formulaic approach.[271] In its RH-1-2008 decision, the NEB stated:

> As explained in the RH-2-94 Decision, the initial return on equity determination was meant to be applied to a benchmark pipeline which was assumed to be a hypothetical utility whose overall investment risks are characteristic of a low-risk, high-grade regulated pipeline. The Board notes that the equity thickness of the benchmark pipeline was not explicitly specified in the RH-2-94 Decision. The Board approved a 30 per cent equity thickness for all gas pipelines subject to the Decision, except for Westcoast, which has been interpreted by some as implicitly assigning an equity thickness of 30 per cent for the benchmark pipeline. However, the role of the benchmark pipeline, its changing risk level and its specific equity thickness have not been considered explicitly, and that leaves a doubt as to the exact level of financial risk inherent in the return on equity as determined by the RH-2-94 Formula for the benchmark pipeline.[272]

As a result, the NEB allowed the applicant, TQM, a gas transmission pipeline, to seek a return different from that provided by the formula. TQM sought to have an overall after-tax weighted cost of capital approved, and the NEB agreed.[273]

Subsequent to the RH-1-2008 decision, the NEB in October 2009 issued a letter decision formally abandoning the formulaic approach to setting ROE. In this letter, the NEB stated

> the RH-2-94 Decision will not continue to be in effect.

and

[271] National Energy Board, Press Release: "National Energy Board Drops 94 Return on Equity Formula," October 9, 2009.

[272] RH-1-2008, p. 17.

[273] RH-1-2008, p. 19.

> The Board's decision not to pursue a multi-pipeline approach does not preclude the Board from doing so at a future date.[274]

Since then, the NEB has not issued a decision on cost of capital for a major pipeline under its jurisdiction because rates have been negotiated between interested parties. Therefore, it is now up to the individual pipelines and other interested parties to suggest to the NEB what a fair return on capital is and how it should be calculated.

C. DETERMINING THE ALLOWED RATE OF RETURN

Because the NEB has not determined the allowed rate of return frequently in recent years, this review focuses on the two decisions that have changed the NEB's methodology. First, we discuss the RH-2-94, which implemented the base parameters to be used in the annual update (Equation (31) above) and second, we discuss the approach taken in RH-1-2008, which moved away from the formulaic approach.

1. RH-2-94

The RH-2-94 decision came out of the NEB's call for a multi-pipeline cost of capital hearing - - a proceeding that took place in 1994-95. The decision determined the allowed ROE as well as a capital structure for several pipelines: TransCanada PipeLines Limited (natural gas), Westcoast Energy (natural gas), Foothills Pipe Lines (natural gas), Alberta Natural Gas Company (ANG, natural gas), Trans Québec & Maritimes Pipelines (TQM, natural gas), and Trans Mountain Pipeline (liquids).

Following submissions from all stakeholders, the NEB decided that

> The comparable earnings test may currently be producing results which do not provide an appropriate basis for estimating a fair return for the benchmark pipeline for 1995.[275]
>
> The DCF test is theoretically sound, but that its usefulness is limited because of certain practical difficulties.[276]
>
> Given the problems associated with the application of the comparable earnings and DCF tests at this time, the Board has decided to give primary weight to the results of the equity risk premium test.[277]

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[274] NEB, Letter Decision, "Review of the Multi-Pipeline Cost of Capital Decision (RH-2-94), Reasons for Decision," October 9, 2009.

[275] RH-2-94 p. 5.

[276] RH-2-94 p. 6.

The NEB's decision was primarily based on the premium equity required over and above government debt.

