Decision **2004-052**

Generic Cost of Capital

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

July 2, 2004

Alberta Energy and Utilities Board

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Application No. 1271597

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FORTISALBERTA (FORMERLY AQUILA NETWORKS)
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1 INTRODUCTION AND BACKGROUND

On May 6, 2002, the Board received a request from the City of Calgary[1] (Calgary) that the Board institute a proceeding to consider generic cost of capital matters for electric and gas utilities under the Board's jurisdiction. The Board responded to Calgary by letter dated June 6, 2002, indicating that it would be appropriate to await the National Energy Board's (NEB) upcoming decision on rate of return before proceeding to deal with this issue.

On September 30, 2002, the Board distributed a letter (attached as Appendix 3) to interested parties indicating that it had decided to call a generic hearing, pursuant to Section 46 of the *Public Utilities Board Act*[2] (PUBA), to consider cost of capital matters for electric, gas and pipeline utilities under its jurisdiction. Gas transmission (pipeline) and electric transmission companies as well as electric and gas distribution companies under the Board's jurisdiction would be included.

In its letter of September 30, 2002, the Board advised that it intended to hold a pre-hearing meeting to deal with the following issues:

- Determination of the scope of the proceeding and list of issues.
- Determination of procedural matters that might be adopted for such a hearing.

A preliminary list of issues and procedural matters was attached to the September 30, 2002 letter. Interested parties were requested to consider the preliminary list of issues and procedural matters and provide the Board with their written submissions on the appropriateness of each issue or matter, as well as their submissions with respect to additional issues or matters that might appropriately be considered through such a generic proceeding.

1 In its May 28, 2003 letter, the Board indicated that for purposes of the proceeding, utility companies would be considered as applicants and all other parties as interveners.

2 R.S.A. 2000, c. P-45

On October 7, 2002, the Board issued a Notice of Proceeding (the Notice). By letter of November 20, 2002, the Board advised parties that their written submissions as a result of the Board's September 30, 2002 letter had been sufficient to clarify the parties' positions with respect to the preliminary issues list and that a pre-hearing meeting was therefore not necessary.

By letter dated December 16, 2002, the Board clarified the next steps in the process with respect to a Generic Cost of Capital proceeding. The Board, in establishing this process, gave regard to the submissions, concerns and questions initially filed by parties pursuant to the Board's letter of September 30, 2002 and the reply submissions filed pursuant to the Board's letter of November 26, 2002. The Board set out its rational for consideration of a generic approach to cost of capital issues and established an initial process module (the Standardized Approach Module) to consider the preliminary question of the appropriateness of a standardized approach in the following manner:

> The Board continues to seek out opportunities to improve and streamline the regulatory process and to decrease the overall cost of regulation. The Board is of the view that the cost of capital matters for gas, pipeline, and electric utilities under its jurisdiction are one such area worthy of consideration, particularly given its importance within GTA/GRA proceedings.
>
> The Board notes the amount of regulatory time and accompanying expense that is expended, whereby parties are engaged in seemingly similar cost of capital issues in multiple applications. Applicants and interveners often address these issues through similar investigative, comparative and interpretive methodologies and cost of capital evidence.
>
> The Board is also cognizant of the increasingly heavy utility regulatory schedule that has resulted from electric and gas industry restructuring, new and expanding Board responsibilities, and the general growth and prosperity of the Province.
>
> The Board notes that in previous proceedings, such as the 99/00 Electric GTA, the Board has addressed the uniformity in treatment between utilities on cost of capital matters by hearing the consolidated evidence from all applicants in the same proceeding and rendering a single Board decision (as occurred in Decision U99099). The Board has also attempted to streamline proceedings in other ways, such as the development of policy guidelines like the Negotiated Settlement Guidelines.
>
> In a first module as discussed below, the Board, following submissions from parties, will assess and determine whether or not to proceed further, in a generic process on this issue. This first module will explore the ability and appropriateness of possibly applying a standardized approach in Alberta for all major gas, pipeline and electric utilities under its jurisdiction, whether collectively or on an industry-by-industry basis. Such an approach may magnify the benefits to all parties and enhance the sustainability of the cost of capital determination process, and thereby streamline the regulatory process. The Board wishes to also explore whether the simultaneous airing of views is likely to be more cost-effective than a separate airing of views over a series of proceedings, which may not be linked in evidentiary terms.

The Board then concluded:

> The Board has determined that it will proceed with a written process followed by a Board decision to address the preliminary issue of whether a standardized approach to cost of capital, including return on equity, capital structure and cost of debt, has the potential to achieve reasonable efficiencies while continuing to result in fair and reasonable rates for all stakeholders. As part of the decision, the Board will determine the subsequent steps, if any, for this generic proceeding.

The Board also presented the initial questions to be considered in the Standardized Approach Module and the Board set out the schedule for the Standardized Approach Module.

Having reviewed the written submissions of the parties on the preliminary questions in the Standardized Approach Module, the Board concluded this module on April 16, 2003 by issuing a Notice of Hearing in respect of the continuation of the Generic Cost of Capital proceeding. The Board noted:

> Having considered the submissions received from the above parties, the Board is of the view that a standardized approach to rate of return on equity and capital structure has the potential to achieve certain positive benefits including reduced regulatory costs, while continuing to result in a fair return for all utilities and in just and reasonable rates for all customers. The Board has therefore determined that it will proceed with a generic cost of capital hearing to focus on the possibility of establishing a standardized approach to rate of return on equity and capital structure for all utilities under the jurisdiction of the Board.

The letter also dealt with transitional issues, minimum filing requirements, and set out a scope for the Generic Cost of Capital Proceeding. The Board also established a preliminary schedule that would result in a hearing commencing on November 12, 2003.

By letter dated May 28, 2003, the Board remarked:

> The Board notes that no party objected to the Board's preliminary scope of the proceeding. Accordingly, the Board confirms the scope for the Generic Cost of Capital Proceeding as set out in Appendix A.

Appendix A of the May 28, 2003 letter outlined the Scope of the Proceeding as follows:

Return on Equity

1. Return on Equity Methodology
2. Allowed 2004 Return on Equity
3. Annual Adjustment Mechanism
4. Process to Review the Return on Equity

Capital Structure

1. Capital Structure for Each Utility Sector
2. Impact on Capital Structure of Utility Holding Company Structures
3. Adjustments to Capital Structure for Non-Taxable Entities
4. 2004 Capital Structure for Each Utility Company
5. Events and Process Which Might Result in Adjustments to Capital Structure

Also in the May 28, 2003 letter, the Board clarified certain transitional issues, refined the minimum filing requirements and indicated that for purposes of the proceeding, utility companies would be considered as applicants and all other parties as interveners. The Applicants are shown below:

Applicant	**Abbreviation**
AltaGas Utilities Inc.	AltaGas
AltaLink Management Ltd.	AltaLink
FortisAlberta (formerly Aquila Networks)	
The ATCO Group of Companies[3]	ATCO
ENMAX Power Corporation (Distribution)	ENMAX
The EPCOR Group of Companies[4]	EPCOR
NOVA Gas Transmission Ltd.	NGTL

A complete list of Participant organizations and their abbreviations is provided in Appendix 1. AltaLink, Aquila and EPCOR collectively referred to themselves as "the Companies". The Board notes that effective May 31, 2004, Fortis Alberta Holdings Inc. (Fortis) completed its acquisition of Aquila and renamed the company FortisAlberta. Any Board decisions or directions in this Decision respecting Aquila should be read as decisions or directions respecting FortisAlberta.

The Board's May 28, 2003 letter also included a Preliminary Schedule shown below:

Notice of Hearing	April 16, 2003
Submissions	May 12, 2003
Reply Submissions	May 20, 2003
Ruling on Procedural and Transitional Issues	May 28, 2003
Utility Applicants Evidence	July 9, 2003
Information Requests (IRs) to Utilities	July 25, 2003
IR Responses from Utilities	August 15, 2003
Intervener Evidence	September 12, 2003
IRs to Interveners	September 26, 2003
IR Responses from Interveners	October 17, 2003
Utility Rebuttal Evidence	November 5, 2003
Hearing Commencement	November 12, 2003

By letter dated, June 24, 2003, the Board clarified the minimum filing requirements, identified electronic filing requirements, and pre-assigned exhibit numbers.

On August 19, 2003, the Board issued a letter advising parties of hearing logistics and a tentative pre-hearing meeting date to resolve scheduling and procedural matters.

By letter dated October 9, 2003, the Board noted that parties generally did not see a need to convene a pre-hearing meeting and accordingly the Board cancelled the meeting that had tentatively been scheduled for October 16, 2003.

3 ATCO Electric Ltd., ATCO Gas, and ATCO Pipelines
4 EPCOR Distribution Inc. and EPCOR Transmission Inc.

The Board conducted a public hearing from November 12-14, 2003, November 17-21, 2003 and November 25-27, 2003 at the Board's offices in Edmonton, and from December 1-5, 2003, December 8-12, 2003, December 15-16, 2003, January 5-9, 2004, and January 12-16, 2004, at the Board's offices in Calgary. A list of parties who appeared at the hearing is included in Appendix 1. The Board sat for a total of 33 hearing days.

The Board received written argument on or before February 23, 2004 and written reply on or before April 5, 2004. Accordingly, for purposes of this Decision, the Board considers that the record closed on April 5, 2004.

The Board notes the full participation of a broad range of stakeholders in the proceeding, the large number of parties involved, and the diversity and sophistication of the views represented. The Board also notes the extensive nature of the record of the proceeding which includes pre-hearing submissions, the minimum filing requirements, a thorough set of responses to information requests, detailed expert evidence, hearing transcripts, undertaking responses, and comprehensive argument and reply argument.

Having considered all of the evidence and reviewed the arguments of the interested parties, the Board sets out its Decision with reasons respecting the Generic Cost of Capital Proceeding (Proceeding).

Abbreviations not otherwise defined within the body of the Decision are defined in Appendix 2.

2 SHOULD THE BOARD ADOPT A STANDARDIZED APPROACH TO RATE OF RETURN AND/OR CAPITAL STRUCTURE?

2.1 NGTL Jurisdictional Objection

NGTL submitted that the Board does not have the jurisdiction to implement a formula approach to establish a fair return for NGTL.

NGTL submitted that the specific jurisdiction of the Board in respect of the determination of the fair return for any gas utility comes only from section 37 of the Alberta *Gas Utilities Act*[5] (GUA). Section 37 reads as follows:

> 37(1) In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed afterwards by an owner of a gas utility, the Board shall determine a rate base for the property of the owner of the gas utility used or required to be used to provide service to the public within Alberta and on determining a rate base it shall fix a fair return on the rate base.
>
> (2) In determining a rate base under this section, the Board shall give due consideration
>
> a. to the cost of the property when first devoted to public use and to prudent acquisition costs to the owner of the gas utility, less depreciation, amortization or depletion in respect of each, and
>
> b. to necessary working capital.

[5] R.S.A. 2000, c. G-5

> (3) In fixing the fair return that an owner of a gas utility is entitled to earn on the rate base, the Board shall give due consideration to all facts that in its opinion are relevant.

NGTL submitted that based on the wording of subsection 37(1), the Board does not have jurisdiction to fix a fair return for a gas utility *"unless and until it has determined a rate base"* for that gas utility. The rate base will vary from year to year, and the Board must determine the rate base for a particular period before it can determine a fair return for that period. NGTL argued that the Board cannot make a pre-determination of the fair return for a particular period, using a formula, and then apply that return to whatever rate base it subsequently determines is appropriate in respect of that same period. NGTL submitted that application of a formulaic return to a rate base that has yet to be determined would fetter the discretion of future Board panels and is not permitted by the statute.

NGTL also considered the wording of section 45 of the GUA, which provides:

> 45(1) Instead of fixing or approving rates, tolls or charges, or schedules of them, under sections 36(a), 37, 40, 41, 42 and 44, the Board, on its own initiative or on the application of a person having an interest, may by order in writing fix or approve just and reasonable rates, tolls or charges, or schedules of them,
>
> (a) that are intended to result in cost savings or other benefits to be allocated between the owner of the gas utility and its customers, or
>
> (b) that are otherwise in the public interest.
>
> (2) The Board may specify terms and conditions that apply to an order made under this section.

NGTL submitted that section 45 of the GUA was implemented to permit approval of negotiated settlements and does not empower the Board to establish a formulaic approach to fair return. NGTL submitted that by its terms, section 45 relates to "rates, tolls or charges", not to return.

NGTL also submitted that the fact it did not raise the jurisdiction issue in the first module of this proceeding does not prohibit it from raising the issue in argument.

Jurisdiction to Interpret the GUA Provisions

The NGTL position in effect poses the following question: "Does the Board have jurisdiction to fix a fair return for a gas utility through a standardized approach based on a formula?" (the Jurisdictional Question) Before the Board can address this question, it must first determine if it has jurisdiction to interpret the subject provisions of the GUA. The Board finds it does have such jurisdiction on the basis of the reasons stated below.

The Board notes section 36(1)(a) of the PUBA which provides:

> The Board has all the necessary jurisdiction and power
>
> (a) to deal with public utilities and the owners of them as provided in this Act;

The Board further notes section 36(2) of the PUBA, which provides:

> In addition to the jurisdiction and powers mentioned in subsection (1), the Board has all necessary jurisdiction and powers to perform any duties that are assigned to it by statute or pursuant to statutory authority.

In order for the Board to perform the duties assigned to it pursuant to sections 37 and 45 of the GUA, the Board must be able to interpret and apply the wording of the legislation.

Board also notes the provisions of section 38 of the PUBA, which provides:

> The Board may, as to matters within its jurisdiction, hear and determine all questions of law or of fact.

The interpretation of the Board's governing legislation is a question of law or of fact.

The Board further notes the decision of the Alberta Court of Appeal in *ATCO Electric Ltd. v. Alberta* (Energy and Utilities Board) [2003] A.J. No. 1634, (2003) 339 A.R. 152 as a recent acknowledgment of the ability of the Board to construe its own legislation.

Accordingly, the Board finds that the ability to interpret sections 37 and 45 of the GUA is within its jurisdiction.

Is the Matter One of Interpretation?

Next, the Board must determine if the Jurisdictional Question is a matter of interpretation of the relevant provisions.

The Board finds that the Jurisdictional Question is a question of law or of fact, the answer to which is dependant on an interpretation of sections 37 and 45 of the GUA and the relevant legislation taken as a whole. Having found that the interpretation of its own legislation is within the Board's jurisdiction, the provisions of section 38 of the PUBA provide the Board with the authority to settle questions of law or of fact within that jurisdiction.

Accordingly, the Board finds that it has the jurisdiction to address the Jurisdictional Question and that the question is matter of law or of fact, dependant on the interpretation of the relevant statutory provisions.

The Jurisdictional Question

With respect to the Jurisdictional Question itself, the Board finds that the proper interpretation of section 37 of the GUA would allow the Board to determine the capital structure for the relevant test period (2004 or 2005) for each gas utility under its jurisdiction by way of a generic proceeding and to establish a standardized approach based on a formula for determining the return on common equity for gas utilities.

The Board makes this finding for the following reasons:

1. In this Decision, the Board has established a standardized approach to setting a rate of return on common equity (ROE), which is adjusted annually by way of a formula, subject to the limitations set out herein. In addition, this Decision has established the capital structure for each utility for the relevant test period. NGTL objects to the adoption of a formula in setting a fair return that determines a result independently, and prior to, the determination of rate base. Although, the Board does not agree with NGTL's submissions in this regard, it does note and agrees with NGTL's explanation of the elements of fair return when it states on page 2 of its Written Evidence, Exhibit 013-04:

   > The fair return on rate base is fixed by the regulator through determinations of the deemed utility capital structure, the reasonable cost of debt capital and the fair return on equity (ROE) capital.

   In this Decision, the Board has not determined all elements of the fair return for a Utility. The Board has implemented a formula in connection with the determination of ROE with an annual adjustment mechanism. The Board has also set the capital structure for utilities in the Proceeding for the relevant test period. It has not dealt with the cost of debt capital. Further, it has left open the possibility that a utility may request changes in its capital structure with respect to subsequent test periods by way of future general rate applications where circumstances so warrant. An applicant is also free to apply to the Board to review the ROE formula in the manner provided for in this Decision. Even without an application by a particular party, the ROE formula will be subject to review in certain circumstances and in any event will be considered for review after five years.

   This Decision approves a formula and adjustment mechanism for ROE, being one element of a fair return, following a long and complex public process. The result furthers regulatory and cost efficiencies while ensuring fairness to parties and future safeguards to address material changes in circumstance. ROE is not the only element required to determine a fair return. On its own, ROE is not determinative of the fair return component of a utility's revenue requirement. It is only when the ROE is combined with the other elements of the fair return and then applied to the rate base that it is included within the revenue requirement of a utility and subsequently in customer rates. Accordingly, the ROE determined in accordance with the formula approved by this Decision is not included within rates until the remaining relevant elements of a fair return and the rate base applicable for a particular period have been determined. With respect to a particular utility, it is the individual panel(s) of the Board seized with the responsibility of making determinations in respect of the appropriate revenue requirement for a particular test period and with fixing just and reasonable rates which must make the final determination that the revenue requirement, inclusive of all elements of a fair return when combined with the ROE determined in this Proceeding, is appropriate and that the rates are just and reasonable.

   The Board also notes that the embedded cost or appropriateness of existing long term debt is not reconsidered each time that the rate base is determined. Individual long term debt issuances are considered by the Board either when the debt is incurred, on a pre-approval basis, or within a GRA/GTA proceeding. Once approved, long term debt costs normally continue in the revenue requirement for the duration of the debt instrument

2. The Board notes and agrees with the submission of CAPP at page 2 of its Reply Argument that the mechanical approach proposed by NGTL to interpreting the GUA would leave the Board without clear authority to utilize the ROE mechanism in its determination of what is a fair return. In this regard, the Board also notes the decision of the Supreme Court of Canada in *Bell Canada v. Canada* (Canadian Radio-Television and Telecommunications Commission), [1989] 1 S.C.R. 1722 at page 1756 where the Court held:

> The powers of any administrative tribunal must of course be stated in its enabling statute but they may also exist by necessary implication from the working of the act, its structure and its purpose. Although courts must refrain from unduly broadening the powers of such regulatory authorities through judicial law-making, they must also avoid sterilizing these powers through overly technical interpretations of enabling statutes.

The Board also notes the decision of the Supreme Court of Canada in *ATCO Ltd. v. Calgary Power* [1982] 2 S.C.R. 557, wherein the Court discusses the nature of the powers of the Board to carry out its responsibilities under the PUBA and the GUA. At page 576, the Court stated:

> It is evident from the powers accorded to the Board by the legislation in both statutes mentioned above that the legislature has given the Board a mandate of the widest proportions to safeguard the public interest in the nature and quality of the service provided to the community by the public utilities.

The Board agrees with the following submission of CAPP appearing at page 2 of its Reply Argument:

> In CAPP's submission, the GUA is properly interpreted as prescribing a form of regulation, namely, rate base/rate of return regulation based on depreciated book cost plus working capital. The GUA does not prescribe how the Board is to determine a fair return and does not prescribe the exact order in which decisions can be made. Nothing precludes the Board from adopting an approach in which rate base is determined independently whatever the level of return and in which return is determined independently of rate base or other cost items such as debt cost. All that is required is that the rates that result would be in accord with the Act, namely, be based on rate base/rate of return among other things.

3. The Board notes that section 45 of the GUA does not require the Board to consider rate base before fixing or approving rates. The Board notes that such rates would include a fair return component either explicitly or implicitly. The Board must consider whether such rates are in the public interest. A consideration of the resultant rates in the context of the public interest is consistent with fixing just and reasonable rates pursuant to section 37 of the GUA and with the Board's approach in this Decision of establishing a just and reasonable standardized approach to establishing rate of return on equity.