At the time of the proceeding, the forecasted yield on long-term government of Canada bonds was estimated to be 9.25%. Expert witnesses submitted evidence that the risk premium of utility equity over and above the long-term government bond yield was 1.50% to 4.25% and that the cost of equity changed by 50 to 80 basis points when the yield on long-term government of Canada bond changed by 100 basis points. Based on this information, the NEB decided to set the initial (or Base ROE) at 12.25% for an equity risk premium of 3.0% and to use an annual adjustment factor of 75%.[278]

The RH-2-94 decision also determined the capital structure for the relevant pipelines. The NEB concluded that while the pipelines had individual risk characteristics that differed, natural gas pipelines were less risky than liquids pipelines and, among the natural gas pipelines, Westcoast was riskier than the other four pipelines. Therefore, the NEB deemed the following capital structures:

- TransCanada, Foothills, ANG, TQM: 30% equity
- Westcoast 35% equity
- Trans Mountain 40% equity

The ROEs resulting from the RH-2-94 formula for the last 10 years are shown below in **Table 15**:

[277] RH-2-94 p. 6.

[278] RH-2-94 pp. 3-6 and 28-31.

NEB Allowed ROE	
	ROE per RH-2-94
2012	n/a
2011	n/a
2010	n/a
2009	8.57%
2008	8.71%
2007	8.46%
2006	9.46%
2005	9.46%
2004	9.56%
2003	9.79%
The NEB discontinued its formulaic approach in 2009 and has since not issued an ROE decision	

Table 15[279]

The NEB discontinued the formula approach in 2009. However, because of on-going settlements, the NEB continues to provide information about the ROE that would result from the RH-2-94 formula post 2009. The NEB reported that the RH-2-94 formula would have resulted in ROEs of 8.52%, 8.08%, and 7.58% for 2010, 2011, and 2012, respectively. [280]

2. RH-1-2008

A feature of the RH-1-2008 decision is that it allows a weighted-average cost of capital[281] on the rate base rather than an ROE and a deemed capital structure. Further, the decision uses market cost of debt rather than the embedded cost of debt (although TQM had debt outstanding).

In determining the specific figures to rely on, the NEB looked to the CAPM to determine the cost of equity capital.

> The Board is of the view that CAPM is widely accepted as a cost of equity model. This model has been relied upon by the Board in previous proceedings and was

[279] RH-2-94, Letter "Rate of Return on Common Equity (ROE) for 2003;" Letter "Rate of Return on Common Equity (ROE) for 2004;" Letter "Rate of Return on Common Equity (ROE) for 2005;" Letter "Rate of Return on Common Equity (ROE) for 2006;" Letter "Rate of Return on Common Equity (ROE) for 2007;" Letter "Rate of Return on Common Equity (ROE) for 2008;" Letter "Rate of Return on Common Equity (ROE) for 2009."

[280] Letter, "2011 Rate of Return on Common Equity (ROE) per Discontinued RH-2-94 Formula" and Letter, "2012 Rate of Return on Common Equity (ROE) per Discontinued per RH-2-94 Formula."

[281] See *Section II.C.7*.

> not contested in this proceeding as a method to estimate the cost of equity. In the Board's view, CAPM captures the risk equity holders have to bear when holding a common stock,[282]
>
> In the Board's view, even if the DCF model is intuitive and theoretically sound, challenges remain in its applicability since historical growth rates might not reflect the future and analyst expectations might be different than the aggregate expectations of all financial market participants. As a result of these challenges, the Board will not rely on the DCF model and will be informed by CAPM when estimating the cost of equity of sample companies using the ATWACC methodology,[283]

and

> CAPM will inform the Board's view on the market cost of equity.[284]

The NEB relied on the basic CAPM (Equation (2)) and did not look to the Empirical CAPM discussed in *Section VI.C.2* (Hydro Québec, Transmission).[285] To determine the ROE resulting from the CAPM , the NEB had to decide, which comparable companies to use, and to determine the risk-free rate, the beta estimate, and a market risk premium.

Comparable Companies

In considering which companies to use as comparable to TQM, the NEB considered Canadian utilities, U.S. gas distribution companies and U.S. gas pipelines. The NEB found that

> TQM needs to compete for capital in the global market place. The Board has to ensure that TQM is allowed a return that enables TQM to do so. Comparisons to returns in other countries would be useful, but challenging, in terms of differences in business risks and business environment.[286]

Based on this consideration, the NEB compared the business risk of Canadian and U.S. utilities as well as the regulatory environment in the two countries. The NEB found that volumetric risk to pipelines is higher in the U.S. than Canada, but that the higher short-term volatility has little impact on the pipelines' ability to recover capital in the long run. The NEB also concluded that the

[282] RH-1-2008 p. 26.

[283] RH-1-2008, p. 27.

[284] RH-1-2008, p. 29.

[285] RH-1-2008, p. 26.

[286] RH-1-2008, p. 67.

> risks resulting from the regulatory environment are higher for U.S. pipelines than for Canadian pipelines, and finds that this was also true in 1994. However, the Board is of the view that the risks faced by TQM and those faced by U.S. pipelines are not so different as to make them inappropriate comparators.[287]

Finally, the NEB found that U.S. gas distribution companies had larger short-term earnings variability than TQM, but a comparison was meaningful.[288] As a result of these considerations, the NEB looked to the estimates on cost of equity capital for both Canadian and U.S. companies.

Risk-free Rate

The RH-1-2008 decision did not specify which risk-free rate it relied upon, but acknowledged the use of a forecast on the long-term government bond yield. Specifically, all experts relied on the *Consensus Forecasts* to obtain a forecasted risk-free rate and added a maturity premium to convert the forecasted yield on a 10-year government bond to a yield on a 30-year government bond.

Beta

In its RH-1-2008 decision, the NEB looked to betas before any adjustment was made. The NEB did not express a preference for the use of weekly or monthly betas or for the time horizon (2 years, 5 years, etc.) over which they were estimated. The NEB did not specify a range or specific value for beta.

Market Risk Premium

Expert witnesses submitted evidence that the overall market risk premium was in the range of 5.0 to 5.75%. The NEB did not comment on the choice of the MRP.

Cost of Debt

The cost of debt was set at the market cost of debt relying on the yield of an index of utility bonds. Specifically, the NEB noted.

> the market cost of debt was assumed to be equal to the current yield on an index of utility bonds corresponding to each sample company's debt rating. In the Board's view, this assumption is reasonable given the considerable effort required to calculate the actual market cost of debt of each individual sample company.

[287] RH-1-2008, p. 68.

[288] RH-1-2008, p. 68.

> Accordingly, the Board accepts the estimated market cost of debt in the estimated ATWACC of sample companies.[289]

As noted above, the cost of equity and the cost of debt were weighted by their respective market-value weights in the capital structure to obtain the After-Tax Weighted-Average Cost of Capital. Looking to the submitted evidence, the NEB chose an After-Tax Weighted Cost of Capital of 6.4%,[290] which is applied to the total rate base. No capital structure was deemed.

3. Subsequent Applications

Since the RH-1-2008 decision, the NEB has not issued an ROE decision. There have been a few applications since the RH-1-2008 decision, but the parties settled prior to the hearing. For example, Enbridge Inc.'s Line 9 Tolls for several years were settled in May 2011[291] as was Trans Mountain Tolls for 2012.[292] These settlements do not specify the methodology used to determine the return on equity or the actual figure used.

XIV. NORTHWEST TERRITORIES PUBLIC UTILITIES BOARD

The Northwest Territories Public Utilities Board (NWTPUB) contracts with the Alberta Utilities Commission for legal and technical expertise. The NWPUB fully regulates NWT Power Corporation, an integrated electric utility and a crown corporation, and Northland Utilities Limited (Northland), an integrated investor-owned electric utility.[293] There are no gas distribution utilities in the NorthWest Territories.[294]

In Northland Utilities Limited's August 2011 "Amended Settlement"[295] the NWTPUB approved the following parameters for Northland

- 9.3% ROE for the 2011-2013 test years
- Set the equity component of Northland's capital structure at the existing level of 43.5% for each of the 2011-2013 test years.