With respect to regulatory efficiency, economy of process, cost effectiveness, and procedural fairness to all parties, the Board notes CAPP's submission at page 2 of its Reply Argument that NGTL failed to question the Board's jurisdiction in its submissions on the Standardized Approach Module of the proceeding. The issue that was addressed in that module was whether or not the Board should proceed further with a generic cost of capital process and the ability and appropriateness of possibly adopting a standardized approach. While CAPP acknowledged that jurisdiction couldn't be conferred by consent, it did call into question the merit of the argument.

The Board agrees with CAPP that the appropriate time to challenge the jurisdiction of the Board to establish a standardized approach to elements of a fair return would have been during the submissions leading to the Board's decision on April 16, 2003 to proceed with the generic cost of capital hearing following the Standardized Approach Module. In its letter of December 16, 2002 wherein the Board established the process for the Standardized Approach Module, the Board stated:

> The Board has determined that it will proceed with a written process followed by a Board decision to address the preliminary issue of whether a standardized approach to cost of capital, including return on equity, capital structure and cost of debt, has the potential to achieve reasonable efficiencies while continuing to result in fair and reasonable rates for all stakeholders. As part of the decision, the Board will determine the subsequent steps, if any, for this generic proceeding.

The Board's letter requested parties to respond to specific questions in their submissions. Question 6 requested parties to respond to the following question:

> Would it be correct to consider a standardized approach to setting:
> - Utility equity rate of return;
> - Utility capital structure; and
> - Utility cost of debt,
>
> for all types of gas and electric utilities under the Board's jurisdiction?

NGTL did not raise its jurisdictional concerns in its response to the Board's request for submissions on this first module, nor did NGTL give notice of jurisdictional concerns following the Board's initial module decision to continue with the generic cost of capital proceeding hearing process. In fact, NGTL actively participated in the proceeding, filing evidence, asking information requests of other parties, presenting 3 panels of witnesses for cross-examination and cross examining other parties.

NGTL raised its jurisdictional concerns for the first time in written argument. The Board considers that the appropriate time to have raised the subject jurisdictional concerns was during the initial module process.

2.2 Should the Board Adopt a Standardized Approach?

AltaGas supported a standardized approach to ROE and capital structure, but only if the starting points recommended by Ms. McShane were implemented. Similarly, the Companies had no objection to the adoption of a rate of return adjustment formula providing that the formula was appropriate and contained reasonable starting point values.

ENMAX had reservations regarding the adoption of a generic approach and submitted that a generic approach must be flexible enough to account for differences between utilities and to consistently meet the comparable investment, capital attraction and financial integrity criteria.

ATCO and NGTL opposed a standardized approach to ROE and capital structure. ATCO submitted that a formula approach would not add to consistency, would not add to predictability and would not necessarily reduce regulatory lag.

As discussed in the previous section of this Decision, NGTL submitted that the Board does not have the jurisdiction to implement a formula approach to establish a fair return for NGTL. NGTL also submitted that even if the Board could legally implement a formula approach for NGTL, practical considerations should preclude the Board from doing so; and furthermore, if the Board establishes a formula for NGTL, then the mitigating measures suggested by Dr. Kolbe were essential.

All of the interveners supported a generic approach. Benefits cited for a generic approach generally included improved efficiency of the regulatory process in Alberta, greater consistency between utilities, and greater certainty and predictability of utility returns. Many interveners noted that the NEB and other Canadian regulators have had generic approaches in place for many years, and submitted that there was no reason why a generic approach could not also be used in Alberta.

The Board notes that some Applicants and all interveners supported a generic approach to ROE and capital structure. The Board considers that a generic approach would improve regulatory efficiency. As set out above, the Board does not agree with NGTL that there are legal impediments to the adoption of a generic process for gas utilities. The Board notes that other regulators have successfully implemented generic approaches to ROE and capital structure. Therefore, the Board is not persuaded that there are any practical impediments to the adoption of a generic process for utilities regulated by the Board.

Accordingly, the Board finds that the evidence in the Proceeding indicates that implementation of a generic approach is in the public interest and accordingly, the Board will implement a generic approach to ROE and capital structure. In the following sections, the Board will address the issues associated with the determinations necessary to appropriately implement this approach.

3 LEGISLATIVE AND JUDICIAL FRAMEWORK

In its letter of April 16, 2003, wherein the Board indicated its decision to proceed with a generic hearing, the Board outlined the purpose of the proceeding in the following manner:

> Having considered the submissions received from the above parties, the Board is of the view that a standardized approach to rate of return on equity and capital structure has the potential to achieve certain positive benefits including reduced regulatory costs, while continuing to result in a fair return for all utilities and in just and reasonable rates for all customers. The Board has therefore determined that it will proceed with a generic cost of capital hearing to focus on the possibility of establishing a standardized approach to rate of return on equity and capital structure for all utilities under the jurisdiction of the Board.

This section reviews the legislative and judicial framework that the Board has had regard to in reaching the determinations made herein.

3.1 Legislation

Authority to Hold an Inquiry

By letter dated September 30, 2002, the Board indicated that it had decided to call a generic hearing pursuant to its powers to hold an inquiry under section 46 of the PUBA to consider cost of capital matters for electric, gas and pipeline utilities under its jurisdiction. Section 46 provides the Board with the necessary statutory authority to commence the process that has culminated in this Decision.

The Board also notes that no party has asserted that the Board lacks the jurisdiction to conduct this generic proceeding. The Board notes however, the assertion of NGTL that the Board lacks the jurisdiction to establish a fair return for a gas utility unless and until it has determined a rate base for that gas utility pursuant to subsection 37(1) of the GUA. The Board has dealt with this objection in Section 2 of this Decision.

Authority to Set Fair Return

The Board's jurisdiction to set rates and in particular, a fair return for the utilities under its jurisdiction, is found in the following statutes:

- PUBA, including Part 2, Division 1 and in particular section 90 thereof;
- GUA, including Part 4 thereof and in particular section 37 thereof;
- *Electric Utilities Act*[6] (EUA), including Part 9 thereof and in particular section 122 thereof.

3.2 Relevant Judicial Decisions

Many of the parties quoted passages from decisions of the Supreme Court of Canada and of the U.S. Supreme Court to delineate the relevant judicial guidance for the Board when embarking on a process to establish a fair return for the utilities under its jurisdiction. The Board has provided below extracts from the most frequently cited decisions. These seminal decisions have, in turn, influenced subsequent decisions referred to by the parties.

In *Northwestern Utilities v. the City of Edmonton* [1929] S.C.R. 186; [1929] 2 DLR 4 (*NUL 1929*), the Supreme Court of Canada found at page 192:

> The duty of the Board was to fix fair and reasonable rates: rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise. In fixing this net return, the Board should take into consideration the rate of interest which the company is obliged to pay upon its bonds as a result of having to sell them at a time when the rate of interest payable thereon exceeded that payable on bonds issued at the time of the hearing. To properly fix a fair return the Board must necessarily be informed of the rate of return which money would yield in other fields of investment. Having gone into the matter fully in 1922, and having fixed 10% as a fair return under the conditions then existing, all the Board needed to know, in

[6] S.A. 2003, c. E-5.1

> order to fix a proper return in 1927, was whether or not the conditions of the money market had altered, and, if so, in what direction, and to what extent.[7]

In *Federal Power Commission et al. v. Hope Natural Gas Company*, 320 U.S. 591 (1944) (*Hope*), the U.S. Supreme Court found at page 591:

> The rate-making process under the Act, i.e. the fixing of 'just and reasonable' rates, involves the balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline case that 'regulation does not insure that the business shall produce net revenues'. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view, it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. The conditions under which more or less might be allowed are not important here. Nor is it important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at. For we are of the view that the end result in this case cannot be condemned under the Act as unjust and unreasonable from the investor or company viewpoint.[8]

In *Bluefield Waterworks and Improvement Company v. Public Service Commission of the State of West Virginia et al.*, 262 U.S. 679 (1923) (*Bluefield*), the United States Supreme Court found at page 692:

> The company contends that the rate of return is too low and confiscatory. What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgement, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit to enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[9]

The Board notes that no party took issue with the general consensus that in order for a return to be fair, it must meet the tests of "comparable investment", "capital attraction" and "financial integrity" described in the above decisions. The Board concurs that the above decisions are the most relevant judicial authorities with respect to the establishment of a fair return for regulated utilities.

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7 *NUL 1929*, at 192-193
8 *Hope*, at 603
9 *Bluefield*, at 692

4 RETURN ON EQUITY

4.1 Common Return on Equity for all Utilities versus Utility-Specific ROEs

In this section, the Board will address whether there should be a common ROE applicable to all Applicants or whether there should be utility-specific ROEs. The Board will address the potential use of an adjustment mechanism for ROE, which could be applicable to either a common ROE or to utility-specify ROEs, in a later section of this Decision.

The following table summarizes the positions of the parties with respect to the issue of a common ROE applicable to all Applicants versus utility-specific ROEs:

Table 1. Common ROE versus Utility-Specific ROE Requirements

Recommended or Not Opposed to Common ROE	Opposed to Common ROE – Favoured Utility–Specific ROE
AltaGas	Companies
ATCO	NGTL
Calgary	
CAPP	
Cargill	
CG	
ENMAX	
IPCAA	
IPPSA	

Parties who supported a common ROE indicated that differences in business risk should be reflected through adjustments to capital structure. Certain of these parties also indicated that in the event that adjusting capital structure was not adequate to reflect the business risk for a particular Applicant, the common ROE could be adjusted for that particular Applicant. These parties generally took the position that the onus should be on each individual Applicant to establish the need for an exception to the common ROE. Interveners took the position that none of the Applicants had established such a need. ATCO, while supporting a common ROE, submitted that an exception was required for ATCO Pipelines.

The Board does not consider that persuasive arguments were raised against the use of a common ROE. The Board disagrees with NGTL's view that a common ROE fails to recognize the impact of leverage on the cost of equity and with the Companies' view that companies in the same industry may have different investment risks that require different ROEs. In the Board's view, a common ROE approach can accommodate these differences, by adjusting for any material differences in investment risk that would otherwise occur, through an adjustment to the capital structure, or, in exceptional circumstances, through a utility-specific adjustment to the common ROE.

The Board will therefore establish a common, or generic, ROE to be applied to all Applicants. The Board will address the need for any utility-specific adjustments to the common ROE in the capital structure section of this Decision.

In this regard, the Board considers that unique utility-specific adjustments to the common ROE should only be made in exceptional circumstances where adjusting capital structure alone is not sufficient to reflect the investment risk for a particular Applicant.

4.2 ROE Methodology and 2004 ROE

4.2.1 Introduction

The following table summarizes the 2004 ROE recommendations of the expert witnesses:

Table 2. 2004 ROE Recommendations by Expert Witnesses

Witness (Sponsoring Party)	Applies to	ERP Tests ROE Results (%)	DCF Test ROE Results (%)	CE Test ROE Results (%)	2004 Recommended ROE (%)
Ms. McShane[10] (AltaGas/ATCO)	All except ATCO Pipelines	10.5-10.75	11.0-11.25	No less than 13	11.0-11.5
Dr. Evans[11] (Companies)	Companies	9.8-10.4		12 (for ETI)	10.5-11.25
Dr. Neri[12] (ENMAX)	ENMAX	10.05-11.65	10.5-10.95		11.5
Drs. Kolbe & Vilbert[13] (NGTL)	NGTL	11	10.3-14.1,[14] used as check		11 at 40% common equity
Dr. Booth[15] (Calgary/CAPP)	All	8.12	Confirmed ERP of 8.12 was fair	9-10, used as check	8.12
Drs. Kryzanowski & Roberts[16] (CG)	All	8.05			8.05

The Board notes that no party relied directly on an ATWACC approach to setting a fair return for utilities. For the ERP results in the above table, all experts relied at least in part on the CAPM form of the ERP test. Most experts also relied in part on various other tests, including other forms of the ERP test, the DCF test, the CE test, and other measures of comparable investment. The Board will consider each of these approaches in the following sections.

4.2.2 After Tax Weighted Average Cost of Capital

NGTL's evidence (Exhibit 013-03) states:

> In the first phase of this proceeding, NGTL recommended that the Board cast the issues net broadly enough to include methodologies other than the traditional. While the EUB Notice of Hearing does not explicitly exclude the ATWACC approach, it does so implicitly by establishing the scope of the proceeding in capital structure/return on equity terms. NGTL has therefore focused its evidence on the traditional methodology, subject to the fundamental precepts that the cost of equity depends on the amount of financial risk of the company, and that financial risk changes with capital structure.[17]

10 Exhibit 005-10-2, Evidence of Kathleen McShane, page 5
11 Exhibit 003-03, Evidence of Robert E. Evans, pages 24 and 25 and Exhibit 012-01, Evidence of Robert E. Evans Supplement C page C-20
12 ENMAX, Argument, page 16
13 NGTL Argument, page 20
14 Exhibit 013-06, Evidence of Michael J. Vilbert, page 52
15 Calgary/CAPP Argument, page 17 and Exhibit 016-11(a), pages 14 and 36
16 CG Argument, page 47
17 Exhibit 013-03, NGTL Evidence, page 5, line 15

In its Argument, NGTL stated:

> In the first phase of this proceeding, NGTL recommended that the Board cast the issues net broadly enough to include methodologies other than the traditional. The EUB Notice of Hearing implicitly excluded the ATWACC approach by establishing the scope of the proceeding in capital structure/return on equity terms.[18] (Footnotes excluded)

Notwithstanding NGTL's statements that the Board had not explicitly excluded the ATWACC approach, under cross-examination NGTL confirmed that it had not requested the Board to consider the ATWACC approach to cost of capital matters. The following dialogue occurred during examination by Board Counsel of NGTL's witness, Mr. Brett:

> Q..........Are you in the context of your evidence, suggesting that the Board should consider ATWACC and ATWACC methodology in terms of coming up with a fair return for NGTL?
>
> A. MR. BRETT:.....We have not asked the Board to set tolls using an ATWACC methodology which, for example, is what we did in the fair return. What we have indicated is that leverage matters and that capital structure impacts the return that is required; and to our mind, in order to determine that interrelationship, you have to be cognizant of the overall return on capital.
>
> Q.......... So, again, just to be clear, you're not asking the Board to consider ATWACC in terms of how it would set a fair return; moreover, it is being suggested by the company that it is one of the tools it uses as, perhaps, a check in terms of what a fair return would be; would that be a fair statement?
>
> A. MR. BRETT: .....I think what I said, and what I intended to say, is we have not asked the Board to use a return on capital or ATWACC for setting a revenue requirement. We have applied for the traditional ROE on equity thickness.[19]

Given the submissions at the beginning of the proceeding, the Board's written views on the scope for the proceeding and the examination during the Hearing, the Board does not agree with NGTL's stated interpretation of the Board's Notice of Hearing dated April 16, 2003. The Board considers it clear that the Notice of Hearing did not limit, either explicitly or implicitly, any submissions or evidence that a party might wish to present in respect of the approach or the methodology that a party would urge upon the Board to consider in making a determination of an appropriate fair return.

In the Notice of Hearing, the Board stated:

> Having considered the submissions received from the above parties, the Board is of the view that a standardized approach to rate of return on equity and capital structure has the potential to achieve certain positive benefits including reduced regulatory costs, while continuing to result in a fair return for all utilities and in just and reasonable rates for all customers. The Board has therefore determined that it will proceed with a generic cost of capital hearing to focus on the possibility of establishing a standardized approach to rate

18 NGTL Argument, page 18
19 Transcript, Volume 20, pages 2777- 2778

> of return on equity and capital structure for all utilities under the jurisdiction of the Board.[20]

It is clear that the Notice refers only to the possibility of establishing a standardized approach to rate of return on equity and capital structure for utilities. Further, in the Board's letter of May 28, 2003, the Board clarified that it had not already made a final determination to adopt a standardized approach to rate of return and capital structure.

> The Board confirms that it expects to adopt a standardized approach to rate of return and capital structure. The Board decided to continue with a generic cost of capital hearing based on a record that supports the overall merits of a standardized approach to rate of return and capital structure. **The Board wishes to emphasize, however, that the approach ultimately adopted by the Board may differ between industries or on some other appropriate basis.**[21] (Emphasis added)

The language in the Board's Notice reinforced the decision of the Board to proceed to a hearing to consider a standardized approach to rate of return and capital structure. However, the last sentence of the paragraph clarified to parties that a standardized approach to rate of return and capital structure may not be found to be appropriate and that the Board remained open to other cost of capital approaches.

The Board also notes the statement of NGTL in their evidence:

> Properly applied, ATWACC and the traditional methodology should yield similar results.[22]

This statement by NGTL clearly indicates its position that the results obtained under one methodology for determining a fair return should be similar to the results obtained through the other methodology, when each methodology is properly applied. The Board also notes that the NGTL evidence and argument provided submissions on an appropriate return on equity and capital structure for NGTL as well as the ATWACC equivalent.[23]

4.2.3 CAPM Test

As noted above, all experts relied at least in part on the CAPM form of the ERP test. The Board will address other forms of the ERP test relied on by the experts in this Proceeding in the next section of this Decision.

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[20] EUB Notice of Hearing, April 16, 2003
[21] Board's letter of May 28, 2003
[22] Exhibit 013-03, NGTL Evidence, page 5
[23] For example Exhibit 013-03, NGTL Evidence, pages 4 and 6 and NGTL Argument pages 19, 89, 92 and 117

The following table summarizes the CAPM recommendations of the expert witnesses:

Table 3. CAPM Recommendations[24]

Witness (Sponsoring Party)	Risk-free Rate (%)	MRP (%)	Beta	Flotation Allowance (%)	ROE (%)
Ms. McShane (AltaGas/ATCO)	5.75	6.0	0.60-0.65[25]	0.50	10.0
Dr. Evans (Companies)	5.60	5.75	0.60	0.75	9.8
Dr. Neri (ENMAX)	6.15	6.5	0.60	0.50[26]	10.5[27]
Drs. Kolbe & Vilbert[28] (NGTL)	5.65	5.5	0.61	0.50[29]	9.5[30]
Dr. Booth (Calgary/CAPP)	5.5	4.5	0.45-0.55[31]	0.50	8.25
Drs. Kryzanowski & Roberts (CG)	5.6	4.7	0.50	0.10	8.05

Risk-Free Rate

A forecast of the long-Canada bond yield is traditionally used as the risk-free rate, for CAPM purposes. The Board notes that none of the experts suggested departing from this practice.

The Board notes from the above table that the range of risk-free estimates was from 5.5-6.15%. Dr. Booth's (sponsored by Calgary/CAPP) estimate of 5.5% was at the low end of the range. However, CAPP noted in argument that the November 2003 Consensus Forecast used by the NEB for its 2004 ROE determination resulted in a forecast of the long-Canada bond yield used by the NEB for 2004 of 5.68%, which would increase CAPP's 2004 ROE recommendations.

The Board notes that Dr. Neri's (sponsored by ENMAX) estimate of 6.15% is significantly higher than any other estimate. Excluding both Dr. Booth's and Dr. Neri's estimates would result in a range of risk-free estimates of 5.60-5.75%.

The Board considers this range of 5.60-5.75% to be a reasonable range for the 2004 risk-free rate, with a midpoint of 5.68%.

The Board notes that this midpoint of 5.68% is the same as the risk-free rate used by the NEB for 2004, which was based on the November 2003 Consensus Forecast. The Board considers the use of a risk-free rate based on the November 2003 Consensus Forecast is consistent with the formula to adjust the generic ROE that the Board establishes in a later section of this Decision. Use of the November 2003 Consensus Forecast is also consistent with the objective of establishing utility revenue requirements based on forecasts made in advance of the test year.

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24 Cargill Argument, page 15, except as otherwise indicated
25 Exhibit 005-10-2, Evidence of Kathleen McShane, page 30
26 The Board has added the 0.50% flotation cost indicated in the CAPP/Calgary Argument at page 7
27 Ibid.
28 Exhibit 013-06, Table No. MJV-10, panel B, "Average C" ("Averages A & B" are virtually identical to C) and Exhibit 013-06, page 39
29 Flotation costs assumed to be 50 basis points; NGTL considered flotation costs as a valid cost, but did not make a specific recommendation. NGTL Argument, page 55
30 Ibid.
31 Exhibit 016-11(a), Evidence of L.D. Booth, page 23

Therefore, the Board finds that an appropriate risk-free rate for 2004 is 5.68%.

MRP (Market Risk Premium)

The Board notes that some parties, including IPCAA, argued that the arithmetic average MRP overstates the returns that investors have received or can expect to receive in the future. In the Board's view, when a forecast is based on the historic average, the arithmetic average MRP represents the best estimate of the short-term return and the geometric average represents the best estimate of the long-term return. The Board has not been persuaded that it should change its practice of using the arithmetic average. Consequently, the Board will maintain its practice of using the arithmetic average rather than the geometric average.

The following table summarizes the evidence on the average arithmetic MRPs in Canada and the U.S. for various time periods:

Table 4. Historical Arithmetic Canadian and U.S. MRPs

	Canada	U.S.
1802-1998[32]		4.7
1900-2002[33]	5.5	6.4
1924-2002[34]	5.0	
1926-2001[35]		7.0
1936-2002[36]	4.7	
1947-2002[37]	5.0	6.7
1957-2002[38]	2.3	4.2

In this Proceeding, a number of concerns were raised regarding the use of historic data as a reasonable estimate for the future MRP:

1. Dr. Booth indicated that Canadian data prior to 1956 should not be used. However, Dr. Booth indicated that the Canadian equity risk premium since 1956 has been only about 2.3%. Dr. Booth then adjusted this figure upward to 4.5%, to take into account the influence of earlier data, the unexpected performance of the bond market, and the U.S. data.[39] This indicates that Dr. Booth was unable to rely on the historic data without a material adjustment;

2. ATCO noted a number of problems in using Canadian historical data including structural changes in the economy, the recent impact of a few large firms on the market proxy and the need to consider U.S. data;[40] and

3. CG noted that the current equity risk premium could be expected to be about 1% lower than the historical equity risk premium due to current lower trading costs.[41]

32 Exhibit 016-11(a), Evidence of L.D. Booth, page 33
33 Exhibit 017-05(a), Evidence of Kryzanowski and Roberts, Schedules, Schedule 4.3 and 4.5
34 Exhibit 016-11(a), Evidence of L.D. Booth, Schedule E1 (Canadian Institute of Actuaries Data)
35 Exhibit 012-01, EPCOR Transmission, Direct Evidence and Supplements of Robert E. Evans, Dec. 2002, Supplement C, page C-10
36 Exhibit 009-02(b) Schedule 5 (Canadian Institute of Actuaries data)
37 Exhibit 005-10-2, Table 4, page 27
38 Exhibit 016-11(a), Evidence of L.D. Booth, Appendix E, Schedule E1 and Appendix F, Schedule F2
39 Exhibit 016-11(a), Evidence of L.D. Booth, page 24
40 ATCO Argument, pages 25 and 26
41 CG Argument, page 31

In the Board's view, a reasonable approach is to consider the longer-term average historic Canadian equity risk premium and then adjust this upward or downward based on the Board's judgment and the Board's assessment of the evidence regarding the prospective outlook for the equity risk premium.

In the Board's view, in general, the present Canadian market already reflects the impact of U.S. data based on the current degree of North American market integration. Participants make market trade-offs in their decisions on how to participate in the various markets around the world. The present high degree of integration would not have been fully reflected historically, accordingly, the Board considers that the U.S. historical MRP should be considered as one of many factors in applying judgment to adjust the Canadian historic MRP. The Board notes Dr. Booth's evidence that U.S. MRPs need to be tax-adjusted and that therefore U.S. market returns are biased high for Canada, but still provide a ceiling for Canadian estimates.

The Board notes from Table 3, that the range of the experts' recommended MRP estimates was from 4.5-6.5%, with a midpoint of 5.5%. The Board also notes from Table 4 above that the historic arithmetic risk premium in Canada has been 4.7-5.5% for those periods ending in 2002 that provide 50 or more years of history. In the Board's view, the historic evidence, along with some recognition of the higher U.S. figures, supports the midpoint of the experts' estimates at 5.5%.

Considering all of the above, the Board finds that an MRP of 5.5% is appropriate.

The Board also notes that this midpoint of 5.5% is consistent with the MRP used by the Board in its most recent rate of return determinations.[42]

Beta

The Board notes that there was general agreement that use of actual data from very recent years, to calculate beta, would under-estimate the prospective beta due to the technology-related market bubble and subsequent collapse, and that there was also general agreement that beta is a relative risk factor that requires judgment.

The Board notes from Table 3 that the range of beta estimates recommended by the expert witnesses was from 0.45-0.65. Dr. Booth's estimate of beta of 0.45-0.55 was the lowest estimate in the range. The next lowest estimate was 0.50, proposed by Dr. Kryzanowski (sponsored by CG). The Board also notes from the argument of Calgary/CAPP that the beta of 0.55 recently used by the Board[43] was at the top of Dr. Booth's range, but "is well within normal estimation error".[44] The Board also notes that the high estimate of 0.65 was partially based on adjusted U.S. data and partially based on a relative risk calculation that utilized standard deviations and not the more usual regression analysis calculation.[45]

Based on the above, the Board finds that a reasonable estimate of beta, or the relative risk factor of utilities versus the overall equity market, is 0.55.

[42] Includes Decisions 2003-63, 2003-71, 2003-72 and 2003-100
[43] Decisions 2003-63, 2003-71, 2003-72 and 2003-100
[44] Calgary/CAPP Argument, Section 4.2.3.2, page 15
[45] Exhibit 008-01, ATCO Pipelines 2003-2004 Application, Evidence of Kathleen McShane, pages 44-47 of 63

The Board also notes that this estimate of beta of 0.55 is consistent with the value that the Board has assigned to beta in its most recent rate of return determinations.[46]

Flotation Cost Allowance

The Board notes that all parties, except the Companies and CG, recommended or were not opposed to a 0.50% allowance for flotation costs and financing flexibility.

The Board notes that CG and CAPP suggested that an alternative to an ongoing flotation allowance was to expense the costs of flotation. CG proposed that this expense could be amortized over 50 years. In the Board's view, there was limited support for changing its past approach to flotation costs.

The Board notes that the Companies argued that the flotation allowance should be increased to 0.75%, based on the increased capital markets volatility. However, the Board considers that there is merit in CG's argument that the apparent higher volatility in the markets was due to a rapid increase in listings by smaller and more risky firms and was not due to the utility sector.[47] The Board is therefore not convinced that a change is required to the 0.50% flotation cost allowance used in recent decisions.

Based on the above, the Board finds that continuation of a 0.50% allowance for flotation costs and financing flexibility is appropriate.

CAPM Conclusions

Based on the above-determined risk-free rate of 5.68%, MRP of 5.50%, beta of 0.55, and allowance for flotation costs of 0.50%, the Board concludes that a reasonable CAPM estimate for 2004 is 9.20%.

The Board will now consider the other ROE methodologies suggested by the parties to determine if the results, obtained from the application of such methodologies, warrant an adjustment to the Board's CAPM estimate of ROE.

4.2.4 Other Forms of the ERP Test

Dr. Booth gave equal weight to CAPM and to a multi-factor ERP model that indicated that a utility's equity risk premium over the long-Canada rate was a function of both the MRP and of the term spread of long-Canada rates over shorter-term rates. The midpoint of the results of Dr. Booth's multi-factor ERP model was approximately 7.5%,[48] which indicated an ROE of approximately 8.0% after including an allowance for flotation costs of 0.50%.

Dr. Booth's multi-factor ERP model would directionally support a reduction from the midpoint of the Board's CAPM range. However, the Board will only place limited weight on the results of Dr. Booth's multi-factor model for the following reasons:

1. The model has a low R-squared statistic, indicating low reliability of the model;
2. Today's interest rates are at the bottom edge of the range experienced over the study period; and

[46] Decisions 2003-63, 2003-71, 2003-72 and 2003-100
[47] CG Reply Argument, page 29
[48] Exhibit 016-11(a), Evidence of L. D. Booth, pages 25-29

3. The adjustments that Dr. Booth indicated were required in developing the model.[49]

Dr. Vilbert (sponsored by NGTL) used both a CAPM model and an ECAPM model. His ECAPM model included an adjustment factor to compensate for an alleged tendency of CAPM models to under-estimate required returns for lower risk companies. Dr. Vilbert's ECAPM model resulted in a recommendation for an 11% ROE on a 40% common equity ratio. Dr. Vilbert's ECAPM results would directionally support an increase from the midpoint of the Board's CAPM range.

The Board notes Calgary/CAPP's argument that applying CAPM using long-term interest rates (long-Canada bond yields) in determining the risk-free rate, as was done by all experts in this Proceeding, already corrects for the alleged under-estimation that ECAPM was designed to address.[50] Calgary/CAPP argued that the under estimation would only be present if the CAPM were applied using short-term interest rates, which none of the experts did in this Proceeding.

The Board finds the Calgary/CAPP position persuasive and considers that the use of long-term Canada bond yields largely adjusts for the tendency of CAPM, when based on short-term interest rates, to under estimate the required returns for lower risk companies. Therefore, the Board will only place limited weight on the results of the ECAPM model.

Ms. McShane (sponsored by AltaGas/ATCO) used a DCF-based ERP test that resulted in a utility risk premium of 4.9%.[51] The Board notes that this implies a total utility ROE of 11.15%, after adding her recommended risk-free rate and the flotation cost. Ms. McShane also provided a realized historic utility ERP, based on Canadian and U.S. utility returns, which indicated a utility risk premium of 4.75%.[52] The Board notes that this implies a utility ROE of 11.0%.

Dr. Neri applied two ERP tests in addition to the CAPM, based on U.S. electric utilities and on U.S. gas distribution utilities, which produced utility equity risk premiums of 5.14 and 5.53%,[53] respectively. The Board notes that this implies a total utility ROE of 11.79% and 12.18%, respectively, after adding Dr. Neri's risk-free rate recommendation of 6.15% and a flotation allowance of 0.50%.

The Board notes that these utility return results of Ms. McShane's and Dr. Neri's other ERP tests are higher than many estimates of the market required return.

Ms. McShane's and Dr. Neri's other ERP tests would directionally support an increase from the midpoint of the Board's CAPM range. However, the Board shares CG's[54] and CAPP's[55] concern that it is not reasonable for the prospective required return on low risk firms to be close to or above the prospective overall market return.

49 Exhibit 016-11(a), Evidence of L. D. Booth, page 26
50 Calgary/CAPP Argument, page 12
51 Exhibit 005-10-2, Kathleen McShane, page 33
52 Ibid.
53 Exhibit 009-02(b), Schedules 6&7
54 CG Argument, page 49
55 CAPP Argument, page 17

On balance, the Board concludes that the results of the ERP tests other than CAPM would generally support a 2004 ROE above the Board's CAPM estimate, but that for the reasons set out above only limited weight should be placed on the results of the ERP tests other than CAPM.

4.2.5 Discounted Cash Flow Test

The Board notes from Table 2 that the Applicants' standard-method DCF estimates for ROE ranged from 10.3-14.1%. The Board notes ATCO's argument that any upward bias in analyst growth estimates may be less prevalent for stable industries including utilities. Nevertheless, the Board considers that there is merit in the intervener arguments[56] that the analysts' earnings forecasts used in the development of the DCF estimates have been biased high, resulting in DCF estimates that overstate the required return. The record of the Proceeding reveals no evidence on an appropriate discount to apply to the DCF test results to appropriately adjust for an overstatement in the required returns. Accordingly, the Board finds reliance on the Applicant's DCF estimates problematic.

The Board notes that Dr. Booth's DCF approach[57] was not based on an assessment of analysts' earnings forecasts, but was based on an assessment of the growth of the overall economy. Dr. Booth considered that the market as a whole would grow at the same rate as the nominal GDP growth rate of about 6%, which would indicate a total investor market return of 8.5% after including average dividends of 2.5% (which included an estimated 0.5% to account for share repurchases as surrogate dividends). Dr. Booth indicated that this was a geometric market return estimate and therefore under estimated the average short-run growth rate, since the arithmetic rate exceeds the geometric rate. Dr. Booth further indicated that his DCF analysis confirmed that an 8.12% allowed ROE for a regulated utility was fair and reasonable. However, the Board notes that Dr. Booth did not quantify the impact of converting from a geometric rate to an arithmetic rate, did not quantify, in this case, the impact of utilities having less risk than the market average, and did not add an allowance for flotation costs.

As a result of the above noted concerns, the Board concludes that no weight should be placed on the results of the DCF tests presented in this Proceeding.

4.2.6 Comparable Earnings Test

The Board notes that several Applicants indicated that the comparable investment test, envisioned in the court decisions referred to in Section 3 of this Decision, obligated the Board to place weight on the CE test.[58] However, in the Board's view, the CE test is not equivalent to the comparable investment test. The CE test measures **actual** earnings on **actual book value** of comparable companies, which, in the Board's view, does not measure the return *"it **would** receive if it **were** investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise"*[59] (emphasis added) (unless the securities were currently trading at book value). The Board notes that Cargill[60] expressed a similar view.

56 For example, Cargill Argument, page 23, and CG Argument, page 13
57 Exhibit 016-11(a), Evidence of L.D. Booth, page 36
58 ATCO Argument page 8, Companies Argument page 24
59 NUL, 1929, at 192-193
60 Cargill Argument, pages 6 and 7

The Board considers that the application of a market required return (i.e. required earnings on market value) to a book value rate base is appropriate in the context of regulated utilities.

The Board notes Ms. McShane's CE test result of "no less than 13%". The Board notes that this result is in excess of Ms. McShane's 11.75% estimate of the market return, excluding flotation allowance, incorporated in her CAPM result in Table 3. The Board also notes Dr. Booth's evidence that at no time in the last fourteen years has the average ROE of Corporate Canada exceeded 12.0%, and only twice in the last thirteen years has the average ROE been in double digits.[61]

In the Board's view, based on Dr. Booth's evidence regarding the achieved ROEs of Corporate Canada, and her own CAPM estimate, Ms. McShane's CE test result of "no less than 13%" exceeds a reasonable forecast of the prospective market required return. In the Board's view, CE test results for low risk companies, that exceed the forecast required return on the overall market, raise serious conceptual or methodological concerns regarding the relevance of the CE test. The Board does not consider it reasonable for the prospective required return on low risk firms to exceed the prospective overall market required return. The Board notes Ms. McShane's evidence that lower risk firms have outperformed the market over certain historical periods. However, in the Board's view, to forecast this result would not be credible.

The Board also notes that, in this Proceeding, various implementation problems with the CE test were discussed. These included sample selection problems, accounting differences, market power concerns, and problems matching the current business cycle stage. The Board recognizes that all traditional ROE tests suffer from methodological difficulties.

The Board concludes that it should place no weight on the CE test because of the implementation problems of the CE test and the above-noted conceptual and methodological concerns with the CE test.

4.2.7 Other Measures of Comparable Investment

Although the Board will not place any weight on the CE test, the Board considers that there may be other measures of comparable investment that should be considered in the establishment of an appropriate ROE. In this section, the Board will address other such measures of comparable investment that were raised in the Proceeding.

Return Awards for Other Canadian Utilities

The Board acknowledges the potential for circularity when considering awards by other regulators. Nevertheless, the Board considers that awards by other Canadian regulators may provide some indication of the appropriate ROE for the Applicants.

[61] Calgary/CAPP Argument, page 6

Dr. Evans provided, at the Board's request, a detailed compilation of ROE awards and other matters for Canadian utilities.[62] The following table is an excerpt from that compilation:

Table 5. Awarded ROEs for Other Canadian Utilities

	Date	Awarded ROE (%)
British Columbia		
Aquila Networks Canada (BC) Ltd.	November 2003	9.55
Pacific Northern Gas Ltd.	November 2003	9.90
Terasen Gas Inc.	November 2003	9.15
Ontario		
Enbridge Gas Distrbution	November 2003	9.69
Union Gas Ltd.	Jan. 1999/July 2001	9.95
Quebec		
Gaz Metropolitain	September 2002	9.89
Nova Scotia		
Nova Scotia Power Inc.	October 2002	10.15
Prince Edward Island		
Maritime Electric	October 2001	11.00
Newfoundland		
Newfoundland Power Inc.	June 2003	9.75
National Energy Board	November 2003	9.56

Directionally, the evidence on recent awards for other Canadian utilities would support a 2004 ROE above the Board's CAPM estimate. However, the Board concludes that limited weight should be placed on this evidence due to the potential for circularity.

Return Awards for U.S. Utilities

The Applicants generally took the view that it is appropriate to consider utility ROEs awarded by U.S. regulators, due to the similarity between Canadian and U.S. utilities and due to the high degree of integration of the capital markets of the two countries.

The Board notes the evidence of various Applicants that low risk gas distribution utilities in the U.S. have allowed returns in the 11% range on a 45% common equity component, and that prior to incentives, the base return for interstate electric transmission companies allowed by FERC is in excess of 12% on a 50% equity component.[63]

The Board also notes the submissions of various interveners that there are several differences between Canadian and U.S. regulation. The Board, in particular, notes CAPP's submission that U.S. pipelines operate under a regulatory regime that has exposed them to severe realized and potential risks. In this regard, the Board notes the evidence[64] of CAPP indicating low actual returns of a number of U.S. interstate pipelines.

[62] Exhibit 021-24
[63] ATCO Argument, pages 29-30
[64] Exhibit 015-11, Written Evidence of CAPP, pages 49-50

In the Board's view, the Applicants did not demonstrate that the regulatory regimes in the two countries are sufficiently comparable that the Board should place significant weight on the return awards for U.S. utilities. For example, the Board notes differences in legislation, public and regulatory policies, the higher prevalence of longer-term settlement arrangements, the federal/state jurisdictional divisions, the development of RTOs and other differences in the structure of regulated industrial sectors, and differences in national fiscal, tax and monetary policies. The Board notes AltaLink acknowledged that there are some differences in the Canadian and U.S. electric industry structures that may impact some of the higher return and equity component awards in the U.S.[65]

Furthermore, the Board notes the recent acquisitions, at premiums to book value, by U.S. companies of an interest in TransAlta Corporation's former distribution and transmission businesses. The Board considers these acquisitions, which are discussed further below, may be an indication that the regulated returns available in Alberta are not too low for U.S. firms, relative to investment opportunities in their home country given all relevant circumstances.

Directionally, the evidence on the awards available to U.S. utilities would support a 2004 ROE above the Board's CAPM estimate. However, the Board concludes that limited weight should be placed on this evidence due to the differences in the regulatory, fiscal, monetary, and tax regimes in the two countries.

FERC Incentives for Transmission Facilities

A number of the applicants suggested that if the Board did not reflect the incentive awards that FERC has in place for new electric transmission facilities, then capital might not be available for utility infrastructure in Alberta. These applicants argued that above-market ROEs would be in the public interest in order to ensure that sufficient capital is attracted for Alberta's infrastructure needs.

The Board is not persuaded that the existence of certain FERC-regulated transmission projects with allowed returns above the current market required rate of return would impair the ability of Alberta utilities to attract capital. In the Board's view, Alberta utilities do not compete for capital only with these projects, but rather with a broad universe of investment opportunities. Furthermore, if the higher allowed returns for these projects were material to the Canadian market required return, the Board considers that the impact of these higher allowed returns would already be reflected in the Canadian market required return.

Furthermore, the Board notes that the FERC incentives are intended to encourage RTO participation, independent ownership of transmission facilities, and investment in new facilities found appropriate pursuant to an RTO process. The Board notes that the objectives of encouraging RTO participation and encouraging independent ownership of transmission facilities are not applicable in Alberta. Similarly, the objective of encouraging investment in new independent transmission facilities into areas presently serviced by vertically integrated utilities is also not applicable in Alberta. Furthermore, the Board notes that both AltaLink and ATCO expressed continued strong interest in infrastructure development in Alberta.

The Board considers that there is no persuasive evidence in this Proceeding that demonstrates that above-market awarded returns are required to attract capital, and the Board notes that there

65 AltaLink Specific Reply Argument, third page

is no evidence of any Alberta TFO having any difficulty in attracting capital to date. The Board considers that to award such returns in the absence of need would unnecessarily and inappropriately result in additional costs to consumers.