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[289] RH-1-2008, p. 27.

[290] RH-1-2008 p. 80.

[291] Order TO-004-2011, issued September 15, 2011, approves the settlement.

[292] Order TO-005-2012, issued March 30, 2012, approves the settlement.

[293] Northland Utilities is owned by the ATCO Companies and Denendeh Development.

[294] Some of the information was obtained through a phone interview with a staff member at the NWPUB (Louise Larocque) as limited information is publicly available.

[295] Decision 13-2011. Some of the information was obtained through a phone interview with a staff member at the NWPUB (Louise Larocque) as limited information is publicly available.

- Used the following forecast debenture rates for purposes of calculating long-term debt rates for the Test Years (i) for 2011 -5.4%; (ii) for 2012 – 5.9%; (iii) for 2013 – 6.2%

The key parameters for Northland's cost of capital and capital structure are as depicted in **Table 16** below.

NW Territories Utility Board ROE and Capital Structure			
	ROE	**Deemed LT Debt Rate**	**Equity %**
2013	***9.3%***	5.4%	43.5%
2012	***9.3%***	5.9%	43.5%
2011	***9.3%***	6.2%	43.5%

Table 16[296]

XV. YUKON UTILITIES BOARD

The Yukon Utilities Board (Yukon Board), like the NWPUB, contracts with the Alberta Utilities Commission for legal and technical expertise. The Yukon Board regulates Yukon Energy Corporation (YEC), which is fully owned by the government of Yukon, and Yukon Electric Company Limited (YECL), which is a subsidiary of ATCO Electric, an investor-owned utility. Both YEC and YECL are integrated electric utilities.

There are two recent decisions regarding the companies' revenue requirement but none specific to the allowed cost of capital or capital structure. On February 19, 2010, Yukon Electrical Company Limited and Yukon Energy Corporation (jointly "the Companies") filed the 2009 Phase II Rate Application (Application) with the Yukon Board. The Companies requested approval of adjustments to rates (on a prospective basis), to be effective September 1, 2010, and to collect an approved 2009 Consolidated Firm Rate Revenue Requirement of $50.833 million. Because the Yukon Board found no issues with the revenue requirement, the requested rates were approved.

Each company separately had previously filed a General Rate Application (GRA) in 2008, for forecast revenue requirements for 2008 and 2009. Board Orders 2009-2 and 2009-5 approved

[296] See Decision 13-2011, pp. 6-7.

YECL's revenue requirements for the test period, and Board Orders 2009-8 and 2009-10 approved YEC's revenue requirements for the 2008 and 2009 test period. Full cost-of-service Studies were filed in 1997 and 2010. The 2010 cost-of-service study was rejected and the Yukon Board is awaiting a revised filing.

APPENDIX A: LINKS TO WEBSITES

Alberta Utilities Commission:

http://www.auc.ab.ca/Pages/Default.aspx

British Columbia Utilities Commission:

http://www.bcuc.com/

Manitoba Public Utilities Board

http://www.pub.gov.mb.ca/

National Energy Board

http://www.neb-one.gc.ca/clf-nsi/index.html

New Brunswick Energy and Utilities Board

http://www.nbeub.ca/

Newfoundland and Labrador Board of Commissioners of Public Utilities

http://www.pub.nf.ca/

Northwest Territories Public Utilities Board

http://www.nwtpublicutilitiesboard.ca/about.htm

Nova Scotia Utility and Review Board

http://www.nsuarb.ca/

Nunavut Utility Rates Review Council

http://www.urrc.gov.nu.ca/en/home.html

Ontario Energy Board

http://www.ontarioenergyboard.ca/OEB/

Prince Edward Island – Island Regulatory and Appeals Commission

http://www.irac.pe.ca/

Régie de l'énergie du Québec

http://www.regie-energie.qc.ca/index.html

Saskatchewan Rate Review Panel

http://www.saskratereview.ca/

Yukon Utilities Board

http://www.yukonutilitiesboard.yk.ca/

APPENDIX B: REVIEWED DECISIONS BY JURISDICTION

Alberta Utilities Commission:

- Decision U99099, issued November 1999
- Decision 2004-052, issued July 2, 2004
- Order U2004-423, issued November 30, 2004
- Order U2006-292, issued November 30, 2006
- Order U2007-347, issued November 30, 2007
- Decision 2009-216, issued November 12, 2009
- Decision 2011-274, issued December 8, 2011
- Decision 2011-450, issued December 5, 2011

British Columbia Utilities Commission:

- BCUC Decision in the Matter of Return on Common Equity BC Gas Utility Ltd., Pacific Northern Gas Ltd., West Kootenay Power Ltd., June 10, 1994
- BCUC, In the Matter of Terasen Gas Inc., et. al. Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism, March 2, 2006.
- BCUC In the Matter of Terasen Gas Inc. et al. Return on Equity and Capital Structure Decision, December 16, 2009.
- Order 158-09.
- Letter No L-55-08.
- Letter No. L-93-07.
- Letter No. L-75-06.
- Letter No. L-104-05.
- Letter No. L-55-04.
- Letter No. L-57-03.
- Letter No. L-46-02.

Manitoba Public Utilities Board

- Order 99/07
- Order 116/08

- Order 128/09
- Order 148/09
- Order 99/11
- Order 5/12

National Energy Board

- RH-2-94, issued March 1995
- RH-1-2008, issued March 2009
- Letter, "Rate of Return on Common Equity (ROE) for 2003," December 5, 2002
- Letter, "Rate of Return on Common Equity (ROE) for 2004," November 28, 2003
- Letter, "Rate of Return on Common Equity (ROE) for 2005," November 25, 2004
- Letter, "Rate of Return on Common Equity (ROE) for 2006," November 23, 2005
- Letter, "Rate of Return on Common Equity (ROE) for 2007," November 23, 2006
- Letter, "Rate of Return on Common Equity (ROE) for 2008," November 29, 2007
- Letter, "Rate of Return on Common Equity (ROE) for 2009," December 4, 2008
- Letter, "Rate of Return on Common Equity (ROE) for 2011 per RH-2-94 Discontinued Formula," November 29, 2010.
- Letter, "Rate of Return on Common Equity (ROE) for 2012 per RH-2-94 Discontinued Formula," December 2, 2011.

New Brunswick Energy and Utilities Board

- Decision IN THE MATTER of an Application by Enbridge Gas New Brunswick Inc. for Approval of Its Rates and Tariffs, issued June 23, 2000.
- Decision IN THE MATTER OF an application by New Brunswick Power Distribution and Customer Service Corporation for Approval of Changes in Its Charges, Rates and Tolls, February 22, 2008
- IN THE MATTER OF an Investigation into the necessity for the 3% increase in the New Brunswick Power Distribution and Customer Service Corporation's charges, rates and tolls which came into effect on June 1, 2010". Issued July 12, 2010.
- Decision IN THE MATTER of a review of the Cost of Capital for Enbridge Gas New Brunswick L.P. (EGNB), November 30, 2010

Newfoundland and Labrador Board of Commissioners of Public Utilities

- Order P.U. 7 (2002), issued June 7, 2002

- Order P.U. 19 (2003), issued June 20, 2003
- Order P.U. 28 (2001-2002), issued November 28, 2001
- Order P.U. 50 (2004), issued December 9, 2004
- Order P.U. 32 (2007), issued December 19, 2007
- Order P.U. 35 (2008), issued December 22, 2008
- Order P.U. 43 (2009), issued December 24, 2009
- Order P.U. 32 (2010), issued December 10, 2010
- Order P.U. 12 (2010), issued December 10, 2010
- Order P.U. 25 (2011), issued December 13, 2011