Furthermore, the Board considers that if it were satisfied in some future application that it was appropriate to award incentive returns to attract capital in connection with the construction of certain new electric transmission facilities in Alberta, such returns would not be appropriate on existing facilities and may not be necessary in respect of all new infrastructure developments.

The Board is not persuaded that there is any requirement at this time to offer above-market ROEs or other incentives to attract capital for the construction of new electric transmission facilities in Alberta. The Board will not put any weight on the FERC incentives for transmission facilities, for the purposes of determining the generic ROE.

Alliance and Maritime and North East Pipelines (M&NP)

NGTL's view was that Alliance and M&NP are particularly relevant comparisons for NGTL. NGTL noted that both Alliance and M&NP are regulated and ship into markets served by gas that moves through NGTL and TransCanada Pipelines Ltd. (TCPL)'s Mainline. NGTL submitted that Alliance and M&NP, as the most recent large greenfield pipelines, show what returns are necessary to entice investment in regulated natural gas pipelines. Alliance has an ROE of 11.25% on 30% deemed equity and M&NP has an ROE of 13% on 25% deemed equity.

In regards to the regulated returns of Alliance and M&NP, the Board agrees with CAPP that these returns are not directly relevant, due to different circumstances (such as the level of ROE being locked in for a long period of time) and because they date back to a period of higher interest rates and returns. In this respect, the Board notes CAPP's argument that Alliance takes risks that NGTL does not, including some volume risk on an exception basis, long-term shipper contract default risk, and long-term interest rate risk,[66] and that the M&NP was built for a new untested basin with few pools having been delineated. In addition, the Board notes that the deemed equity ratios for Alliance and M&NP are lower than any Board-approved equity ratio, which would directionally reduce the impact on customer rates of a higher ROE.

Although, directionally, the absolute level of return for Alliance and M&NP would support a 2004 ROE above the Board's CAPM estimate, the Board concludes, based on the above analysis, that it should place limited weight on the Alliance and M&NP returns.

Market-to-Book Ratios and Acquisition Premiums

The Board notes the evidence, including that of AltaGas[67] and Calgary/CAPP[68] that the equity of utilities that earn a large portion of their earnings based on regulated formulas in other Canadian jurisdictions tends to trade at market-to-book ratios well above 1.0, albeit at premiums less than the average market premium.

The Board also notes that there have been a number of acquisitions of Alberta utilities in recent years, at prices that significantly exceeded book value. For example, in 2000, Aquila acquired TransAlta Corporation's distribution and retail businesses at a total price of 1.5 times book value. Book value was forecast to be $472 million at time of close, resulting in a forecast premium of

66 Exhibit 015-11 Written Evidence of CAPP, page 36 and 49
67 AltaGas Argument, page 24
68 Exhibit 016-11(b), Written Evidence of J.D. McCormick, page 5

$238 million.[69] Aquila subsequently sold TransAlta's former retail business to EPCOR Energy Services (Alberta) Inc. for $110 million, including a premium of $99 million.[70]

As well, in 2004, Fortis purchased Aquila for a premium of $215 million above the book value of $601 million.[71]

Similarly, with respect to the AltaLink acquisition of TransAlta Corporation's transmission assets, the Board notes Mr. McCormick's[72] evidence that a premium of $200 million was paid to acquire a rate base of approximately $644 million.

The Board agrees with the Applicants that there are a number of factors impacting market-to-book ratios of utility holding companies and that one has to be cautious making inferences regarding the regulated utilities. The Board also agrees that there may be strategic factors affecting the price that is paid to acquire a utility.

For example, NGTL submitted that its parent did not acquire a further interest in the Foothills pipeline, paying 1.6 times book value, for the opportunity to earn a return at the NEB formula rate; rather, the investment was made in an effort to increase the probability that TCPL will participate in a Northern pipeline project. The Board also recognizes that, in some cases, a premium might be paid for regulated assets in anticipation of significant future growth in rate base, to achieve geographic diversification or to obtain a foothold in a new market. However, parties are also aware of the constraints placed on regulated utilities with respect to affiliate transactions, particularly those with unregulated affiliates.

In the absence of such strategic factors, the Board would not expect a prudent investor to pay a significant premium unless the currently awarded returns are higher than that required by the market. The Board acknowledges the views of some parties that payment of a premium over book value for a regulated utility indicates that the recent ROE awards may have been higher than required by the market. The Board is not aware of the strategic factors that may have affected the price paid to acquire Alberta utilities in recent years. Nevertheless, the experience regarding the market-to-book values of utilities and the experience regarding the acquisition of Alberta utilities in recent years gives the Board some comfort that its recent ROE awards have not been too low.

Further in this regard, the Board notes AltaLink's testimony, in response to examination by the Chairman,[73] that AltaLink's decision to purchase TransAlta's transmission business considered Board awards for transmission entities of 9.75% ROE on a capital structure including 35% equity.

Directionally, the Board concludes that the experience regarding the market-to-book ratios of utilities and the experience regarding the acquisition of Alberta utilities in recent years is relevant and supports continuation of an ROE at or below the Board's CAPM estimate.

69 Decision 2000-41, page 3
70 Decision 2000-71, page 3
71 Decision 2004-035, page 18
72 Exhibit 016-11(b) Evidence of J.D. McCormick, pages 39-40
73 Transcript, Volume 15, pages 2004-2006

Income Trusts

The Board notes the significant disagreement among parties with respect to return expectations of investors in Income Trusts. The Board notes that Mr. McCormick relied primarily on a sample of only five Income Trusts and that the validity of his sample selection was the subject of substantial debate.

In the Board's view, the theoretical return, indicated by Mr. McCormick, based on ROE does not address actual investor expectations on investment or actual historic returns on investment of Income Trust investors. For example, the Board notes that Income Trust prices often rose despite the fact that part of the distributions represented return of capital.

The Board generally agrees with the views of the Applicants that Income Trusts may be overvalued[74] due to investors' misperceptions and may be too new to be a reliable indication of required market returns. The Board also does not consider that there is any evidence that the allegedly lower return requirements for Income Trusts are achievable in a corporate structure. The Board notes that no party advocated that the Applicants be required to reconstitute as Income Trusts. The Board also notes that some Income Trusts have much higher equity ratios than the Applicants, which would directionally offset the impact of a lower ROE on customer rates.[75]

Nonetheless, the Board notes that Income Trusts are attracting a substantial amount of new capital.

Directionally, the Board considers that the experience with Income Trusts would support an ROE at or below the Board's CAPM estimate. However, for the reasons cited above, the Board concludes that limited weight should be placed on this experience.

Pension Return Expectations

Interveners generally took the position that TCPL's forecast pension return on Canadian equity investments of 9.5% was an indicator of the Canadian market return expected by TCPL. NGTL argued that the forecast of 9.5% was prepared by its actuaries and was not comparable to an investment hurdle rate. NGTL further argued that the forecast of 9.5% was a geometric estimate rather than an arithmetic estimate.

The Board acknowledges that forecast pension returns on equity investments may be conservative by their nature, but the Board nevertheless considers that forecast pension returns on equity investment are a valid indicator, albeit potentially conservative, of the forecaster's current market equity return expectation. However, the Board agrees with NGTL that the forecast pension return is akin to a geometric average and would therefore understate the forecaster's short-term expectation for the market return. Directionally offsetting this impact, the Board would expect the required return for utilities to be below the required overall equity market return.

On balance, the Board concludes that the evidence on forecast pension returns would support a modest increase from the Board's CAPM estimate.

74 NGTL Argument, page 105-107; ATCO Argument, page 43

75 NGTL Argument, page 107

Other Investment Alternatives Available To Utility Shareholders

The Board notes NGTL's evidence that its parent, TCPL, has other investment alternatives, such as unregulated power generation projects, that earn a return higher than the return allowed for NGTL. NGTL also argued that TCPL has the option of making investments at higher returns in the U.S. and repatriating the profits to Canadians via the dividend tax credit. NGTL submitted that it requires a higher return in order to compete with these other investment opportunities of TCPL.

The Board agrees with the interveners[76] that NGTL's evidence regarding earnings on power generation projects were merely forecasts of earnings, and represented a limited and select sample. The Board also notes that NGTL did not supply any evidence that evaluated historical returns from other investments versus returns from its Canadian utility investments, which is one relevant factor to be considered when making prospective investment decisions.

The Board concludes that there is no basis on which to place any weight, other than already reflected in earlier tests, on other specific investment opportunities potentially available to utility investors or on stated expectations of return from such opportunities.

4.2.8 2004 ROE

The Board found above that a reasonable CAPM estimate for 2004 is 9.20%. The Board considers that it is appropriate to assess the results of other tests to determine if the 2004 ROE should be above or below the CAPM estimate.

The Board found above that the following evidence would generally support a 2004 ROE at or below the CAPM estimate:

1. Market-to-Book Ratios and Acquisition Premiums
2. Income Trusts

Similarly, the Board found above that the following evidence would generally support a 2004 ROE at or above the CAPM estimate:

1. ERP Tests Other Than CAPM
2. Return Awards for Other Canadian Utilities
3. Return Awards for U.S. Utilities
4. Alliance and M&NP
5. Pension Return Expectations

As discussed above, the Board did not put any weight on the following evidence in determining whether the 2004 ROE should be above or below the CAPM estimate:

1. Discounted Cash Flow Test
2. Comparable Earnings Test
3. FERC Incentives for Transmission Facilities
4. Other Investment Alternatives Available to Utility Shareholders

[76] Cargill Argument page 22 and CAPP Argument page 23

In the next section of this Decision, the Board establishes an adjustment mechanism that includes an adjustment factor of less than 100% of the change in the long-Canada yield, which in the Board's view also supports a 2004 ROE above the CAPM estimate since the allowed ROE will not reflect a 100% adjustment factor, which is implicitly suggested by CAPM, and since a formulaic approach effectively creates a longer test period with respect to ROE.

In consideration of the impact of the above factors, it is the judgment of the Board that it would be appropriate to establish the 2004 ROE at a level that is 40 basis points above the Board's CAPM estimate. Therefore, the Board concludes the generic ROE for 2004 should be set at 9.60%.

4.3 Annual Adjustment Mechanism

As outlined earlier in this Decision, the Board will now address the potential use of an adjustment mechanism for ROE.

The following table summarizes the positions of the parties:

Table 6. Annual Adjustment Mechanism Recommendation by Parties

Party	Annual Adjustment Mechanism Recommendation
AltaGas/ATCO	50% of long-Canada bond yield change
Companies	75% of long-Canada bond yield change
ENMAX	100% of long-Canada bond yield change plus 100% of utility bond spread change
NGTL	Link to changes in Corporate bond yields
Calgary/CAPP	75% of long-Canada bond yield change
Cargill	75% of long-Canada bond yield change (80% or 100% also acceptable)
CG	75% of long-Canada bond yield change plus 50% of market dividend yield change
IPCAA	75% of long-Canada bond yield change

The Board notes that most parties favored an adjustment formula with the ROE changing by 75% of the change in the forecast long-Canada bond yield, provided that the Board accepted their starting positions on ROE.

The Board also notes Dr. Evan's evidence that a change based on 75% of the change in the long-Canada bond yield is driven by the differential tax rates between bonds and equity.[77]

The Board notes ATCO's and ENMAX's concern that it would be unfair to set an initial ROE based strictly on a CAPM analysis and to then allow only 75% of any increase in the long-Canada bond yield. In such a situation, ATCO and ENMAX favoured a 100% adjustment. The Board notes that in the previous section of this Decision, the Board established a generic ROE for 2004 of 9.60%, a level that is 40 basis points above the Board's CAPM estimate of 9.20%.

The Board does not consider that ENMAX's proposal to adjust the ROE by the sum of the change in the long-Canada bond yield and the change in the utility bond spread to be appropriate due to the difficulty of determining and tracking bond yields for a representative sample of corporate bonds.

[77] Companies Argument, page 89

The Board also does not consider CG's proposal to adjust the ROE by the sum of 75% of the change in the long-Canada bond yield and 50% of the change in the market dividend yield to be appropriate because of potential double-counting and because independent forecasts of dividend yields are not readily available in the same manner as the Consensus Forecast for debt.

The Board notes the Companies' proposal that the adjustment formula not commence until the year 2006. The Board notes that no other party proposed that implementation of an adjustment formula not commence until the year 2006. The Board does not consider that there is any reason to delay implementation of the adjustment formula until 2006.

Considering all of the above, the Board concludes that an adjustment to the generic ROE based on 75% of the change in long-Canada bond yield would be appropriate, beginning in 2005.

The Board considers the formula proposed by Dr. Evans (sponsored by the Companies) to be an appropriate method of implementing this adjustment:

$$ROE_t = 9.60\% + [0.75 \times (YLD_t - 5.68\%)]$$

where YLD_t = the forecast long-term Canada bond yield for year t.

Consistent with the approach used by the NEB, the forecast long-term Canada bond yield for year *t* shall be calculated as the average of the 3-month-out and 12-month-out forecasts of 10-year Canada yields as reported in the Consensus Forecasts[78] issue in November of the previous year, plus the average of the daily difference between the 10-year and the 30-year Canada bond yields for the month of October in the previous year, as reported in the National Post.

[78] Consensus Forecasts Inc., London, England

4.4 Process to Review ROE

The following table summarizes the review process recommendations of the parties:

Table 7. Process to Review ROE – Recommendations by Parties

Party	Periodic Review	Other Review Triggers
AltaGas/ATCO	Review in 2007	• Long-Canada yield below 4% or above 8%. • A-rated utility bond spreads exceed 50% of the generic risk premium.
Companies	5 years	
ENMAX	Not more than 3 years	• Any Alberta utility is downgraded by a rating agency. • Formula result rises or falls more than 200 basis points from initial level.
NGTL	2 years	
Calgary/CAPP	5 years	• Long-Canada bond yield changes by more than 3.0%.
Cargill	3 to 5 years	
CG	3 years for the first review; 5 years thereafter	• Material change in investment risk of the regulated sector. • Material change in the market equity risk premium.
IPCAA	5 years	
IPPSA	5 years	

In the Board's view, it would be appropriate to trigger a review of whether the adjustment mechanism continues to yield a fair ROE, if there is a material change in the forecast long-Canada bond yield from the November 2003 forecast.

The Board considers that the most straightforward method of implementing this trigger is by placing bounds on the range of ROEs that can be established pursuant to the adjustment mechanism.

In this regard, the Board considers ENMAX's proposed change of 200 basis points in the generic ROE to be a reasonable trigger. The Board notes that a change of 200 basis points in the generic ROE is equivalent to a change of 267 basis points in the long-Canada bond yield, which is effectively higher than the long-Canada bond yield trigger proposed by ATCO but lower than the long-Canada bond yield trigger proposed by Calgary/CAPP.

Therefore, if the ROE resulting from the adjustment mechanism results in an ROE of less than 7.6% or greater than 11.6%, the Board will seek the views of parties on whether the adjustment mechanism continues to yield a fair ROE in the manner described below.

The Board considers that ATCO's proposed trigger of A-rated utility bond spreads exceeding 50% of the generic risk premium would be difficult and contentious to implement, principally due to controversy in the choice of the sample of utility bonds.

The Board does not consider ENMAX's proposed automatic trigger of any Alberta utility downgraded by a rating company to be appropriate because of the many factors and judgments that may contribute to a downgrade for an individual company, including their unregulated business results.

The Board considers that CG's proposed triggers of a material change in the investment risk of the regulated sector or a material change in the market risk premium would be difficult and contentious to implement. The Board considers that material changes in investment risk of the regulated sector or in the market risk premium can be addressed at the time of the periodic review.

The Board notes that all parties agreed that a review of whether the adjustment mechanism continues to yield a fair ROE should be conducted after a defined period of time. The Board notes that the time period for a review suggested by the parties varied from 2-5 years.

The Board considers that a review period of 5 years would appropriately balance the desire to achieve regulatory efficiencies through the use of an adjustment mechanism and the need to ensure that the ROE adjustment process continues to result in an appropriate ROE.

In the Board's view, triggering an early consideration on whether or not to conduct a review if the ROE resulting from the adjustment mechanism is less than 7.6% or greater than 11.6% also supports the selection of a five year review period.

The Board notes the Companies' proposal of a *de novo* review of all cost of capital matters at the end of five years. However, the Board does not consider that it would be appropriate to automatically trigger a *de novo* review either in the event that the adjustment mechanism results in a ROE of less than 7.6% or greater than 11.6% or at the end of five years, without first assessing whether the adjustment mechanism continues to yield an appropriate ROE result.

Therefore, the Board will first seek the views of parties on the preliminary question of whether the adjustment mechanism continues to yield a fair ROE prior to the establishment of the common ROE for the year 2009, or earlier if the ROE resulting from the adjustment mechanism for years prior to 2009 is less than 7.6% or greater than 11.6%. The Board will consider the views of parties on this preliminary question before deciding whether to undertake a general review of ROE or of the adjustment mechanism.

The Board notes that any party, at any time, will be free to petition the Board to consider a review of the adjustment formula, or to exempt a particular party from its application. The Board agrees with the submissions of the Companies,[79] Calgary/CAPP,[80] and IPCAA[81] that there would be an element of judgment involved in determining whether circumstances have changed sufficiently to warrant review, and that the ROE and adjustment mechanism determined by the Board should be entitled to a presumption of reasonableness, with any party seeking early review or an exemption bearing the onus of demonstrating that circumstances have rendered them unreasonable. The petitioning party would bear the onus of demonstrating a material change in facts or circumstances from the evidence filed in this Proceeding to merit a review of the adjustment formula or an exclusion from the formula.

[79] Companies Argument, page 92
[80] Calgary/CAPP Argument, pages 23 and 64 (the later regarding capital structure)
[81] IPCAA Argument, page 24

5 CAPITAL STRUCTURE

5.1 Introduction

The Board notes that the capital structures determined in this Proceeding are premised on the business risks that existed at the time of the Proceeding.

For the convenience of readers, the following table (ordered by sector) compares the equity ratios that were last approved by the Board with the equity ratios recommended by the Applicants, CG and Calgary/CAPP:

Table 8. Recommended Equity Ratios vs. Last Board Approved Equity Ratios

	Last Board-Approved (%)	Recommended by Applicant (%)	Recommended by CG (%)	Recommended by Calgary/CAPP (%)
Electric and Gas Transmission				
ATCO Electric TFO	32.0	38.0	30.0	30.0
AltaLink	34.0[4]	37.5	30.0	32.0
EPCOR TFO	35.0	40.0	30.0	35.0
NGTL	32.0	40.0	32.0	33.0
ATCO Pipelines	43.5	50.0[3]	40.0	38.0
Electric and Gas Distribution				
Aquila	N/A [1]	42.5	35.0	35.0
ATCO Electric DISCO	35.0	45.0[2] (+ 5-10 %)	35.0	35.0
ENMAX DISCO	N/A [5]	50.0	35.0	40.0
EPCOR DISCO	N/A [5]	45.0	35.0	40.0
ATCO Gas	37.0	40.0	37.0	35.0
AltaGas	41.0	45.0	40.0	35.0

1 The Board did not specifically approve this ratio; it was part of a negotiated settlement approved in Decision 2003-019, which included a deemed 40% equity ratio as one of many settled parameters of the revenue requirement.
2 ATCO Electric DISCO requested a further increase of 5-10%, beyond its original request of 45%, in its equity ratio to account for ATCO's perception of additional business risks resulting from the *RDS Amendment Regulation.*[82]
3 ATCO Pipelines, in addition to a 50.0% equity ratio, also proposed a 0.5% addition to ROE.
4 In Decision 2003-061, the Board approved an equity ratio for AltaLink of 32%, plus an additional 2% to offset the impact on the interest coverage ratio of a partial allowance of income taxes in the revenue requirement.
5 ENMAX and EPCOR Distribution were subject to Board jurisdiction effective January 1, 2004.

The Board notes that, with the exception of CGA, the interveners who did not sponsor expert evidence generally supported the views of CG and Calgary/CAPP in argument. The Board also notes that the Applicants did not generally take a position on the appropriate capital structures for other Applicants.

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

82 *Regulated Default Supply Amendment Regulation* (AR 323/2003)

To determine the appropriate equity ratio for each Applicant, the Board will consider the evidence and, where applicable, the experts' views and rationales in each of the following topic areas:

1. The business risk of each utility sector and Applicant;
2. The Board's last-approved equity ratio for each Applicant (where applicable);
3. Comparable awards by regulators in other jurisdictions;
4. Interest coverage ratio analysis; and
5. Bond rating analysis.

The Board notes the general consensus that the electric and gas transmission sectors had the least risk of all Applicants in this Proceeding. Further, the Board notes that no party argued otherwise.

The Board will first consider the appropriate capital structures for the electric and gas transmission Applicants, and the Board will subsequently consider the appropriate capital structures for the electric and gas distribution Applicants.

5.2 Electric and Gas Transmission

The Board notes from the above Table 8 that for the taxable electric transmission companies,[83] the Applicants proposed equity ratios of 37.5 and 38.0%, whereas the interveners proposed an equity ratio of 30.0%.

With respect to transmission companies that are not fully taxable, the Board will provide its findings later in this Decision.

With respect to gas transmission, NGTL proposed an equity ratio of 40%, while the interveners proposed 32 and 33%. The equity ratios proposed by all submitting parties for ATCO Pipelines were materially higher than the equity ratios each proposed for NGTL. The Board will address ATCO Pipelines later in this Decision.

Business Risk

The Board notes that the Companies[84] compared the risks of electric transmission companies with the risks of NGTL as they existed in 1995. Dr. Evans (sponsored by the Companies) considered that electric transmission companies have more risk today than NGTL had at the time NGTL's equity ratio was last approved, for 1995.[85]

However, the Board considers that because it now has evidence regarding all Applicants' current risks, the utilities should be compared based on the business risks that existed at the time of this Proceeding. This was the approach of the experts other than Dr. Evans.

ATCO submitted that electric transmission companies were more risky than NGTL, principally due to the smaller size of the electric transmission companies relative to NGTL, the higher expected growth rates of the electric transmission companies relative to NGTL, and ATCO's

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[83] In this Proceeding, AltaLink assumed it was fully taxable, but the Board did not.

[84] Companies Argument, page 96

[85] Companies Argument, page 98

perception of a greater degree of regulatory uncertainty for the electric transmission companies relative to NGTL.

Although NGTL did not compare its level of business risk to that of other utilities, it did submit extensive evidence with respect to its own business risks, including operating expense risk, supply risk, competition risk, volume risk and credit risk.

Calgary/CAPP[86] and CG[87] each considered NGTL to have higher short and long-term business risk than the electric transmission companies, because NGTL faces operating expense risk, supply risk, competition risk, volume risk and credit risk, whereas the electric transmission companies only face operating expense risk. The interveners[88] viewed TFO growth prospects as an opportunity rather than a risk.

The Board agrees with the interveners that NGTL has a higher short-term business risk than the electric transmission companies, principally due to higher competition and credit risks. The Board also considers that NGTL potentially faces higher long-term risks due to supply risk although, in the Board's view, the bulk of that risk, if it materializes, will likely be identified early enough for NGTL to apply to the Board for potential adjustments to throughput forecasts and/or depreciation rates.

The Board also notes that NGTL does not have the same revenue certainty, as do the electric transmission companies. The Board also considers the higher expected growth rates of the electric transmission companies to be an opportunity for the TFO shareholders to increase their investments, and not fundamentally a matter of increased risk. The Board notes that utilities are allowed a return on funds used during construction. In addition, the Board was not persuaded that electric transmission companies have a greater degree of regulatory uncertainty than gas transmission companies.

The electric transmission companies have a single customer, the AESO. The Board considers the AESO to be of minimal credit risk. Further, the Board notes that the AESO pays the electric transmission companies 1/12 of their approved revenue requirement on a monthly basis with no adjustment for changes in demand or supply of electricity carried by the TFO.

For all of the above reasons, the Board does not agree with ATCO and the Companies that the electric transmission companies are more risky than NGTL.

The Board concludes that taxable electric transmission companies have the lowest business risk of any utility sector regulated by the Board, and that the risks of NGTL are somewhat higher than the risks of a fully taxable electric TFO.

The Board notes, from the above Table 8, that CG's and Calgary/CAPP's recommended equity ratios for NGTL were 2% and 3%, respectively, higher than their recommended equity ratio for a fully-taxable electric TFO. The Board also notes that NGTL did not provide the Board with an indication of its views respecting its risks relative to electric transmission companies, and, more particularly, did not indicate a view on an appropriate equity ratio differential compared to electric transmission companies.

86 CAPP/Calgary Argument, page 56
87 CG Argument, pages 67-70
88 CG Argument, page 70; Calgary/CAPP Argument, pages 67-70

The Board considers that business risk, in isolation, would indicate an equity ratio for NGTL that is 2-3 % higher than the equity ratio for a fully taxable TFO.

Comparison to Previous Board Awards

The Board notes that the last Board-approved equity ratio for NGTL of 32% was established for 1995.[89] The Board agrees with the general view of the experts that the business risks of NGTL have increased since 1995, principally due to a potentially higher supply risk and a higher competition risk.

Directionally, the Board concludes that NGTL's higher business risk, in isolation, supports an equity ratio for NGTL higher than 32%.

In Decision U99099, the Board established an equity ratio for electric transmission companies (TFOs) of 35%. In Dr. Evan's view,[90] the risks of electric TFOs have not changed since the time of Decision U99099, which would indicate that no change in equity ratio was appropriate. However, the Board considers that the risks of electric transmission companies have likely decreased since the time of Decision U99099 due to increased clarity of the role of the TFO, increased clarity with respect to the AESO's role and structure, the resolution of liability issues and the changes in transmission policy including the role of competitive bidding.

Directionally, the Board considers that this factor, in isolation, supports an equity ratio for fully taxable electric transmission companies lower than the 35% determined in Decision U99099.

The Board notes the last approved equity ratio for ATCO Electric TFO was 32% and for AltaLink was 34% (32% + 2% for the interest coverage ratio adjustment). However, these ratios were established when NGTL's award was 32%.

Directionally, the Board considers that this factor, in isolation, supports an equity ratio for fully taxable electric transmission companies similar to the last award of 32% or marginally higher.

Comparable Awards by Regulators in Other Jurisdictions

The Board acknowledges the potential for circularity when considering awards by other regulators. The Board also recognizes that business risks may be quite different in other jurisdictions. The Board has discussed some of these differences in the ROE section of this Decision and will provide further comment in following sections of this Decision. Nevertheless, the Board considers that comparable awards by other regulators may provide some indication of the appropriate capital structures for the Applicants.

As a result of the electric industry restructuring in Alberta, the Board notes that there are no TFO entities in the other provinces of Canada that are directly comparable to TFO entities in Alberta. However, in the Board's view, Canadian federally regulated natural gas transmission pipelines are of some assistance in drawing comparisons to both NGTL and the taxable electric transmission companies.

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[89] U96001, Nova Gas Transmission Ltd., 1995 General Rate Application, Phase 1

[90] Companies Argument, page 110

The Board considers that the nature of NGTL as a gathering system, with numerous receipt and delivery points, a diverse customer base, and other related factors demonstrates an additional degree of business risk for NGTL when compared to the TCPL Mainline. However, the breadth of NGTL's diverse customer base mitigates the additional risk to a large degree, since the loss of any one customer or point of supply would likely not be material to the long-term risks faced by NGTL. The Board notes that in RH-4-2001, dated June 2002, the NEB awarded TCPL's Mainline a 33% common equity ratio based on its conclusion that "the level of business risk facing the Mainline has increased since 1995…".[91] The NEB cited "increases in the risks resulting from pipe-on-pipe competition and increased supply risk but noted, "other sources of risk have not changed materially".[92]

The Board notes that NGTL's last awarded equity ratio of 32% for 1995 was 2% higher than the contemporaneous NEB award of 30% for TCPL's Mainline. The Board notes that the same 2% differential if applied today would result in an equity ratio of 35% for NGTL. The Board considers that this factor, in isolation, supports an equity ratio of 35% for NGTL.

Since the Board considers electric transmission companies to have less risk than NGTL, the Board considers that this factor, in isolation, supports an equity ratio of less than 35% for taxable electric transmission companies.

The Board notes Dr. Evan's evidence,[93] provided at the Board's request, that the awarded equity ratios for the Foothills, ANG and TQM pipelines remain at the 30% level that the NEB established in 1995.

However, the Board notes the NEB's view[94] that Foothills and ANG operated on a lower risk monthly cost of service basis, and that TQM had a high degree of assurance that its costs would be recovered. For these reasons, the Board considers the risks of the taxable electric transmission companies and NGTL are somewhat higher than the risks of Foothills, ANG and TQM. Consequently, the Board considers that this factor, in isolation, supports an equity ratio of more than 30% for both the taxable electric transmission companies and NGTL.

The Board notes that the awarded equity ratio of the Westcoast Energy pipeline remains at 35%, which was set by the NEB in 1995. The Board also notes the NEB's view[95] that Westcoast had higher risks due to the nature of its gathering system and processing plants and due to the hydrogen sulfide content of the gas it transports. For these reasons, the Board considers the risks of taxable electric transmission companies to be lower than the risks of Westcoast and the Board considers the risks of a large gathering system like NGTL to be more similar to Westcoast than to the electric transmission companies. Consequently, the Board considers that this factor, in isolation, supports an equity ratio of approximately 35% for NGTL and less than 35% for the taxable electric transmission companies. However, the Board would note that there are also differences between Westcoast and NGTL.

91 RH-4-2001, page 58
92 RH-4-2001, page 28
93 Exhibit 021-24
94 RH-2-94, page 26
95 RH-2-94, page 25

Interest Coverage Ratio Analysis

The Board notes that S&P provides guideline interest coverage ratios,[96] corresponding to various corporate credit ratings, for utilities of various business risk profiles (risk ranking levels). The Board further notes ATCO's evidence[97] that the estimated S&P risk ranking for ATCO Electric transmission is "2" and that the actual S&P business risk profile ranking for NGTL is "3".

The S&P guidelines indicate that for a utility with a risk ranking of "2", a pretax interest coverage ratio in the range of 2.3 to 2.9 times is indicated for an "A" debt rating.

The Board notes that S&P does not rigorously apply its guidelines with respect to each specific financial ratio. In addition to interest coverage ratios, S&P reviews a number of other key financial ratios, as well as many diverse and often subjective factors, in order to arrive at a specific credit rating for an individual utility.

The Board notes that Enbridge Gas has been assigned a risk ranking of "2", which would imply that electric and gas transmission companies, which are less risky, could be considered to be ranked at less than "2".

The Board does not have a target credit rating for utilities under its jurisdiction. The Board is of the view, however, based on the evidence before it in this Proceeding, that interest coverage ratios and credit ratings are important considerations in assessing the appropriate capital structure. However, the Board considers that the foregoing are just one set of factors to consider.

The Board notes that DBRS has indicated, in its NGTL credit rating report,[98] that an interest coverage ratio "above 2 times ... is acceptable for a regulated cost of service-based business".[99] The Board notes that the DBRS report, "Methodologies in Rating Utilities", dated June 2002,[100] indicates a fixed-charge coverage ratio of 1.5 for a DBRS debt rating from BBB to A. The report's definition of fixed-charge coverage, in cases where preferred shares do not exist, is the same as the definition of interest coverage that the Board has used throughout this Decision. The Board notes the apparent inconsistency in the two statements, but considers that taken together, a conclusion can be drawn that an interest coverage ratio near 2 times might be appropriate for low risk regulated entities. The Board also notes Dr. Booth's (sponsored by Calgary/CAPP) evidence that an interest coverage ratio of 2.15 times is reasonable for pipelines, considering their historic actual levels.[101]

The Board notes that some parties have expressed a concern that the acceptable equity ratios for regulated utilities in Alberta could potentially be overstated,[102] if the S&P guidelines with respect to interest coverage ratios were applied in a mechanical manner without consideration of other factors.

96 Exhibit 008-02, pre-filed Information Response AUMA-AP-11
97 Exhibit 005-11-1, Capital Structures for the ATCO Utilities, Kathleen McShane, pages 9-11
98 Exhibit 013-17, DBRS credit rating report on NGTL, dated June 26, 2002, page 1
99 Exhibit 013-17, page 9 of 35
100 Exhibit 008-02, pre-filed Information Response CAL-AP-8
101 Exhibit 016-11(a), Evidence of L.D. Booth, page 63
102 Calgary/CAPP Argument, page 28

The Board has calculated the pretax interest coverage ratios that would result for a utility, with no preferred shares, using a 2004 tax rate of 33.87%,[103] using the ROE that the Board determined in this Decision of 9.6%, and applying a range of equity ratios and embedded debt costs. The Board will use the following table as one of several tests to evaluate and determine the appropriate common equity ratios.

The interest coverage ratio results for a range of equity ratios and embedded debt costs are as follows:

Table 9. Pretax Interest Coverage Ratios at Varying Embedded Debt Costs

Equity	Embedded Debt Cost					
Ratio	6.0%	6.5%	7.0%	7.5%	8.0%	8.5%
30.0%	2.0	2.0	1.9	1.8	1.8	1.7
31.0%	2.1	2.0	1.9	1.9	1.8	1.8
32.0%	2.1	2.1	2.0	1.9	1.9	1.8
33.0%	2.2	2.1	2.0	2.0	1.9	1.8
34.0%	2.3	2.2	2.1	2.0	1.9	1.9
35.0%	2.3	2.2	2.1	2.0	2.0	1.9
36.0%	2.4	2.3	2.2	2.1	2.0	2.0
37.0%	2.4	2.3	2.2	2.1	2.1	2.0
38.0%	2.5	2.4	2.3	2.2	2.1	2.0
39.0%	2.6	2.4	2.3	2.2	2.2	2.1
40.0%	2.6	2.5	2.4	2.3	2.2	2.1
41.0%	2.7	2.6	2.4	2.3	2.3	2.2
42.0%	2.8	2.6	2.5	2.4	2.3	2.2
43.0%	2.8	2.7	2.6	2.5	2.4	2.3
44.0%	2.9	2.7	2.6	2.5	2.4	2.3
45.0%	3.0	2.8	2.7	2.6	2.5	2.4

The above table shows the results of the mathematical calculations. The Board understands that bond ratings do not rely solely on precise mathematical results. Bond ratings incorporate a variety of factors, including the use of judgment.

The Board cautions readers not to interpret the level of precision expressed in the above table to be absolute in arriving at the appropriate equity ratio.

The Board is aware that some companies have higher embedded debt costs but these embedded debt costs are expected to decline as older, higher-cost debt is retired. The Board also notes that the embedded debt cost for AltaLink is lower than 6%, but that this embedded cost of debt could be understated since AltaLink's long-term financing does not appear to be fully in place.

The Board did not use the above table in a precise mathematical manner. Rather, the Board evaluates the data in the table above by looking at ranges, various company situations, longer-term effects, impacts of declining embedded costs, stability of capital structure awards as embedded debt costs change, and the consideration of other factors that are discussed in this Decision.

[103] 21% Federal rate, 1.12% surtax and 11.75% provincial tax (12.5% through March 31, 11.5% thereafter)

The Board further considers that all of these differing ratios are merely indicators in arriving at a level of coverage that is considered comfortable and acceptable.

Accordingly, based on the evidence and the above discussion, the Board concludes that an acceptable pretax interest coverage ratio for electric and gas transmission companies, in isolation, is near 2 times.

The Board considers that interest coverage ratio analysis, in isolation, supports equity ratios for taxable electric transmission companies and gas transmission companies greater than the currently approved equity ratios of 32% for ATCO Electric and NGTL.

The Board considers gas transmission companies to have slightly more risk than electric transmission companies and, therefore, the Board considers that this factor, in isolation, indicates that gas transmission companies should have slightly more equity than electric transmission companies.

Bond Rating Analysis

As noted above, the Board does not have a target credit rating for utilities under its jurisdiction. Further, the Board has discussed bond ratings, earlier in this Decision, in the context of the interest coverage ratios. Bond ratings are another factor in determining an appropriate capital structure.

With respect to the indications provided by actual bond ratings, Dr. Evans provided, at the Board's request, a detailed compilation of comparable equity ratios and bond ratings. The following table is an excerpt from that compilation, showing the awarded and the adjusted actual equity ratios for each utility regulated by the Board that has its own bond rating:

Table 10. Equity Ratios and Bond Ratings

	Last Board Awarded Equity (%)	Adjusted Actual Equity[104] (%)	DBRS credit rating[105] and deemed equity ratio at the same date (%)		S&P credit ranking and common equity ratio at the same date (%)	
AltaLink L.P.	34	38.3	A (high)	34.0[106]	A-	35 – 40 implied[107]
EPCOR Transmission	35	37	BBB (high)[108]	35.7[109]		
NGTL	32.2+0.3 preferred	40.3	A	38.9[110]	A-	36.0[111]
Aquila	40 (settlement)	41.9	A (low)	45.5 / 40.0[112]		

104 Exhibit 021-24 Dr. Evans calculated the most recently available Adjusted Actual Equity by treating short-term debt as debt, and by treating preferred shares and subordinated debt as 80% equity, consistent with the treatment described at page 106 of Decision 2003-061.

105 Source: Dr. Evans, Exhibit 021-24

106 Exhibit 021-45, AltaLink DBRS credit report, dated September 26, 2004, page 6

107 Exhibit 003-02-6, AltaLink S&P credit report dated May 16, 2003, page 4, indicates expected allowed equity of 35% and actual debt at 60-65% (implies actual equity of 35 to 40%).

108 Exhibit 012-03-h, DBRS letter regarding EPCOR Transmission Inc.'s indicative bond rating dated June 19, 2002

109 Exhibit 012-03-b, EPCOR Transmission Inc. Cost of Capital

110 Exhibit 021-43(c), beginning page 21 of 52, DBRS report on NGTL dated October 17, 2003, page 5

111 Exhibit 013-17, page 23 of 25, S&P report on NGTL dated June 19, 2003, page 3

Regarding EPCOR Transmission, the Board notes that the DBRS rating in the above table was only an indicative DBRS rating of BBB (high)[113] if DBRS had rated EPCOR in 2002, assuming no debt guarantee from the parent. The DBRS rating indication did not show the equity ratio used. However, the Board notes that an equity level of 35.7% for EPCOR Transmission was applicable[114] at the time that DBRS determined their bond rating to be BBB (high). The Board notes that the cost of debt has been declining since 2002[115] and as a result, the bond rating for a given equity ratio should improve as debt reaches maturity and is replaced. Consequently, the Board considers that this factor, in isolation, indicates that the equity ratio for EPCOR Transmission should be approximately 36%.

From the above table, the Board notes that AltaLink had DBRS and S&P credit ratings of A (high) and A- based on an equity ratio of 34% and a projected equity ratio of 35 to 40%, respectively. Furthermore, the Board notes that AltaLink has a substantial amount of goodwill on its books,[116] amounting to approximately 19% of its assets, which would require incremental equity support, compared to a TFO without goodwill. Consequently, the Board considers that this factor, in isolation, supports an equity ratio for AltaLink, based on rate base, somewhat below 34%.

The Board notes that NGTL has DBRS and S&P credit ratings of A and A- based on equity ratios of 38.9 and 36.0% respectively. In addition, the Board notes that the DBRS credit rating[117] of NGTL is partly based on its parent, TCPL. However, the Board notes that the S&P report[118] indicates that the credit rating is effectively that of TCPL, rather than that of NGTL itself. Therefore, in the Board's view, the adjusted actual equity ratio of NGTL may not be indicative of its required equity ratio, on a standalone basis.

Conclusion

At the beginning of this section, the Board indicated that it would consider a variety of factors for the electric and gas transmission companies.

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

The following table summarizes the indicated equity ratios that arise from various factors as discussed in the earlier sections.