Northwest Territories Public Utilities Board

- 13-2011 Decision

Nova Scotia Utility and Review Board

- NSUARB-NSPI-P-873, 2002 NSUARB 1, issued January 24, 2002
- NSUARB-NSPI-P-881, 2005 NSUARB 27, issued January 21, 2005
- NSUARB-NSPI-P-888, 2008 NSUARB 140, issued November 5, 2008
- NSUARB-NSPI-P-888(2), 2010 NSUARB 6, issued January 20, 2010
- NSUARB-NG-HG-R-10, 2010 NSUARB 241; issued December 16, 2010
- NSUARB-NG-HG-R-11, 2011 NSUARB 183; issued November 24, 2011
- NSUARB-NSPI-P-892, 2011 NSUARB 184; issued November 29, 2011

Ontario Energy Board

- Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities, March 1997 (1997 Draft Guidelines)
- RP-2002-0158, issued January 16, 2004
- EB-2005-0520, issued June 29, 2006 (Union Gas)
- EB-2006-0034, issued July 5, 2007.
- Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, issued December 20, 2006
- EB-2008-0272, issued May 28, 2009

- EB-2009-084, issued December 11, 2009 (Generic CoC)
- EB-2010-002, issued December 23, 2010
- EB-2011-038, issued January 20, 2012
- EB-2011-0268, issued December 20, 2011 (Hydro One)
- "Cost of Capital Parameters Updates for 2010 Cost of Service Applications," issued February 24, 2010
- "Cost of Capital Parameters for 2011 Cost of Service Applications for Rates Effective May 1, 2011," issued March 3, 2011
- "Cost of Capital Parameters Updates for 2012 Cost of Service Applications," Issued November 10, 2011
- "Cost of Capital Parameters Updates for 2012 Cost of Service Applications for Rates Effective May 1, 2012," 3/2/2012.

Prince Edward Island – Island Regulatory and Appeals Commission

- Order UE92-17, issued December 21, 1992
- Order UE93-11, issued 1993.
- Order UE06-03, issued June 27, 2006
- Order UE08-01, issued January 24, 2008.
- Order UE09-02, issued February 20, 2009.
- Order UE10-03, issued July 12, 2010

Régie de l'énergie du Québec

- D-99-11, issued
- D-2002-95
- D-2003-93
- D-2007-116
- D-2008-024, issued February 26, 2008
- D-2009-156, issued December 7, 2009
- D-2010-147, issued March 4, 2010
- D-2011-182, issued November 25, 2011

Saskatchewan Rate Review Panel

- Report to the Minister of the Crown Investments Corporation of Saskatchewan, November 23, 2001
- Report to the Minister of the Crown Investments Corporation of Saskatchewan, May 1, 2003
- BCUC Staff Review Report, SaskEnergy Incorporated, October 18, 2005
- Report to the Minister of the Crown Investments Corporation of Saskatchewan, December 29, 2009
- Crown Investments Corporation of Saskatchewan Annual Reports

Yukon Utilities Board

- Board Order 2010-13, issued December 30, 2011
- Board Order 2010-13, Appendix A