112 Exhibit 004-12, DBRS Report on Aquila, page 5, indicating 54.5% net debt at March 31, 2002 (implies 45.5% equity), and indicating 40.0% deemed equity at December 31, 2001

113 Exhibit 012-03-h, DBRS letter regarding EPCOR Transmission Inc.'s indicative bond rating dated June 19, 2002

114 Exhibit 012-03

115 Ibid.

116 Exhibit 021-45, AltaLink DBRS credit report, dated September 26, 2004, page 6

117 Exhibit 021-43(c), page 21 of 52, DBRS report on NGTL dated October 17, 2003, page 1

118 Exhibit 013-17, page 23 of 25, S&P report on NGTL dated June 19, 2003, page 1

Table 11. Indicated Common Equity Ratios for Transmission Companies By Factor

Factor	Indicated Electric Transmission	Indicated Gas Transmission
Business Risk	Lowest	TFO + 2-3%
Previous Board Awards	≥32%, <35%	>32%
Awards in Other Jurisdictions	>30%, <35%	~35%
Interest Coverage Ratio Analysis	>32%	>32%, >TFOs
Bond Rating Analysis	EPCOR ~36% AltaLink <34%	May not be indicative

After considering all of the above factors and after applying its judgment, the Board concludes that an appropriate common equity ratio for fully taxable electric transmission companies, with no preferred shares, is 33.0% and that an appropriate common equity ratio for gas transmission companies is 35.0%.

The Board will now consider each electric and gas transmission Applicant, individually.

5.2.1 ATCO Electric Transmission

The Board considers that ATCO Electric Transmission does not have any material differences in business risk from the typical TFO.

The Board also notes that ATCO Electric Transmission has preferred shares in its capital structure. 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.

For the same reasons that were provided above, the Board concludes that an appropriate common equity ratio for ATCO Electric Transmission, a fully taxable TFO, is 33.0%.

The Board will further address the issue of ATCO's preferred shares later in this Decision.

5.2.2 EPCOR Transmission

The Board considers that EPCOR Transmission does not have any material differences in business risk from the typical TFO.

The Board therefore considers that any difference between the equity ratio for a fully-taxable electric TFO with no preferred shares and the equity ratio for EPCOR Transmission should only reflect the fact that EPCOR Transmission does not have any allowance for income taxes in its approved revenue requirement.

Dr. Evans (sponsored by the Companies, including EPCOR Transmission) recommended that non-taxable utilities be allowed an extra 2.5% equity. Dr. Evans argued that this additional equity component was warranted due to the generally lower interest coverage ratios and the greater variability of net income for non-taxable utilities.[119]

[119] Companies Argument, page 94

For similar reasons, Calgary/CAPP recommended that non-taxable entities be allowed an extra 5% equity.[120]

ENMAX argued[121] that its non-taxable status justified an additional 8% equity, based on the precedent established by the Board for AltaLink in Decision 2003-061.

All other parties who took a position, on the issue of non-taxable utilities, were of the view that no allowance for additional equity should be provided for non-taxable entities, principally due to a perceived offsetting benefit of lower, more competitive rates. ATCO argued that such an increment to the equity ratio would provide an inappropriate competitive advantage to non-taxable entities.

The Board agrees that a non-taxable entity has a higher volatility of earnings than an otherwise equivalent taxable company, arising from the lack of an income tax component in its forecast revenue requirement. The Board notes that there was no disagreement that the absence of taxation, while lowering costs, increases the volatility of earnings.

In the Board's view, arguments regarding the competitive advantage of non-taxable entities do not have persuasive merit in the context of regulated electric utilities, which do not compete with each other.

However, the Board is not persuaded that the higher volatility of earnings warrants an increase in the equity ratio as high as recommended above. The Board considers that an extra 2% equity would appropriately account for the higher business risks and earnings volatility of a non-taxable entity.

Adding the 2% increment to the 33% equity ratio determined above for a fully taxable TFO, the Board concludes that an appropriate common equity ratio for EPCOR Transmission is 35.0%.

5.2.3 AltaLink

The Board considers that AltaLink does not have any material differences in business risk from the typical TFO.

The Board therefore considers that any difference between the equity ratio for a fully-taxable TFO with no preferred shares and the equity ratio for AltaLink should only reflect the differences in the amount of income taxes included in the respective revenue requirements.

The Board notes that in Decision 2003-061, the Board allowed an additional 2% on the equity ratio to recognize the disallowance of 25% of the requested income taxes, bringing the total common equity component to 34%. The additional 2% equity was intended to maintain the same interest coverage ratio as if there had been no disallowance of income taxes. The Board recognizes that a review and variance application with respect to Decision 2003-061 is pending.

The Board notes the adjustment to AltaLink's equity ratio was intended to maintain the same interest coverage ratio as if there had been no disallowance of income taxes, whereas the purpose of the adjustment to the equity ratios of the municipally owned utilities in this Decision is to

[120] Calgary/CAPP Argument, page 59-60
[121] ENMAX Argument, page 36

appropriately account for their higher volatility of earnings. The Board considers these two situations to be fundamentally different.

The Board notes that no party addressed the appropriate adjustment to AltaLink's equity ratio to reflect the partial disallowance of income tax. Assuming that the Board's disallowance of 25% of the requested income taxes is continued, the Board considers that it would continue to be appropriate to adjust AltaLink's equity ratio to maintain the same interest coverage as if there had been no disallowance of income taxes.

Adding the 2% adjustment to the 33% equity ratio determined above for a fully taxable TFO, the Board concludes that an appropriate common equity ratio for AltaLink is 35.0%.

If AltaLink were to have a full income tax allowance included in its approved revenue requirement, the Board considers that the appropriate common equity ratio for AltaLink would then be 33.0%.

5.2.4 NGTL

For the same reasons that were provided above, the Board concludes that an appropriate common equity ratio for NGTL, a gas transmission company, is 35.0%.

5.2.5 ATCO Pipelines

The Board notes that no party took the position that ATCO Pipelines has the same or lower business risk as NGTL, the other gas transmission Applicant. From Table 8, the Board notes that Calgary/CAPP considered ATCO Pipelines to be the highest risk investor owned utility, and that CG considered ATCO Pipelines to be tied with AltaGas as the highest risk utility.

Accordingly, in this section, the Board will assess the appropriate equity ratio for ATCO Pipelines and its differences from the typical gas transmission company. In this regard, the Board will draw on its previous analysis and discussion earlier in this section. Further, the Board will address the additional information applicable to ATCO Pipelines.

The Board notes the general consensus that ATCO Pipelines has higher competition risk than NGTL. Several parties suggested that resolution of outstanding gas pipeline competition issues could result in a reduction to the competition risk faced by ATCO Pipelines. The Board notes that at least some of the competition risk faced by ATCO Pipelines may have resulted from the growth of the system to connect customers either already served by NGTL or in direct competition with NGTL for those loads. The Board also notes that ATCO's largest customer is ATCO Gas, which, in the Board's view, has little credit risk. In any event, the Board considers that it should establish capital structures for 2004 based on the business risks that exist at the time of this Proceeding. The Board does not consider that it should speculate on the possible resolution of outstanding pipeline competition issues.

The Board notes that in NGTL's last Phase I proceeding,[122] the Board indicated that there would be a proceeding to address outstanding gas pipeline competition issues (the Competitive Pipeline Module). The Board considers that the Competitive Pipeline Module is the appropriate forum to

[122] Application 1315423, Transcript Volume 1, pages 44-49

deal with the inter-pipeline competition matters that may impact the business risks presently confronting ATCO Pipelines.

The Board directs ATCO Pipelines, at the time of its first GRA following the Board's decision in the Competitive Pipeline Module, to apply either:

a) For a change to its deemed equity ratio, to reflect the change in business risk arising from any directions contained within such a decision; or

b) For maintenance of its then existing capital structure on the basis that no change to business risk resulted from the decision in the Competitive Pipeline Module.

The Board notes that CG recommended that the equity ratio of ATCO Pipelines be set at 40%, which was 8% higher than its recommendation for NGTL, while Calgary/CAPP's recommendation for the equity ratio of ATCO Pipelines at 38% was 5% higher than its recommended equity ratio for NGTL.

The Board notes that if the interveners' differentials were applied to the Board's 35% determination for NGTL, the result would be a range of 40% to 43% for ATCO Pipelines.

The Board agrees with all parties that ATCO Pipelines has higher business risk than NGTL.

The Board notes that the last Board decision for ATCO Pipelines, Decision 2003-100, set the 2003 common equity ratio for both ATCO Pipelines North and ATCO Pipelines South at 43.5%.

Regarding gas transmission companies with higher risk than NGTL, the Board notes Dr. Evan's evidence[123] that Pacific Northern Gas (PNG) had an awarded equity ratio of 42.9% and an adjusted actual equity ratio of 44.2%, with a credit rating of BBB (low). The Board also notes Dr. Booth's view[124] that PNG is a highly risky utility and Dr. Robert's view[125] that PNG is riskier than the other utilities.

The Board also notes that ATCO Pipelines has preferred shares in its capital structure. 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.

Considering all of the above, the Board concludes that an appropriate common equity ratio for ATCO Pipelines is 43.0%.

The Board will further address the issue of ATCO's preferred shares below.

5.3 Electric and Gas Distribution

The Board will now consider the appropriate capital structures for the electric and gas distribution Applicants in light of the 5 topic areas set out in section 5.1 as shown below:

1. The business risk of each utility sector and Applicant;

[123] Exhibit 021-24
[124] Exhibit 016-11(a), Evidence of L. D. Booth, page 54
[125] Transcript, Volume 34, page 5602

2. The Board's last-approved equity ratio for each Applicant (where applicable);
3. Comparable awards by regulators in other jurisdictions;
4. Interest coverage ratio analysis; and
5. Bond rating analysis.

Business Risk

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

ATCO proposed that the difference in the equity ratio between its electric distribution companies and its electric TFO should be 12.0-17.0%. The Board observes that 5%-10% of this difference in the equity ratio was due to ATCO's perception of a higher regulatory risk following the passage of the *RDS Amendment Regulation.*[126]

The Board is not persuaded that the *RDS Amendment Regulation* has materially increased the risk to an electric distribution company that has appointed a third-party as RRT provider. The Board notes that the requirement for an electric distribution company to provide a hedged rate is contingent on the default of its RRT provider. The Board notes that it did not receive evidence regarding what contractual protections and security, if any, are available to ATCO in the event of a default by its appointed RRT provider. Also, it is possible that a default would be foreseeable over some period of time prior to it occurring, which may permit time to implement contingency plans to minimize associated impacts. Further, in the event of such a default, an application could be made to the Board to recover, from customers, prudent costs incurred by the electric distribution company in resuming the provision of the RRT. The Board would then consider the merits of such an application, considering factors such as the contractual circumstances and remedies available to the electric distribution company, the circumstances of the RRT appointment, and the potential harm to customers. The Board also notes that no other electric distribution company filed evidence asserting a similar increase in risk.

ATCO also argued that its electric distribution company had higher risk than its electric TFO as a result of potential franchise loss. However, in light of the lack of recent actual occurrences of municipalities closing a transaction pursuant to an option to acquire utilities assets, the Board does not consider, at this time, that the risk of franchise loss or of a municipality acquiring utility assets has increased over what it has been historically. Should there be a material change in the business risk arising from risk of franchise loss an affected utility could apply to the Board at that time to seek appropriate relief.

As shown in Table 8, the Companies, CG and Calgary/CAPP all recommended equity ratios for fully taxable electric distribution companies that were 5% higher than their recommended equity ratios for fully taxable electric transmission companies. The Board understands that this does not necessarily mean that the recommended differential would always be 5%.

ATCO considered the business risk of ATCO Gas to be lower than the business risk of its electric distribution company due to ATCO's perception of a higher regulatory risk for its

[126] Ministerial Order 73/2003, November 4, 2003

electric distribution company. As discussed above, the Board does not agree with ATCO's perception of the magnitude of the regulatory risk for its electric distribution company.

The Board notes that Calgary/CAPP and CG considered that ATCO Gas has the same or slightly higher business risk than a fully taxable electric distribution company, due to higher volatility of revenue resulting from a different rate design and higher sensitivity to fluctuations in weather conditions.

The Board agrees that a gas distribution company has slightly more risk than a taxable electric distribution company due to higher revenue volatility. The Board does not agree with ATCO that the higher revenue volatility of ATCO Gas is more than offset by higher regulatory risk for electric distribution companies.

The Board notes from Table 8 that parties making recommendations, other than ATCO Gas, suggested that the difference between the equity ratio for ATCO Gas and the equity ratio for a fully-taxable electric distribution company should be in the range of 0-2%.

The Board concludes that electric distribution companies have higher business risks than electric transmission companies, and that gas distribution companies have slightly higher business risk than electric distribution companies.

The Board considers that business risk, in isolation, would indicate that gas distribution companies should have a common equity ratio that is 0-2 % higher than the equity ratio for fully taxable electric distribution companies.

Comparison to Previous Board Awards

The Board notes from Table 8 that the most recent equity ratio approved by the Board for a taxable electric distribution company was 35%, and the most recent equity ratio approved by the Board for fully-taxable electric transmission companies was 32%, a difference of 3%. Earlier in this Decision, the Board determined an equity ratio of 33% for taxable electric transmission companies. The Board considers that this factor, in isolation, would indicate an equity ratio of 36% for the taxable electric distribution companies. Since the Board considers that ATCO Gas has slightly higher business risk than the electric distribution companies, the Board considers that this factor, in isolation, this would indicate an equity ratio of more than 36% for ATCO Gas.

The Board notes from Table 8 that the last equity ratio approved for ATCO Gas was 37%, established in Decision 2003-072. The Board considers that the business risks of ATCO Gas have not changed materially from those assessed by the Board in this prior decision, which, in isolation, would indicate an equity ratio for ATCO Gas of 37%.

Comparable Awards by Regulators in Other Jurisdictions

The Board notes its earlier caveats on relying on comparable awards by other regulators in a previous section of this Decision.

The Board notes that the gas distribution companies in Ontario, Enbridge Gas and Union Gas have been awarded a common equity ratio of 35 to 37% and a total equity ratio of 38 to 40%, treating preferred shares as 80% equity.[127]

[127] Exhibit 021-24

The Board considers that this information, in isolation, would indicate that the equity ratio for ATCO Gas could be maintained at its current level of 37%.

The Board does not consider that there are any other electric distribution companies in Canada that are comparable to the electric distribution companies in the restructured electric industry in Alberta.

Interest Coverage Ratio Analysis

The Board notes that Enbridge Gas has been awarded an S&P rating of "2".[128] The Board notes Ms. McShane's estimate that ATCO Gas would warrant an S&P risk profile of between "2" and "3". The Board notes that Ms. McShane estimates an S&P risk ranking of "3" for ATCO Electric. However, the Board earlier noted its view that ATCO had over-stated the business risk level of ATCO Electric. In the Board's view, an appropriate S&P risk score for both distribution utilities is between "2" and "2.5".

The S&P guidelines indicate that for a utility with a risk ranking of "2", a pretax interest coverage ratio in the range of 2.3 to 2.9 times is indicated for an "A" debt rating.

Similarly, the S&P guidelines indicate, through pro-rating the guidelines for a "2" and for a "3", that for a utility with a risk ranking of "2.5", a pretax interest coverage ratio in the range of 2.55 to 3.15 times is indicated for an "A" debt rating.

The Board refers the reader to the Interest Coverage Ratio Analysis section provided earlier in the Electric and Gas Transmission section, including the DBRS guidelines indicated there, as additional factors to consider for determining the appropriate common equity ratio for either an electric or a gas distribution company.

Based on this evidence, the Board concludes that an acceptable pretax interest coverage ratio for a taxable electric distribution company distribution company is at or above 2.2 times.

The Board considers that this factor, in isolation, indicates an equity ratio for taxable electric distribution companies and for gas distribution companies higher than the currently approved 35% for ATCO Electric Distribution.

The Board considers gas distribution companies to have slightly more risk than electric distribution companies and, therefore, the Board considers that this factor, in isolation, indicates that gas distribution companies should have slightly more equity than electric distribution companies.

Bond Rating Analysis

The Board notes that Aquila is the only electric or gas distribution company regulated by the Board with its own bond rating. From Table 10, the Board notes that Aquila has a DBRS rating of A (low) based on an equity ratio of 40 to 45.5%. However, the Board notes that Aquila has a

[128] Exhibit 005-11-1, Capital Structures for the ATCO Utilities, Kathleen McShane, page 11

substantial amount of goodwill[129] on its books, amounting to approximately 29% of its assets at the time of the DBRS report, which would require equity support compared to a distribution company without goodwill. Therefore, based on this factor in isolation, the Board concludes that the target equity ratio for a taxable electric distribution company is somewhat below 40%.

The Board considers the most comparable other Canadian gas and electric distribution companies, available in Dr. Evan's evidence, to be Union Gas and Enbridge Gas.

The Board notes that Union Gas Ltd. has an adjusted actual equity ratio of 35% and credit ratings of A and A-.[130] The Board notes that Enbridge Gas has an adjusted actual equity ratio of 51% and credit ratings of A and BBB+.[131] The Board notes that the date of the adjusted actual equity ratio date is not necessarily the same as the dates of the two credit reports. The Board considers this broad range of adjusted actual equity ratios for Ontario gas distribution utilities and its impact on bond ratings to be of little assistance in this Proceeding.

Conclusion

At the beginning of this section, the Board indicated that it would consider a variety of factors for its determination of the appropriate level of equity in the capital structure of electric and gas distribution companies.

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

The following table summarizes the indicated equity ratios that arise from various factors as discussed in the earlier sections:

Table 12. Indicated Common Equity Ratios for Distribution Companies by Factor

Factor	Indicated Electric Distribution	Indicated Gas Distribution
Business Risk	Lowest for Distribution	Electric DISCO + 0-2%
Previous Board Awards	~36%	~37%
Awards in Other Jurisdictions	N/A	~37%
Interest Coverage Ratio Analysis	>35%	>35%, >DISCOs
Bond Rating Analysis	<40%	N/A

After considering all of the above factors and after applying its judgment, the Board concludes that an appropriate common equity ratio for a fully taxable electric distribution company with no preferred shares is 37.0%, and that an appropriate common equity ratio for a gas distribution company is 38.0%.

The Board will now consider each electric and gas distribution Applicant, individually.

129 Exhibit 004-12, July 31, 2002 DBRS Report on Aquila, page 5 indicating 54.5% net debt at March 31, 2002 (implies 45.5% equity), and indicating 40.0% deemed equity at December 31, 2001; and Decision 2004-035, page 18

130 Exhibit 021-24

131 Ibid.

5.3.1 FortisAlberta/Aquila

The Board considers that FortisAlberta (formerly Aquila) does not have any material differences in business risk from the typical electric distribution company.

The Board notes that Aquila is a fully taxable electric distribution company with no preferred shares.

Therefore, for the same reasons that were provided above, the Board concludes that an appropriate common equity ratio for FortisAlberta is 37.0%.

5.3.2 ATCO Electric Distribution

The Board considers that ATCO Electric Distribution does not have any material differences in business risk from the typical electric distribution company.

The Board also notes that ATCO Electric Distribution has preferred shares in its capital structure. 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.

The Board concludes that an appropriate common equity ratio for ATCO Electric Distribution is 37.0%.

The Board will further address the issue of ATCO's preferred shares below.

5.3.3 ENMAX Distribution

The Board considers that ENMAX Distribution does not have any material differences in business risk from the typical electric distribution company.

The Board notes ENMAX's argument that it has additional risks due to its municipal ownership, including a fixed dividend requirement, lack of equity access, and the change in regulator, and that as a result it required a capital structure with 50% common equity.

The Board does not agree with ENMAX that its fixed dividend or lack of access to public equity markets raises its risks in the circumstances. In the Board's view, having established a fair return, the Board need not concern itself with the particular internal policies to which a utility may be subject regarding distributions of dividends or acquisition of equity. The Board also considers that the change in regulator for ENMAX does not result in ENMAX having higher risks, all else being equal, than other electric distribution companies regulated by the Board.

With respect to the ENMAX DISCO, which just came under Board jurisdiction in 2004, the capital structure determined in this Proceeding is based on the assumption that the deferral accounts that the Board will ultimately approve for this Applicant will not be materially different than those in existence at the time of this Proceeding for FortisAlberta/Aquila and ATCO Electric Distribution.