APPENDIX C: ABBREVIATIONS AND GLOSSARY

AAM	Automatic Adjustment Mechanism
ANG	Alberta Natural Gas Company
Arithmetic average	The sum of observed values divided by the number of observations (sometimes referred to as the mean)
ATWACC	After-Tax Weighted-Average Cost of Capital
AUC	Alberta Utilities Commission
AEUB	Alberta Energy and Utilities Board (predecessor to AUC)
BaseROE	Allowed, Base-line ROE at the time it was evaluated for use in a formulaic approach
Beta *(β)*	The responsiveness of a company's stock return to a systematic risk; typically the return on the market (*e.g.,* S&P/TSX)
BCUC	British Columbia Utilities Commission
Blume Adjustment	An adjustment to beta that moves the estimate 1/3 towards 1
CAPM	Capital Asset Pricing Model, which is an equilibrium asset pricing model that shows that equilibrium rates of expected return of risky asset is a function of their covariance with the market portfolio. It is often used as a method to estimate the cost of equity capital.
CB	Yield on 30-year Canada Bonds
CE	Comparable Earnings. The comparable earnings methodology looks at the earned ROE of comparable companies to assess the cost of equity. It is used as a method to estimate the cost of equity capital.
Consensus Forecasts	A subscription service that provides consensus forecast on macroeconomic variables including interest rates. Forecasted interest rates for Canadian government bonds are used in several jurisdictions.
DCF	Discounted Cash Flow. The discounted cash flow model is often used as a method to estimate the cost of equity capital.
EBIT	Earnings Before Interest and Taxes
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortisation
ECAPM	Empirical CAPM
EGNB	Enbridge Gas, New Brunswick
Disco	Distribution Company (electric or natural gas)
ERP	Equity Risk Premium

FFO	Funds from Operations (a measure of cash flow and often used by credit rating agencies to assess interest coverage)
Geometric Average	Annualized holding period return
HQD	Hydro Québec, Distribution
HQT	Hydro Québec, Transmission
Interest Coverage	The degree to which a measure of a company's income or cash flow covers its interest obligations.
IRAC	Prince Edward Island Regulatory & Appeals Commission
LCBF	Long-Term Government of Canada Bond Forecast
LDC	Local Distribution Company (*e.g.,* Gas LDC)
LTDR	Long-Term Deemed Debt Rate
Maritime Electric	Maritime Electric Company Limited
MBPUB	Manitoba Public Utilities Board
MRP	Market Risk Premium; the return on the market portfolio that is the difference between the expected return on the market portfolio and the return on the risk-free asset.
Multi-stage DCF	A multi-period version of the DCF model that allows the growth rate to vary over time.
NEB	National Energy Board
NBEUB	New Brunswick Energy and Utilities Board
NLH	Newfoundland and Labrador Hydro
NLPUB	Newfoundland and Labrador Board of Commissioners of Public Utilities
NP	Newfoundland Power, Inc.
NWTPUB	Northwest Territories Public Utilities Board
NSPI	Nova Scotia Power Inc.
NSUARB	Nova Scotia Utility and Review Board
Nunavut Council	Nunavut Utility Rates Review Council
OEB	Ontario Energy Board
PNG	Pacific Northern Gas
Régie	Régie de l'énergie du Québec

Risk-free Rate	The expected return on a risk-free asset. Often government bills or bonds are used as a proxy for the risk-free asset.
Risk Premium	The excess return on the risky asset that is the difference between the expected return on the risky asset and the return on the risk-free asset.
ROE	Return on Equity
S&P/TSX	Index on stocks traded on the Toronto Stock Exchange
SEDAR	System for Electronic Document Analysis and Retrieval was developed for the Canadian Securities Administration to facilitate electronic filing of securities information. It provides access to most public securities documents and information filed by public companies.
SRRP	Saskatchewan Rate Review Panel
STDR	Short-Term Deemed Debt Rate
SVGC	Swan Valley Gas Corporation, a gas LDC
T-bill	Short-term treasury debt
TFO	Transmission Facilities Owner
TGI	Terasen Gas Inc.
TQM	Trans Qubéc & Maritimes Pipeline
TSX	Toronto Stock Exchange
Value Line	A subscription service that provides information on the economy and 1700 companies in the U.S., Canada and overseas. It provides growth rates for a large number of companies.
WACC	Weighted-Average Cost of Capital
YEC	Yukon Energy Corporation
YECL	Yukon Electrical Company Limited
Yukon Board	Yukon Utilities Board