For the same reasons that were provided with respect to EPCOR Transmission above, the Board concludes that the equity ratio for a non-taxable electric distribution company should be 2.0% higher than the equity ratio for a fully taxable electric distribution company.

Therefore, the Board concludes that an appropriate common equity ratio for ENMAX Distribution is 39.0%.

5.3.4 EPCOR Distribution

The Board considers that EPCOR Distribution does not have any material differences in business risk from the typical electric distribution company.

With respect to the EPCOR Distribution, which came under Board jurisdiction in 2004, the capital structure determined in this Proceeding is based on the assumption that the deferral accounts that the Board will ultimately approve for this Applicant will not be materially different than those in existence at the time of this Proceeding for FortisAlberta/Aquila and ATCO Electric distribution companies.

For the same reasons that were provided with respect to ENMAX Distribution above, the Board concludes that an appropriate common equity ratio for EPCOR Distribution is 39.0%.

5.3.5 ATCO Gas

The Board considers that ATCO Gas does not have any material differences in business risk from the typical gas distribution company.

The Board notes that ATCO Gas also has preferred shares in its capital structure. 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.

As determined above, the Board concludes that an appropriate common equity ratio for ATCO Gas is 38.0%.

The Board will further address the issue of ATCO's preferred shares below.

5.3.6 AltaGas

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

AltaGas and ATCO Gas considered the business risks of AltaGas to be higher than the business risks of ATCO Gas, due to AltaGas' relatively small size, rural service area, geographically dispersed customers and high level of customer contributions.

Calgary/CAPP was the only party who took the position that AltaGas did not have higher business risks than ATCO Gas. Calgary/CAPP considered the main risk to AltaGas to be commodity cost risk, for which AltaGas has a deferral account. As a result, Calgary/CAPP recommended the same equity ratio for AltaGas as for ATCO Gas.

The Board notes that AltaGas' parent has a credit rating of BBB (low) and has been unable to raise debt with a term longer than five years. AltaGas had the view that, due to its size, it was very unlikely that it would be able to access debt on more favourable terms than its parent.[132]

The Board notes that AltaGas' parent is involved in a significant level of non-regulated activities. The Board is unable to establish the effect that those activities have on the parent's rating. The Board is not persuaded that that AltaGas would not have a higher rating than its parent and that it would not be able to access debt on more favourable terms than its parent. Nonetheless, the Board is persuaded that the business risks of AltaGas are greater than the business risks of a typical gas distribution company because of the nature of its service territory, not necessarily because of its smaller size.

The Board notes that CG's recommended equity ratio for AltaGas was 3% higher than its recommended equity ratio for ATCO Gas, whereas AltaGas and ATCO considered that the equity ratio for AltaGas should be 5% higher. The Board considers that this factor, in isolation indicates that the equity ratio for AltaGas should be 41-43%.

The Board notes that the previous Board approved equity ratio for AltaGas was 41%.

Considering all of the above, the Board concludes that an appropriate common equity ratio for AltaGas is a continuation of its currently approved 41%.

5.4 Utility-Specific Adjustments to ROE

Some parties in this Proceeding indicated that when a common ROE approach is used, it might be necessary to consider a utility-specific adjustment to the common ROE to adequately reflect the investment risks of individual utilities.

In particular, the Board notes that ATCO Pipelines indicated that an adjustment to its ROE was required to adequately compensate its investors for the risks confronting the company, because adjustments to capital structure would not be sufficient.

As noted earlier in this Decision, the Board considers that unique utility-specific adjustments to the generic ROE should only be made in exceptional circumstances where adjusting capital structure alone is not sufficient to reflect the investment risk for a particular Applicant.

The Board notes that the equity ratio approved for ATCO Pipelines in this Decision is marginally lower than the last Board-approved equity ratio for ATCO Pipelines. The Board considers that the capital structure for ATCO Pipelines in this Decision adequately reflects the investment risk for ATCO Pipelines.

The Board concludes that there is no need for utility-specific adjustments to the common ROE for any of the Applicants.

5.5 2004 Deemed Common Equity Ratios

Based on the Board's findings above, the Board approves the following deemed common equity ratios for 2004:

132 AltaGas Argument, page 32

Table 13. Board Approved Equity Ratios

	Last Board-Approved Common Equity Ratios (%)	2004 Board Approved Common Equity Ratios (%)	Change in Approved Common Equity Ratio (%)
ATCO TFO	32.0	33.0	1.0
AltaLink	34.0[133]	35.0	1.0
EPCOR TFO	35.0	35.0	0.0
NGTL	32.0	35.0	3.0
ATCO Electric DISCO	35.0	37.0	2.0
FortisAlberta (Aquila)	N/A [134]	37.0	N/A
ATCO Gas	37.0	38.0	1.0
ENMAX DISCO	N/A [135]	39.0	N/A
EPCOR DISCO	N/A [125]	39.0	N/A
AltaGas	41.0	41.0	0.0
ATCO Pipelines	43.5	43.0	(0.5)

5.6 ATCO Utilities Preferred Shares

In earlier sections, the Board noted that the 2004 approved common equity ratios in this Decision for the ATCO utilities were not adjusted to reflect any impact of ATCO's use of preferred shares. The Board notes that there was essentially no evidence presented regarding the impact of preferred shares on the required common equity ratios.

The Board has recognized in previous decisions that during the period of time when income tax rebates were in place, it was prudent to utilize preferred share financing in place of debt.

However, the Board considers that there may be merit in further consideration of the appropriateness of the continuing use of preferred shares as a form of financing, to understand the redemption options and to fully explore the related implications and options.

The Board directs ATCO to address the appropriateness of the continuing use of preferred shares as a form of financing, in the next Phase 1 GRA/GTA for ATCO Gas, ATCO Pipelines or ATCO Electric, whichever comes first.

5.7 Process to Adjust Capital Structure

The Board notes that all parties, except for CG, considered that it would be appropriate to address any future changes in capital structure in utility-specific GRA/GTAs. CG proposed a scheduled review of the capital structures of all Applicants.

The Board agrees with the general consensus that it would be more appropriate to address any future changes in capital structure in utility-specific GRA/GTAs. The Board also agrees with the general consensus that such changes should only be pursued if parties perceive that there has

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133 In Decision 2003-061, the Board approved an equity ratio for AltaLink of 32%, plus an additional 2% to offset the impact on the interest coverage ratio of a partial allowance of income taxes in the revenue requirement.

134 The Board did not specifically approve this ratio; it was part of a negotiated settlement approved in Decision 2003-019, which included a deemed 40% equity ratio as one of many settled parameters of the revenue requirement.

135 Both EPCOR and ENMAX Distribution were subject to Board jurisdiction effective January 1, 2004.

been a material change in investment risk since the time of this Proceeding, except as otherwise specifically directed in this Decision.

6 DIRECTIONS TO APPLICANTS

The Board directs any Applicant that has a Board-approved revenue requirement for 2004 that includes a placeholder for ROE and/or capital structure to file with the Board by August 1, 2004, for information, its plans on how it intends to comply with any outstanding directions from the Board to replace the placeholders for ROE and/or capital structure, when these changes might be reflected in customer rates, and the magnitude of the impact on customer rates for the changes arising from this Decision. The Board would appreciate being advised of the status and magnitude of any other known adjustments to rates that might be forthcoming in the same timeframe as the adjustments arising from this Decision.

With respect to applications to establish a 2004 revenue requirement that are currently before the Board for a decision, the Board will use the 2004 generic ROE and capital structure approved in this Decision.

With respect to applications presently before the Board and future applications to establish a revenue requirement for 2005 or later, the Board will apply the generic ROE for that year resulting from the adjustment mechanism approved in this Decision and the capital structure provided for in this Decision, barring the applicant demonstrating a material change has occurred requiring adjustment to capital structure.

7 SUMMARY OF BOARD FINDINGS AND CONCLUSIONS

This section is provided for the convenience of readers. In the event of any difference between the Approvals in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. With respect to the Jurisdictional Question itself, the Board finds that the proper interpretation of section 37 of the GUA would allow the Board to determine the capital structure for the relevant test period (2004 or 2005) for each gas utility under its jurisdiction by way of a generic proceeding and to establish a standardized approach based on a formula for determining the return on common equity for gas utilities. 7

2. Accordingly, the Board finds that the evidence in the Proceeding indicates that implementation of a generic approach is in the public interest and accordingly, the Board will implement a generic approach to ROE and capital structure. In the following sections, the Board will address the issues associated with the determinations necessary to appropriately implement this approach. 11

3. The Board will therefore establish a common, or generic, ROE to be applied to all Applicants. The Board will address the need for any utility-specific adjustments to the common ROE in the capital structure section of this Decision. 14

4. Based on the above-determined risk-free rate of 5.68%, MRP of 5.50%, beta of 0.55, and allowance for flotation costs of 0.50%, the Board concludes that a reasonable CAPM estimate for 2004 is 9.20% 21

5. On balance, the Board concludes that the results of the ERP tests other than CAPM would generally support a 2004 ROE above the Board's CAPM estimate, but that for the reasons set out above only limited weight should be placed on the results of the ERP tests other than CAPM. 23

6. As a result of the above noted concerns, the Board concludes that no weight should be placed on the results of the DCF tests presented in this Proceeding. 23

7. The Board concludes that it should place no weight on the CE test because of the implementation problems of the CE test and the above-noted conceptual and methodological concerns with the CE test. 24

8. Directionally, the evidence on recent awards for other Canadian utilities would support a 2004 ROE above the Board's CAPM estimate. However, the Board concludes that limited weight should be placed on this evidence due to the potential for circularity. 25

9. Directionally, the evidence on the awards available to U.S. utilities would support a 2004 ROE above the Board's CAPM estimate. However, the Board concludes that limited weight should be placed on this evidence due to the differences in the regulatory, fiscal, monetary, and tax regimes in the two countries. 26

10. Although, directionally, the absolute level of return for Alliance and M&NP would support a 2004 ROE above the Board's CAPM estimate, the Board concludes, based on the above analysis, that it should place limited weight on the Alliance and M&NP returns. 27

11. Directionally, the Board concludes that the experience regarding the market-to-book ratios of utilities and the experience regarding the acquisition of Alberta utilities in recent years is relevant and supports continuation of an ROE at or below the Board's CAPM estimate. 28

12. Directionally, the Board considers that the experience with Income Trusts would support an ROE at or below the Board's CAPM estimate. However, for the reasons cited above, the Board concludes that limited weight should be placed on this experience. 29

13. On balance, the Board concludes that the evidence on forecast pension returns would support a modest increase from the Board's CAPM estimate. 29

14. The Board concludes that there is no basis on which to place any weight, other than already reflected in earlier tests, on other specific investment opportunities potentially available to utility investors or on stated expectations of return from such opportunities. 30

15. In consideration of the impact of the above factors, it is the judgment of the Board that it would be appropriate to establish the 2004 ROE at a level that is 40 basis points above the Board's CAPM estimate. Therefore, the Board concludes the generic ROE for 2004 should be set at 9.60%. 31

8 SUMMARY OF BOARD DIRECTIONS

This section is provided for the convenience of readers. In the event of any difference between the Directions in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. The Board directs ATCO Pipelines, at the time of its first GRA following the Board's decision in the Competitive Pipeline Module, to apply either: 47
   a) For a change to its deemed equity ratio, to reflect the change in business risk arising from any directions contained within such a decision; or 47
   b) For maintenance of its then existing capital structure on the basis that no change to business risk resulted from the decision in the Competitive Pipeline Module. 47
2. The Board directs ATCO to address the appropriateness of the continuing use of preferred shares as a form of financing, in the next Phase 1 GRA/GTA for ATCO Gas, ATCO Pipelines or ATCO Electric, whichever comes first. 55
3. The Board directs any Applicant that has a Board-approved revenue requirement for 2004 that includes a placeholder for ROE and/or capital structure to file with the Board by August 1, 2004, for information, its plans on how it intends to comply with any outstanding directions from the Board to replace the placeholders for ROE and/or capital structure, when these changes might be reflected in customer rates, and the magnitude of the impact on customer rates for the changes arising from this Decision. The Board would appreciate being advised of the status and magnitude of any other known adjustments to rates that might be forthcoming in the same timeframe as the adjustments arising from this Decision. 56

9 ORDER

For and subject to the reasons set out in this Decision, IT IS HEREBY ORDERED THAT:

1. With respect to Applicants that have a Board-approved revenue requirement for 2004 that includes a placeholder for ROE and/or capital structure, the placeholder for ROE shall be replaced by 9.60% and the placeholder for capital structure shall be replaced as set out in this Decision;

2. With respect to applications by an Applicant to establish a 2004 revenue requirement that are currently before the Board, the Board shall apply an ROE of 9.60% and shall apply the capital structure as set out in this Decision; and

3. With respect to current or future applications by an Applicant to establish a revenue requirement for 2005 or later years, the Board shall apply the common ROE for that year resulting from the adjustment mechanism approved in this Decision and shall apply the capital structure as set out in this Decision for such Applicant, unless the Applicant can demonstrate to the satisfaction of the Board that there has been a material change in business risk that warrants a change to the capital structure set out in this Decision.

Dated in Calgary Alberta on July 2, 2004.

ALBERTA ENERGY AND UTILITIES BOARD

(original signed by)

A. J. Berg, P. Eng
Presiding Member

(original signed by)

R. G. Lock, P. Eng
Member

(original signed by)

J. I. Douglas, FCA
Member

APPENDIX 1 – HEARING PARTICIPANTS

Name of Organization (Abbreviation) Counsel or Representative (APPLICANTS)	Witnesses
AltaGas Utilities Inc. (AltaGas) F. Martin R. Jeerakathil	L. Heikkinen K. McShane
AltaLink Management Ltd. (AltaLink) H. Williamson	Dr. R. Evans K. Johnston D. Frehlich J. Harbilas
Aquila Networks Canada (Alberta) Ltd. (Aquila) T. Dalgleish	Dr. R. Evans
ATCO Utilities (ATCO) L. Smith	K. McShane J. McNeil D. Belsheim O. Edmondson
ENMAX Power Corporation (ENMAX) L. Cusano D. Wood	R. Henderson A. Buchignani R. Falconer Dr. J. Neri
EPCOR Utilities Inc. (EPCOR) D. Crowther	Dr. R. Evans
NOVA Gas Transmission Ltd. (NGTL) K. Yates Ms. Moreland D. Holgate	R. Girling S. Brett G. Lackenbauer P. Murphy Dr. P. Carpenter M. Feldman S. Pohlod Dr. W. Langford A. Jamal G. Zwick Dr. L. Kolbe Dr. M. Vilbert

Name of Organization (Abbreviation) Counsel or Representative (INTERVENERS)	Witnesses
Alberta Association of Municipal Districts and Counties, Federation of Alberta Gas Co-ops Ltd., Gas Alberta Inc. and Municipal and Gas Co-op Intervenors (AAMDC) T. Marriott	
Alberta Federation of REAs (REAs) K. Sisson	
Alberta Irrigation Projects Association (AIPA) H. Unryn	
BP Canada Energy Company (BP) D. McGrath	
Canadian Association of Petroleum Producers (CAPP) N. Schultz	Dr. L. Booth M. Romanow G. Stringham P. Tahmazian D. Gilbert M. Pinney T. Kelley P. Nettleton
Canadian Gas Association (CGA) P. Jeffrey	M. Cleland P. Case
Cargiil Power & Gas Markets (Cargill) M. Stauft	
Cities of Lethbridge and Red Deer (Cities) P. Smith	
City of Calgary (Calgary) P. Quinton-Campbell R. Brander	K. Sharp H. Johnson J. McCormick Dr. L. Booth
Consumers Coalition of Alberta (CCA) J. Wachowich	
Consumers Group/AUMA (Consumers Group) J. Bryan	W. Marcus R. Liddle Dr. L. Kryzanowski Dr. G. Roberts
First Nations Communities (First Nations) J. Graves A. Ackroyd	
Fortis Alberta Holdings Inc. (Fortis) B. Ho	

Name of Organization (Abbreviation) Counsel or Representative (INTERVENERS)	Witnesses
Industrial Power Consumers Association of Alberta (IPCAA) M. Forster D. Macnamara	
Independent Power Producers Society of Alberta/Senior Petroleum Producers Association (IPPSA/SPPA) L. Manning	D. Hildebrand A. Moon J. Keating
Nexen Inc. (Nexen) S. Young	
Public Institutional Consumers of Alberta (PICA) N. McKenzie	
Utilities Consumers Advocate (UCA) R. McCreary R. Jackson	

BOARD STAFF B. McNulty (Board Counsel) J. Wilson S. Allen W. Taylor R. Litt R. Schroeder Dr. V. Mehrotra	

APPENDIX 2 – ABBREVIATIONS

AESO	Alberta Electric System Operator
ANG	Alberta Natural Gas Ltd.
ATWACC	After Tax Weighted Average Cost of Capital
CAPM	Capital Assets Pricing Model
CE Test	Comparable Earnings Test
DCF Test	Discounted Cash Flow Test
DISCO	Electric or Gas Distribution Utility
ECAPM	Empirical Capital Assets Pricing Model
Equity Ratio	Common Equity as a Percentage of Total Financing
ERP Test	Equity Risk Premium Test
Foothills	Foothills Pipelines Inc.
GRA/GTA	General Rate Application/General Tariff Application
MRP	Market Risk Premium
NEB	National Energy Board
ROE	Rate of Return on Common Equity
RTO	Regional Transmission Organization
S&P	Standard & Poor's
TFO	Electric Transmission Facility Owner
TQM	Trans Quebec and Maritimes Pipeline

APPENDIX 3 – BOARD LETTER OF SEPTEMBER 30, 2002

"2002-09-30 EUB
Letter.doc"

(Consists of 8 pages)

Also, within this embedded document there are two further embedded documents.
(Appendix B consists of 5 pages and Appendix C consists of 1 page)

EUB Alberta Energy and Utilities Board
Calgary Office 640 – 5 Avenue SW Calgary, Alberta Canada T2P 3G4 Tel 403 297-8311 Fax 403 297-7336

File No. 5681-1

September 30, 2002

Sent to Parties on Various Utility Branch Lists via Email

Dear Sir/Madam:

PROCEEDING NO. 1271597
GENERIC COST OF CAPITAL HEARING - ELECTRIC AND GAS UTILITIES
- **Notice of Registration as Intervenors**
- **Notice of Pre-hearing Meeting – November 26, 2002**

On May 6, 2002, the Board received a request from the City of Calgary (Calgary) that the Board institute a proceeding to consider generic cost of capital matters for electric and gas utilities under the Board's jurisdiction. The Board responded to Calgary by letter dated June 6, 2002. Copies of both letters are attached as Appendix B and Appendix C[1], respectively.

The Board has decided to call a generic hearing pursuant to its powers to hold an inquiry under Section 46 of the *Public Utilities Board Act* (PUB Act) to consider cost of capital matters for electric, gas and pipeline utilities under its jurisdiction. This would include pipeline and electric transmission companies as well as electric and gas distribution companies.

The Board will hold a pre-hearing meeting as specified below to deal with the following issues:

- Determination of the scope of the proceeding and list of issues
- Determination of procedural matters that might be adopted for such a hearing.

A preliminary list of issues and procedural matters that the Board will consider through such a process is attached to this letter as Appendix A.

The Board requests that interested parties consider this preliminary list of issues and procedural matters and provide the Board with their detailed written submissions on the appropriateness of each issue or matter as well as their submissions with respect to additional issues or matters that might appropriately be considered through such a generic proceeding.

[1] Please note that these Appendices are embedded and may take a second or two to appear.

The following are key dates that the Board has established as follows:

Registration as intervenors with the Board	October 18, 2002
Written Submissions: List of Issues and Procedural Matters	November 12, 2002
Pre-Hearing Meeting	November 26, 2002
Hearing (Preliminary Schedule)	2nd Quarter 2003

After receiving parties' written submissions the Board will prepare a consolidated list of issues and procedural matters for discussion at the pre-hearing meeting.

The pre-hearing meeting will be held as follows:

- DATE: November 26, 2002
- TIME: 9:00 a.m.
- PLACE: Govier Hall, EUB Calgary offices (2nd floor, 640 – 5 Avenue SW)

The generic hearing would likely be scheduled for the 2nd quarter of 2003.

The Board is prepared to consider submissions respecting cost recovery for this proceeding given possible future cost savings associated with streamlining of the Cost of Capital determination process. The Board has the ability to allow costs of the proceeding and to direct that such costs be borne by consumers through the utilities' hearing cost reserve accounts pursuant to the Board's discretion under Section 68 of the PUB Act and pursuant to Rules 55 and 57 of the Board's Rules of Practice.

The Board would appreciate the efforts of any or all parties to work together, in advance of the pre-hearing meeting, in order to consolidate and simplify the views of parties on any matter, including procedural and timing issues.

Any questions or correspondence, including submissions, should be directed to the writer in the EUB's Calgary office. I can be reached at (403) 297-3539 telephone, (403) 297-6104 fax, or via email at jim.wilson@gov.ab.ca. Parties should also file an electronic copy of their registrations and any submissions at the email address eub.utl@gov.ab.ca.

Yours truly,

(Original signed " J. Wilson")

Jim Wilson
Lead Application Officer

Attachments

APPENDIX A

Preliminary List of Issues and Procedural Matters

A preliminary list of issues and procedural matters that will be considered at a pre-hearing meeting for a EUB generic hearing into utility cost of capital matters.

For clarity, the Board will not be discussing the merits of each issue in the list below (i.e. in section **I. Preliminary List of Issues)** but the Board, in its Decision arising from the pre-hearing meeting, will determine the scope of the proceeding.

Further, the Board will make determinations, in its Decision arising from the pre-hearing meeting, on procedural items listed below (i.e. in section **II. Preliminary List of Procedural Matters**)

I. Preliminary List of Issues

A. Pros and Cons of a Standardized Approach

1) In general and without specifying which methodology (ies) might be used, what are the pros and cons of adopting a standard methodology (ies) for setting equity rate of return in utility rate cases?

2) In general and without specifying which methodology (ies) might be used, what are the pros and cons of adopting a standard methodology (ies) for setting capital structure in utility rate cases?

3) Is the adoption of a generic approach to utility equity rate of return and capital structure in keeping with developments in other jurisdictions in North America?

B. Alternatives within a Standardized Approach

1) Assuming that the establishment of a standardized approach to setting equity rate of return is desirable:

    i. What options or alternatives should the Board consider? For example, the comparative earnings method, the risk premium method, the discounted cash flow method, ATWACC, and the NEB's approach that includes an adjustment formula.

    ii. What are the pros and cons of each option or combination of options?

2) Assuming that the establishment of a standardized approach to setting utility capital structures is desirable:

   i. What options should the Board consider?

   ii. What are the pros and cons of each option or combination of options?

C. Standardized vs. One-by-One Approach?

1) Would it be correct to consider a standardized approach to setting utility equity rate of return for all types of utilities under the Board's jurisdiction, including gas transmission, gas distribution, gas retail, electric transmission, electric distribution and electric regulated rate option providers?

2) Would it be correct to consider a single standardized approach to setting utility capital structure for all types of utilities under the Board's jurisdiction, again including gas transmission, gas distribution, gas retail, electric transmission, electric distribution and electric regulated rate option providers?

3) What principles should guide the determination of capital structure for utilities that are owned by holding companies, i.e. what principles and issues should be taken into account in dealing with a deemed vs. actual capital structure?

4) What differences exist between investor owned and municipally owned utilities that affect determination of cost of capital issues and how should those differences be taken into account with respect to cost of capital issues including return on equity, capital structure, debt costs and income tax?

D. Timing Issues

1) The Board is considering setting an implementation date for any cost of capital methodology (ies) adopted sufficiently far in advance, so as not to impact rate cases or settlement negotiations occurring during the generic hearing process. Alternately, the Board could direct parties to use placeholders for rate of return and capital structure with respect to applications not presently before the Board. What are the pros and cons of each approach?

2) What are the implications of the substance and timing of a cost of capital generic hearing with respect to the possible regulation by the Board of municipally owned utilities?

3) Should the Board consider setting an expiry date or a mandatory review date for any methodology (ies) it may determine to be appropriate for cost of capital issues? If so, what is an appropriate length of time that should elapse before a review is required?

4) How should adjustments in equity rate of return and capital structure be dealt with between test periods?

E. Special Considerations

1) Should parties have the option of agreeing, through a negotiated settlement process, on an equity rate of return and/or capital structure that is different from the equity rate of return and/or capital structure that would result using the standardized approach?

2) What provision, if any, would an inquiry into cost of capital issues need to make with respect to the Performance Based Rates (PBR) methodology or other evolving methodologies for setting rates or rate components?

3) Should the Board consider negotiated pricing arrangements in respect of expansion or merchant projects as a substitute for traditional forms of earning through equity rate of return and capital structure, (for example the Alliance Pipeline)?

II. Preliminary List of Procedural Matters

A. One or Two Phases

1) At a generic hearing:

   i. Should the Board conduct a single-phase hearing to consider both equity rate of return and capital structure generic issues?

   ii. Alternately, should there be two separate phases, one into equity rate of return applicable to all types of utilities and the other into capital structure for each type of utility?

   iii. Should the proceeding be with respect to all utilities or do the distinctions between gas, pipeline and electric industries merit separate and distinct generic hearings or phases?

B. Schedule for the Proceeding

1) Designation of "Applicant(s)" for initial evidence submission

2) Desired Process and dates for the following:

   i. Initial Evidence
   ii. IRs
   iii. Response to IRs
   iv. Intervenor Evidence
   v. IRs to Intervenors
   vi. Response to IRs to Intervenors
   vii. Rebuttal Evidence

C. Costs

1) With respect to costs for the generic hearing(s):

   i. Should some parties be only partially funded?

   ii. If so, which parties should this apply to?

   iii. How could parties be provided with incentives to combine positions where possible to achieve cost and time efficiencies?

APPENDIX B

City of Calgary Letter dated May 6, 2002

"Appendix B.doc"

(Consists of 5 pages)

Please note that the above Appendix is embedded and may take a second or two to appear.

APPENDIX C

Board Letter dated June 6, 2002

"Appendix C.doc"

(Consists of 1 page)

Please note that the above Appendix is embedded and may take a second or two to appear.

Burnet,
Duckworth
& Palmer LLP
Law Firm

Reply to: R. Bruce Brander
Direct Phone: (403) 260-0165
Direct Fax: (403) 260-0332
rbb@bdplaw.com

Assistant: Donna Koenig
Direct Phone: (403) 260-0186
Our File: 50343-135

VIA EMAIL

May 6, 2002

Alberta Energy and Utilities Board
640 - 5th Ave. S.W.
Calgary, AB T2P 3G4

Attention: R. D. Heggie
Executive Manager, Utilities Branch

Dear Sirs:

Re: Cost of Capital for Electric and Gas Utilities under the Board's Jurisdiction

Pursuant to the provisions of the *Public Utilities Board Act*, R.S.A. 2000 c. P-45 (the "PUB Act"), the *Gas Utilities Act*, R.S.A. 2000, c. G-5, (the "GUA"), the *Electric Utilities Act*, R.S.A. 2000 (the "EUA"), c. E-5, and the *Alberta Energy and Utilities Board Act*, R.S.A. 2000, c. A-17 (the "AEUB Act"), The City of Calgary ("Calgary") hereby applies to the Board to convene a proceeding or inquiry to establish a mechanism for the appropriate cost of capital (return on equity and capital structure] for the gas and electric utilities under the Board's jurisdiction. This Application is being made on behalf of Calgary by its legal counsel Burnet Duckworth & Palmer LLP. The particulars of, and support for, this Application, are provided in the following sections.

Interest of Calgary

As the Board is aware, Calgary has a long history of intervention in regulatory proceedings which impact its citizens. With respect to gas utilities, core customers within Calgary represent approximately 70% of the gas consumption and revenue requirement of ATCO Gas South. Through the ATCO Gas South and ATCO Pipelines South rate structure, core customers within Calgary are also responsible for approximately 40% of the revenue requirement of ATCO Pipelines South. Consumers within Calgary also consume approximately one-sixth of the provincial electrical production, and are affected by the rates charged by the Transmission Facility Owners ("TFO"'s).

Cost of capital (including return on equity, capital structure, and associated income taxes) is a significant portion of the revenue requirement of any regulated utility. Using the applied for amounts for 2001 for ATCO Gas South, return on equity and taxes were about 16% of the revenue requirement, and for ATCO Pipelines South about 33%. Based on the TFO materials filed for 2001, return on equity and associated taxes for ATCO Electric and TransAlta were approximately 35% and 33% respectively (EPCOR Transmission Inc. with no tax was approximately 16%).[1]

[1] The percentages increase significantly if return on rate base is used instead of return on equity.

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Frank L. Burnet Q.C. (1890-1982)
Thomas J. Duckworth Q.C., Counsel

In recent years Calgary has retained experts to present evidence on cost of capital in several proceedings: Canadian Western Natural Gas 1997/1998 GRA, the 2001 TFO Tarff Applications of ATCO Electric, TransAlta and EPCOR Transmission Inc., the ATCO Gas South 2001/2002 GRA, and the ATCO Pipelines South 2001/2002 GRA. As one of the few parties that can afford to carry the significant cost of presenting evidence in this area, Calgary expects that it will be presenting cost of capital evidence in future proceedings affecting its citizens.

As a result, the citizens represented by Calgary are directly affected by return on equity and capital structure issues

Grounds

As noted above, cost of capital constitutes a significant portion of the revenue requirement of the utilities regulated by the Board. Dealing with cost of capital issues is also a significant portion of hearing costs. Cost of capital is also an area where there are a limited number of experts available and the costs of presenting such expert reports is a substantial cost to an intervention – often at rates that exceed the Board's guidelines.

In the recent ATCO Gas South and ATCO Pipelines South proceedings the return on equity and capital structure experts retained by ATCO and Calgary cost just under $200,000 for each proceeding. In the TFO proceedings for 2001 rates, where the three TFO's each filed separate return on equity evidence, expert witness costs totaled about $711,000 for Calgary, ATCO Electric and TransAlta[2]. In addition to the fees of the cost of capital experts, there are significant additional costs for legal counsel, and other experts, to interact with the cost of capital experts to present the case. Where an intervenor incurs these costs as part of the hearing process, the intervenor not only must carry the cost until a Costs Order is issued, but also bears the risks that the utility will oppose the costs which the intervenor has incurred to benefit all customers, or that hourly rates that are in excess of the Board's guidelines will be denied. In addition, the intervenors also bear the utility's costs through the revenue requirement and the hearing reserve account.

In the ATCO Gas South and ATCO Pipelines South 2001/2002 GRA's the utilities filed identical return on equity evidence. Calgary, as the intervenor dealing with return on equity, then had to file evidence responding to the utilities' return on equity requests in two different proceedings, with two attendances by the experts. In Decisions 2000-96 and 2000-97 dealing with these GRA's, the Board issued identical reasons on return on equity matters[3] and made, *inter alia*, the following observations:

> The Board is concerned that, despite its volume, the nature of the expert evidence provided is ultimately of little probative value to the Board in establishing this important determinant of the utility's revenue requirement.
>
> In particular the Board notes the effect that the application of professional judgement [sic] has on the outcome of the equity risk premium test. This test has been noted to be the mainstay of this Board and other Canadian regulatory boards over recent periods...
>
> ....

---

[2] Calgary, $163,000 (for evidence on all three TFO's); ATCO Electric TFO, $79,000; TransAlta, $468,000. Calgary has not yet been provided details of EPCOR Transmission Inc.'s costs.

[3] Decision 2000-96 pages 52 – 59; Decision 2000-97 pages 31 - 38.

> Further, these [equity risk premium] estimates are far enough apart that the underlying evidence is of little value to the Board in establishing an accurate and well justified estimate of the utility rate of return required to maintain the financial integrity of the utility in the eyes of investors and the market. Subsequently, the Board must rely on an examination of past awards to CWNG to determine if there is a requirement for adjustments to those awards. The Board is also of the view that alternative methods of determining appropriate utility return may need to be examined for use in future rate cases. (emphasis added)

Other Canadian regulatory boards have addressed concerns with respect to the determination of the appropriate cost of capital by taking what could be called a "generic" or formulaic approach to the issue. These include:

- National Energy Board, Multi-Pipeline Cost of Capital, RH-2-94[4],
- British Columbia Utilities Commission, Return on Common Equity Decision, June 10, 1994, Order G-35-94
- Ontario Energy Board Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities, March 1997,
- Manitoba Public Utilities Board Order 49095, page 50.

In Alberta, there has been some limited discussion of a generic approach to return on equity:

- In the Board's Costs Workshop of June 20, 2000 the question of why intervenors did not reduce costs through a different approach to return on equity was raised. Intervenors responded that they had to deal with the applications as filed by the utilities, and no utility had filed for a formula based approach to return on equity.

- In the 2001 TFO proceeding the evidence of Drs. Booth and Berkowitz on behalf of Calgary recommended the use of an adjustment formula for 2002 return on equity[5]. The issue of a formula based approach to return on equity was briefly discussed during the TransAlta portion of the hearing.[6]

- In the 2001/2002 ATCO Gas South and ATCO Pipelines South GRA's the evidence of Drs. Booth and Berkowitz on behalf of Calgary again suggested consideration of an adjustment formula for 2002.[7]

To date, so far as Calgary is aware, none of the utilities under the Board's jurisdiction has filed an application to have cost of capital determined on a generic or formulaic basis, nor is Calgary aware that any of the utilities are planning on doing so. However, Calgary believes that there will be several proceedings in the near future where cost of capital will have to be addressed. These include:

- ATCO Gas 2003 – 2000x GRA for ATCO Gas North and South combined,

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[4] In proceeding RH-4-2001 TransCanada PipeLines Limited sought a review of the RH-2-94 Decision and presented a methodology that the EUB was presented with by TransAlta in the 1999/2000 GTA, and was included in TransAlta's 2001 TFO filing.
[5] Applications 2000132, 2000133 and 2000134, Evidence of Laurence D. Booth and Michael K. Berkowitz, page 75.
[6] 2001/2002 TFO Proceeding, September 25, 2000, Volume 3, pages 497 – 501.
[7] AGS GRA Exhibit 43, Evidence of Laurence D. Booth and Michael K. Berkowitz, page 68; APS GRA Exhibit 69, Evidence of Laurence D. Booth and Michael K. Berkowitz, page 63.

- A combined ATCO Pipelines North and South 2003 – 2000x GRA,

- The ATCO Electric TFO (and DISCO) negotiated settlement expires in 2002, and ATCO Electric has notified the Board that a 2003 – 2005 combined application for Transmission and Distribution will be filed in mid to late second quarter 2002.

- The EPCOR Transmission Inc. TFO negotiated settlement will expire at the end of 2002 and, presumably, a 2003 GRA will result,

- Altalink Management Ltd. TFO will need to file a GRA for 2002 and subsequent years.

In addition to the foregoing there may be other gas and electric utilities, with which Calgary is not involved, that will require rate hearings for 2003 and beyond.

Given the recent history with cost of capital matters, and the likelihood of several hearings in the near future dealing with cost of capital, it is Calgary's view that there would be several advantages to a "generic" cost of capital proceeding:

- *Reduction in expert witness costs.* Even if all of the utilities used different experts for a generic proceeding, there would be a likely cost saving to intervenors in only having to retain cost of capital experts for a single proceeding, instead of for multiple proceedings.

- *Reduction in overall hearing costs.* The fees for cost of capital experts are only a portion of the overall expense of dealing with cost of capital in a hearing. Fees for counsel and other experts to deal with cost of capital matters and present the case are also significant. Calgary would expect that a generic proceeding would result in cost reductions through synergies or economies of scale.

- *Efficiencies in use of Board resources.* Dealing with cost of capital matters for several utilities at the same time would, presumably, allow the Board to deal with the issues more expeditiously as it would not have to be dealing with evidence filed at different times, and in different proceedings, when ensuring that the issues are addressed in a consistent manner.

- *Future Cost Savings.* Should a generic proceeding result in Board decisions on cost of capital that last over a period of years, then Calgary would expect that future cost savings would be achieved either through simplification of future GRA's, or through facilitation of negotiated settlements by removing the cost of capital issue from negotiations.

Statutory Provisions

Calgary believes that the Board has the required jurisdiction to convene a generic cost of capital proceeding pursuant to the provisions of the AEUB Act (ss. 13 and 15); the PUB Act (ss. 36, 37, 46, 47, 89 and 90); the GUA (ss. 22, 36, and 37); and the EUA (ss. 47, 49, and 52).

Consultation Process

As discussed above, Calgary does not believe that the utilities under the Board's jurisdiction have shown any interest in the past in a generic approach to cost of capital issues. As a result, and considering the number of utilities potentially involved, Calgary concluded that the best way to address this issue was through an application to the Board that would allow all interested parties to express their views. Calgary has, however, held informal discussions with some intervenor groups and believes that customer groups, who ultimately bear the burden of cost of capital litigation, will be supportive of any approach that has the potential to reduce costs.

Summary of Relief Requested

Calgary requests that the Board institute a proceeding to determine:

1. the appropriate rate of return on common equity for each utility examined,

2. the appropriate capital structure for each utility examined,

3. the time frame over which the rate of return on common equity should apply,

4. if the time frame for the rate of return on common equity is to be more and one year, or other specified test period, the mechanism by which the rate of return would be adjusted in further years,

5. the time frame over which capital structure should apply, and the process for adjusting capital structure,

6. the appropriate regulatory process for future proceedings dealing with return on equity and capital structure.

Communications

All communications with respect to this Application can be addressed to the undersigned.

Service

Calgary will be providing a copy of this Application to the Interested Party lists from the ATCO Gas South and ATCO Pipelines South GRA's, GCRR Methodology Proceeding, the 2001/2002 TFO Proceeding, and the TransAlta/Altalink Proceeding. Copies will be provided to any other party, or list, that the Board directs.

Yours truly,

Burnet, Duckworth & Palmer LLP

(Original signed by R. Bruce Brander)

R. Bruce Brander

RBB\dk
cc: Interested Parties Lists:
ATCO Gas South 2001/2002 GRA
ATCO Pipelines South 2001/2002 GRA
GCRR Methodology Proceeding
2001/2002 TFO Proceeding
TransAlta/Altalink Proeeding
G:\050343\0135\AEUB Capital Cost Application from Calgary May 6 2002.doc

EUB Alberta Energy and Utilities Board
Calgary Office 640 – 5 Avenue SW Calgary, Alberta Canada T2P 3G4 Tel 403 297-8311 Fax 403 297-7336

Via Email and Mail

File No.: 5681-1

June 6, 2002

Mr. R. Bruce Brander
Burnet, Duckworth & Palmer LLP
Law Firm
1400, 350 - 7 AVE SW
CALGARY AB T2P 3N9

Dear Mr. Brander:

APPLICATION 1271597
COST OF CAPITAL FOR ELECTRIC AND GAS UTILITIES UNDER THE BOARD'S JURISDICTION

I refer to your letter of May 6, 2002, on behalf of the City of Calgary, requesting that the Board convene a proceeding or inquiry to establish a mechanism for determining the cost of capital for utilities under the Board's jurisdiction.

The Board has now had the opportunity to thoroughly review this request. Upon reflection, the Board considers that it would be appropriate to await the National Energy Board's upcoming decision on rate of return before proceeding to deal with this issue.

We will be contacting interested parties further with respect to procedure once this decision has been released.

Yours truly,

<original signed by>

Robert D. Heggie
Executive Manager
Utilities Branch

pc: Interested Parties Lists via Email Only:
- ATCO Gas South 2001/2002 GRA
- ATCO Pipelines South 2001/2002 GRA
- GCRR Methodology Proceeding
- 2001/2002 TFO Proceeding
- TransAlta/AltaLink Proceeding
- EAL Congestion Management Proceeding